BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of :
REVIEW OF GENERATOR : Docket No RM16-12-000
INTERCONNECTION AGREEMENTS :
AND PROCEDURES :
AMERICAN WIND ENERGY ASSOCIATION:
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Commission Meeting Room
Federal Energy Regulatory Commission
888 First Street, Northeast
Washington, D.C. 20426
Friday, May 13th, 2016

The technical conference in the above-entitled matter was convened at 9:00 a.m., pursuant to Commission notice and held before:

CHAIRMAN NORMAN BAY
COMMISSIONER CHERYL LaFLEUR
COMMISSIONER COLETTE HONORABLE
COMMISSIONER TONY CLARK

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PRESENTERS:

PANEL 1:

Tim Aliff, MISO

David Gabbard, PG&E

Dean Gosselin, NextEra

Alan McBride, ISO-NE

Steven Naumann, Exelon

Rick Vail, Pacificorp

PANEL 2:

David Angell, Idaho Power

Jennifer Ayers-Brasher, E.ON

Joshua Bohach, EDP

David Egan, PJM

Charles Hendrix, SPP

Randal Oye, Xcel

Stephen Rutty, CAISO

Kris Zadlo, Invenergy

PANEL 3:

Tim Aliff, MISO

Dean Gosselin, NextEra

Paul Kelly, NIPSC

Omar Martino, EDF

Alan McBride, ISO-NE

Stephen Rutty, CAISO

Rick Vail, Pacificorp

PANEL 4:

Tim Aliff, MISO

David Angell, Idaho Power

Jennifer Ayers-Brasher, E.ON

Daniel Barr, ITC Holdings

Charles Hendrix, SPP

Paul Kelly, NIPSC

Omar Martino, EDF

Steven Naumann, Exelon

PANEL 5:

David Egan, PJM

Mason Emnett, NextEra

John Fernandes, RES Americas

David Gabbard, PG&E

Alan McBride, ISO-NE

Stephen Rutty, CAISO

Court Reporter: Alexandria Kaan, Ace-Federal Reporters

P R O C E E D I N G S

(9:00 a.m.)

MR. PAN: Good morning. Welcome to the Review of Generator Interconnection Agreements and Procedures technical conference. This conference will focus on select issues from the AWEA petition on rule-making, and other interconnection-related issues including interconnection of electric storage. I'm Adam Pan with the Office of General Counsel. This is a staff-led technical conference and any comments made here represent the views of Commission staff and do not necessarily reflect the Commission's views. A final agenda is available for attendees at the meeting room entrance. There a few minor changes in the biographical information.

We have a few housekeeping matters to note: Please turn you mobile devices to silent. We also note in the Commission meeting room no food or drink other than water are allowed. If you need Wi-Fi information, there are forms at the meeting entrance. You need to sign the forms before you sign in. We will break for lunch from noon to 1:00 p.m. There will be a morning break from 10:20 to 10:30 a.m. There will be an afternoon break from 2:10 to 2:20 p.m.

Speakers, please be sure to turn your

microphones on and speak directly into them so that audience and those listening to the webcast can hear you. Please turn your microphones off when you are finished speaking. Panels 1 through 4 will be moderated by Tony Dobbins, panel 5 will be moderated by Michael Herbert. Thank you.

Commissioner Honorable is here. I don't know if you wanted to take the opportunity to say a few words.

COMMISSIONER HONORABLE: Thank you. Good morning everyone. I'd like to thank the representatives here from the various stakeholders groups, and in particular there are a number of you that I've known for a number of years, so you've seen me try to transition from being a state regulator and now a federal regulator. And more importantly, I appreciate the ways in which you've attempted to educate regulators about, not only the important resources that we're attempting to ensure stay not only in the queue but integrated well, but also ways in which you're educating us, and me and my staff in particular, about the barriers of some of the concerns and issues that you're having in the interconnection process.

Generation interconnection queue issues have the potential to negatively affect the competitiveness of our markets and the reliability and resilience of our grid. And I believe that these processes can not and should not be a barrier to entry for needed generation capacity, for variable resources, or energy storage, if we are to maintain a robust and reliable power system.

In particular, during my tenure here at the Commission, I've had a number of very robust discussions with a number of you regarding experiences that you have had navigating the interconnection queue process, and I have heard you loud and clear, as have my colleagues here at FERC and my staff, and I'm very pleased that under the direction of our Chairman and my colleagues, we have approved this technical conference.

I'd like to thank our very capable staff who have worked very, very hard, as you can tell from the agenda, we will cover a lot of ground today, and that's why we're here an hour earlier, so thanks to those of you who actually read the notice.

But our purpose here today, and in particular I'm interested in hearing about not only concerns and issues that you're experiencing with regard to the queue process, with interconnection agreements, also I'm particularly interested in hearing about the study process in ways we can improve this work. I was joking I think with Rob Gramlich that we are looking to you all for the silver bullet. Maybe there isn't one, but I'm hopeful that through our dialogue throughout the day that we will hear from you. You all are the experts, maybe proposals for the solution, because I think we all share in common that we want this to work well to ensure we have robust markets, and ultimately that we are providing diverse, reliable, and affordable energy for the people that we serve.

So I'd like to thank all of you for your attendance here today, I look forward to hearing you comments, and thank you for the opportunity to participate.

MR. PAN: We'll begin our first panel at 9:20. So we ask that all staff and panelists be seated and prepared at that time.

MR. DOBBINS: We're going to go ahead and start panel 1 at this time, which is to discuss issues related to the current state of the generator interconnection queues. We are starting five minutes earlier than in the agenda, so everyone please take note of that. I'm sure that additional five minutes will be well deserved for a topic such as this.

We will ask panelists to introduce themselves and present their prepared remarks which were submitted to the docket or mention the one or two most important points they would like us to come away with today. Please keep your remarks under two minutes. We will use the timer, which the panelists can see upfront, to let them know how much remaining time there is. And we'll start on my left with Mr. Tim Aliff.

MR. ALIFF: Thank you. Good morning. My name is Tim Aliff, I'm director of reliability planning with MISO. My purview includes the generation interconnection process.

MISO has always been looking to improve the interconnection queue process; we've done that over the last almost 10 years, including three different queue reform proposals that were successful in moving the process forward, making the process better. Today we're experiencing challenges in our queues specifically related to delays and how long it takes for units to move through the queue process. And we are working with our stakeholders continually and through our interconnection process task force and then also working with the Commission and the guidance that we received through the Commission on how we can make our process better.

One of the things related to being at the FERC level here is that we want to point out that each of the regions, each of the transmission providers, have unique differences that need to be at least respected, if you will, in the interconnection process. One size doesn't fit all from an interconnection queue process, something that works in a one-state RTO may not work in a multistate RTO such as the MISO.

And specifically within the MISO, the multistates, each of the states has their own view on renewable portfolio in that state. And so recognizing that difference and also the flexibility that provides to each of the regions and being able to move that interconnection queue process forward and to the benefit of the stakeholders moving through, and also to ensure the reliability of the transmission group going forward.

MR. DOBBINS: Thank you.

MR. GABBARD: Good morning. My name is Dave Gabbard. I'm director of electric generation and interconnection at Pacific Gas and Electric Company. My team's responsible for interconnection generation to both PG&E's transmission and distribution systems. First, I want to thank the Commission for the opportunity to participate today.

Under the direction of the California ISO, PG&E has safely and reliably commissioned over 6,200 megawatts of generation over the last 10 years. We have an additional seven gigawatts of active generation in the CAISO queue progressing towards interconnection on the PG&E transmission system. In addition PG&E has interconnected over 400 megawatts of distribution generation to its distribution system under its wholesale distribution tariff, and has an additional 400 megawatts of generation in its queue.

PG&E has both witnessed the legacy issues impacting the transmission interconnection process and the tariff reform led by the California ISO to mitigate these issues. PG&E commends the California ISO for its efforts to lead industry collaboration and stakeholder processes that result in an enhanced interconnection tariff, that helps mitigate queue management, backlog, and transmission overbuild challenges. That said, the solutions developed within the California ISO territory are unique to the environment and stakeholders involved within the CAISO interconnection process.

While PG&E supports benchmarking across regions for lessons learned, PG&E does not recommend forcing region-specific solutions across other RTOs and stakeholders. Maintaining a regional flexibility at the interconnection process will allow RTOs, PTOs, and generator stakeholders to continue to refine processes and tariffs to accommodate transmission generation interconnection in an evolving market landscape. Thank you.

MR. GOSSELIN: I'm Dean Gosselin with NextEra Energy Resources. I'm vice-president of business management transmission services. We are a developer owner operator of renewables across the country. What we find is the process of the system impacts study on the interconnection queue process' result is a key input to every one of our projects; its costs and the timing of those facilities, are necessary to make a determination of whether a project is viable or not.

So at the beginning of a process when we think about entering a queue, what's important is that we have valid solutions coming back to us in a timely manner and that they're accurate, that they're accurate in what they say.

The issues that we see is there's lots of restudies going on now. So at the initial offset of a queue or of a group study, there's a lot of generators, new generator requests, that won't be built. And as the queue progresses and they begin to get answers back, they drop out. And that destabilizes the queue, and then the queue process starts again.

So what we're seeing is more and more entrants, more and more megawatts coming at any given study queue, and then many restudies having to drag out the process of determining ultimately who's left and what are those costs and schedules for system upgrades. So what we need is an optimal solution, that's the tough part. Right? I don't think anybody in the country has an optimal solution today. There are pieces of good, everybody's working towards it, nobody's trying to impede it. But it's difficult when that queue is not stable, at least the study entities are not stable. Thank you.

MR. McBRIDE: Good morning. My name is Alan McBride. I'm the director of transmission strategies and services at ISO New England, and my responsibilities include the oversight of the interconnection queue. I want to thank the Commission for the opportunity to speak here today.

ISO New England has been working with the interconnection issues with our stakeholders. And the ISO's recent filing with the interconnection improvements was approved by the Commission on April 15th. That filing contained important clarifications of data modeling, requirements for new generation, in particular for inverter-based generation. It also included the clarifications of the ISO's material modification review process, as well as the establishment of dynamic reactive power factor requirements for wind generation.

The ISO's continuing to work with stakeholders on interconnection improvements. We're currently undertaking a discussion of different approaches to clustering, and we are investigating the identification of new transmission infrastructure that could be used to interconnect multiple interconnections.

Our considerations have included a survey of clustering approaches used by transmission providers including ISOs and RTOs throughout North America. The surveyor identifies some useful features and practices. It also highlighted the importance of regional differences in the appropriate design of interconnection practices, as there are different needs in each local area driving the development.

For example, in New England, the interconnection process is integrated with the forward-capacity markets, and that is an integration that is working well; I can talk about that later if we need to. The ISO also noted meaningful differences in approaches to ratepayer support for network upgrades in different regions.

Within New England, the ISO has identified differences in the rate of progress of interconnection request depending on the technical challenges. There have been a large number of requests that are geographically concentrated in a over-subscribed area of the system that is already at its performance limit. So our current work is to identify potential solutions and move that process forward. Thank you.

MR. NAUMANN: Good morning. I'm Steve Naumann, vice president of transmission policy at Exelon. Thank you for asking me to speak here.

As you have heard, there have been a lot of improvements in the processes since 2003, especially within the ISOs and RTOs and they've been working with their stakeholders. We agree with some of the requests, such as increasing transparency, having access to the models. But many of these requests would result in asymmetrical shifts and risks from the interconnection customers, and that's something we do not agree with.

While there have been improvements, the system has also changed since 2003. We have serious concerns about implementation process for ERIS interconnections because of the impact on existing resources. The ERIS generators use "as available transmission capacity."

But in midbase market environments without proper analysis, it matches the way the systems operate.

These generators can be allowed to cause additional congestion, and that congestion has caused harm to existing base load units that can no longer withstand the financial harm that is being done to them.

To be more specific, along the lines of not harming existing customers when considering new interconnections, new interconnection resources that are most likely to impact the system need to be, as I said, studied as they operate, not necessarily at peak load.

So what you need to do is look how they're operated, and obviously combined cycle may be on a peak load but other intermittent resources are not. And in those cases, light load needs to be studied for congestion and reliability. This is a best practice in PJM, and it's also being done here. Thank you.

MR. VAIL: Good morning. I'm Rick Vail, I'm the vice president of transmission with Pacificorp. Some of the areas under my responsibility are generation interconnection queue, the transmission planning staff, as well as all of the capital budgeting that's associated with the transmission system at Pacificorp.

So Pacificorp has what I would call a well-established queue process. I will say we're under that mode of continuously evaluating it, getting feedback from our customers, and trying to improve what that queue process is. It is a serial queue process; Pacificorp is not currently part of any regional ISO, so it may be a little bit unique or different perspective than some of the other entities here.

Pacificorp has processed roughly 750 interconnection requests, about 20 percent of those end up going into service. Over time we've had a higher percentage of the projects go into service, a lot of the requests that we get seem to be a little bit of a fishing expedition in trying to determine where within the transmission system is probably the most appropriate place to attach for generators.

I think one of the main issues or concerns from a Pacificorp perspective is that we get a significant number of requests in small geographic areas, and that can put a lot of stress and pressure on the existing system, especially from a reliability standpoint.

So some of the kind of suggestions that we've looked at is trying to minimize what the suspend status of higher queue projects is, that really can have a big impact on the uncertainty that developers face when higher queue projects drop out, and I'll talk a little bit more on that as we go forward.

One other concept we have to consider is just trying to increase the deposit requirements and financial security backing as some of these developers come in. The more sophisticated developers are very well-aware of what the requirements are, as we get some more sophisticated developers that can kind of bring a lot of volume to the queue that may or may not end up going forward. So thank you.

MR. DOBBINS: All right. Thanks to all of our panelists on panel 1 for their time and participation for today and their opening comments. And I'd also like to acknowledge Commissioner LaFleur who has joined us, and we thank you for your attendance and participation. And before staff moves on to ask questions, I wanted to see if you would like to make any comments.

COMMISSIONER LaFLEUR: Well, thank you. I am happy to be here. I had an appointment out of the office; it's hard to find a day when there's no tech conference to schedule things. Sorry I missed the first panel, but I look forward to the conversation. I think the topic of today covers a lot of important issues, so look forward to hearing it. Thank you.

MR. DOBBINS: Okay. Well, now we're going to move on to our staff here from FERC asking questions. Panelists, please limit your responses to around a minute so that other panelists will have time to speak and we can cover as many topics as we can. And apologies in advance if we aren't able to hear from everyone on every topic.

I'll start us off with the first question. We've had, through your comments filed in the docket and also some of your remarks and introduction, an indication of improvements made in the queue process, but also areas where, you know, there are challenges. We would be interested in getting your general overall thoughts on how the queue process is working and if there are any clear areas for improvement, if you've targeted solutions there. And we'll start off on my left with Mr. Aliff.

MR. ALIFF: Thank you. So first, how is the current queue working? As I mentioned in my opening remarks, we understand there are challenges related to delays in the queue that's mostly related to restudies, as you heard in some of the opening remarks, projects withdraw and then be have to restudied. We're seeing withdrawal rates over 50 percent in lots of parts of the queue, specifically in our northern areas where it's more congested.

As far as metrics that we've implemented, we measure the cycle times, how far behind are we on our queue, and we're currently on it close to about a year behind in our queue processing. So some ways that we present that make that clear, transparent to our stakeholders as we provide that through stakeholder meetings, we provide that on our website so you can see how far behind we are in the projected dates for completion of the queue.

As far as the process improvements, discouraging non-ready projects, the projects that are likely to withdraw moving through the queue, reducing the amount of restudies, having more scheduled restudies in the process rather than unforeseen restudies. Also, clear requirements related to everyone involved. Clear requirements for the interconnection customers providing information, the transmission owners performing studies, and then MISO as well performing studies and meeting timelines. Thank you.

MR. DOBBINS: And before we move on to our next response, I just wanted to get a clarification on your saying over 50 percent withdrawal. Is that, in your opinion, mostly due to projects who aren't really ready to move forward and were testing the water, or is it projects that they got in the queue, found out that information they need, and from a business standpoint have decided it's not a viable project moving forward?

MR. ALIFF: It can be both of those scenarios, projects that aren't quite ready, there are various things that impact a project, the permitting process, regulatory approval, et cetera, from a project's perspective. Also, it's not known until a project enters the queue what other generators are in the queue. We study a group so we group resources together and we move the group through the process. So the individual interconnection customer doesn't know who's in that group until they've actually entered the queue and moved forward.

And that picture can change if someone else in that group withdraws, that impacts another party in that group and can change their cost related to that interconnection request.

MR. DOBBINS: And just one last followup. Is there any percentage of that group that express to you that they're withdrawing for more reasons of time, that the process is going too slow so they're not able to advance their projects in a timely fashion rather than a cause or a fishing-expedition approach?

MR. ALIFF: We have not heard anyone say that they are withdrawing because the process is taking too long.

MR. DOBBINS: And we'll just go down the

line of the panel to see if anyone else would like to address the original question, which was: Your general thoughts on effectiveness of the queue and if there were areas that are easy areas for improvement. And please understand we have your responses, which have been filed in the docket. So if you don't want to -- if you haven't addressed this in your docket, also please feel free -- sorry, in filing the docket -- please feel free to offer any information here.

MR. GABBARD: Again, I'm Dave Gabbard, director of electric generation at PG&E. I just want to touch on a couple of points. I think the specific enhancements to the interconnection process in the California ISO service territory are unique to the configuration and different characteristics of operation in that territory.

But I do want to call out and acknowledge the process in which we have evolved the interconnection processes over the last five years specifically. There have been macro reforms to the tariff, but also the California ISO has led interconnection processing enhancement stakeholder discussion that have allowed us as a collaborative set of stakeholders to identify issues and then find solutions that work for all parties. As a metric for identifying the success of those enhancements, I would acknowledge the amount of generation that is being interconnected on an annual basis.

I don't think that fallout is a good metric for whether or not a process is successful other than the fact that fallout of nonviable generation earlier in the project is proof of success. So the process we have in place within the California ISO service territory and specifically within the PG&E service territory allows for generation to come in and identify the impacts to the grid from interconnecting a proposed generator. But it requires a certain level of commitment with respect to the process and allows generation that's nonviable to withdraw earlier in the queue, allowing more viable generation to successfully progress through the queue, effectively without too much overheated and overbilled challenges going forward.

From a timeline perspective, both on our WDT side, the wholesale distribution side, as well as within the CAISO process, we are up to speed with tariff timelines and progressing interconnection queues and serial request in a timely manner in compliance with our tariffs. And we have seen those projects successfully move forward to completion. The delays that are experienced within the process have happened on both sides, the interconnection customer who participated and transmission owners. It's at various stages. Need for financing and other things naturally cause certain delays at certain phases, but the overall progression towards cooperation continues through actively and our processes are set up to support that. Thank you.

MR. GOSSELIN: Dean Gosselin with NextEra Energy Source. I'd like to just talk about what is optimal. We were thinking about it, as a developer we were bringing a new project idea and trying to advance it to fruition, "fruition" being completion of the project. I would say for the interconnection queue that the initial results closely match final results in a defined and reasonable timeline, that would be my definition.

So all of the RTOs really provide us models, they give us their models and they're repeatable, they're accurate. The problem with us running the models -- and we do that in advance of submitting a project, and we look at the results and if they look to be expensive or costly and a long schedule to do upgrades, we are not putting in a request because it's not going to go anywhere, it just doesn't work; not in our schedule, not in our cost, and not in the RTO's.

However, what we don't know is who else is going to enter that queue with us, and what is the cumulative impact of that group. And we can't know that, it's unknowable at the time in which we put in a request. And that is I think one of the fundamental issues with queue timing and schedule and accuracy of the study process coming out of it. That's obviously the area of challenges: Stabilizing the group to the point where the study that goes on, the final study that goes on, gives you valid results.

And the results are, I don't think any of us -- certainly NextEra does not believe we're getting invalid results, it just believes we're getting a lot of restudies that stretch out the timeline. And we have a saying in our world of development which is time kills all projects. So the longer it takes, the more unlikely it is that a project will be valid and go to fruition. Thank you.

MR. McBRIDE: Alan McBride, again, with ISO New England. Many of us have been thinking through your question, we want to make sure we were careful to identify what was working well and what was not working well, and not approach it from just generically "there are queue problems."

In New England, we study energy interconnections in serial queue order, and then we integrate the queue with the forward-capacity market and what's effectively an annual group study or annual cluster. That would be very important that that works well, we have a sufficient number of generation that's seeking to participate in the forward-capacity market successfully, be able to qualify and do so, and that has been going well over these past few now 10, going onto our 11th, forward-capacity auction.

The problem we do have is in a specific part of the system that's already at its performance limit, we have a significant number of interconnection requests, mostly are pretty much exclusively for renewable interconnections. So that is the diagnosis of the problem, and then we went down the path to see what would be appropriate solutions to that.

The first step was we did identify some issues with the performance of the particular type of generation and we saw some benefit in making clear that we were communicating appropriate expectations for what the modeling and data should be that should be provided that we can plug those into the models and get the study done quickly, and we're already seeing some benefits from that.

And then the remaining part of the solution is the infrastructure challenge. It seems like it lends itself to some kind of either a clustering solution or some other solution to bring infrastructure to integrate the requests that we have for that situation, and that's what we're working on now.

MR. DOBBINS: And before we move on, I just want to clarify you're saying moving to a clustering-solution region why are you looking for a way just to cluster the geographically constrained or concentrated area?

MR. McBRIDE: I think that's exactly the question we're asking ourselves and that we're going to be working with with our stakeholders. We are very cognizant of some of the difficulties of clustering and with restudying and uncertainty. So we're looking at ways, seeing if we can find a way to minimize the uncertainty and the restudy and present something. It could be specific locational and it could be something more problematic. But we'd like to come up with the best design possible to answer that very question.

MR. NAUMANN: Quickly, one improvement that we're seeing in PJM is more clear requirements at the beginning. So, for example, if a request is deficient, it just gets kicked out of the queue, you don't have to start working on it. But I think you've heard a theme here, that is we need to have a robust and reliable transmission system to integrate new generation and provide reliable service to customers.

On the other side of that is the serial impact of new interconnections and the option now that was mentioned that earlier queue projects when they get their results for any reason or no reason at all, and it could be many reasons, maybe they put in for alternatives; they only intend to build one, then three of them will drop out. The higher queue projects drop out, all those studies that were done now have to be redone. And now if you get -- now you're shifting the cost of the upgrades to somebody else and you may get more dropouts or something.

That's the challenge. I don't think there's a generic issue unless you start looking at a completely different solution than what you're looking at. But short-circuiting that process to say, "We're going to take the initial answer." Well, that could mean you're building more than you need, which might be good in the long run, or, "We're going to kick people out before they want to because they're "speculative." None of those are necessarily good answers. So it's a tough answer and may have to look at how do these upgrades get done and how do they get funded?

But the first thing that needs to be agreed upon is that there will be a robust and reliable transmission system both for the interconnection customers and for the load customers who ultimately pay. Once you get that process, you can start debating about how you make the other process faster or more optimal to use the tariff. But we need to start with a process that gives us that reliable, robust transmission system; don't build congestion into the system, don't build reliability problems into the system. It's not necessarily a target enhancer, but I think it's a high level identification of the issue.

MR. VAIL: Rick Vail with Pacificorp. I probably echo a lot of the same comments I heard on the panel here, no question about it. I think one other thing I would probably add into that is one of the responsibilities as a transmission provider is to make sure we're not passing on some of these costs to connect additional generation, especially if it's not required for load service of native retail customers onto our other transmission customers. So we're very customer-focused for both, not only our transmission customers, but any of the generators that want to connect to the Pacificorp system.

With that being said, though, I think having the time and the effort that goes into all the restudy of impacts of higher-queue projects dropping out is probably one of the biggest concerns, especially as I mentioned in the opening comments when we have a smaller geographic area where these renewable requests are coming in and they're concentrated on a small geographic area.

I think it also get complicated a little bit more just because the way Pacificorp is set up, we're very rural, the majority of the generation in our system is hundreds, if not many hundreds, of miles away from our load center. So you certainly have different areas where you have transmission constraints but those also continue to be the areas where we are often requested to connect to the system as well, so.

MR. DOBBINS: I guess along the same lines, understanding that there aren't generic issues across regions, I have a question for Mr. Gosselin and Mr. Naumann. Are there queue practices that you've seen that work well that you would like to see implemented across all regions?

MR. GOSSELIN: Dean Gosselin with NextEra Regional Resources. One of the things that we find is successful, is not used by all regions but at least a couple of regions do, is they set forth fairly stringent requirements, and one of those requirements is a show of land control, that you have control of land to be able to build a project that you're saying you want to interconnect. That seems to work decently in terms of keeping even our own projects that we would otherwise have submitted out of the queue and keeping it from clogging up from the initial standpoint. But in and of itself, that's not sufficient.

I think from there on the stringent -- as the study process progresses, stringent requirements and basically financial liability certainly acts within NextEra and our decision making process. It keeps us very disciplined about what we keep in the queue. So if we're at a point of process where we're responsible for system upgrade costs, regardless of whether we go forward or not, that is a true -- a point of decision for us on whether we want to stay in or not.

Now, unfortunately, the interconnection results, the cost and schedule, are important to decide whether or not a project is viable, especially in today's competitive markets where we're competing with cost on everything. And our customers we're selling to are suffering as well. They want to know there's a valid interconnection and they're not signing up or looking to enter into a power purchase agreement or some form of commitment on a project that's not going to go forward, they want projects that go forward as well.

So it's kind of egg and chicken here and what goes first. Right? And until that group stabilizes -- any tools that stabilize the group quicker I think are necessary to get the valid results in the timely fashion. Thank you.

MR. NAUMANN: Just to add to that, I think I mentioned having clear requirements -- this is true at PJM -- that the customer knows about, and that if you don't meet them you're out of the queue and no one is spending time doing evaluations on something that's not quite right. Just to give an example -- and I know you're going to talk storage in the last panel, but it's an example of interconnection -- you get a customer, you go through the study, study phase, several studies, then they change the manufacturer of the inverter and it has different characteristics.

Now you have to redo -- this isn't dropping out, this is technically you have to redo the flicker study. This is another study that has been occasioned by a change that had that not been done you wouldn't be spending your time. The other thing is not so much a requirement, but it's really -- and it's something we see as the transmission owner at PJM and also on the other side as a generation owner, is continual meetings between PJM, the TO and the customer on a regular basis. Where you are; where the study is; where a problem is showing up trying to short circuit the problem; making sure everybody knows what's going on so you don't come toward the long end of a study, and say "Oh, here's the study. Oh, by the way there's a problem so now you have to redo things over again."

So throughout the process, keeping in touch and then taking the feedback where there have been problems and feeding that back into your system to make corrections. I think in addition to having stringent requirements, communication becomes very important to avoiding problems.

MR. DOBBINS: Thank you. I now have a question for the transmission providers. Earlier, Mr. Aliff, you referred to a withdrawal rate of about 50 percent and one-year delay in cycle time. I'm interested and we're interested in knowing how all of you evaluate your interconnection queue operation and what metrics are used to evaluate the performance?

MR. ALIFF: So today we're evaluating the delay, the time delay, as I mentioned before and we are looking to develop further metrics related to that. But today that is the metric that we are monitoring today. Because of the interest in how long the process is taking and we wanted to provide transparency to that metric. We also provide other metrics that aren't really related to the performance but what type of units are coming into the queue, where are those projects coming in -- so we see projects come in to our northern part of the footprint, more because that's where the wind-rich areas are, if you will, as we see a number of projects coming into that area.

But we are seeing an increase of solar coming into our southern part of our footprint and an increase in gas with the changing fuel mix, if you will, that we're expecting over the next several years. That's something we keep track of and we provide that transparency to our customers, but it's not really a metric per se on the queue performance.

MR. DOBBINS: So in terms of a metric to evaluate how well you're doing, would the withdrawal rate and cycle time be the primary ones?

MR. ALIFF: Withdrawal rate provides some information. As mentioned before, it can be a little misleading depending on where that is being measured. So a withdrawal rate late in the game and towards the end of the study process is certainly more concerning than a withdrawal earlier in the process.

If you can provide those, as mentioned

before, the site control or the milestones to prevent that, the projects from entering the queue at first, then that withdrawal rate should go down. But it kind of depends on where it is in the process.

MR. DOBBINS: And we have that same question for the other transmission providers: How is queue performance evaluated and what are the metrics used for evaluation?

MR. McBRIDE: So the headline metric for us would obviously be the time from the middle of the interconnection request to the completion of the system impact study, that's the one we focus on the most. But when looking at that headline metric, we look beneath to see are there differences in different geographic areas? And I talked about those a little bit. And are there differences based on technology or technology type?

We did find differences in time taken complete studies and restudies, data requests, deficiency requests, based on technology type. The newer technology, mostly inverter-based renewable technology, is new. A lot of the manufacturers are less acquainted with the data and modeling requirements that are needed to get through a system impact study. It's different from the traditional equipments that have well-established data models and performance models that have been in place for some decades now.

So we have put together some clear guidelines and requirements, the tariff portions were approved, that we think that were already helping that. So for that situation where underneath the headline metric, you have a particular, troubling area, we think we can move that forward.

In terms of withdrawal rate, the withdrawal rate in New England is quite low during the system impact study phase. There are some cases where you'll hear of a withdrawal because of a fundamental change in the circumstances like a pipeline no longer being built or no longer expected, might cause a gas generation to withdraw. For the most part, we see withdrawals after the system impact study, sometimes if the interconnection upgrades are more than what was expected by the interconnection customer.

We also see withdrawals after a resource might have participated in the forward-capacity market maybe one, two, or three times. If it's not clear about that modification then we'll withdraw the project, and that would be the end of the endeavor.

MR. VAIL: Rick Vail, Pacificorp. So from Pacificorp's standpoint, we have dedicated project managers who track each of these security parts all through the different processes. We also have established timelines in our open access transmission tariff that we have specific timelines to meet.

So we're tracking as this goes through each of the different processes from a timing perspective. We also track at what stage each of our interconnections is at, so the feasibility phase, impact study, or full facilities study, and then where they are in the process as far as getting billed. So there are a lot of metrics around our process and over time we have continued to add additional metrics. We do track in order to, again, try to improve processes as much as possible.

I think the one area, as I've kind of mentioned, when you start getting significant movement in higher queue projects, especially in a specific geographic area, I would say that's the one time from Pacificorp's standpoint is a real challenge to the meet the timelines that we're required to meet on a steady process.

MS. COCKRELL: So thank you for your participation. A couple of times the production kind of impacted those discussions. So I wanted to drill down on that a little bit more and better understand to what extent some of the backlogs you're saying are directly related to projects being geographically concentrated, and whether you come up with any reasonable solutions or you're working on reasonable solutions to account for the fact that there are a lot of requests, it sounds like in certain particular areas and how to address that.

I guess that's probably more for the transmission providers on the panel more so than others, but anyone can answer.

MR. ALIFF: Maybe I'll go first. Tim Aliff, MISO. So we do see differences from the geographical standpoint. It's usually related to where a lot of projects are trying to move into an area that there is a lot of congestion that the transmission system is not necessarily built at the time if you will to support all of the projects coming in. So it takes a little bit more time developing the network upgrades, for those projects to interconnect reliably.

And then there can be even more impact in that area when a project withdraws, as you've heard several times today. Those projects withdraw and then have a greater impact on other projects and their network upgrades costs. Areas that aren't so congested, projects can withdraw, there's little to no restudy through that. So it kind of varies.

One thing we've done at MISO is to split up our queue process by geography so we have four different areas that we're looking at in our footprint. So the areas that aren't as congested can move quicker than areas that are congested. Outside of the queue process, MISO has taken steps to build that transmission system to support those interconnection going forward specifically related to our multi-value projects that are looking to come in in the next several years that would increase the ability in the north region upwards of 26,000 megawatts of generation to interconnect in that area, so outside of the queue process that is being done as well.

MR. GABBARD: This is Dave Gabbard with PG&E. I will just take the opportunity to give one example of where we have a very overheated queue in a geographical area and we were able to proceed forward and continue to move viable generation towards interconnection.

In our queue cluster 3 and 4 in the California ISO service territory, we had a significantly overheated queue in our Central Valley Area in Fresno, California, triggering over a billion dollars worth of upgrades to our transmission system. But through the iterative process of the phase 1 study, phase 2 study, and then subsequently annual reassessment, paired with the financial security obligations of the process, we're able to see viable generation post financial security to proceed through the process, and then our iterative cluster study reevaluated the impacts on the grid from the less-heated viable generation queue.

And we have continued to progress generation from that queue cluster towards completion. So the iterative queue cluster process and the financial security obligations embedded in our process have allowed us to successfully mitigate that geographical challenge. Thank you.

MR. GOSSELIN: Steve Gosselin with NextEra. I don't have a lot to add on just the terms clustering and how you deal with the clustering of resources in a certain subregion. But I did want to just emphasize that locationally constrained resources like wind, it matters tremendously in terms of the overall cost per-unit of production, as finding a windy area is very meaningful to that equation. So the windier it is, the lower the price, the cost, the lower -- and price matters in the marketplace. So clustering usually happens because of that, because there's a good wind resource in some spot.

MR. McBRIDE: Alan McBride with ISO New England. To drill down a little bit more on the geographic piece, there is, of course, the first piece is just a lot of requests in the same part of the system. But, for example, in New England, we have that in Maine, and I've talked about that being a challenge, but we also have that, a lot of requests, in what we call southeast New England, and those requests are in response to that being import-constrained zones in the forward capacity market.

And there is a relative difference even there in terms of the rate of progress of those, and comparing to each other. And what drives that is not just the oversubscription, but the nature of the system in the particular area. So in Maine, it's a system that's already fully stressed and hard to bring in imports from New Brunswick. But it's also these requests are very different from load, they're very different from the existing transmission system, and they are inverter-based in nature. So it's the level of subscription but also the underlying technical characteristics of the system that the interconnection customers are seeking to interconnect to.

MS. COCKRELL: Any other responses?

MR. QUINN: So I wondered if anyone had thoughts on the degree to which the transmission planning process can address, or be concerned to having to address, some of the challenges that you get with geographically clustering resources?

MR. NAUMANN: Well, this is what I was trying to allude to. MISO stakeholders have chosen to do this and at PJM we have a different process that follows the but-for process that the interconnection customers should be the ones to pay for the upgrades. So as Rick said, so that the load customers don't end up paying for it. That's a philosophical difference that maybe the Commission has to look at again.

I'd be glad to have that conversation, I'll tell you now I'll come out on where we are in PJM, but I think it may be worth having that conversation because, as I said, and I think everyone agrees, to interconnect and to run the system you need a reliable system, a robust system that matches how you operate the system.

Against that, as people have said, especially locational-restrained resources, are generally being connected to a system where it's weak, and they require a lot of upgrades, and a lot of upgrades are expensive. And then as the first customer in the queue says that's too expensive, drops out or part of that queue shifts it to others in the queue, you now have to have restudies.

So it may be the time to generically look at how do you plan? But if you do that, you need to understand that may end up shifting those costs, possible overbuilding, to the load customers. And that will have consequences, I would suspect, state regulators would like to be present at the panel to discuss that. I'm not saying that's not a solution, but you need to start "what do we need?" And after you say "What do we need," how do we get there? And then you create other issues on how you get there.

So it works for MISO, they've had buy in from their stakeholders, and that may be a unique solution to that area. That's not where we are in PJM. But it might be worth looking at something in between in order to get a system that you don't have this upgrade by upgrade.

MR. GOSSELIN: Dean Gosselin with NextEra Energy Resources.

So I have a different view on that. As I think the MVP projects have been -- certainly I can tell you that projects we considered a decade ago that were not valid projects at that time because of upgrades and not being able to move them on the system, have become feasible again and we're looking at them and dusting them off and saying are they projects for the future?

So we think it's a good idea. We saw that in ERCOT CREZ where they built major backbone transmission in advance of resources coming on, and that has brought the price of the cost of the market down, pricing of the market down and that's good for America. And we think transmission enables that, especially with this certain progression of renewables that we're seeing. Thank you.

MR. VAIL: Rick Vail with Pacificorp again.

Just from a transmission planning perspective, I would say the planning process is already pretty robust in looking at -- it's no secret where the main areas core renewable development are going to be, from Pacificorp standpoint, looking at Eastern Wyoming and the wind capacity out there. One of the difficulties starting with that planning process is the time it takes to build a significant transmission infrastructure. If you go back to 2005-2006, a lot of load growth, there was a lot of wind development that had the potential to happen.

Then the economic crisis hit us. So a lot of those projects and a lot of that load growth slowed down and things were generally put on hold. And Pacificorp has been in the middle of permitting some pretty significant transmission infrastructure. But you do have to take into account that long timeframe to get a significant transmission improvement permitted and built.

And I think that brings definitely some risk and uncertainty not only to the transmission provider but to the developers as well. And again, I just go back to another comment you have to make sure that throughout this long process that those costs are not being borne by the load serving, the load customers.

MR. DOBBINS: Are there any other comments on this topic? If not, before we move on, I'd like to acknowledge the attendance of Commissioner Clark, and to thank you for coming. Right now we're talking about general queue effectiveness metrics and geographic concentration. Did you want to make any remarks or ask any questions on this topic?

COMMISSIONER CLARK: Having just got here, I don't have any questions at this point. But just welcome to everybody, thanks for being here and everyone in the audience as well. It seems like generator interconnection issues and queue reform issues have been something I've lived with for about 16 years because I happened to be on a state commission, as about 1,500 megawatts of wind power connect into the state's grid over the years.

So I was there, and then since coming to

FERC it's been one of those things we hear about from time to time. It's one of these issues with the advent of renewable resources that we're seeking to interconnect on the grid that I think we just need to stay on top of and to ensure that the rules are working as they're intended to. Every now and then, I think we just need to make sure that they are and make sure the queue reform process were appropriate.

So I thank the Chairman for scheduling this, for the staff for putting it together, and looking forward to having a good record.

MR. DOBBINS: And I believe we have a question from Commissioner LaFleur.

COMMISSIONER LaFLEUR: Well, thank you, Tony. Arnie and Steve kind of teased out what was is going through my mind, which is where does the interconnection process leave off and the transmission planning process start? And with the references to MVP and CREZ? And I guess picking on Alan from ISO New England, where you see a clustering of continued requests interconnection in a particular region with a renewable potential -- I presume you're talking about Maine in your comments -- is there any feedback loop from the interconnection process and the queue to the transmission planning process where that may be an opportunity for regional transmission line driven by public policy requirements that could be like the facilitator then of the specific interconnections in the same way that an MVP was in MISO? And I guess I'm wondering if there's any connection between these queues and that process and then the planning process?

MR. McBRIDE: Thank you, Commissioner. The cost allocation discussion in New England, I think like everywhere, is a big discussion when it comes up, and going back over the years of the framework that's becoming developed. In New England, we have the interconnection space, we have the but-for, the interconnection customer will pay for only the upgrades that are needed but for its interconnection.

Along with that, in New England, interconnection customers do not pay for transmission service. And just to kind of throw out some commentary on that some of the thinking behind that was that would lead or incentivize generators proposing resources to locate in a place where there would be fewer upgrade requirements. It would be easier to upgrade. It would be quicker to upgrade, especially would align that incentive and to keep their upgrade costs down.

But as we've seen and discussed, that doesn't always work, especially when the resource is just far away from the transmission system, which is what we have in Maine. So we are looking at clustering approaches, first of all, to see if a clustering approach would work in that context through the interconnection process. We don't have a design -- in our current world, we don't have such a thing in our interconnection process.

So we're seeing if that's achievable, and other regions could have something that would support it. Transitioning then to the public policy piece that is under Order No. 1000, we're going to be kicking off our first round of public policy next year at the beginning of 2017. And that may be, under our process, something that people bring up and want to talk about, and it would be discussed in that context.

COMMISSIONER LaFLEUR: Thank you very much. I would just comment that if you were building out your system in what we'll call it traditional approach for reliability where your transmission was keyed to where your major resources were your population centers, the concept that many people pay for interconnections by where they locate because you want to incentivize them to locate in an efficient place -- that's how it was always done, that makes perfect sense.

When you start to overlay building out your systems to meet public policy requirements, the Clean Power Plan -- I forget what they call it in Massachusetts, the Global Warming Solutions Act if I'm not mistaken -- and a host of other environmental aspirations. The paradigm that if you just hook into the existing system you'll get what you need, just seems to not maybe work in the same way. And that's why these breakthrough process like CREZ or MVP are having that impact, to the extent that there's a decision on the part of society that meet those public policy requirements. I think that's more of a comment. Thank you.

MR. DOBBINS: Yes.

MR. NAUMANN: I think the difficulty in what Commissioner LaFleur described is a general change in the philosophy of planning from the but-for that many of the regions use to almost an integrated resource planning. It's worked in several regions, and ERCOT of course that's a single state, and MISO there's a lot of buy-in by the state regulators. You need to have all of the states come together and say we're going to accept these charges on our customers.

And that is I think, someone who's been involved in litigation on one of these things for 12 years at least, is difficult. So you're going to have that kind of paradigm shift. And, again, I want to come back you want a robust system that doesn't end up with a reliability or congestion problems.

And that out of paradigm shift, you're going to have to get the state regulators here. Because in the end, you can plan anything you want, but if they don't site the lines it's not going to matter. So you're going to need them at the table to have that discussion. In PJM, the public policy is handled through a state agreement, where the state would say, "I have an RPS requirement and therefore I want this transmission built and I am willing to have the customers in my state pay for them."

A little harder when you start impacting multiple states. So it is a further conversation, and I would suggest not an easy conversation but maybe one that is worth happening, if the goal is to end up with a reliable system that doesn't introduce congestion. And in the end just to say again, kicking off some of the diverse resources that you're going to still need to keep your system running at peak load and get you essential reliability sources.

MR. DOBBINS: Would anyone else like to comment on this? If not, staff, are there any questions from FERC staff on this topic before we have a break?

No additional questions. All right.

At this time, we're going to take a 12-minute break until 10:30. At that point we will have our next panel. All right, thank you.

(Whereupon a short recess is taken.)

MR. DOBBINS: If everyone will take your seats, we're going to jump into our next panel. So we welcome everyone back. We're going to begin panel 2, which is Transparency and Timing and Generation Interconnection Study Process. We're going to ask the panelists -- sorry, please hold on for one moment.

We're going to ask the panelists introduce themselves and make the prepared remarks that they submitted in the docket or just to indicate the one or two most important points they would like to make today. Please keep your remarks under two minutes. We will use a -- there's a timer at the front to let panelists know how much time they have left.

And, Mr. Angell, please start.

MR. ANGELL: Thank you for allowing us to be with you today. I'm Dave Angell, I manage planning for Idaho Power Company. We're a company that serves Southern Idaho and we're vertically integrated. And we've been processing 500 interconnection requests since 2001. And we found that if we hold ourselves and the customers to the timelines given by the FERC existing process, we're able to manage the queue.

And we started with some flexibility in the beginning but found that by providing that opportunity, it gets abused and one can't really manage a queue. We also find that we do have quite a bit of churn in the queues as well, we only take about 20 percent of the projects to construction and service.

So there are restudies that we do undertake, and that restudy process, though we are typically able to manage that within reasonable periods of time and not having to extend the queue. Mostly the extensions of time -- so our time range ranges from about 18 months to about 24 months -- to process through the queue. And the variance there is, quite frequently or mostly, caused by the interconnection customer providing inaccurate data, insufficient data, or changing their interconnection request itself. And with that, I will leave it for the rest of the panelists.

MS. AYERS-BRASHER: Good morning. My name is Jennifer Ayers-Brasher and I'm the transmission and market analyst at E.ON Climate and Renewables. And we have over 2,700 megawatts of renewables in service across the country. And we want to thank the Commission and staff for the opportunity to speak here today and hold the conference.

One of our primary takeaways for today is the need for higher accuracy, accountability and transparency in the interconnection process. Delays and lack of transparency are harmful for generation. E.ON has projects that have been in the system for five years, and in that, as an example, limits our opportunity to move other projects forward. We've also had to withdraw projects due to lack of transparency. One example would be when affected system costs were brought in very late to the process and increased the network upgrades by 14 million dollars in addition to what we were already expecting, which made the project unviable -- from the queue, and that's not ideal to the system.

And so those transparent issues needed to be brought up early. And these are just a few examples that we've experienced. The interconnection process has some flaws, and there have been improvements, and there have been reforms and we appreciate that. We need more improvements and we think the forum by FERC will definitely move things forward. Thank you.

MR. BOHACH: Good morning. My name is Josh Bohach. I'm senior development manager for EDP Renewable North America. EDPR North America and our subsidiaries, we develop, construct and operate wind farms and solar parks throughout North America. We have approximately 37 wind farms and solar parks across 12 states and we operate more than 4,600 megawatts of clean, renewable generating capacity.

In my role, my capacity of the company, I lead development activity for multiple wind projects across the central region, primarily the MISO and SPP regions. Among various aspects that I manage in the development process is the projects generation interconnection studies and ultimately working through the interconnection agreements with the appropriate ISO.

I hope to bring to the panel a practical generation interconnection experience in both of those footprints, having recently experienced ramifications of interconnections study delays and how they affect the project on the ground level. My objective is to help the Commission work towards a solution that will allow wind generators to interconnect in every ISO in a timely, non-discriminatory manner. I'd like to thank the Commission for holding this panel and this conference and the opportunity to present our views. Thank you.

MR. EGAN: Yes, my name is Dave Egan. I'm the manager of interconnection projects for PJM. My department interfaces directly with the interconnection customers, transmission owners, internally our legal staff as we do all of the agreements, as well as our study staff. So we deal with both the technical side, as well as the legal side, as well as all of the project management issues. From a transparency perspective, PJM posts loads of market and operational data, our planning models are available as are our reports and agreements.

One of the issues we have and I believe in the first discussion that was brought up is there are a lot of entrants into a queue. Some are savvy and some are not. So having a lot of data available can be a challenge for a new entrant because they're not aware of where to go on a website, so PJM is always trying to improve access to data too. So just having data is not necessarily the answer, also having access to it, and we do a lot of time, my staff, talking to customers to guide them, to show them what's available.

Regarding backlog, in the first session Mr. Naumann mentioned communication, we're finding that to be key to reducing our backlog. My department, we go out and try to meet annually with all of the transmission owners. We have new staff just from turnover, as well as just showing them what our process is, what we expect from them, and then talking about their issues of timing.

The first 30 days of a study we do our analysis. What does it look like when they receive it and how quickly are they able to turn it around? We show them our needs at the end to be able to potentially restudy, so if they provide us with a result that doesn't solve the issue, we get into potentially looping, and that can result in the delay. So we've been better at communicating that.

The other thing Mr. Angell -- is that how you pronounce your name? -- Mr. Angell brought up the issue of interconnection requests being deficient, and it was also brought up in the first -- we have a stakeholder process right now at PJM trying to be very strong on those rules.

Finally, on the delay causes it was also brought up in the first, we see a lot of equipment changes with new technology. The customer enters the queue, by the time they get to their study there have been large changes in the technology that require restudies.

MR. HENDRIX: Charles Hendrix, manager of generator interconnection studies with Southwest Power Pool. My group administers the interconnection procedures from accepting new requests through the interconnection agreement. I appreciate the opportunity to participate in this conference.

SPP's, our interconnection process, functions pretty effectively since our last queue reform in 2013. Our first cluster in that queue reform started about 18 months ago, we had one outstanding request within the interconnection agreement. The second study that started 12 months ago, we had three requests that are in facility restudy. Both of these clusters start out with 7,200 and 5,200 megawatts of wind and oil generation respectively. Furthermore, this has been achieved in light of significant growth of wind in our region. Through these processes, through our transition to a energy market and our consolidated balancing authority, and regional planning process, SPP has now installed over 12,000 megawatts of wind.

However, despite the successes SPP has experienced, the continued interest in wind has resulted in obstacles to the efficiency of the execution of the process. The volume of requests just continues to grow and our last cluster from last September we had 11,000 megawatts of generation coming in one cluster. That cluster that all went through one impact study, 7,700 megawatts went into the facility study in that one cluster. So we're thinking the obstacles to go into the facility study are not quite high enough. This past study window that closed we had 11,000 megawatts of generation come in. So now we've got 19,000 megawatts of generation that are pending, that we really are in a pickle to determine how to analyze that.

With the minimum loads that SPP sees and with the wind operating at minimum loads, we are very concerned about our wind penetration levels. Minimum loads at SPP are about 20 gigawatts. So we're looking at clusters of 20 gigawatts. Thank you.

MR. OYE: Good morning. My name is Randy Oye. I'm a transmission access analyst for Xcel Energy working on generator interconnection issues, and also the chairman of the MISO interconnection process task force. Xcel energy is a facility holding company composed of four subsidiaries with operations in MISO, SPP, and the western interconnection. Xcel Energy participates in generator interconnection activities in all three regions. MISO and SPP, Xcel Energy functions as a transmission owner with the RTO acting as the transmission provider. On the Public Service Company in Colorado system in the western interconnection, Xcel Energy functions as the transmission provider. Xcel Energy is also an interconnection customer in all regions.

Xcel Energy agrees that generation interconnection queue reforms are necessary but does not support a standardized approach across all regions and transmission providers. Xcel Energy believes that the stakeholder process in each region is the best venue for reform. Xcel Energy urges the Commission to take timely action to implement reforms, especially in the MISO region, and believes that MISO's recent queue filing which the Commission rejected without prejudice included a number of improvements that would greatly enhance MISO's generation interconnection process. The improvements should include adding multiple scheduled restudies with off-ramps to allow interconnection customers to assess the viability of their projects. Xcel Energy also believes creating milestone payments structured to reward projects who select the most cost-effective locations with the best transmission are needed. Tying milestones to the cost of the transmission network upgrades identified in system impact studies could accomplish this. Thank you again for allowing me to participate in the conference.

MR. RUTTY: Good morning. My name is Steve Rutty. I'm the director of grid assets at California ISO. One of my duties is to oversee the generation interconnection process for the ISO. California ISO appreciates the opportunity to participate in this proceeding and in this conference. The ISO and stakeholders have greatly benefited from the mutual flexibility that the Commission has afforded us, and we encourage FERC to continue down that path.

In 2008 when the ISO made a big move to cluster studies, we have studied over 800 projects for over 120,000 megawatts, and this is for a system that has a peak load of about 50,000 megawatts. Most recently we've disclosed our cluster 9 window that had 125 projects for another 25,000 megawatts. But under the recent flexibility you've afforded us, our stakeholders and California ISO have been able to develop a process that allows us to run through 100 projects in a year, and aligns very well with our transmission planning process and where we developed the appropriate transmission for reliability economic and policy needs: As Commissioner LaFleur mentioned earlier, it aligns well with the distribution owners' studies that they do for their distribution-connected assets; it provides our interconnection customers with fixed and anticipated annual studies and schedules, and the annual costs for those studies as well, and it has no restudies; and it provides cost certainty for network upgrades to alert the interconnection customers very early in the process.

The ISO continually works with the stakeholders to identify enhancements to the process, as you're probably well-aware of our annual interconnection process improvement efforts. So with that, the ISO respectfully requests the Commission continue to ensure each region maintains the flexibility to adopt interconnection procedures that fit their needs.

MR. ZADLO: Good morning. My name is Kris Zadlo. I'm a senior vice president at Invenergy. Let me start by saying that Invenergy supports the AWEA's petition. The interconnection process continues to impose significant barriers to generation development, in some case delays of up to six to seven years. Generic reforms are necessary to overcome these barriers, RTOs and utilities should be required to show that they have adequate resources available to accomplish their obligations, and they should be required to clearly enumerate study assumptions up front before commencing on the studies.

TO should be required to abide by firm deadlines or to state in writing why they cannot. Meaningful Commission oversight, along with timely and expedited dispute resolution mechanism, must be built into the process. Greater Commission involvement in the

RTO interconnection process is sorely needed. Each time an RTO deviates from a generic reform or Commission-approved best practice, the RTO should be required to file a notice of untimeliness or noncompliance to explain these deviations. The Commission should review these reports where appropriate and investigate them.

Just as the market monitor and the Commission enforcement staff scrutinizes outlier bids, they should also scrutinize outlier interconnection practices. The Commission should also require each RTO to establish an ombudsman with direct access to designated FERC staff to provide a venue for timely relief when customers are at an impact or have a dispute about matters affecting studies. These measures should not prove unduly burdensome to any RTO that's doing their job, because if it is no reports will be required or calls to ombudsman necessary. Thank you for this opportunity to speak today and I look forward to the Q and A.

MR. DOBBINS: All right. Thank you again to all of your participation and for your opening statements and remarks. FERC staff will now begin asking questions. Please limit your responses to around a minute so that other panelists have time to speak.

And once again we apologize in advance if we aren't able to hear from everyone at the table on every topic. We'll start off with a question of -- talking about time frame for studies. Are the completion time frames and the pro forma LGIP and regional tariffs -- sorry, are the completion time frames of the pro forma tariff and regional tariff reasonable in regards to the amount of time provided for completing an interconnection study? And we'll start on the left and move down towards on the right.

MR. ANGELL: Yes.

(Laughter.)

MS. AYERS-BRASHER: I can't comment to whether the RTOs and TOs feel like they have enough time, although I think we just heard from one that they do. However, following those timelines and the documentation of those, then we can plan with those, so it goes both ways. And we have those laid out, we plan based on those. So if they need to be different, we need to know what those are.

MR. BOHACH: Along those lines, I'm speaking for the time to put a study together, but from the operator. And knowing what -- those timelines and being able to plan around those for a project development, those are sufficient timelines if we're able to adhere and bank on those timelines.

MR. EGAN: At PJM we have timelines for both large gen and small gen. And the issue we run into and I think might be part of some of the issues the generators have, in 2008 and '12 we've had reforms through the stakeholder process where, for example, the small generator said "We don't like the but-for cost." If you look at a distribution circuit and three projects ahead of us use up the existing overhead on that, we end up the fourth project picks up the overall cost. So they requested for under $5 million upgrades to have those socialized within the queue so everybody who contributes to the overload pays for it.

The problem with that is now you have to wait for the queue to close to be able to study everyone. So it actually -- where before, the smaller generators could have been moved along quicker, because if we analyzed it and saw there was overhead, we could give you your agreement and move you along. Now you're bundled together. So it's a clash of cost sharing versus timeliness that I see right now at least on the smaller distributed generators.

MR. HENDRIX: At SPP, we had a number of stakeholders processes where we decided instead of timelines ordering the impact study, we also put in increased milestones to get into the impact studies so we were compressing time frames and we would have fewer projects in the studies. As it turned out, I just mentioned the studies have doubled and tripled in size, so we're now finding that the timelines that we have are very difficult to meet.

MR. OYE: Xcel Energy is comfortable in the timelines to complete the interconnection studies. I guess issues that have come up is when they start. Lately, they've been delayed quite a bit, and that is an issue. And as Charles said, there's a lot of projects in the queues so they take a lot longer to complete because of the restudies and others. So that's it. Thanks.

MR. RUTTY: So at the California ISO the queue cluster process takes about two years to get through the study process, that's the phase 1 and phase 2. There are a couple of faster options if the generator can show they have a demonstrated viable need to move quicker and they are determined to be independent from other projects that would be sharing their cost. But the cluster side does take about two years. It is fully integrated with our transmission planning process. The timelines are in our tariff, we can't miss them, and so far we've been able to meet all the timelines. We don't have a study backlog. The tariff requires that -- the transmission owners to meet tight deadlines as well. So, so far so good. It doesn't mean things won't change.

The deadlines that we have in there also provide the interconnection customer time between studies to make decisions as to whether they want to move forward and how they're going to finance their project, if they're going to get a PPA in time and so forth, a power purchase agreement. And so the study has that built into it as well, the whole -- the entire process. So it's a give-and-take with the customers to make sure that we have time to provide them a study that gives them what they need to move forward, and that they also provide financial security along the way to make sure they're in the game as well. So --

MR. ZADLO: The problem is not the timelines, the problem is the lack of rigor going through the process. I'm going to give a shout-out to Mr. Hendrix. When we enter the queue in SPP, we're reasonably assured that within a year and a half to two years we're going to end up with an interconnection agreement. That can't be said with other ISOs. Cal ISO also meets their timelines. Can't say I'm happy with the length of their time, but at least after two years I know I'm going to get an interconnection agreement. I can't say that for other jurisdictions.

This is 2016, folks, this isn't 50 years ago where engineers were doing power flows on punch cards and using slide rulers. We have phenomenal models at our disposition here where you can model the whole entire eastern interconnection, have 100,000 contingencies analyzed in under a couple of minutes. So the RTOs do a phenomenal job managing their markets, but on the flip side, on the interconnection process, I think there needs to be a higher standard there.

MR. DOBBINS: And taking into account the comments just made by Mr. Rutty and Zadlo about the CAISO process and the SPP process, here's a question for the transmission providers: How often are studies completed within the time frame establishing the tariff? It seems like at ISO and -- I guess and SPP, pretty often. And when these completion rates vary, what generally accounts for this variance?

MR. ANGELL: Well, with Idaho Power, again as I mentioned earlier on, the variance, we actually don't start the clock until all the data comes in. And once we start that clock, if they do come in -- well, all the data comes in and is correct. And then we start the clock. If they go and change the technology that they're using, then obviously we start the clock over. So we always meet our time, and it's dependent upon the customer providing the data as far as what that overall time will be from when they first come in.

MR. EGAN: At PJM the issues that you get into, and discussed earlier and mentioned earlier, the customer is accountable to providing the data timely. Data holdups right now, we end up -- if you look up at the 90-day feasibility study, window for our tariff, almost the whole first month is wasted in the process of getting data in and holding scoping meetings. We have some queue reform that we're getting ready to propose, but that is not in place right now. So that's one issue. As far as going to get the studies out, we still are able to get the feasibility studies out on time. We've improved greatly in the last I would say three to five years on that. Impact studies are generally out on time. The problem you get into when you issue, for example, an impact study, and you're sending them out in the cluster format, is you're going to get now people who see the results and withdraw, so you're almost automatically into some form of model cleanup and central retools as far as lining up where the obligations to build network upgrades are going to follow but-for issues. So that's one of the biggest problems.

I agree we have great modeling, but the problem is you also have business decisions that have to be made and reaccounted for after they're made. And they are in queuing order, so --

MR. HENDRIX: In SPP, it can take over a month to six weeks to validate all of the generator data. And we have been pretty rigorous in withdrawing requests that haven't met those timelines once we've been able to validate that. However, the way our tariff is and our studies, timeline starts as soon as the window closes, so that's really counting against us while we're evaluating all that data. Despite that, we have a pretty good percentage of completing the impact studies on time. SPP is pretty -- we have a large region, the western part of the region we kind of study separately. That's where a lot of -- where wind is, that's where the transmission system is not near as robust. So what happens is that -- and there seems to trail, we will have more restudies there with withdrawals, and so that -- we will that area is generally behind maybe 30 days to 60 days. With the upcoming clusters, we've actually put a hold on this latest study so we can get a better handle on the last study that had 7,700 megawatts going into facility studies. So the speculative requests that appear to continue going forward even in the facility study are going to cause greater delays going forward.

MR. DOBBINS: Feel free to skip this question. Since you answered this in the last -- did anyone else want to speak?

MR. ANGELL: I just had one more comment. And so as a fairly small utility, we augment our staff with consultants in order to meet the time frames that are in the tariff. And so augmentation is always required.

MR. DOBBINS: Thank you. We have a follow-up question.

MR. LUONG: Yes, I had a question regarding the input data. Is there any way you contain the -- how to improve that between the transmission provider and transmission customer, along the way help to -- help out the good data, get the thing right away and meet -- up front? And then we hear about a lot more new technology from modeling. Is there any way that in the industry can work together with the manufacturing, try to come up a lot of new model and then onlook -- go with a vendor for the tool so you can shut down the issue about your data at the beginning of the input --

MR. ANGELL: So in the western system, WECC has the nearest models that are approved and defined. So that information is provided to the interconnection customers, and then it's up to them to either choose to use a generic model or provide the full data with regard to the exact equipment that they're supplying.

MR. EGAN: Regarding your issue improving the process, we are trying to make tools so that it's very clear what the customer needs to provide coming in, and tightening up the rules so that if they do put in bad data or don't provide the data, that they really don't get to participate in the queue or hold the queue up.

MR. HENDRIX: In SPP, similarly we've been working with customers the front end, and we've got a checklist. Many of our customers who have been through the process many, many times. So they're well-aware of what's needed, yet sometimes they still don't provide everything. It's just when our window closes, let's get everything in there that we can, and hopefully let's get things sorted out. So to an extent, that's an obstacle.

MR. EGAN: I'll add one other point here. A comment on working with the manufacturers: Some of that actually comes from the customers, too, as far as if they keep updating their models, they need to be providing models that the transmission providers can use to study. They're the ones that would have the financial leverage to get the manufacturers to provide that, so --

MR. DOBBINS: How much has this been an issue, not getting the technical information from the manufacturer?

MR. HENDRIX: It's very difficult when you're doing the dynamic studies to get the dynamic models. And the issue there, that goes back to what I was saying about the speed at which some of the newer technologies are being updated all the time, the manufacturers have to also be in parallel updating their models, and that's been an issue.

MR. ANGELL: And I might add to that as well. Sometimes it has to do with these new designs, confidentiality around those designs, and the manufacturers have definite concerns there and will withhold information, or try to.

MR. ZADLO: I just want to provide some color to this topic. The interconnection process takes way too long. And we know today, if I submit a request today, I know by the time I get through the process the equipment that I submitted my request with is obsolete, it will be no longer in production. So you all need to keep that in context, and that's why those material modification requests are so needed, because technology is evolving at a rapid pace. So there needs to be flexibility and you need to consider that, that this isn't a stagnant "Okay, I submit this and this is what I'm going to eventually interconnect."

MR. DOBBINS: Is there anything in terms of information and transparency that can be done or changes that could help that process if there's an issue of when I start the process, here's what I'm presenting throughout the process, that they may be changing some part of it is information flow, part of it is just timing, as you get updated and -- yes or no? What can be done to improve that process so that everyone is aware as soon as possible about any changes in a project and other projects, what sort of helps with that?

MR. ZADLO: So what I will say is I think the bar for restudies is set very low. I think a lot of these restudies are unnecessarily performed or they can be performed in parallel with the queue. And I mean unnecessary, there was an instance where we had to move the substation 500 feet, okay. The transmission owners said "We got to re-perform all the studies."

Good engineering judgment would say that's not necessary. With the situation with the equipment changing, rarely has that caused or flagged additional upgrades, all right. So if that's the case, let's have a separate group that performs re-studies on change of equipment in parallel while the interconnection analyses are being performed; that's another way to deal with it. Goes back to my original comment that there's not enough resources studying interconnection. The same individual who is studying the interconnection request is the same individual that is doing the restudy.

MR. DOBBINS: Would anyone else like to comment on this before we move on? Okay. Sorry. I thought I heard a click of the microphone. In the event that there are delays in the study process, how are those reported to interconnection customers?

MR. ANGELL: So the delays in the study process are recorded by a phone call, e-mail, and of course hard copy letter. And with that, we also identify the cause for the delay and essentially the party that has the action item to clear that delay, whether it's either the customer themselves or the utility and a timeline for that.

MR. DOBBINS: Would that include information on other projects, maybe that they're somehow involved?

MR. ANGELL: Yeah, sure. If it's a restudy effort, yeah, project in the queue, senior project dropped out, that is correct.

MR. DOBBINS: I'm going to have the same question for everyone else. How are they reported in the clauses?

MS. AYERS-BRASHER: I think our experience has been that some places give you a reason why, some don't. Sometimes it's a phone call and sometimes it's an e-mail. You might hear about it. Sometimes you hear about the delay before the study's even started, and sometimes those have reasons like the project -- the queue ahead of us and sometimes they don't. So there's no consistency. We don't have -- and it may be consistent within a region, but it's not consistent across. We don't always know what's going on what the causes of those delays are, and it makes it difficult, again, to figure out what we're doing on our side and where we need to slow down or what we need to do.

MR. BOHACH: The inconsistencies, to go on what Jennifer said, the issue regarding the notifications, there's lots of venues depending on which ISO we're operating in. Websites are obviously a tool. We'll get letters, stakeholder or ad hoc groups to meet with or discuss delays. But those will often ebb and flow through the process. Frankly, what we sometimes find is just our inquisition with the ISO, that is often where we find it on the one-off e-mail or phone call to discuss a particular study or group project on that, or hearing from potentially another person in that group or something. So consistency I would say is one thing that's lacking in that notification.

MR. EGAN: At PJM we have for each transmission owner a project manager so the customer will have a direct line with someone on my staff to be able to contact. We issue e-mail notification if the study's going to be delayed. Part of the process, when you have a tight process, for example, 90 days to do a feasibility study and 30 days get eaten up upfront, so you're looking at about a 60-day study, I think some of the issues the customers have is, from what I've heard from them when they call me to complain about it, is that we're notifying them just before the study's due. That's about when we're hearing from the transmission owner that there's an issue or they're going to be behind.

So I think that's part of the rub, is that you're finding out late in the process, but that's just how the process is set up right now. It's very tight time so therefore you're at the end before you know that you're going to be delayed.

MR. HENDRIX: We'll send out e-mails to the customer as - generally as soon as we know and as soon as we're reasonably sure we're going to be late, we'll let them know. And sometimes that's early and sometimes that's late in the process.

MR. OYE: Our experience is usually it's through e-mails, we'll receive an e-mail, and then stakeholder meetings. So there's usually updates on what's going on. So those are the primary ones.

MR. RUTTY: At the California ISO each interconnection customer has an interconnection specialist assigned to them, and they communicate all of the schedules for the study process, all the due dates for financial security, for postings, to provide additional information after phase 1 and before phase 2 to accommodate their needs for any material modifications that they may have. So we have a single individual for each interconnection customer on that. And as far as communications, it could be a variety of things. It could be a letter with receipt required or it could be an e-mail or a phone call.

MR. ZADLO: It varies across the board. Some transmission owners, it's a black hole, you get no feedback. Typically, it's just an e-mail with little explanation as to why the delay is occurring. What's more interesting is when you do get an explanation as to the why the delay is occurring and usually it has to do with that resource that's studying your process that is being diverted to something else. And that's when it gets really interesting because you clearly get a view that the interconnection process is not a priority to that transmission planner. We've gotten explanations that, "Well, we have to do the transmission expansion plan by the end of the year, so your folks studying your requests has to now work on the transmission expansion plan," which always gets done on time with every RTO. There's hundreds of different scenarios and upgrades being studied, yet when it comes to one generation interconnection request it's difficult for them to process that in a timely fashion.

MR. OYE: Just kind of general on this topic. The delays aren't -- there's a lot of reasons for the studies being delayed. The transmission provider, getting the studies done and having enough people to do it, you could maybe say, "There's something to that but they could do better." But our experience is there's -- especially in our area, Minnesota, North Dakota, South Dakota, it's a very good wind area, and we have tens of thousands of projects coming into the queue. And there really isn't the market for that many.

So the projects come into the queue, they're studied, a lot of them drop out. And they tend to drop out at different times in the process, so they're not all dropping out at once so it's not just one restudy. The August 2012 cycle in MISO, there was six restudies, and that was because projects just drop out at certain stages.

And so really there's reasons for the delays and why things are behind, and a lot of it has to do with just, my opinion, our opinion, the company opinion, there's -- the financial milestones are not appropriate, MISO, I've been involved in three queue reforms and every time we've done it we make it a little harder. The first time we said if you have turbines, and then everybody managed to get turbines. That was a milestone. The second one we made it about money, and again, still there was a lot of projects coming in. And we keep upping it, and it usually works for a little while and it works for a couple cycles, but it doesn't necessarily solve the problem.

So our opinion is really what MISO came up with recently, it gives you three shots to get through. You do an initial study as a cluster, which kind of gives you a better idea of what your upgrades are; and then you have a choice to move forward or not. And we think those milestones, what's important is they're tied to transmission upgrades. If you're a 100-megawatt project and you've got 10 million or five million transmission upgrades, your milestone should be a lot lower than if you're a 100-megawatt project, 50 million upgrades. So we really think that there's some structural things that could be fixed in the interconnection process that would help with the restudies, would get some of the things, the timeliness and completion done, and better approval. Thank you.

MR. DOBBINS: I think that's a good time for -- FERC Staff has a few question on restudy, so I think we'll jump in on that.

MS. GRAF: Thanks, Tony.

As we've seen restudies, the problem of them, the stability of the queue is an emerging theme at this tech conference. So we were wondering, especially for the transmission providers, how often do you perform restudies or is there a set procedure for how often you do restudies? And for developers and those that operate within different regions, whether you see variations and how restudies are performed or how commonly they're performed?

MR. ANGELL: So first I'd address -- so Idaho Power did operate a cluster many years ago, and in that cluster we did have multiple restudies that occurred at that time. Since then we've tended to avoid a clustering of studies. So the restudies for a group have definitely diminished relative to that. However, for, again, those entering the queue and then dropping out, only 20-percent conversion rate, there are restudies, but with regard to our system and our staffability, the restudies are done within the time frame so it's not extending the project's time.

MR. EGAN: PJM, our tariff defines when we do the restudies, so if you have a withdrawal the IROT has to restudy everybody else after it to find out if the obligations to build the network upgrades shifts. The issue with that is, when you issue a study you got to tell a customer, right now you may actually fall through our cost allocation rules and not have a cost allocation. But if you're after someone who has caused it, you'd ultimately have to include it in there because if someone withdraws the stack-up where the hundred percent threshold crosses may fall on that customer. So any time you have that you have to restudy to make sure the but-for costs are being applied to the right customer. So it's a lot of work to do restudies, but it's a required work to do for analysis.

MR. HENDRIX: Restudies will trigger higher withdrawal, we know we're going to have restudies after every impact study that we could, and our new procedures pretty much have that built into it. We're pretty much agreed again to have another restudy, once the requests are going into interconnection agreement. But even after that, there's really no set time of when you know somebody is going to withdraw, it just happens any time after an interconnection agreement that you can terminate that agreement. And so you just have continuing restudies, we've had one cluster with seven or eight restudies due to withdrawals. At some point in time you can have a withdrawal and determine that this is an area that we don't have to restudy. But in our western footprint where more wind is, there can be several restudies.

MR. OYE: If it's okay for me to speak to MISO, MISO's tariff has three conditions where restudies will be performed.

MR. RUTTY: So the California ISO, we have a process, it's a two-phase study process. Phase one study is done the first year where we identify upgrades that are going to be needed for that clustered route. Each interconnection customer within that study receives a cost cap, which throughout the rest of the study process that will be the maximum cost responsibility they will have. It helps them to decide whether they're going to move forward or withdraw.

When we go into the phase 2 study, we go into a much more detailed study. The study now has already taken into account for the withdrawals of the phase 1, and it's just the interconnection customers that moved on into phase 2.

Now, they'll get a new cost allocation, but if it's higher than the phase 1 they're still protected by the cap that got in the phase 1 study. This has helped a lot in reducing the need for restudies and makes decisions to move forward, post-financial security, and move on. But if we do have additional withdrawals after the phase 2 and we do an annual reassessment where we look at who's left in the entire queue, all the clusters together, and identify where, based on withdrawals or projects, where network upgrades can be removed -- and usually it's the case that upgrade networks are removed from the clusters and from an interconnection customer so that their costs continually go down -- they get a new what we call "cost responsibility." Ultimately, they only pay for what they need at the end.

So through this process, it's really eliminated the need for a restudy; we're allowed to continually move the clusters through the process and reassess them annually without a need for what we call a "complete restudy" that would completely throw an IC's financial book out the window. That consistency and security that they have from very early in our study process.

MR. ZADLO: If I'm batting .300, I'm not a bad guy, I'd most likely go to the All Star game. So there needs to be an understanding of the development process. And when you build something in many jurisdictions, okay, your special use permit is only good for two years, all right. So I've constantly playing this game of trying to marry up my construction permit with the timing of the interconnection process. And unfortunately it's the interconnection process that's along the items in developing power plans, all right. So I can't move forward with the permitting process until I have line of sight on my interconnect, make sure I can get that project across the line. That's just one of the many things that I'm weighing here. Right? So just because people drop out, it isn't because they have bad intent. Why would have spend hundreds of thousands of dollars on an interconnection request just to drop out? Right? So I want you guys to keep that in context.

The other thing you all should keep in context is that there are RTOs and ISOs out there that have phenomenal dropout rates and are able to deal with it. PJM and SPP, they have large dropout rates, and they're able to do it because they know that during the different stages there's a certain dropout rate, and they do a probabilistic analysis knowing that, okay, these folks in the feasibility study only 70 percent -- or Dave can tell me -- 80 percent will go forward. Once you get to the system impact study, 50 percent go forward, so forth and so forth. So they're able to deal with the issue.

MS. GRAF: Some of you mentioned some of the tariff triggers for restudy. For developers, do you find that the triggers for restudy and the procedures or the tariff are sufficiently clear? And do you see variances between the regions?

MR. BOHACH: So we do see variances between the regions, the difference between RTOs, ISOs and all that. As Chris had mentioned, for example operating in SPP, we know when those are going to occur, we can plan for those and make those good, sound business discussions based on that, knowing whether we'll see restudies. So that's a good case scenario in our experience operating in SPP with the tariffs. Those restudies get drawn out and then you have -- you lose that cost certainty, which now a project that maybe didn't affect my project drops out and there's something that now attaches to my project now, which potentially calls into question the viability of that project. So we do see the variance, some good and some bad.

MS. AYERS-BRASHER: Yeah, we see the variance and it is somewhat defined in the tariff, the higher queue project drops out, we see that, we understand that. But I think there's got to be ways to either have the restudies perform quicker or ways to accumulate the data that allows to have a quicker understanding. I don't know if a full restudy is necessary, possibly what California ISO does, that limits those restudies. There are options and ways and we just need to find those and make them work. And they may be slightly different for each region, but we need to find what those are and fix it. Because those restudies do make it difficult. Earlier information could make things -- if people had a little bit more information in the feasibility study, maybe they'd drop out sooner. So that when you get into those longer studies that take more time and also cost us more to complete, there's a little bit more uncertainty at that time as well.

MR. DOBBINS: We have a question from Commissioner LaFleur.

COMMISSIONER LaFLEUR: Thank you.

Listening to this conversation, I'm hearing a couple high-level messages that are in conflict or in tension with each other at least. One is that there's considerable disparity among the regions in their ability to work through their queues and meet their timelines, the way the processes work. And the second is, in the opening comments I heard a few pleas for regional flexibility and leading the regions in different ways, which seems to be a little bit in tension with having best practices spread through the generator interconnection or otherwise. In the interest of stability, you want regional flexibility, if you could expand on why you think that's important and where you think we should kind of -- how do you think we should look at this tension, because it's always a tension in so many things, in posing the best way to do it or letting people do it differently? And we've heard a lot of different things. Thank you.

MR. DOBBINS: We'll begin on the left and move down the panel.

MR. ANGELL: For one of the first reasons for regional flexibility in the western system is not a full market throughout, so there's a starting point. Additionally, having worked in a lot of stakeholder processes at the local level with Idaho Power itself, at the regional level through the Pacific Northwest, we find that stakeholders' involvement locally allows us to engage with those individuals and make reforms to the benefit of -- where we can essentially compromise and come up with the best solution. But I do understand best practices throughout industry are always important to take throughout. The question is what's the right level of -- not heavy-handedness to enforce things -- but to allow it to grassroots grow.

MS. AYERS-BRASHER: Maybe just a quick comment. While we feel there should be more commonality, maybe across the board especially where there's more markets, we understand there might be some need for flexibility, but we would like to see a lot more consistency.

MR. BOHACH: We're consistent with that view as well. Commonality across would help on the operator end.

MR. EGAN: I guess I would mirror David's original comments, though, the issue with markets, how the markets interface with regional areas makes that somewhat difficult.

COMMISSIONER LaFLEUR: Even between organized market areas, I can certainly see bilateral market areas and RTOs having a different paradigm as Mr. Egan said, even among the market areas.

MR. HENDRIX: The different states, as mentioned earlier, have different appetites for renewables. And SPP stakeholders have approved a lot of regional transmission that's facilitated our queue greatly. So that's one main regional difference. The markets work differently as well, so I thought I'd bring up what those regional differences are, are important.

MR. OYE: Our Colorado system, it's not a market, it's one state and it's worked really well. Whereas in MISO in our area, there's just huge amounts of renewables, wind in the process. I don't think -- SPP is also in that same situation, but I think the East Coast -- I don't think they have that kind of amount of renewables. And in our area for every 5,000 megawatts or 2,000 megawatts of PPAs or off-takers, we might get 20,000 megawatts of requests. So the market doesn't support all the amounts of queues or prejudices in the queues, so I think those areas should be handled just a little differently than others, so regionally I guess is the answer to your question.

MR. RUTTY: Yeah, I believe the ISO has a similar view points to the panelists. We've were able to create an interconnection process that's worked well for us. The serial approach was just unworkable. And so allowing us that flexibility to move forward with solutions that worked well in California was key to being successful. Now, that -- it's no hidden secret that the ISO is looking at regionalization possibly in the future, and this could change our game and we'll have to be able to be very nimble on our feet to adapt to that as more states may join in and move forward, so just having the regional flexibility to allow us to really listen to our stakeholders and provide a solution is very key for this.

MR. ZADLO: I personally dislike the deference that's given to the RTOs. Many times many of our requests are, let's say, on the scenes where it's unclear whose RTO or TOs reliability standards apply, are we meeting this standard or that standard? So there are issues when you start diverting from the standard pro forma. The other issue is deference is okay, if they're meeting their timelines, if they're not meeting their timelines then they should be required to take on best practices.

The last thing I will say is just because something's been performed in the past doesn't mean that's the best path moving forward. Again, there's lots of regions where it's taken six to seven years, and to say, "Well, this is our regional practice, this is how we've done it for the last 50 years," well, if this is how you've done it for the last 50 years and it takes you six or seven years to get through the process, then maybe it's time to change it.

COMMISSIONER LaFLEUR: Thank you.

MR. DOBBINS: Commissioner Clark?

COMMISSIONER CLARK: Thank you.

Just quick followup on the last question because it's very similar to the question I had. And I think this is mostly a commentary for a folks who are going to be submitting comments to the Commission post record.

I would really appreciate some focus on that particular issue from those folks who are arguing for lots of regional flexibility amongst the organized markets. I guess the bilateral markets are different. I think there's some reasons you could separate that issue out. But with regards to the organized market, if you could give me some examples of why different market constructs really impact a process management issue -- which is how I see this -- that would be very helpful. I understand from the purely market issues like one region has a capacity market because we have certain state regulatory regimes in that area and another region doesn't, and on its face I could see why you would have regional flexibility.

When it comes to just a process for doing engineering studies for how different projects interconnected with the grid, to me it just seems like obvious on why a market-to-market difference would dramatically impact that. So if you could give some examples on why that's the case, that would be very helpful.

I understand that there are regions in the country that have -- my own region in the country where there's tens of thousands of megawatts in the grid -- which is different from another region of the country. But from a process standpoint, I'm not understanding exactly why there has to be a great deal of flexibility if there are indeed ways that we've found that you can process that better than others. So if you can provide examples to that, that would be helpful for me.

The question I have, it's come up in a few different comments. It seems like one of the real challenges, especially for regions of the country that have a large amount of especially renewables that are seeking to be interconnected is this kind of almost Oklahoma land rush issue kind of issue that we've run into for well over a decade now, which is you have lots of developers who are out there trying to develop projects -- and God bless them for trying to do it -- but we all know, realistically, not all of that can come on to the line, there are going to be market issues why you can't have that sort of thing.

And the gentleman from Xcel who's talking about the threshold that's going on -- not to be cold-hearted about it -- but is there anything wrong with just as a means of trying to deal with that issue to continue to ramp up those requirements? It might be kind of Darwinian, but does it become something where if there's that much wind power, for example that's trying to get down to the queue and get through the interconnection process, could you simply add to that high bar to weed out projects that realistically don't have a chance to getting on? And is there a way to do that in a nondiscriminatory way so that you can clean up the queue? And what would that bar look like, how high does it have to be? Are there sort of -- I'll leave it open. Are there outside-of-the-box ways we haven't thought of to weed through the project so that in a non-discriminatory way only the fittest do survive?

Go ahead.

MR. OYE: I'm not sure who you were asking. We agree with that. And I think at MISO they recognized that years ago and we just never set the bar high enough. So yes. And there's been a lot of discussion since MISO filed their queue reform, and there was a lot of discussions on what the milestone should be. And it's really hard to determine what is right.

But through discussions and working on it with a lot of stakeholders, our opinion, my company's opinion and some of the other stakeholders, that if you tied it to the network upgrade -- and it's been mentioned about models and somebody I think on the earlier panel mentioned that you can get a model, you can run studies, you can get an idea what your project look like, but until it's run with all the other clusters you really don't know.

So if you did the first cluster study and you identified the cost of the network upgrades, and you somehow tied the milestones for the next step that you had to pay to go further to what your upgrades are, and the logic behind that is, if you're in a spot and you have 100 million in upgrades and you're a 200-megawatt project, you probably should drop off. But if there's no milestone payment, maybe you don't. Maybe you think, "Well, I'm going to stay in but all these other guys are going to drop out."

And we used this -- in my opening

statement we used the term "we do the good projects." So if you set some threshold that you didn't have to pay -- you pay your initial milestone to get in the process, your next milestone you would not have to the pay more if your network upgrades were under some threshold, likely based on your size. So much $100,000/megawatt, if your network upgrades are below that you don't have to pay more. But if your network upgrades are above $100,000/megawatt, you pay some percentage of that amount. And as you step through it, we actually ran some simulations on some of the MISO queue reforms and we applied that criteria to projects.

And after we ran through it three times, a lot of the projects didn't have any upgrades. And most of the projects that survived -- again, you don't know what the project is going to do -- it seemed like it could work. And again, if you get to discriminating, small developer in a bad spot, if he's got a lot of network upgrades, we don't think that would be discriminatory. So again, tying it to network upgrades seems like the reasonable.

The other thing that I think you have to do is I think you have to have firm deadlines and firm timing, that somebody can't sit in the facility study so the last point and kind of -- because I think projects, there's an incentive to stay in as long as they can. Everybody's trying to get a PPA or sell their projects, so there's incentives to be there until the last moment. So anyway, that's my thoughts.

COMMISSIONER CLARK: Thanks.

Anybody else who want to take a stab at that?

MR. RUTTY: I'd like to take to respond to that. The California ISO put in very high bars for financial security. And with hundreds of projects competing to be that five or six that actually complete the whole process, even with a high bar we see a lot of people putting down financial security and in the end withdrawing. So that was a loss for them because they lose some of their financial security if they drop out.

One of the things we did in this last big change was to move the delivery network upgrades that allowed a project to become deliverable and meet our RA requirements, the resource adequacy requirements in California, was to once they finished the pay-to study, if they said, "Hey, I don't want to pay for any of these upgrades, I'm only going to take what's available to me," they actually compete for those based on milestones they've met.

So putting in milestones such as do they have financing, do they have a power purchase agreement, do they have permitting, rank them up to be able to be awarded the deliverability from the transmission network and they came out of their transmission planning process, that was a big part of integrating it.

Yes, having a high bar did get rid of some, but it wasn't the whole solution, it was a multiple of solutions. One was financial security; as well as they needed to progress along as well to be able to achieve the deliverability allocation at the end of the process. And if they didn't, they could continue on as an energy-only project or withdraw at that point.

But in California -- I know others are seeing the same thing, I believe our dropout rate is 80 percent or more. It's very competitive out there; and that's not a bad thing, but it's tough on the developers when they realize they're one out of 10 that are going to succeed.

MR. EGAN: The issue of every customer, the speculative customer, every customer when they come to me tells my how real their project is. So to say that we can find a bar to get rid of a speculative project, I don't think is possible, at least I'm not sure how you would do that. The marketplace, I think, will clear projects that aren't real. When they see a cost that's not going to be economical they'll withdraw the project.

And I think it's tied together, as the issue Kris mentioned, six- to seven-year project delays, projects become coupled together. The longer you have projects in your queue or backlog, the more they get coupled together. In other words, you need the first project to make a decision, the second project to know what their costs are going to be. If you get a complex project upfront that's drawing that out, that gets to be very problematic for everyone else.

So working, and this was talked about in the first session with communication, I'm finding that if we can keep the transmission owners working, projects in parallel, even if the TO thinks, "Well, that project needs to make a decision first," still go ahead and engineer all of it. We have the facilities studies. And the one studies process we haven't mentioned today, we talked about feasibility impact studies, the facility study, the tariff really doesn't have a set deadline for that. It says it should be completed in 180 days. And the issue you get into is putting the planning resources, generally once you get to the facility studies phase, you're working with the engineers that are working in the field. Feasibility impact studies are generally desk-side studies.

So to get the transmission owners, even if they don't have enough staff working in the field, to augment their staff -- and I've heard others say they're doing that -- to me, that's the big thing that has to occur to get rid of these backlogs, allow people to make their decisions on the economics, and then if you have to restudy a restudy, but things will be moving along faster because you've done all of the studies and know what has to be done.

MR. HENDRIX: At SPP, I think our deposits are pretty good. We still have too much room for those to be refunded. At SPP, I mentioned we have a restudy built in after the impact study. We're pretty much giving the customers a free look after the impact study to get all their deposits back. They can reduce the size of their interconnection request; they can drop network resource interconnection service; anything they want to do after that impact study. But going into the facility study, we require a higher deposit. But the intent of serious projects going into the study, they go and get that money back, but there are still avenues for getting that money back, so we probably would like to tighten that up so we only have viable projects going into the facility study. The problem with tying it to network upgrades is you may have -- it's like if a new

345 line gets built into the planning process and you're the first customer to interconnect that 345, you may not have a lot of network upgrade, doesn't mean you're not clogging up later queue projects. Thanks.

COMMISSIONER CLARK: Did you have a comment?

MR. ZADLO: Yes. So what higher deposits do is essentially limit throughput. If you look at the two RTOs with the lowest deposit requirement going in, I think it's PJM and ERCOT, and they have the highest throughput as far as interconnection studies go.

COMMISSIONER CLARK: When you say "throughput"?

MR. ZADLO: The amount of interconnection studies processed, okay. So I think by raising the bar -- when I say "bar" raising the deposit bar -- you're not addressing the underlying issue which is lack of expediency of the analysis. That's ultimately the issue there that needs to be resolved. The second thing is you raise it to high, you get into a discriminatory situation where only the really big companies or the vertically-integrated utilities in those footprints are the only ones that can move forward.

Let's look at ERCOT for instance, with PJM in the Marcellus Shale, they have low interconnections amounts, right, but yet ERCOT over the last five-six years interconnected over 10,000 megawatts of wind.

Now, it's buyer beware because a lot of those interconnection requests in those facilities that got built were in the panhandle or behind the panhandle stability limit and get curtailed a lot. But the onus is on the developer to make sure that they're in an area where they can deliver their output to the market. So I guess what I'm saying is you can have the market -- the better way to do it is to let the market decide.

COMMISSIONER CLARK: This is actually a really fascinating topic I think. Because it doesn't seem like it should be something that should be impossible to solve. I mean, it's process management, and maybe the box we've been looking at isn't exactly the right box, because we seem to keep having these same issues come up over and over and over again. Maybe there's some other way of looking at it that we can -- we have lots of smart economists in the room and folks who might be able to come up with some way to price this particular issue in the sense of scarcity that we see.

So anyway thanks to everyone who's been here and look forward to the comments in the record.

MR. DOBBINS: All right. We have a question from Commissioner Honorable.

COMMISSIONER HONORABLE: Thank you.

It's really more of a comment. And I think the gentleman with the last comment really summarized what I wanted to say. We have to find the sweet spot, we dont want -- I have to link to the comment, I think it was, the gentleman from NextEra who said stringent requirements are good, make sure they are serious projects in the queue. But we don't want to make it so difficult that they could be smaller players, but they have viable projects. So I appreciate Commissioner Clark's question, it really gets to the heart of the difficulty in finding the good place, making sure, yes, that there is throughput, that they're getting through the process, but making sure that the projects that are viable are getting through. So thank you.

MR. DOBBINS: And before we move on to questions about information, content, and transparency, I had a follow-up question for Mr. Angell. We've heard comments about the restudy process and how that can result in delays in getting information out. Earlier you commented that even when conducting a restudy you'll still complete the study process within the allotted time frames. Would you just maybe give more information on how that is accomplished?

MR. ANGELL: Well, and I also mentioned about having augumented staff, the comment about having augumented staff.

Well, it's just about juggling resources is, really all it's really about. And if one makes a commitment to study times and sets up their process and resources in order to meet those times -- again, it depends on when their restudy occurs. If the trigger of a higher order queue falling out at the very tail end a week before the study is due, obviously you're not going to make those times. But in general our planners are able to quickly remodel the system and come up with those study parameters. It doesn't generally take -- it doesn't take months to perform these studies.

As was mentioned by the gentleman that far end there, the processing power of the tools are very great and do many things. It's a matter of having the resource to be able to analyze it. Because again, at the end of the day there's data and then there's information and then there's taking information and writing a report that provides the customer with what they're looking for. But in general it's about resources and committing those resources.

MR. DOBBINS: All right, thank you very much. If there are no other Staff questions -- are there any other Staff questions on this topic?

MS. LORD: This question is directed to Mr.

Oye. You were talking about the Midwest ISO in the latest round, and you were talking about the off-ramps that were part of that reform proposal. I was wondering if you would talk a little bit about -- where you have seen that work, off-ramp specifically, and maybe what we've learned in various regions? You're part of SPP, part of MISO, you're involved obviously in Colorado.

MR. OYE: I think SPP -- MISO doesn't have off-ramps right now built in, they don't. The process that exists today is you can withdraw, but there's not really a point that -- they run a study and you can look at it and go "I want to withdraw and go forward."

So that doesn't -- and I think Charles can probably explain this better than me. SPP kind of has that, they got a two-step. It sounds like Cal ISO does, too, I'm not familiar with the Cal ISO. But yeah, MISO, I think this was proposed at a stakeholder -- I'm not sure who came up with it, MISO -- MISO came into the meeting with this idea, "Hey, let's give a restudy automatically for everybody." And then during processes it expanded well, probably need two restudies.

MS. LORD: Actually, I was just thinking I probably should have directed my question to Cal ISO. You're the RTO with experience on the scheduled restudies. And I was wondering if you've learned anything from that over time?

MR. RUTTY: Well, it seems to be working well at this point. Before we implemented that for a couple years. And the whole integration of the study process, the phase 1, phase 2, the transmission planning and the restudy, all are done, in coordination, so the phases that are developed before those studies, are the same, are in harmony. So as we move forward they all move forward together.

As off-ramps, after someone completes phase 1 study if they want to withdraw because their costs are too high or it's one of 20 projects that they don't want to move forward with, there are options for them to get part of study process back. If they decide not to, continue -- if they decide to continue on -- then the risk ramps up, they may not get it back. The study deposits aren't really the big one, the big one is after phase 1 they're going to move forward as posting that first financial security which is at risk, that's a major percentage of their upgrades. So -- and then it ramps up again after phase 2; 15 percent after 1 and 30 percent after phase 2. So it's ramping up their commitment and our commitment to them as well as we move forward. I'm not sure if I answered your question.

MS. LORD: You did, thank you.

MR. DOBBINS: If the Commissioners don't have any other questions, we're going to move into questions -- Commissioner Clark?

COMMISSIONER CLARK: This isn't a question. But indeed flipping through the filings I noticed Mr. Oye is a graduate of North Dakota State University. And I think deserves to be recognized for that.

(Laughter.)

MR. DOBBINS: We're now going to move into questions on information and content and information transparency.

MS. WOODS: AWEA made an argument that curtailment risk information should be provided on the transmission provider's website under interconnection studies, and we had several transmission providers that argue that this information is already sufficiently transparent. So the question is: What information is currently provided that allows interconnection customers to discuss congestion in order to reach curtailment and what additional congestion and operational data would be helpful?

MR. DOBBINS: Sorry, and we'll begin on the left and move down the panel.

MR. ANGELL: Yeah, so again in the western system, the posting, again bilateral markets and whatnot, the posting of available transmission capacity, that's on the Website. So if the project knows where they're going to -- a customer is going to know where they would like to site their project relative to transmission plans that are identified in the West consistently, we'd get an indication of where congestion may be based on that information.

MS. AYERS-BRASHER: Some of the data is posted, we can find it. But for those that are newer to the queue or not as -- we do a lot of economic studies currently, but not everyone does. And so they need to have that data posted where they can find it, but they shouldn't have to search it out, so it should be very clearly posted or linked on the interconnection site so they are also aware, and right in front of them. In addition having access to the cases earlier and through NDAs and even a small cost, if they can have access to the economic cases, we can either -- if you have a consultant or the internal -- have those products to run those studies, you can do more work. But without the data easily accessible and there, we can't do those things. So some if it's there, but I think it can be improved significantly.

MR. BOHACH: Some of the data is out there, for us to do modeling. But the full assumptions that are used to in the ISO modeling helps for us to do those calculations, as well as knowing what conditional study or conditionality you'll have at your GIA or when you're operational. Knowing that early on -- for example, we'll have certain projects, certain transmission projects, that will be conditional on our interconnection, but we won't know the full extent of what that means operationally. What would be the project on until essentially the facilities study when we're going into the GIA. And that can have real impact to the viability of the project based on the finances. I can only inject 75 percent or 50 percent or something. As an IPP, it's that generation that really makes these projects viable and not knowing that until -- I mean, essentially going into it receiving your GIA really hampers being able to make that decision in a timely manner on the viability of your project.

MR. EGAN: At PJM, we provide in our studies, we're providing a reliability study, not a market study. But we do provide wind and solar, for example, renewables are getting a capacity so they get 38 percent for solar and 13 percent, unless they want to argue more from a technical perspective. So with the upgrades that you're requesting a resource, you would need to build for would be based on the 13 percent portion of your power output. The remaining portion we identify in our studies. These are optional for you to build, you need to come in with a merchant transmission project to upgrade them. The risk would we that you upgrade it and someone else comes along and patches through it and passes the resource and uses up -- so that's the risk for the renewables on the energy portion.

The other thing I think is a bit of a chicken and the egg, is that their capability for capacity to prove it once you've interconnected is based on your overall output during the summer period. So if you're curtailed, that would reduce your overall capacity. There are issues on this topic.

MR. HENDRIX: SPP, the market monitor would post flowgate data at the most congested areas. As far as the interconnection study process, or a reliability study process, we don't look there at the curtailments on that. We would have customers that have requested NRIS, network resource interconnection service, which would give them a look at constraints that would impact their curtailments. What we've seen, though, is going into facility studies most generators will stick with energy only, knowing -- having that look at what curtailments would do, they chose to go with energy only.

MR. OYE: When we -- we buy a lot of projects and we sign PPAs and stuff. When we're evaluating those, we use historical LMPs and information that's already available from MISO, and we feel that's sufficient to do most of our analysis. The other side of this is our company doesn't think transmission providers should be put in a position of projecting future congestion because of variables and uncertainty involved in such assessment. Thank you.

MR. RUTTY: I don't believe this has been a big issue with a lot of our interconnection customers, I haven't heard it, that we're not providing enough information. We did post our base cases for all of our studies as soon as they're available, it's only available to market participants who signed nondisclosure agreements with us. That is available right at the beginning. We have an annual process with our transmission owners where we identify pre-unit costs for typical upgrades that are available. So if an interconnection customer wants to do their own study and it identifies different upgrades, they can actually use these costs to kind of estimate what their costs might be compared to what we come up with.

Our transmission planning process does

forecast congestion for economically-driven transmission analysis through that type of analysis. And I know our markets put out a lot of information that's available online, but again it really hasn't been an issue that I've personally heard, that we're not providing enough information for folks to come into the queue, so --

MR. ZADLO: Historical LMPs are insufficient to finance a new power plant. What you have to do in order to finance a new power plant, you have to show to the banks and independent engineer, you have to do two things. You have to do a reliability study, which includes a power flow analysis to prove to them that facility can be interconnected reliably; as well as the other thing you have to do is production modeling case where you're doing an LMP analysis, 8760 in the future, not what happened in the past but in the future.

That's the two things we need. We need the power flow study and we need the production modeling study in order to move forward. It's very clear in the LGIP that the transmission owner/RTO are supposed to provide the power flow cases. I forget what section it is, 4.4 or something like that.

Getting those cases is always an issue, always an issue. They say it is CEII, they say it's confidential information, whatnot. We've had to, we actually go as far as call the FERC hotline in order to get the case. So transparency is very lacking there, okay, in the power flow stuff and the production modeling.

Production model is a little bit different, we understand, much more sensitive because you would have other generator data and economics in there. But again, certain RTOs are able to mask that information. Again, those are kind of the two sets that are needed for us to project finance the power plants.

MR. DOBBINS: Thank you.

MR. RICHARDSON: I have a question for the developers in the panel. In your experience in entering the interconnection process, is it your experience that the interconnection procedures and study results sufficiently communicate the assumptions used in the studies? And if not, what changes to the process would you like to see?

MR. BOHACH: I would say it really depends on who you're working with, which ISO on that. There are some that, yes, they're sufficient, we know that the tariffs would be able to make those decisions moving along. There are some that we operate in that we're not able to essentially replicate or duplicate the study to be able to forecast and make those business decisions, especially on the timelines that we need. So one thing we would like to see is having the full assumptions and having access to that data to be able to replicate it to mirror/validate what we're seeing and what we're getting back.

MS. AYERS-BRASHER: And I'd agree with that. When we work with a consultant to get an upgrade done, we know what all the assumptions are. We're paying for these studies just like we're doing that for the consultant, so we really should know all of the assumptions that are going into our study and we should be able to replicate those studies. And we also cannot always replicate those studies to ensure that there aren't errors in the cases, because we've had experiences where we've had to deal with that. So if we're also -- and it allows us to have that communication back and forth, if there is a question -- because nothing is necessarily perfect -- but we need to be able to ask those questions. And without those assumptions, we're not able to always do that as well.

MR. ZADLO: I'll say this as a former transmission planner. Assumptions will dictate what your study is going to uncover. You can make any overload appear or disappear based on your generation dispatch and your load assumption. And transparency on how these cases are developed upfront before the analysis happens is paramount.

MR. DOBBINS: Would anyone else like to comment on this topic? Sorry. Would anyone else like to make a comment on this topic?

MR. RICHARDSON: And in an AWEA petition there was some comment in regards to capacity factors used to model generation. So the question for everyone would be how were those capacity factors determined? And for the transmission providers on the panel, where are those capacity factors located? Are they in the tariff or are they in a business practice manual or are they available to developers?

MR. ANGELL: So for Idaho Power, capacity factors are not in the tariff and not in a business practice. However, the capacity factors being used are discussed during the scoping meeting at the very beginning. As far as the reliability studies, this was mentioned earlier, power flow, within the localized area we use a hundred percent capacity factor such as we know when the wind project or solar project is producing their sufficient capacity in the area to transmit. However, once you move away and get into again talking about the western system paths that are defined, we look there and we look at historical capacity factors of the other units in the system and we apply those capacity factors along with this project as it's coming through. And, again, when we do those studies, one of the things we do look at on those particular paths, we ensure that this project does not limit the path capability that previously existed, so we won't let the project adversely impact those paths.

MS. AYERS-BRASHER: So we're able to find them in a general comment that's posted. And that's fine, as we know what they are. However, there are certain allowances that we can elect for a higher level. And in that case, I guess the only thing there would be is if we elected a higher level and we moved forward at that level, then that needs to be held for future studies and future generators and then not put -- in some cases we are then dispatched in the wind projects for instance, and if we had elected it at a higher level that should be held, we shouldn't just be dispatched for everyone else's.

MR. BOHACH: Regarding specific NCF moving forward, we would probably put that in our post-conference comments.

MR. EGAN: I believe I mentioned before 13 and 38, wind and solar, that is in our manual the customers can request higher, so if you had, for example, solar with tracking, we see as high as 67 percent capacity factors on solar. And if we study them as capacity, they're entitled to that as a capacity output. So the issue gets into, and that's the energy portion, in the coupling of that to maintain the capacity, that does become a difficulty for the developer, but that's not an easy solution.

MR. HENDRIX: In SPP, we felt this was a reliability study. We will have all the generation in the local area as full nameplate, and then for variable resources beyond the outer areas we'll have little over 20 percent. And the week after that, the studies, I believe we have it posted on our website.

MR. OYE: I really don't want to comment on this one for MISO because I don't remember exactly what they are. But my memory is that I think they used historical values to come up with stuff, and they have run studies to kind of see what real-time operations that they looked at to kind of set it, so --

MR. RUTTY: Very similar to the other panelists, the ISO, we don't post it -- I mean, we don't have in our tariff, we don't have it in the BPM because they do change. The technology is getting better, solar output is getting better, weather patterns have changed. We've noticed changes in the different regions. So we do discuss it with interconnection customers at the scoping meeting, what we're setting their unit at. And it varies by region, Northern California versus Southern California versus the desert areas. But we do utilize capacity factors so we don't overbuild the system. And I guess that's about all I have to say on that one.

MR. ZADLO: I think it's a little less important exactly what number those capacity factors should be, we can debate that. I think it's more important that those study assumptions be established before the study takes off.

MR. DOBBINS: And with that, we plan to break for lunch, unless there's any questions or comments from our Commissioners.

So we will restart questions -- panel 3 at 1:00 p.m. There are a lot of great options around here for food. We have a great cafeteria in the building as well. I've just been told it was closed, so there are a lot of trucks outside, food trucks nearby.

(Whereupon a lunch recess is taken.)

MR. DOBBINS: Okay, we're now ready to start panel 3 of today's conference. This panel is on certainty and cost estimates and construction time. We're going to ask the panelists to introduce themselves and make their prepared remarks, which were submitted into the docket, or just to tell us one or two points they would like to make today. Panelists, we ask that you please keep your remarks under two minutes. We have a timer at the front to let panelists to know how much time they have left. We'll start on the left and move down the line.

I'm sorry, real quick before we start, I just wanted to acknowledge Chairman Bay who just joined us in the room and ask if he wanted to make any comments or any questions.

Okay, and with that, we'll start.

MR. ALIFF: Thank you again. As I said before, my final is Tim Aliff, director of reliability planning at MISO and my purview does include generation interconnection process for MISO. As far as my opening remarks here, MISO's looking at the technical conference as a way of gathering best practices. And we've heard a lot of practices that we have brought with our stakeholders already and we look forward to continuing that discussion with our stakeholders as well as the guidance that the Commission has provided us.

There was some questions earlier about regional differences, I just wanted to comment on that a little bit. Regional differences should be allowed, but where there are conflicts in those differences, that's really where the focus needs to be addressed and that's where the effort and time needs to be put in, not just making everybody have a uniform process.

As far as that cost estimates and the construction time, there can be tradeoffs with providing more accurate results quicker. Right? It takes longer time to produce those more accurate results, which then also leads to longer time in the queue. You can provide cost estimates quicker, but then it's not necessarily the most accurate.

And finally from MISO's perspective, and specifically, MISO has a provision in our tariff that allows for a customer to withdraw if those costs exceed 25 percent between the system impact study and the facility study phase. And we have had very rare cases where that cost has exceeded the 25 percent. We've seen costs go down, but in a few instances we've seen that occur greater than 25 percent. Thank you.

MR. GOSSELIN: Dean Gosselin with NextEra Energy Resources.

This morning we had comments around the interconnection study process and the certainty and timing of those outputs from that process. For this panel my comments go generally to what happens after the study process. So we saw network upgrades and those network upgrades have a proposed cost and an estimated cost and a proposed schedule. The way that the construct works today is the transmission owner that we're interconnecting into cannot meet our schedule, we can challenge that and schedule and ask that under the option build them ourselves. We're really talking about generally about direct assignabilities, and those that have cost responsibility 100 percent of and they're typically the switchyard or the point of interconnection on the system where we're cutting into the system to put a generating plant on line.

And where -- we've had several instances where the transmission owner has tendered us that option to build it ourselves, and when we're taken it what we've found is our costs are well below their estimates, even with our contingencies in it, and our schedule is much as half of what their schedule is. So what we're asking for here today is the idea that we're able to self-construct, that we're given the absolute right to self-construct those facilities where the direct assigned, and a hundred percent our cost responsibility. Thank you.

MR. KELLY: Good afternoon. My name is Paul Kelly. I work for NISCOT out of Northern Indiana. And today I'm here on behalf of the MISO transmission owners as vice chairman. I'd like to thank FERC for taking the opportunity today to pick up a very important topic. We'd like to make three points today across the two panels I'll be speaking on, and I wanted to refine the concept around respecting regional differences. We've heard a lot from the panel on that today. And the one statement that we make is that, particularly from MISO I think a lot of the best practices in the opportunities to optimize and draw some efficiency in the GIP, has been presented today and also was reflected in a lot of the reforms that were proposed at the end of 2015.

We thank FERC for the opportunity to circle back to those because it was dismissed without prejudice. So with the opportunity for regional differences to take the direction from FERC that we take from this technical conference and then be able to take that through our stakeholder process and having enough time to implement that as would be able to fit the market there for MISO.

The second statement would be that I know one of the driving features for part of this technical conference were some proposals. And from the owners, we just wanted to ask that FERC respect the reality that there's a difference between approving a process and driving efficiencies, versus shifting risk onto different parties. And as FERC recognizes the issues, I think, that have been considered in the past, there are inherent risks for certain business activities and there can't be a guaranteed insurance policy. So to the extent that today is about finding those efficiencies and best practices, the owners are very supportive, but also recognizing that a balance has to be struck and that certain risks can't be mitigated entirely.

And then finally just to recognize, and I think it's already been mentioned here today, that there are tradeoffs and there are tensions, and that we want information to be timely and accurate and cost-effective, but often to influence ones will show there's other variables in it as well. And so the owners would recognize again there a balance has to be struck and that part of the procedures that we have in front of MISO recognize at a different phase as we have different escalating levels of commitment. We thank you for the time and look forward to the discussion today.

MR. MARTINO: Good afternoon. My name is Omar Martino, I am the director of transmission strategies with EDF Renewable Energy. EDF Renewable Energy is a subsidiary of Electricite de France, a French utility electric company. In North America, EDF Renewable Energy has developed over six gigawatts of generation since 2012. EDF Renewable Energy currently owns 3.1 gigawatts of generation and we have approximately 1.1 gigawatts under construction and 10.5 gigawatts under operation of internal services agreements. I want to thank the Commission and also Staff for inviting me to speak here today.

One topic of concern is the ability to get accurate RTO cost estimates earlier in the process. The RTOs usually provide cost estimates of a study stage that is based on per-unit cost without full knowledge of what the transmission owner will actually require. When the transmission owner pays close attention at the facility studies stage, new costs may arise that were not communicated earlier, and some of these differences can be quite large and dramatic.

The generation developers must also have the ability to assess congestion risk. Interconnection studies are not being provided this information; we have seen on several occasions where generation projects interconnected the grid, they followed the GIP rules, and then they severely faced congestion, and the only option for those projects at that time is to fund upgrades outside of the interconnection process. And some of these issues are discussed in earlier dockets that were filed at FERC.

One of the means that we think that we can propose to address congestion and curtailment at the RTO is the fund load is reasonable factors on a standardized concept such as, for example, below five percent. We believe that if these studies, these standards are applied consistently and continuously, the grid will not be underbilled and it will be able to accommodate new projects while protecting some of the existing assets.

To conclude, we think there are several ideas we can utilize to enhance the process and improve the process. I believe that reducing the interconnection time frame to 12 months can reduce the risk of construction delays and cost estimates. We believe that having a three-process milestone can also reduce the risk of withdrawals, one milestone for entry, one milestone for exit, and one milestone in between in the process to make a decision. We also believe that, giving the interconnection customers the ability to self-fund interconnection, facilities and specifically transmission facilities can reduce the uncertainty and the withdrawals that the customer is faced by having longer schedules. And at last we believe that congestion is a significant issue of the grid level and we have to have a process where it takes a look at congestion and resolve the issues for both existent and new asset integrating into the grid. Thank you.

MR. McBRIDE: Good afternoon. My name is Alan McBride. I'm the director of transmission strategies and services at ISO New England. My responsibilities include interconnection queue. I want to thank the Commission for the opportunity to speak today at today's technical conference.

The edification of cost schedule estimates for interconnection upgrades is an important part of the overall interconnection process. The ISO, however, depends on who see estimates, however, does not produce these estimates. This work is performed by the New England transmission owners. Once an upgrade has been identified, the ISO knows that there is a clear tradeoff between the desire for cost and schedule adversity and the time cost taken to prepare the estimate. It would seem appropriate that, in order to keep the study process moving, estimates should not be meant to be highly accurate during the study phase. It may be worth considering whether different study management designs contribute to cost and schedule uncertainty.

As noted in the AWEA petition, some redesign can result in significant re-estimation of costs, especially when earlier queue projects withdraw. In New England interconnections are energy studied serially. In addition, generators do not receive capacity interconnection service until they have achieved commitment in the -- forward capacity market. As a result of these features, it may be the case that New England appears to incur less uncertainty from an upgrade cost perspective. Thank you.

MR. RUTTY: Good afternoon again. Steve Rutty from California ISO, director of grid assets. We went through that in the earlier sessions, so I won't bore you with all that again.

For this session just a couple of points. The interconnection process we developed at the ISO was an evolving process, it took many years. There was a lot of give-and-take by the stakeholders to make it work. For instance, the interconnection customers have agreed to post-financial security, serious amounts of money to move forward. At the same time, our transmission owners have stepped up to provide cost caps early in the process that allows the interconnection customers certainty to move forward. If the actual cost of these upgrades go above that cost cap, the transmission owners are then required to fund it. So getting all the parties to give and take through the process was very important and makes our process work.

The only other thing I wanted to say was, based on how accurate the studies are early is a direct relation to the amount of time that we allow for the studies and to put out accurate estimates. So that was another give-and-take. There was a need for the interconnection customer to have their studies early and quick in the process done, and then there's also, "Hey, I want it to be accurate." So coming up with a good balance was very important there as well, so --

MR. VAIL: Rick Vail, vice president of transmission with Pacificorp. Just a couple of points when it comes to cost estimates and the certainty around that. Pacificorp has about 16,000 miles of transmission line, so building projects and interconnecting things to the transmission system really is something we do every day. So when you start looking at the queue process, we have a lot of experience on what the costs should be, even if it's at a per-unit or a lock level. Quite a bit of certainty on the timing, at least from the Pacificorp experience, how long it takes to construct some of these facilities. We certainly have developers on a quicker timeline, not only on whether it's going through the queue process but also the construction process as well. And we do work with them as long as they're following our standards, and they can do some of their own construction work.

But just like anything, the more detail you want, the more certainty you want or around those estimates, the more time you have to spend around it upfront. That's the kind of same thing with the construction. And again, it does depend on where it's at, what are the purviewing activities that are required to get something built.

So there's some variables there, but I think as long as you're communicating all this upfront, at the very beginning of a project, that first project scoping meeting having those conversations and making sure you're detailing out that these expectations are with each other, to me it does seem very critical when you get down the road. If you are not communicating that this is a plus-or-minus-30-percent estimate to a customer and then you provide it and then they come back and now you're saying it's going to be 30 percent more, that is probably about the worse thing you can possibly do. So I think having that communication and being very explicit of, "Here's where we think we have our expertise here, what are assumptions are," what we base it on, and do that upfront, goes a long way to working through issues on the back end.

MR. DOBBINS: Once again, we'd like to say we thank all the panelists for coming and participating and providing their opening remarks. At this point Staff will now move into asking questions. We ask that you please limit your responses to a minute so that other panelists have time to speak, and apologies once again in advance if we're unable to hear from everyone on every topic.

What is the frequency of disputes regarding interconnection configurations for direct assignment and network upgrade calls? How are such disputes typically resolved? And do you have any suggestion for how they can be avoided?

So we'll start on the left.

MR. ALIFF: So for MISO, we typically don't encounter disputes related to interconnection configurations or network upgrade costs. But when they do arise, we try to resolve those on a more informal basis, working with interconnection customers and the transmission owner to work through those areas of concern. And if that process doesn't work, then we do have other opportunities to escalate that and to provide more formal matter to work through the dispute resolution processes. But for the most part we handle that through the informal discussions. How can you resolve some of that? You're providing information, like has been discussed earlier, additional model review and further discussion through that time frame, maybe upfront, maybe during the process depending on where the concern or issue is coming from.

MR. GOSSELIN: Dean Gosselin with NextEra. So we do have disputes. We have disputes over what is the configuration of which yard we will build and interconnect into. And what we find is different standards amongst different transmission owners, and they want us to build to effectively up their standard. There's very little latitude or any leniency in terms of what is that standard? Even though we may be able to show them that within the same RTO footprint amongst another transmission owner, we're able to build a cheaper facility. And I talk about things like ring bus versus a breaker-and-a-half scheme, and it's just the amount of equipment and the amount of cost that goes into each of those.

And most of it is about providing future flexibility. Well, in our case, we clearly don't care about future flexibility, we care about interconnecting our facilities into the grid at that moment and providing the necessary reliable operation of it.

So the dispute resolution is a discussion with the engineering groups of the relevant transmission owners. And ultimately we lose, because if you hold out nothing's going to change. No standards change. And therefore you don't get your project done, so you have to perpetuate. I don't think there's a real sense of building prudent practice, as opposed to this is our standard, we're doing it this way, there's no latitude. Thank you.

MR. KELLY: Paul Kelly for the MISO transmission owners. I was listening to Dean's statements and it was occurring to me that, because of the companies that are collectively represented in the transmission owners, we're sympathetic in a lot of areas because many of us own generation, been through the queue on that side, versus those of us that own transmission as well. So we've seen both sides of it.

I would say where we come down on it is that when you're going through the GIP it's a reliability analysis and you're trying to make sure that the grid can provide the level of transmission service necessary for the level of the interconnection that's being requested. So that's always for us has continued to win the day. And as far as the number of disputes I would say experienced at the collective level, it's a mixed bag. But I was even, in reviewing Order 2003, just reminded that I don't think that some of these issues have gone away, really it just comes to the scope the work that's necessary to provide a reliable service, the cost related to that to that.

So for the owners, I think we would say we understand, on the interconnection side wanting to have a cost-effective solution, because you are entering a competitive market in these opportunities and you want to be able to be competitive, so lowering your cost of entry is always important. As somebody that wears the TOP hat at on the other side of it, we'd say that it's very important that we maintain reliability. And I understand the words like about the "overbuilt" come into it, but at of the end of the day we're trying to make a decision of what do we need to do to the system now so the asset which is going to live for decades can reliably serve. And when you have to try to make that decision at a point in time, I think reliability needs to continue to remain the same decisions. Thank you.

MR. MARTINO: This is Omar with EDF. We do see disputes. Both of the disputes are both on costs and schedules on the interconnection facilities. Now we're experiencing, our review, some of the RTOs are not very flexible in meeting the requests of the interconnection customer. They don't provide the flexibility to achieve a certain date or to have more discovery on the fundamental reason of the changes of the costs. For example, what we have experiences that -- in MISO, for example some of the TOs will not get involved at the system impact study stage, at the level of detail and the level of expertise and we see it more at the facility study stage. So some of those costs can change dramatically between system impact and facility study.

And also the utilization of per-unit costs rather than an actual construction, actual material figures, earlier in the process. We also see that the disputes often on schedules are due to having a lack of participation of effective systems.

In fact, again, from our experience we have a number of LGIAs that are closed, they're executed, and there's no or little information about effective systems. And the risk or exposure that some of them are experiencing are either not identified or they're identified but they're essentially not costed, because the affected system simply does not provide that information. So providing that information earlier in the process would be key to relieving some of these cost disputes and construction schedules.

And one last comment to end, we really think that having the flexibility to build interconnection facilities and to build transmission can reduce some of these disputes, both from the interconnection side and on the transmission side, and also will provide interconnection customers with the flexibility needed to achieve a particular COD.

MR. McBRIDE: Thank you. In New England, to deal with the interconnection configuration discussion, we have some planning procedure guidance on standard substation design and standard substation requirements for new generation interconnections. So those are known to everybody as they come to the table so people know going into the process what their direct interconnection is likely going to look like. I think that helps people's understanding of what they're heading into. I think overall in New England disputes have been rare, there are probably a number of reasons for that. We have built an amount of transmission in the region over the past recent years, so I think that's given transmission owners a lot of experience in preparing estimates and in preparing schedules.

So for the most part things work out. In the case where there is a dispute that we would seek to help communications between the interconnection customer and the interconnection transmission owner and work through the various mechanisms that are provide in the tariff. There are cases, and I think there was a recent case where the issue may come down here in the form of an unexecuted interconnection agreement and then resolved through that process. So that is something that has happened. But that's just one recent example I can think of for that process.

Finally, I think I'd agree that communication is important and does help. If in presenting an estimate and a schedule, if it's explained, the level of accuracy that was involved in the schedule, what would happen next as the project moves forward to more certainty and more completion in terms of estimate updates, all of those I think can help give customers the understanding of how the process is going to evolve.

MR. RUTTY: Very similar to some of the other panelists. The ISO holds results meetings with all of our interconnection customers to discuss study results. We bring into those meetings the engineers that did the studies for both the transmission owners and the ISO. We have our interconnection specialists there to be able to log and note any discrepancies, anything that needs to be resolved.

And pretty much it's a very open, interactive process and concerns are resolved fairly quickly. I would say that we really do not have too many problems, and a lot of that is because it's a transparent process upfront where we post the base cases, where we post our per-unit cost guides, we discuss what the scoping meeting might be, how they're going to be studied and to what factors and so forth. And if there are any disputes -- so we do have our dispute resolution process that runs through our executive team. But again, I think it's been years since we've had to use that:

One point on effective systems, one thing we did hear loud and clear from our interconnection customers was that very issue about bringing effective systems into the process early. And we advised them at the very first scoping meeting, we post on our website what the effective systems on the various areas are that you might be trying to interconnect to and who you would be likely dealing with. The ISO is not in a position to steady effective systems, but we do bring them, very quickly identify them, and allow them to identify themselves in study process if they are truly affected and to work with our interconnection customers to resolve those issues. Thank you.

MR. VAIL: This is Rick Vail. I don't have a lot to add to that, again I would just say, trying to get to those expectations upfront, I think one of the most important things is it's truly a reliability assessment upfront. And so from a Pacificorp standpoint we don't find ourselves in a dispute situation very often. Certainly, if there are any issues that come up, and again address that head-on with the customer right away and make sure you're communicating.

But having that reliability assessment and ensuring the reliability of the system I think is very important. And one of the difficult things is trying to communicate to developers sometimes the requirements that we are under, whether it happens to be a NERC reliability standard and along with that standard comes a methodology, and that methodology you've been through audits with your regional entity with -- so changing a standard, on the face of it I don't think any standard should be overbuilt or you should have way too much of a safety factor built in. But it is not simple or easy for a utility to just change their standard if there is a whole line or sequence of other processes or requirements that go along with that. So that was my speech on that one.

MR. DOBBINS: I had a followup question for Mr. Gosselin. You indicated that there is at times a push for you to change or do your configurations based upon future flexibility. Just to clarify, are you saying future flexibility in case of your actual operations are different than what you have modeled, or is this in anticipation of other projects being on line and needing to use those facilities?

MR. GOSSELIN: Just a couple of examples. We've had one recently where the transmission owner has tendered us the opportunity to self build. And it looks like our costs from their estimates, original facility study estimates, are going to be two-thirds of what their cost was. However, in their standard they had an additional 10 acres of land, including prepping that land. And that's expensive, so you have to buy the land, you have to prep it, so new service. And presumably ground grid and other things that also add expense and fence it.

When we're building it we're building it for us and only us and our future. Their idea was they would expand it in the future and potentially tie someone else in there. So there's a gap in expectations right there. Ultimately we resolve that piece of it fairly simply by saying we will option the rights for the land for them if they want to expand in the future, and it's their cost, not ours. So we're restricting when I say we want facilities that serve our needs of our facilities that we're asking to interconnect now until the end of that project. There's other instances where I talked about a ring bus configures versus a breaker-and-a-half scheme. So in this case three breakers versus five breakers. And about two more breakers is more than a million dollars to install, plus -- plus work and other things associated with those.

And ultimately we lost on that, and that was really because they said, "That's our standard, we're not going to let you build a ring bus on here," even though we built a very similar interconnection the prior year within the same RTO's footprint for a different transmission user that allowed us to do a ring bus. So in some cases we're able to work through, in other those cases, they insisted for their own standard.

Certainly, breaker-and-a-half schemes are more easily expandable in the future than a configuration associated with a ring bus, but they clearly weren't thinking from the perspective of what is adequate to meet reliable electric service on the grid? Thank you.

MR. QUINN: I guess I have a question about the degree to which you'd have these discussions between interconnection customer, how much the ISO can play a role to mediate those disputes? And if there's not much of a role, the independent entity variation that we use to justify deviations from the pro forma for the RTOs is premised on this idea that there's independence and that the independent system operator has no incentive to do anything for the disadvantaged customer if the RTO can play a role to help mediate inner disputes. Are there parts of the LGIA where we should grant the independent entity variation because it really is the transmission owner that has most of the control over the process and so the underlying premise of independence, the variation doesn't really kind of stand up?

MR. GOSSELIN: Dean Gosselin again. Specifically with regard to the two situations I just laid out for you, which truly happen: The RTO basically had no dog in that fight, they said, "We're not going to be a party to dispute resolution, deal with it directly with the transmission owner." And so for us, you can think of it like the shop clock's running, we buy equipment, we're spending hundreds of millions of dollars in these particular cases in terms of advancing our project and our project development. We don't have time to take it to arbitration, take it to you, take it to someone else, right; we lose, we have to capitulate and move on, we have no choice. So as far as the independent variation goes, there are different standards out there, we recognize that. However, do those standards truly meet pre-utility practice tests that we all have to apply as well?

MR. MARTINO: This is Omar with EDF Renewable Energy. I believe the RTO does have leverage to resolve the disputes. However, they don't use their leverage or they don't usually get very involved in the matters. What I mean by having leverage, the RTO does require the TO to become more involved earlier in the process. There is no justification, if you will, to have a TO in an affected system not participate in the study plan or not participate in the interconnection process, and as a consequence of that, have executed LGIAs and risks given to the interconnection process. Because the RTO, in that case indicates that we're not going to deal with the affected systems, this is going to be the building of the interconnection customers, and if the affected system is not willing to be dealt with then it's unresolved. But I believe there are ways to do that, and also there are ways to do that as well with no jurisdictional entities.

The point here is that the RTO plays a very neutral role, but I believe they do have the leverage to mandate participation and to mandate closure on some of these disputes so we can de-risk some of the issues that the interconnection customers are facing. Similarly on the standards issue, the RTO will play no role whether a breaker and a half or a ring bus is the right solution, because that's the standard of the TO. I can personally respect that.

But on the RTO level, the RTO should have a say and should have a clear indication and criteria to be able to say that ring bus or breaker and a half is actually justifiable for that part in particular as a reliability entity. So the point there is whether or not there are standards by the TOs, by the utilities, the RTO as a reliability entity should be able to say whether that standard in that particular case makes sense, and therefore take up decision on the issue.

MR. DOBBINS: Mr. Kelly.

MR. KELLY: Paul Kelly with the MISO transmission owners. I just wanted to say from past experience, the owners have worked with the RTO in resolving matters like this. I think the other piece is to recognize there are dispute resolution procedures that are part of the GIP's generally. It's not that these are wholly absent, and I'm just recognizing that certain parties have said, "We had a dispute, we didn't like the outcome, we chose not to avail ourselves of that particular procedure and we weren't happy with the outcome." And I understand that, because, again as a transmission owner, I think with different business models here, we've seen both sides of that equation. But I just wanted to highlight the fact that there are different dispute resolution procedures available. Thank you.

MR. DOBBINS: Mr. Aliff?

MR. ALIFF: Tim Aliff with MISO.

So I do think the RTO does play an important role. And the fact that we don't have a dog in the fight I think is a valid reason why we should play a role. Because we're making sure the reliability of the system is maintained. And also there is the equity issues too. If we start allowing individual interconnection customers to mediate from planning standards, then you end up with a previous customer built to a level that a later customer did not build to that same level, which could have a reliability impact down the road. And also from an efficiency standpoint, building substations that have future ability to expand on may be a cheaper alternative down the road for all other customers, and MISO does have a provision that allows for in those type of scenarios, shared network upgrade costs to be -- those upgrade costs shared amongst others that come in behind the initial interconnection customer.

MR. DOBBINS: Are there any other comments on this topic?

MR. McBRIDE: I think there may be a specific difference here in New England on interconnection configurations, and I think it's an example of the RTO or ISO can play. Even though we have several transmission owners in our footprint, we do have a common substation design and interconnection configuration standard that would apply across our system. As I said, that's in our planning procedures and that's known to customers when they come into the process. And I think beyond that -- and I think I'd agree with the way Tim put it -- the ISO is a party to the interconnection agreement and obviously oversees the overall interconnection process.

So we can convene with the interconnection customer, the interconnection transmission owner, and we do that. And we'll ask questions of why something might seem different in one part of the system versus in another part of the system, and it could be there's good reason for that. But that's the kind of question we can ask with the visibility that we have throughout the region.

MR. DOBBINS: All right. If there aren't any other comments, we have a question for the two -- on the panel. Are there any elements that you commonly received inaccurate estimates? And how do final estimates compare to the estimates throughout the process?

MR. GOSSELIN: Dean Gosselin with NextEra Energy. So the vast majority of our interconnections, it's well over 100, have come in under the estimate. So the estimate's -- inflated, but contingency is in there more than sufficient to cover them. However, we have had several what I will call "epic fails" where the actual cost came in in multiples of what the estimate was without really any -- well, in one of the cases no heads' up until after the money is spent, which may have changed a decision. In the other cases I would say as soon as they knew.

However, by that time it's too late because we've spent this huge bulk of money trying to build a generation project to tie into the system. So we're swept in the current, if you will, and have to accept it. So it's gone in both directions on us.

Now, ultimately what we want is accuracy. Right? Because if you think about the process we're going through and the thought process of a new project, we're trying to price in every component accurately, and then we're pricing it to a customer, and if we get that wrong, high or low, we may not have one competitive solicitation or we may have built something that we shouldn't have built. Right? So it really cuts both ways, we want accuracy, accuracy is important.

I think the second thing we're not really talking about is schedulewise. We find in the majority of our cases that schedule and schedule completion is challenged against what the estimate was. And there's no consideration for that from the transmission owner, it's clearly they're mandated to build it, they don't have any liability for missing it.

But we need them to be accurate, right, we need them to be accurate. It's part of why I asked -- to the extent that it's just our interconnection facility that is affecting our cost, let us go build it because we can manage those; cost and schedule, they both matter. We don't want to be sitting there with several-hundred-million-dollar renewable facility that can't generate because the interconnection's not complete. And we find ourselves more in that situation than in the cost-overrun situation. Thank you.

MR. MARTINO: Omar Martino with EDF Renewable Energy. I agree with the previous statements. We see common issues both from the interconnection and on the transmission side, and we see them both on schedule and costs. Just to cite a very few examples on the interconnection side, I have to say that they're rare, but they do happen on cost deviations. But on one particular deviation we saw cost deviations on almost a hundred percent, and that was well after the LGIA was executed with respect to the start project. So that can happen and that can take significant financial impact to the project.

On the transmission side, we also see those very large deviations. Those deviations can be as high as 70 percent. And to that point, on the transmission side a company like EDF Renewable Energy needs those upgrades, needs those improvements to integrate. And there's no other option, there's no just simply fund those large deviations.

The schedule is a significant, issue and it's a significant but it's also a very constant issue. I can hardly say on a number of very, very few times when the actual schedule by the interconnecting transmission owner was actually met. So schedule issues are seen all of the time.

One point I do you want to say here, and see if I can try to differentiate, is that on the cost estimates I want to make a very slight distinction, but I think it's also an important distinction. On the cost estimates they essentially go into two buckets. One are the physical upgrades whether they're on the interconnection side or the transmission side, those physical upgrades they're going to have; and then on the other side, the second bucket, that I don't think we have discussed here today, is those contingent upgrades which are part of the schedule and they're part of the cost responsibility of interconnection the study process. They can be very large deviations on those contingent upgrades, whether they are required because of real studies or modifications of the queue or whatever the reason might be.

But the fact of our experience is that we see a great deal of variations just in the study process; this is not at the termination of the LGIA, or I should say the completion of the LGIA and the construction of facilities. I'm talking about through the study process we see very large variations of costs on a schedule, and I think that is an issue that is very persistent, very much across the RTOs at the national level.

MR. DOBBINS: Are you able to make choices whether to proceed or not to proceed coming out of the SIS phase based on the information that you currently receive from that?

MR. MARTINO: We as a company, we do what we call very good educated guesses. We do a lot of work on our side. Our experience, what we have seen, is that not all of the information that's needed to make a decision is made and presented at that point in time. We also understand that, even if the information that is presented at that point in time at the study phase, we know that it's going to change, we know that it's subject to change, and we know that we have seen very large deviations, just like I said earlier, on cost schedules and estimates.

So having said that, that puts a significant burden on the interconnection customers to try to figure it out or try to provide that visibility. But as far as the information that's coming from the RTOs, as far as what's coming from the TOs, at that stage, I don't think it's enough, I don't think it's adequate, and I think it could be a significant improvement going forward.

MR. DOBBINS: Thank you.

Mr. Gosselin, same question.

MR. GOSSELIN: I'd say in general, yes. However, there are exceptions to every generality. Where a system impact study where the group is still not stable, right, where they present a system impact study results to us, if it's going to get restudied we don't know that, right, we don't know that something's going to drop out and cause a restudy. But if we make a decision at this point and then that changes significantly on subsequent restudies, we're not able to make it -- we either made a bad decision, we got lucky or got lucky. Neither of them are good in this, right? You don't want to have to run your work on being lucky and you don't want to make bad decisions. So if it's a final, final result, if there really is no more changes, yes, there is sufficient information. But if not, it's anybody's guess as to what might happen.

MS. RATCLIFF: So I wanted to dig a little more into the idea of the balance between the accuracy of the studies and the time it takes to complete the studies. So I think what we've heard from the developers here is that you guys were really interested in accurate results, but I think the panels earlier this morning talked a lot about getting through the queue quickly and having these studies completed quickly. So I was wondering for the whole panel, if you could just talk a little bit to that the balance and whether it would be possible to get more accurate results earlier or if that would have a really negative impact on the time it takes to proceed through the queue?

MR. ALIFF: So there is that balance between that obviously. In the MISO process through the system impact study phase, we are providing planning level estimates. We expect -- what's an estimate for or replacing a transformer or reconnecting in a line or upgrading a line? We provide that information. But until you get to that facility study phase where you actually have someone in the field looking at the equipment that actually needs to be upgraded, looking at what the substation's actual design is going to be, you can't really get to that accurate level that maybe the developers are looking for.

And then starting that process earlier, has tradeoffs as well, because you don't necessarily know who's going to stay in that system impact study phase; projects withdraw, maybe you don't need that. And then now you have expense related to trying to develop that accurate result that you have to throw out and you have to start over again. So I agree there is that tradeoff that you have to try to work through.

MR. GOSSELIN: Dean Gosselin with NextEra Energy.

What we see is the big mover in cost is not so much the facilities estimate, it's what's in that facilities estimate, so what elements, is it multiple-line re-conductorings, and we've got to add dynamic VARs and we've got to add other shunt capacitors all over the system and change out breakers, or do we just have to do one thing? And that's what matters, right, that stabilizes understanding what it is that final groove that is -- the overloaded elements that need to be upgraded through the system upgrades are known. Once we know that, the rest moves not that much, but that's the big deal for us. Thank you.

MR. KELLY: Paul Kelly for the transmission owners. I would say our experience around the facility. Study component has been that to get the accurate information out we think that under the current MISO process, it's a 90-day study, and when you're in the definitive planning phase you get 90 days to do the system impact, 90 days to the facility study. And we think that that is probably the right amount of time if the data quality was there, but I think the owners have noticed that it can take awhile to negotiate through all that to make sure you have all the data you need in order to perform it.

And just contemplating what our recommendation would be here, we would just want to leave a thought that we think the study timelines are appropriate. We're really focusing on the overall GIP process, how can we squeeze some efficiency out of the downtimes where you're waiting to actually initiate the study, coming up with packages of information, so that rather than spending the first five, ten days or more, trying to figure out where all the right data is and making sure everybody's on the same page, because it is a balance among several parties, getting that upfront. And the other piece just recognizing the project management idea of do you want it fast, good, or cheap? Pick two of the three. It's a real issue here and so when you put multiple parties into that, that is also another consideration. Thank you.

MR. MARTINO: I think we can achieve the right balance between having timely accurate cost estimates and construction schedules with shorter time periods to study. I think what we need to do is we need to create a process that allows essentially just that. And what I mean by that is we need to have a GIP, an interconnection study process, that is targeted for 12 months, a 12-month process so that interconnection customers don't go into the queue thinking it is going to take me five or six years to get something, and therefore they crowd the clusters because they understand they will not be able to do anything for the next five or six years. If we limit the cluster the study process to 12 months, the amount of study from the time of instability in that, the study cluster would be greatly reduced, which can reduce the cost schedules issues that we face.

The other suggestion for improving the process is having a smaller number of milestones. Instead of having four, five, or six milestones during the process, have three milestones in the process, one for entry, one for exit, and one for making the decision. Introducing more milestones in the process introduces more uncertainty and introducing more uncertainty introduces a likelihood of withdrawal, therefore the complicating effects that we see on cost estimates and schedules because those projects affect each other. Those two can be achieved to mitigate that issue.

And to conclude, I believe that involving affected systems, involving the TOs earlier, moving away from using the per-unit costs, getting away or using a planning-level estimates, they should be gone away. The entity should be providing estimate, accurate and detailed processing at that point in time, because if we keep using per-unit estimates or planning level estimates the risk of having those change and impact the projects are greater. So I think we can achieve a balance, we can do that.

And fundamentally speaking, my last point is that there needs to be a significant amount of resources added at the RTO level to process the status. And having said that, it can be done.

MR. McBRIDE: Thank you. We definitely agree that there is a tension that we're hearing between the desire for the study process to go faster versus the desire for more accurate information in something like upgrade cost estimates. We actually talked about an aspect of this recently in making our own stakeholder process, and we noticed that on the reliability planning side we have kind of a sequence of development of increasing accuracy of upgrade costs.

So we have a concept level for a project you consider a concept, it's an order of magnitude-type estimate, and that's plus or minus a hundred percent in terms of what the overall cost would be expected to be. The next stage is proposed, it's further along, that's minus 25, plus 50 percent; then we have planned, minus 25, plus 25; and construction is something like minus 15, plus 15.

And to prepare a construction grade estimate takes a lot of work for the transmission owner, it's weeks' worth of work, if not months. It involves site surveys and getting bids from equipment suppliers and those kind of endeavors. In our stakeholder discussions we landed on, at least in the feasibility stage, that an order of magnitude estimate was -- our customers told us that that would give them what they needed at the feasibility phase. And we are going to think through and discuss more with our stakeholders, maybe using more of these bandwidths as we go through the project completion steps.

MR. RUTTY: I think I definitely agree with MISO down at that end, that to provide the right balance of the cost estimates and the study results with what the interconnection customer needs is key; to rush through it and give them something doesn't make sense.

So again, the way the ISO works is we have the two-phase study process, granted it's a two-year process. I know Omar would love to have the one-year process. But with 125 projects coming in cluster 9, it just doesn't make sense to go out and do detailed analysis in the field and what it would take to give a phase II result at that point. We've come to a good balance to provide per-unit cost at that point. Allow them ample time after the studies are done to decide if they're going to move forward. Do they have a PPA opportunity, Power Purchase Agreement opportunity? Are they going to be able to get financing? Do they have their sites fully secure? It gives them time to adjust as well. Not everybody that comes in our door is ready to be moved at a year pace, And so that balance has been struck in California ISO.

I do agree with Omar that bringing the affected systems in very early is very important, and we've adjusted recently to do that. I'm not sure I could add any more than that at this point.

MR. VAIL: So Pacificorp, not being part of a regional ISO, I think there's a couple points that I would make. It's certainly a challenge to hire really good technical talent. But a Pacificorp standpoint is we are processing these generation interconnection requests. The dates are very important to Pacificorp, we will meet our dates. If we don't have enough staff available in order to meet those dates, we will contract and augment our staff with consultants as well.

But it's important to note the cost of going outside of the company can be dramatically higher than inside the company. We have some pretty much dedicated staff to the interconnection review process, and they tend to be some of the highest-level experts that we do have, because again, what you're doing is bringing up this generation on the system, is doing a reliability assessment. So you want to be careful not to have too much volume through them and also you don't want to contract too much of that work out. Outside consultants may not have the same familiarity with the system.

And I think there is a really fine balance between that accuracy and detail, and I talked a little bit about what's that communication upfront and really trying to understand what level of detail do you need at that project scoping? Because I think to Steve's point, we have a real mixture of people that come in the queue, and it's great when we have a very motivated, sophisticated developer that already has their plans laid out. I totally understand at that point wanting to hit the ground running, and it's absolutely critical that we as a transmission provider try to meet those customer's expectations. We have a lot of customers that really are putting their toe in the water, and I think it makes a big difference. I would hate to put exacting processes in place, because it isn't necessarily a one-size-fits-all. And out of all of the requests that come through Pacificorp's queue, the majority of them are not large or sophisticated developers. So something to keep in mind.

MS. RATCLIFF: Thank you.

MR. JACKSON: Mr. Rutty of CAISO has

frequently referenced CAISO's study approach and how it provides interconnection customers with a cap for interconnection and network upgrade costs. Are there any other frameworks under which these costs or caps are based on study estimates? And if so, how do you account for these studies?

MR. ALIFF: I guess I'll start. Tim Aliff with MISO. So we do not have cost cap, per se, like California ISO does. And we kind of see that as shifting costs from the interconnection customer to the transmission owner and ultimately the ratepayer having that from a cost perspective I think you also touched on the phase study approach, that is something we have looked at implementing as part of our queue reform as well.

MS. RATCLIFF: Can I ask a quick followup to Tim? You said earlier in your introduction, you talked about the 25 percent cost overrun number. I just wanted to ask, that my understanding is that's not in place when it comes to restudies and people dropping out of the queue ahead of you. Is that the case?

MR. ALIFF: So it implies that the system impact study results are different from the facility study results. So it may or may not apply there in the restudy, depending on what phase that restudy had occurred.

MS. RATCLIFF: Thank you.

MR. JACKSON: Just a followup to Mr. Rutty on your phased approach. In instances where the actual cost are more than the phase estimate, how do you all deal with those situations?

MR. RUTTY: Well, like I had mentioned earlier, if the phase 1 sets the cap, original cap, phase 2 goes above that, the transmission owner upfront funds that payment. It should be stated here that our ratepayers ultimately pay for all of the network upgrades that go into our system. So if an IC ends up paying for something, they're refunded by the transmission owner over a five-year period or sooner than that. So ultimately all the transmission upgrade costs go to the ratepayer in California.

So, I mean, that's a distinction that probably should be thought about as other folks are trying to implement something like this. It's different. But the bottom line is if it does ultimately go above the cap, the transmission owner picks up that delta and they put it into our transmission access charge at that point.

MR. JACKSON: Thank you.

MR. DOBBINS: Did anyone else want to

comment?

Mr. McBride.

MR. McBRIDE: If I may? I do want to follow up on what Stephen said. I think the ratepayer component is critical in evaluating each different -- comparing each process. If -- we're talking today about looking for best practices, and we just need to make sure we're identifying what are the components of each design that actually will support and then make it work, and I think the ratepayer support makes a very big difference to the overall California process. So I think it's important to bear that in mind. As I said earlier, in New England we do not have any ratepayer support of interconnection upgrades, they're all through the interconnection customer, and so that puts us at a very different starting point.

MR. DOBBINS: Mr. Kelly?

MR. KELLY: Paul Kelly with the MISO transmission owners. I think I would just follow through with what Alan had said there, that within MISO it is not refunded. So that would be more of kind of the regional differences and to pick back up on that there, I think this would be a great example of there are certain things that support the philosophies and methodologies that are used here, but this would be one where that concern, as stated earlier around where do you put the costs that comes to the network, and in MISO the stakeholder process those that have participated in have made the decision, that for interconnecting customers that's going to be something they would have to bear the cost of that analysis.

Now, there's -- outside of the scope of that there's certainly questions around how many years out is the study, and when do you draw the line about how a particular upgrade may be needed in the future versus whether you need to get that on the system now. But I just thought that was important to point out that that balance is constructed differently. But I think it goes to the question that Commissioner Clark had earlier today of just what are those driving differences that would say this one needs to be maintained and do something? Thank you.

MR. DOBBINS: All right. If there aren't any more comments on this, we'll move on to contingent facilities, and make this the last topic area. And this is a question for the transmission providers. What is the process for identifying those facilities that are relevant to an interconnection customer for inclusion as a contingent facility and its GIA and those which are not? And then what are the challenges in identifying and in listing the appropriate facilities?

MR. ALIFF: So the process for identifying the contingent facilities that would go through the interconnection involves the generation resources impacts on those facilities, or whether those facility are needed for that interconnection to occur in a reliable manner. For example, our multivalue projects, that I mentioned earlier today, is a contingent facility for quite a few of our interconnection agreements, especially in our west most part of our footprint.

As I said before, those were implemented to ensure that large amounts of megawatts could interconnect into the system at a later date, and we're working through that process. So as far as some of the technical challenges, identifying what the impact, the criteria related to when does a resource actually impact the facility, that can be debated and discussed. On what level, whether it's distribution factor, whether it's megawatt criteria, and those types of things that could be discussed further and how those are impacted.

MR. DOBBINS: Mr. McBride?

MR. McBRIDE: Our process sounds very similar to the Midwest ISO's. It's something that prevents itself through the study process. In New England we do have an overall transmission project list that would be the defining list of what upgrades have already previously been identified. And those could be either for reliability upgrades or for other generation upgrades.

And so if it's identified in the study and then noted in the interconnection agreement as appropriate, if it's a reliability upgrade in pretty much all cases, that's going to be expected to go forward. There may be cases where the interconnection customer has to pay to accelerate a reliability upgrade, that has happened on occasion. If it's a contingent upgrade to another generator's upgrade, then we do note the circumstance if that generator withdraws it doesn't move forward, the upgrade can become that next interconnection customer's responsibility. But that would have been communicated to them through the process through the interconnection development agreement.

MR. DOBBINS: And Mr. Vail and Rutty, unless your process varies from the other two, I'm going to just ask a question to Mr. Kelly. What role does the transmission owner play in identifying contingent facilities?

MR. KELLY: Paul Kelly for the transmission owners. So I would just point to maybe the local design requirements in recognizing that each of the owners is going to have a specific design requirement on the system. But as far as identifying the contingent facilities, that's really, from my understanding, in the purview of the transmission provider.

MR. DOBBINS: Thank you.

And Mr. Gosselin and Martino, I'd going to ask you this last question of this panel. I'm going to ask you to keep your responses to under a minute just in the interest of time. How and when are you generally made aware of contingent facilities that may affect your project? And is it made clear to you why and how these projects may affect yours? The and that last piece is what I'm most interested in.

MR. GOSSELIN: So generally we're made aware that incurring a system impact study process where they said, "Okay, these other facilities have to be in place prior to you coming on line and they have been allocated to generators ahead of you in the queue, and if the generators don't move forward or suspend and if you want it you're going to have to be responsible for it." It's been okay, it hasn't hindered us or created any real big failures. But we've had a recent one where I think Cal ISO has changed their process that say any facilities that were ascribed to earlier queues that haven't come on line, you may be responsible for those costs. And now it's an open liability, I don't know how we're going to handle that yet. Thank you.

MR. MARTINO: Sometimes we never get the response on the contingent facilities. In fact, this is a significant issue for our company at the seams, specifically in MISO and PJM. In that case, as you may be aware, we had operating projects there and there were no facilities that were required for the interconnection of our project, nor the interconnection for many other projects. But in that case, there was a lack of connection between MISO and PJM which resulted in congestion at the seams, and the only result to resolve that congestion was actually the interconnection group funding 50 or 60 millions of dollars of upgrades. And we feel that's very unfair, very unjust, and is simply not an integration process that would be reasonable. So the identification of contingent facilities has been an issue for us at the seams.

In the actual footprint in the case of MISO, the problem that we have there with -- I think it is really a viability question, a viability issue, a financeability issue, is that MISO's many contingent facilities sometimes do not make any sense for the project, but they are listed on the LGIA. And the issue with that is when you try to finance the project, the risk and the uncertainty for these contingent facilities, even though they don't make any sense from the reliability perspective, but they are just listed there because they are from prior queues, makes matters very difficult for interconnection customers. So the message there is that for our experience, for our company, facilities at the seams are an issue of lack of correlation and a lot could be done there to hold congestions, of assets, and at the level of MISO reducing the contingent facilities to more reasonable levels would be adequate.

And just to close, we think we can do that by proposing the integration, the GIP integration, focusing on short-term status, and having the complete integration, like CAISO does, on the transmission planning side where the RTO would take a look at the number of the longer term and as well as the integration of economic studies as well.

Thank you.

MR. DOBBINS: Once again we want to thank all of there panelists for their participation. We're going to take a short five-minute break and reconvene for panel 4 at 2:20, 2:22.

(Laughter.)

(Whereupon a short recess is taken.)

MR. DOBBINS: Again, we are going to ask the panelists once again to introduce themselves and make either their prepared remarks which were submitted to the docket or indicate the one or two most important points they would like to make today. Please keep your remarks under two minutes. We have this very nice wood clock up here we're keeping track of time with, I know some of you have seen it already, which we will use to let you know how much time is left.

Please begin on the left. Mr. Aliff.

MR. ALIFF: Thank you again. I'm Tim Aliff, director of reliability planning with MISO. Again, my purview involves the interconnection, generation interconnection processes. And thank you to the Commission and the Staff for allowing me to speak on three of these panels. So it's my third and final one, so I won't have any more opening remarks after this.

Specifically, for this panel, coordination is very important. Coordination amongst neighbors to the RTOs and transmission providers; and then coordination amongst standard connection customers and transmission owners as well.

So that is something that MISO has worked with. We have worked with some of our neighbors to develop those processes and procedures, and we continue to look forward to being able to do that with other areas of our footprint. One of the things related to coordination to Omar's comment about the MISO's process, actually on Tuesday, a couple days from now, we are going to discuss the very concerns that he brought up about the contingent facility in our interconnection process task force. So we are listening to our customers, and I did make sure that Omar was aware of that and look forward to his feedback, as well as others that participated in the MISO stakeholder process related to that.

So that's all I have for my comments. Thank you.

MR. ANGELL: Dave Angell with Idaho Power Company. And again thank you for allowing IOUs to participate in these proceedings as well.

With regard to this particular topic, coordination with effective systems is less clear in the OATT today and the tariff, and I think there's an opportunity to clear that up just a little bit. From two perspectives: One being a utility dealing with an interconnection customer and affected system, oftentimes those affected systems have different standards, different expectations than we have as a particular utility. So whether they're different standards, and all utilities have pretty fair reasons for the standards that put in place. So trying to coordinate that effort is complicated. Being on the other side, interconnection customer is trying to interconnect with another utility. And being an affected system you have no relationship with that interconnection customer, yet there's an expectation oftentimes that that utility will have that affected system deal with the interconnection customer. So some clarity around that would be useful. And there are portions of the tariff where it appears to imply that there should be a relationship between the affected system and the interconnection customer, but it's truly not spelled out. Those are my opening remarks. Thank you.

MS. AYERS-BRASHER: My name is Jennifer Ayers-Brasher. Again, thank you for letting me participate in the second panel and holding this technical conference.

As I mentioned this morning, improved accuracy, accountability and transparency is needed. And improvement in those areas can reduce the impact on generators and I think, create a better balance. There's been mentioned today that generators have brought a lot of these issues on themselves, by withdrawing from the queue and causing those restudies and some of those issues.

But it really is a balance. If we can get earlier, more accurate information, they're going to withdraw sooner; if there's information available to do more analysis ahead of time, that would also help as well and reduce withdrawals and reduce them in the later stages where there's the most impact.

There also needs to be more accountability for the studies. Currently, in some areas we're paying higher deposits, higher milestones, and yet if there's errors in the study that are outside of our control, it's not having to do with our information, we're still the ones left paying for those. And it's most impactful to the design of the interconnection agreement, we're building the project and then we see additional costs later on. It's still harmful in the process, but at least we can work with that, and improve communication and coordination as well. Those are my opening comments.

MR. BARR: Thank you. Good afternoon. My name is Dan Barr. Thanks for the opportunity for allowing ITC to provide comment. I work as a principal engineer in system planning at ITC. We're working with generator interconnection for about the last 12 years. As the nation's largest independent transmission company, we like to think we've been successful working with interconnection customers and MISO to achieve the large growth in wind generation within the MISO footprint. With the current incentives available to the developers for renewable energy like production tax credit, wind generation capacity will continue to grow, processing that increasing number of requests will be difficult, it will be exceptionally difficult through the existing MISO queue process where a significant number of requests are competing for dwindling transmission capacity in the areas, as well as those entities. If the goal is effective processing of the queue, uncertainty needs to be minimized in the study process. Uncertainties in the process lead to wasted time and effort and restudies, and restudies are the greatest impediment to effective queue processing. Just to highlight a couple of the items that we sent in in our written comments, most importantly, we strongly support MISO's development of three separate, sequential study phases separated by off-ramps or decision points that were proposed in MISO's queue reform under Docket No. 16-675. As part of that three-phase study process, we also recommend incorporation of the cash-at-risk milestone based on the cost of network grades that was discussed a little bit earlier today. We also recommend, as was heard earlier today, providing interconnection customers with transmission models early on to incentivize judicious choices in points of interconnection, and allow them to do their own feasibility analysis, putting the work in the hands of the interconnection customer, giving them some responsibility seems to make a lot of sense.

We also encourage RTOs and ISOs to take advantage of existing information that they have and provide to interconnection customers. There's a wealth of information and facilities studies, cost estimates, taken for us, several years, and there's also access to real cost information for network upgrades. So, for example, you could take a history of Greenfield substation costs by voltage class, take all the actual costs, and post them on the transmission website.

And then finally, we encourage FERC to continue to allow individual RTOs and ISOs to address the issues within their own respective stakeholder processes. There's important differences within the RTOs and ISOs, and we think they're best equipped to deal with those through their stakeholder processes.

Thank you.

MR. HENDRIX: Good afternoon. Charles Hendrix, Southwest Power Pool owner, manager of generator interconnection studies.

As far as coordinating affected systems, that is the challenging aspect. We've been working with our neighbors, we still have some work to do on that. One of those is we're dealing with our large queue and speculative requests and now you're also having to deal with affected systems and speculative requests as well. So it's a challenging aspect. Withdrawals are primary reasons for restudies of length of time it takes to complete the interconnection process. We believe that restudies are necessary on occasion to -- not build unnecessary projects, but we believe there is too many restudies occurring due to withdrawals. We think the interconnection rules and procedures, we should further reduce the incentive to engage in speculative requests. Right now our process has to relook after the impact study so that we had the restudy built in as a -- time to withdraw, but we still see speculative requests going into the facility study. As I said earlier, we have 7,800 megawatts going into the facility study in our last facility study cluster.

After the impact study, we're allowing the customer to withdraw and get their full refund back, they can change the size of their interconnection request and they can make any other modifications as they see fit. Because the problem is their customers haven't taken advantage of this option to direct a facility study, and so we would like to see more restrictive rules for nonrefundable deposits in that department. Thanks.

MR. KELLY: Good afternoon. Paul Kelly with the MISO transmission owners. I'm thankful again to have the opportunity to participate on such a panel.

In looking at the issues in this particular panel, around affected systems, I've heard the three C's of communication, clarity, and coordination, and the owners would support that. I think in looking at working -- and particularly with affected systems, we make the recommendation -- or I'm trying to develop very clear flowcharts that kind of show timelines, I think it was a great point that was just made that when you're dealing with your own speculative projects in the queue and end up working with somebody else, that can be a mighty undertaking. But in those downtimes where there is some capacity available and people's schedules trying to work with through the major entities that you can, and so that way you can also give notice to interconnecting customers, "Here's what the timelines tend to look like between our organization or our RTO and another organization." Also as -- related to what should generate the need to restudy, we would recognize the flexibility's value. As mentioned in the past panel, we wear multiple hats for many of the owners. At the same time, though, when it comes down to a reliability analysis, that once reliability's impacted, that needs to be based on reality. So if there's a change in the ability of that generator, depending on whatever is adjusted, if it needs to be restudied, then we fall down on saying yes, we think that also needs to be upheld.

And then finally just getting back to the point around I think a lot of the discussion we heard today was encapsulated in a lot of the reforms that MISO has proposed at the end of 2015. And so I think what I had just heard here from Dan regarding the three sequential studies and pairing that with milestone payments that allowed interconnection customers to increase their commitment to the process, as well as the transmission provider to increase their commitment to the next restudy, we think that was the appropriate balance and we think that would be the right solution there. Thank you for the time.

MR. MARTINO: Good afternoon again. My name is Omar Martino. I am the the director of transmission strategy with EDF Renewable Energy. Thank you again for allowing me to speak with this panel.

Our view, that coordination is vital to an effective interconnection process, and a coordination between RTOs is vital between different regions, and as well as coordination with affected systems. From our experience, affected systems is a real concern for EDF Renewable Energy. The matter of the fact that a generator cannot even move forward through the interconnection process, through the interconnection standard, and execute an LGIA where the affected system, timing and cost schedules of the upgrade are simply not known at that time. We also want to point out that there's a significant gap in the Commission's integration policy for non-jurisdictional entities. A number of non-jurisdictional entities either don't get addressed or they don't get incorporated or are participating in the planning process or integration process, and essentially they can put a commercial viability of a project at risk. And I believe that's an issue that is a serious enough issue, and the Commission should require measures in the tariff to remedy the problem.

The second set of comments I want to say here is there are a number of different areas where I believe we can improve and a number of different items we can accomplish to improve the process. You have heard me indicate in the past that I think I really believe having a shorter interconnection status can alleviate the process, we should go for a 12-month process, we should allow interconnection customers to fund and build interconnection facilities, as well as transmission facilities. We should provide reasonable modifications to the interconnection facilities, to the generation modifications, I mean by turbine changes. Those should be more standardized -- COD extensions of generators, as well as there's a significant need to limit the restudies.

And my last point is while CAISO has done this, they have precisely eliminated the restudy by having an annual assessment, and they also have a very flexible policy on extending the COD. Because we believe strongly that should be standardized across the multiple RTOs in the regions.

Thank you.

MR. NAUMANN: Good afternoon. Steve Naumann, vice president, transmission and NERC policy for Exelon. I can't really see the clock, so someone give me a heads-up.

On the coordination issue, there's been a lot said, but I'd like to reiterate something Mr.

Martino said earlier, that others have, they've asked that congestion, which has not gotten as much discussion here as reliability, be resolved both existing and new -- this continues to be a challenge, and especially on the seams, and especially seams between RTOs. You heard Mr. Martino talk about the upgrades they had to pay. And there's a tension between what's called as-available interconnection service and later the as-available becoming unavailable and the customer not being happy and the harm to existing customers from taking the headroom with the understanding that new customers eventually become existing customers, and the same thing happens to them. We want a resilient system, and we need to do that analysis, especially on the seams. One of the issues we've seen is the congestion gets ignored because there's a filter, a high-distribution factor saying, "Okay, we got a 20-percent distribution factor, you got to put 20 percent of the machine on the line. Oh, it's only 15 percent. We are going to ignore it in real time" -- don't care about the distribution packet. And you got to look toward I think best practices, and especially on the seam, of dealing with this issue, or you're going to get kind of congestion, the customers would be unhappy. Thank you.

MR. DOBBINS: Once again we want to thank all of our panelists today for both their participation and their remarks. Staff will now begin asking questions. You may have heard me say before, we are going to ask that you please limit your responses to around a minute so other panelists have time to speak. And apologies in advance if we're unable to hear from everyone on every topic.

Earlier today I believe it was PJM who talked about their process and that transmission owners, TPs, and interconnection customers are all very involved in communication throughout the process. And I think someone else also referred to the time and resources spent in the early stages on scoping. And RTO ISO tariffs and the pro forma, their provision for scoping meetings between transmission providers and interconnection customers, do these scoping meetings normally take place within the time frames established in the tariffs? And is there appropriate information exchanged during those meetings? And then sort of compound question is: When does transmission owners end up getting involved in the process? And is that the appropriate time? And are there any challenges for that? I realize that's somewhat a long question, so if people want to go beyond the one minute, I think that may be okay.

(Laughter.)

We'll start on the left with Mr. Aliff.

MR. ALIFF: So as part of the MISO process, we call an ad hoc meeting where we pull together the interconnection customers and the group transmission owners and discuss the group and the project and move forward. As far as the question is it within the timeline, as I mentioned earlier, we are delayed so as we kick those studies off, that is when we are moving into that process. The interconnection customer also has the ability to request those meetings prior to entering the queue, to ask for details related to the point of interconnection, to work with the transmission owner, the MISO, on how to best submit their application, the data required for that application. We very rarely see that occurring from an interconnection customer's perspective. But when you actually get into the queue, we do have that process that moves through, and that stays -- that's little more of a communication we talked about earlier occurs through that ad hoc route through e-mail and then also through our Web page as well, making folks aware of that process.

MR. ANGELL: Dave Angell, Idaho Power.

Not being part of an ISO or a RTO, I don't know that we have the same sort of issues, but with regard to setting up scoping meetings with the customers, they are typically held a little bit later in time at the customer's request rather than the utilities' request. We're able to, but oftentimes they are delayed by the customers themselves. As far as information exchange, so we do focus as much information as we can on our website about process and have essentially a handler deal with the interconnection customers right up front with quite a bit of exchange of data prior to that scoping meeting so we can have an effective scoping meeting, so I think that communications even prior to the scoping meeting is critical for a good information exchange.

MS. AYERS-BRASHER: I think we find that the scoping meetings occurred, sometimes they are delayed if the queue is delayed. But we are sent meeting requests and we participate in those meetings for our projects. One of the things that probably would be useful is only the affected systems were included in those early on so that everyone is aware that there is that impact and that effect, and maybe those are even looked at sooner. But the meetings are occurring, and generally within time frames where we know about the delay if there's a delay to the process.

MR. BARR: I think in general MISO does a pretty good job of shepherding interconnection customers through the scoping meeting. They're generally very brief. Some of the transmission system in the western MISO, there's a lot of different pricing zones, there's a lot of different owners of transmissions, so a lot of questions are: Well do you own that? Is that yours? How much is that rated? So it's all very preliminary information, and again it's a pretty quick process and pretty basic.

MR. HENDRIX: At SPP it's also a pretty quick process. We -- a typical window, this last one we had 70 requests come in. So typically we'll send out messages, e-mails, saying: Who wants scoping meetings? Once we have questions, we'll initiate the scoping meetings and we make sure that that is available to all of the customers. A lot of our customers have been through the process many times, so they're well-aware. But we're always open to having the scoping meetings and we will initiate when we need to.

MR. KELLY: Paul Kelly with MISO transmission owners.

I think given Tim and Dan's extensive responses here, I think there's enough said there. Thank you.

MR. MARTINO: We don't really see -- this is

Omar Martino with EDF Renewable Energy.

We don't really see the scoping meetings as being an issue for coordination, for coordination between transmission owners, transmission customers, interconnection customers. I think when we discussed in my opening comments about the need for better coordination, the need for more effective -- and the need for really resolving the congestion, it's more of an issue not of the scoping meeting but more of the coordination of the status. And more importantly, not the coordination of the status but resolve issues into actionable items, meaning that if there is congestion in the system, if there is congestion at the seams between MISO and PJM, if there is issues for new facilities or for existing generators, there has to be a way, an avenue, whether it's tariff or a policy, to actually resolve that issue and make it into an actionable item. And that's one of the concerns that we have, is that there has been long-standing congestion in certain areas in RTOs. And it seems like different RTOs use different standards, and some of the standards are not agreed upon between the very same RTOs, so nothing really gets done on that front. There's also a concern of utilizing different DFAX, or distribution factors. Some RTO may use 5 percent, maybe MISO might use 5 or 3 or 20 percent, and PJM uses 10 percent. So there's a lack of coordination in the actual -- for the major structure of the studies and how things are even weighted.

And just to conclude, there's also a fundamental concern of getting the TOs more engaged earlier in the process and getting the affected systems engaged earlier in the process. So the point I'm trying to make here is the scoping meetings don't seem to be an issue for us, but it's really the engagement of the parties, and the actionable item that come after the engagement of these parties that lacks unison.

MR. NAUMANN: Just briefly to pick up on what Mr. Martino said, I mentioned earlier and he just mentioned, on the seams the difference in the distribution factor makes a huge difference as to whether you even see an impact or not. And so you get an interconnection, and as Mr. Martino said, there are different policies on dealing with congestion, but the fact is that, dealing with it after projects are online and people have spent money and said "I'm not happy now," but now we got a process to try to fix it, that's a timing issue. It's a bad timing issue because the facilities that are online and now have seen the congestion have now, by the time it's resolved with upgrades, have seen three, four, five, or even longer, years of harm. So it needs especially on the seams between systems, or between RTOs, it needs to be taken into account up front. Now, as I say, someone who wants the least-cost interconnection, and I'm going to take as-available, and say, "I don't want to pay for these facilities." Well, as I said before, the new customer will sooner or later be an existing customer, will be impacted by the other customer, and be unhappy. So there needs to be a serious look at how congestion is dealt with, the interconnection process up front, and that's a coordination issue. The better coordination you have, the better estimates, the better studies, and the more you can do up front to eliminate that and have a resilient system.

MR. DOBBINS: One thing I think has clearly come out of today is dealing with coordination with affected systems. Mr. Martino just indicated that coordination with affected system he would find helpful, and I guess EDF would find helpful. What are the challenges associated with affected systems, coordination, and what are the clear areas or manners of improvement? And we'll start once again on the left with Mr. Aliff.

MR. ALIFF: Yes, thank you. Tim Aliff again here. Some of the challenges related to that tend to involve the different criteria as has been brought up, and I'll address the 20 percent energy resource interconnection service which is the MISO criteria. And that is defined in our business practice manuals, and it also came from our stakeholders, it is something we discussed with our stakeholders, and we also brought up with our stakeholders last year and discussed with that. So some of that comes from our stakeholders and, as mentioned earlier, what the difference is in the flexibility. And then also there's challenges in interconnection request, meaning that if a customer requests network resource interconnection service, what does that mean outside of -- for example on the MISO system, what does that mean outside of the MISO system and what criteria is used to evaluate those resources? So those are where the coordination items need to occur. The flexibility in the timeline, we've heard there's differing timelines from six months to a year to two years. Which you have to make sure you're coordinating through those processes, and we've set up a defined schedule with PJM where we will coordinate on certain time periods and make sure we are coordinated in that process.

Thank you.

MR. ANGELL: From IOU to IOU, the standard practices, per constructions, efforts mentioned earlier about whether it was a ring bus or breaker-and-half requirements, those are some of the issues we find with the effective systems. And, again, when studying projects, what assumptions, distribution factors and those sorts of things, always come up. And there's -- it appears at this point in time, just working through the FERC tariff, the transmission provider that's working with them seems to have the responsibility to work through and coordinate those issues. And if there's some clarity that could be provided there, that would be useful.

MS. AYERS-BRASHER: Jennifer Ayers-Brasher from E.ON.

From our perspective, the affected systems there just needs to be more coordination and studies need to be run more often. The last one we had was done initially a year ago, and then they did update it the following year, and then after that we had -- our costs for the impacting upgrades go from 5 million down to 2-1/2, up to 21 and then to zero. So -- and that was in about a four- to five-month time frame. To just have maybe better coordination, have studies done more often so there isn't a long time frame, because I believe the time frame initially, that year time frame, could have caught some of those things earlier on. So it's a lot greater in our project process to make those decisions. And when it went up to $21 million, that nearly was a project-killer, and that's several years down the road. And it would have been nice to work through that earlier in the process. So just more coordination for us.

MR. BARR: In the interest of singing the same song, that's basically a coordination or sometimes a jurisdictional issue. But if there's adherence to well-defined turnaround times, that would certainly help. Outside of that again, just more of a coordination issue.

MR. HENDRIX: Coordination can be challenging with the different criteria, the different assumptions, the different interconnection service products where some provider may give essentially a deliverability product with interconnection service, in the challenge, how that analyzed for impacting on your system. Whereas, we're as big as we are as a energy resource flavor to its queue. So just trying to mesh those different products, it's a challenge.

MR. KELLY: Paul Kelly for the MISO transmission owners.

I just point out that in the current MISO GIP, we're in the pre-queue process, MISO publishes a contour map to get in a sense of this is where the saturation is in the system and this is where you can find capacity. Looking at affected systems, I think obviously when you're starting to look at geography you can get a sense of how close am I to another affected system? And I think the recommendation from the owners would be just try to give as much notice as possible to those looking to interconnect depending on where they kind of fall geographically, to have a sense of, okay, if you're here it's very likely that you're going to need to be working with the entities.

So we already talked about the scoping meeting, but just recognizing that when you start to get near another RTO's border, that they're likely going to need to be involved. And as far as the owners are concerned, we take the responsibility to make sure that we are monitoring the other potential affected systems because we always want to know how the changes are in effect. There are some I don't want to call them "failsafes," but there is active monitoring that is taking place. I just would encourage, according to as the panel has pointed out, there is more coordination/communication in trying to get through things like the flowcharting process, recommendations, just as much known as possible so that interconnection customers understand when I start to get to these areas I'm likely to run into a little bit of the slower process because now I'm going to be bringing two large processes together to try to run in parallel.

Thanks.

MR. MARTINO: I agree because I think a lot of the comments already describe my ideas. I think definitely coordination is an issue. But I think I would probably take it now to the next issue, which I think that -- the reason coordination is simply not happening is because we just don't address it from the issue, which is RTOs they have different standards that transmissions triggered and wherever there's congestion and one RTO, there may be no congestion on the other RTO, so nothing gets built because there's no common sets of standards. And the interconnection process at the right time and at the right -- the current state simply does not address congestion. The integration process allows for 20 percent threshold between the identification of the facilities and the actual location of facilities and the acutal grid improvement that are required for a particular process. Without lowering that 20-percent threshold, without having common standards between RTOs, there's going to be a perpetual congestion issue at the seams. So I think the issue is coordination, but the fundamental concern is really to have a mechanism to have an avenue to incorporate congestion and addressed into the interconnection process. And we can do that by having a common set of standards.

Thank you.

MR. NAUMANN: The only thing I would add to Mr. Martino. It's more of a common set of standards, it's not congestion, it's simply not necessarily addressed at the interconnection stage. And therefore when generation comes on it sees congestion or eventually sees congestion, as new generation comes on and now we've got a problem and you're a few years down the road now you're relying on the regional and interregional processes to fix the congestion after the fact which is years after and people have been harmed. So it really means something fundamentally changed in the interconnection process upfront to be able to actually deal with congestion.

And the second thing is, you need to also deal with the customer who says, "Okay, I will be perfectly willing to take the risk, but I don't want to pay for a single upgrade more than I have to have the reliability interconnection." On the other hand, that's harming existing customers and those customers are dealing with this fundamental issues and also the fundamental disconnect between, "I will take my chances" and the bid energy market, which doesn't recognize "I will take my chances," it simply lets flow who can flow. Now, you can change that and say, "I say I take my chances, you earn the first office as soon as I see congestion."

The point is, it should be addressed, but this is not the incremental fix. This is something major that has to be set up upfront and done right and thought about how it's going to be done. Otherwise, and I'll just give you a statistic, just last week in Zone 4 of MISO, you got notices of 3,400 megawatts of base load generation retiring. You're going to keep seeing that as the congestion harm occurs. Not that that is the sole driver, or maybe not even the major driver, but every additional harm adds to things like that, and you're going to lose your diverse generation.

Thank you.

MR. DOBBINS: I have a question for Mrs. -- I apologize if I don't get this right -- Ayers-Brasher? Thank you, you're very kind.

I think that the examples you provided was a very interesting anecdotal example of swings which may occur, if I understand correctly these things came through to, I guess, were pushed by the interconnection trying to coordinate with the effective system. Just to give it more context, what sort of information were they attributed to go from 21 million to zero as such as what the coordination of models assumptions, dropping in and out of the queue, what was sort of the rationale for something like that.

MS. AYERS-BRASHER: Our understanding was there were changes in the system. The $5 million had been there for over a year, and then it did drop down based on some changes in the system. And then unfortunately when the transmission was unable to assess the actual upgrade that was needed, they then went from two and a half to 21 million. The problem there is, understand maybe that's the upgrade that's required, but how do you go from that big swing -- and then it dropped to zero because it actually turned out that the criteria being applied was not the correct criteria for an affected system, so then it went to zero. Now, that upgrade, if it's necessary, is still $21 million out there, whether the system needs it or the next generator possibly. But those big changes are very difficult for projects to work through, especially when you're nearing an interconnection agreement.

MR. DOBBINS: All right. Thank you.

Mr. Angell alluded to possible needs of clarity in the tariff. The RTO and pro forma tariffs provide guidance for coordination of studies in the protected system. Is that guidance sufficient for proper coordination?

MR. ANGELL: Yeah, with regard to coordination I think the guidance is sufficient. How to deal with disagreements is not covered at all. And with the interconnection customer having essentially an interconnection agreement with one party and then an affected system, the interconnection customer may end up with an agreement with them as well. And there's no, I guess -- I don't know if there's any accountability for the affected system with regard to time or cost. And it seems like that might need to be addressed.

MR. DOBBINS: Would anyone else like to comment on this in terms of if the guidance is sufficient in the tariffs, in the pro forma? No. And then before we move on from affected systems, do FERC staff have any other questions on this topic?

MR. LUONG: Yes, I had a clarification question regarding the distribution factor threshold.

Is it applicable to both synchronous machines and asynchronous machines? And it is posted anywhere on OASIS clearly what is the number?.

MR. ANGELL: The distribution factor, basically not threshold distribution factor, are a factor of the system where the energy will disburse through the system and through a type of machine that's actually operating.

MR. LUONG: I think when we mentioned about congestion, you know, the way I understand the distribution factor threshold is, you know, you can see how much you impact on your distribution factor on your transmission constraint, is it three percent or five percent? So when you use that, you know, in order to do that, right? So, just trying to see that, you know, it's not like you have different number for the, you know, regular, you know, synchronous machine resource and for the asynchronous machine, you know, the transmission provider use a different number and those are available, you know, normally posted. So, I'm looking at the ATC calculation. You know, you have that kind of threshold and when you have congested, you know, then we normally in our own way we call TLR, you know, then that threshold is there and then in the West you have unschedulked flow mitigation, you know, those threshold is there. So I'm surprised to hear that the threshold is really an issue, big issue, you know, in terms of congestion for the interconnection.

MR. NAUMANN: First of all, the distribution factors vary by transmission provider. As was said earlier -- and I hope I'm not quoting out of context -- MISO has worked with their stakeholders and come up for certain cases with a 20-percent distribution factor. For those same kind of studies, PJM is five percent for the lower voltage facilities and 10 percent for 500 kV and above; that's a big difference.

Our view is 20 percent allows a whole lot of congestion be put on the system. Now, TLRs for example, that's in the operating frame. Again, the wire doesn't care what the distribution factor is, the only distribution factor is when you line up the transactions or the generators that are going to be curtailed or reduced. It's what threshold it is, which is a much lower threshold, and then how much they end up being reduced.

So, yes, there is that disconnect. But as far -- each TP deciding what it should be, either through its own process or through its stakeholder process. We just feel 20 percent is excessive and is one of the -- with respect to the stakeholders in MISO who have come up with that, we just simply disagree. We think that's excessive and has resulted, as I believe, in congestion on the seams between PJM and MISO.

MR. MARTINO: I just wanted to add that maybe the factors are established that they are the same for different technologies, so they are the same for different technologies but they are different according to the TOs, and that's especially where the issue is at the seams because we have different standards.

Just to add on to that, the congestion issue really plays into the earlier discussion this morning the need to create an operational model right. There was a discussion, and I'm going to point to that in a second when I can find it in my notes. But there was a discussion where there was a need to create a model where it actually mimics operational characteristics and having these very different factors is essentially the complete opposite. It allows for grade levels of congestion into the grid, which obviously does not get dispatched in real-time, that's where specifically wind energy at the seams get curtailed very significantly. And the importance of this matter for the wind industry -- but on a different note maybe I will just leave it there. I sort of lost my thought.

MR. KELLY: Paul Kelly for the MISO transmission owners.

I just wanted to approach this congestion question from a different aspect because obviously it depends on the type of service that you're requesting and the timing of where your project falls in and how many years go by before the next project comes along. So there's a lot in that aspect, and looking at it from a reliability question in that when you go through the interconnection process you're looking at reliability assessment. I think the owners would be supportive to the extent MISO wanted to reevaluate the philosophy around how you get generators, and the reality is -- and I think Steve is pointing it out -- depending on how you set some of those levels around the distribution factor, you can encourage the connection of a generator at a much cheaper cost than you might incur depending on where you set that threshold at.

Based on the notice in this particular technical conference, I didn't want to try to overstep on the congestion piece, but just to recognize that to the extent your reliability assessment shows that you need a particular level of upgrades based on how you stress the system. Well, if you make that upgrade, it can relieve the congestion, because you'll never run into it because you designed the system, will allow that power flow.

Thank you.

MR. DOBBINS: Are there any other comments before we move on?

MR. MARTINO: I have one last.

MR. DOBBINS: Okay.

MR. MARTINO: The point I wanted to make earlier was tied the congestion to the accuracy of the results also. And I think -- and I'll talk in a second but I think this is important -- this is important because if we get to the point that we don't get results, we have a very difficult time in financing projects, so we have consequences down the streams.

So it is very important that we get our LGIA on time and on schedule and have representation of cost estimates on a certain schedule and so on that we talked about earlier. But that the results are also accurate in the sense that we don't get a set of the studies that are not representative of system conditions, and therefore financial investment entities simply cannot rely on them or ask for more information. So that's where the congestion piece actually ties back to accuracy of results back to the generation industry.

MR. DOBBINS: All right. We're going to move on now. I know there all other questions from our staff here.

MS. RATCLIFF: Changing topics a little bit from management issues I know we've talked a lot --

especially with MISO earlier -- about preventing speculative projects from entering the queue. And I just want to get a sense from the panel from different perspectives on what the balance is between preventing a project coming in that maybe has no chance of really succeeding versus recognizing the project won't -- perhaps in Ms. Brasher's case -- that a $21 million upgrade automatically makes a project speculative in some sense? So if we could just go around and talk a little bit more about where that line should be drawn in your opinion.

Thank you.

MR. ALIFF: So I guess I'll start. I heard one of our stakeholders say that every project's viable until it is not. So that is the concepts that can change that and can change it quickly. As far as the milestones, we had a thought, and we've heard from our stakeholders on what that means -- I don't know that we have the exact answer on what that is yet -- the idea of it applying to the congestion seems reasonable because if you're likely going to -- that's going to be the outcome if you come up with a project with several-million-dollar upgrades, that it's probably going to be a point where that project becomes unviable depending on how that would work out, so.

MR. ANGELL: The speculativeness of the project is dependent upon where that project attempts to site on the system. Again, when there's congestion and if they're on the wrong side of that, any project becomes speculative in that point in time. So how to actually develop a standard pro forma tariff that addresses that fine detail, I'm not sure how to do that. But if we do come up with something, we'll put it in comments.

MS. AYERS-BRASHER: I think we're trying to reduce some speculation. There is that balance, more information upfront so people can make a better decision and based on that decision they know the congestion so that they're not going to those places. We may have made some different decisions on some of our projects had we known upfront instead of dealing with it on our back end and at a high cost.

So knowing that up front and being able to do that -- and as generators become more sophisticated we're also doing more and more of these things internally so if the information is available we're more able to do a lot more. That's not going to take care of everyone; I think you'll understand that. But the more information that's up front, and also in the first round of studies the more information that's available so that the withdrawals occur earlier, probably the better.

MS. RATCLIFF: Quick follow up with that. When you say more information up front, are you speaking about more information from the transmission owners. But getting that meeting, getting more involved, the facilities, could you be a little bit more specific?

MS. AYERS-BRASHER: Better access to cases, both economic cases and the transmission-planning cases, better understanding of assumptions, more accurate assumptions in some cases, pretty much any information that can help to make a better decision.

MR. BARR: I think in terms of viable projects, it's hard to say you know you're not viable from somebody passing judgment on it. Assuming that you all are viable and assuming that you have to process your queue, and assuming that at some point you have to do a final study to determine what's needed for projects, you're not going to want anybody in that study group to drop out. So you have, let's say 1,000 megawatts study, the impact of one of those projects dropping out is significant.

If you take it to the extreme, under the current GIP, you could be a nonviable project in the queue and your obligation financially from the point that study ends under the current process is that your only obligation is to fund the facility study.

So you fund the facility study, let's say that takes $20,000 for your project, you fund the facility study, you go forward, you're still trying to sell your project, you're the developer, you're pretty sure you have a good project but you're not a hundred percent confident. But your only stake in the game is to provide that what we'll call $20,000 for the facility.

Continue to look for your project and under the current process with the GIA, GIA takes 60 days where you have 30 days to negotiate, you have another 60 days from the interconnection customer's perspective to sign the GIA.

So let's say you take that and you put up the entire clock: You take 30 days to negotiate, you drag that out, you take another 60 days, and then you circulate the GIA for signature, you sign the GIA. And in the GIA there are payment requirements, one of those payment requirements says provide a payment entered. Another 30 days adds on there and you still haven't sold your project.

So you don't really lose anything if you don't make that payment but the process continues, there's still other projects queuing in, there's still doing other studies, so that 30 days go by.

Well, our policy is, as transmission owners, we send a breach notice if you're 30 days late, so there's another 30 days on top of it. So then after we send the breach notice, then there is -- under the tariff there's I believe 30 days for a cure. If you don't cure by then, then you have to say you're trying to cure. So you say you're trying to cure it. And then eventually when you get 90 days after that time point, then you GIA is terminated. In the meantime you've still got this study queue progressing, you still got other projects that they're basing their projects successful reliability on your project and your upgrades being there.

So if you back that out then somebody like MISO is forced to do a restudy. So under the current process there's problems inherent in the process. So making sure that when you get to that final study that none of those projects drop out is a pretty key element.

And I think that the proposal that MISO has where you give you project two chances to drop out, and when you get that second change you should be reasonably certain that you project is willing to go forward, you're willing to put your chips in the game. And if that's the case then a lot of that restudy stuff should go away, but that's not what we have today.

MR. HENDRIX: At SPP, we give customers a lot of opportunities to view this information. We have feasibility study, which is a $10,000 deposit, pre-look at the system; we have a preliminary impact study which is a full-blown impact study that the customer does an impact on the regular queue; and then going into the definitive study there is the built-in restudy there. So the customers have plenty of opportunities of what they're getting into even after the interconnection impact study.

So going into that interconnection facility study for SPP should be a critical step. And that should be the last chance when they put in that facility study deposit that we know they're going to move forward, but it just hasn't come to that yet so far.

Thank you.

MR. KELLY: Again, I think the comments have been made. I'll say that rather than focusing on the end of that process, maybe I think the question was directed of, How can you discourage people from even entering the queue if they have something speculative? And I think earlier this morning we heard discussion around if you can ratchet up the entry-level requirements and try to have some natural barriers to discourage. I don't mean to be a broken record, but I would say the owners evaluated the proposal that MISO put together, kind of had the right balance right now because facing the opportunities to go in there and do the feasibility study, get a basic sense, make a decision, "Okay, do I want to move forward or not?" And then once you start getting into those sequential studies, because you're escalating the commitment through milestone payments, we thought that was the right balance and way to start to test it out.

I think reality is, one thing I'm hearing throughout a theme today, is I'm not necessarily requiring a particular timeline but at least give me certainty I know how long it's going to take. I think if you know you're going to go through a series of restudies, we should have a particularity around that. And the owners saw that has being very valuable that it may not be the exact number of months that any particular interconnection customer may want, but at least you know, "Okay, there's a sequence of events, I can plan my business, if it's a permitting issue I would kind of have an window of opportunity that I know need to start moving the other pieces of my project."

And the last point I would make is that, it has been recognized that when an interconnection customer enters a queue, they're not shovel-ready to sell. They're also developing their pieces. And I think that type of proposal that was put out there, although tweaked and refined, it did recognize we're we're trying to land several planes on the same runway at the same time, and all of a sudden it's going to become one viable project in the end.

Thank you.

MR. MARTINO: I think the question of reliability really highlights the fact that the interconnection queue is simply not working today. And I say that because, right now, interconnection customers enter the queue thinking that they're going to be there five, six, or seven years in some cases, and by extending these very large timeframes just by itself puts viability on to projects just on the outset.

So blaming interconnection customers for lack of viability is, I think, a very unfair statement and I think the fundamental issue, which is queue reform, that targets the new era that we're living, which is competitive markets, the ability to integrate into competitive market very quickly and get your LGIA an agreement in place.

So having said that, we can reduce project's viability by having the interconnection process that is fast, that is expedited. And you heard me say earlier that a 12-month process should be ideal. Currently, the MISO process certainly is not working, and I can say "certainly" because they're delayed, they're delayed by over one year. So MISO is proposing to put more and more milestones to the process, to increase viability is simply not going to be a good measure. Increasing milestones actually increases viabilities. We have to have, not only a short process, but a very well-defined short set of milestones to increase viability.

And the last comments is that we need to start thinking of having a process that is somewhat similar to what California ISO has. And to the extent that, as much as I want a 12-month process, the fact is that CAISO is the RTO that can get this done in 18 months or 24 months. I don't think many of the other RTOs can actually say that. And that increases project viability. As well as the California ISO has a very flexible criteria in changing, changing COD's for the project, something that many of the RTO's can -- one of the RTO's actually go after interconnection customers and cancel their agreements by changing the COD. And in the case of CAISO, something as being in the negotiations of the PPA, for example, would qualify for a criteria to change that PPA to that COD. So if you want to reduce viability, we have to have a short process. We have to have very well-defined milestones. We have to have a process that incorporates into the transmission flow just like the California ISO does as well. So those are the key elements.

MR. NAUMANN: Quickly, I don't know what "speculative" is. I'm going to speak first as a transmission -- generation owner and developer. We would look at putting let's say new gas-fired generation in PJM, it may have four queue positions. And we only intend to go through with one, that's not speculation, that's trying to get information on which is the most viable. So maybe we can change the term. You start getting that information and then you drop out. But that's having multiple positions is not speculative, it's the flexibility one needs but it does create, because of the way the evaluation is done, there's nothing that says, "Evaluate this because I'm going to take one of four," they have to be all evaluated and they're added. And, again, this goes back to I think the conversation we had this morning and Commissioner LaFleur asked about it, a lot of the time, the restudies end up occurring because somebody at some point says "this is too much" or "my project is not viable for some other reason," and somebody drops out of the queue and the cost now -- it has to be restudied for two reasons, one, you may not need upgrades because you got somebody out of the queue, two, it shifts the cost of those upgrades to somebody else and they may not want the metric.

The last thing about some of the California process is understanding it's a single-state RTO. They can do certain things on the costs of the upgrades by putting them on the customers because that's where it's going to go. A multistate RTO like PJM or MISO or SPP, those things can get really controversial. So I think you may look at what California does, I would say before you put it into a multistate RTO, think of what other reactions may occur.

Thank you.

MS. RATCLIFF: Great. Thank you.

MR. MONCAYO: I'd like to ask a question. Earlier, panelists alluded a needed ability to clear projects in the queue as appropriate.

How frequently have any of you been involved in disputes involving GIA termination.

MR. DOBBINS: And while answering that, please also let us know, are there clearer standards with regards to what constitutes or what allows for a GIA termination? And we'll start on the left.

MR. ALIFF: So MISO has filed for termination of several generation and interconnection agreements. And I think from a clarity standpoint related to that, we have a provision that allows for generators to go three years beyond their commercial operation date, and if they have not achieved commercial operation by that time, we have the ability to terminate that generator interconnection agreement.

Now, there isn't a defined criteria that says what makes this project the project to terminate or not. So we err on the side that we terminate the project in that standpoint. We did try discussing that in our stakeholder groups last year. We didn't get a lot of support for that. We got a few folks that were supportive in developing a set criteria related to that termination provision, but we don't have anything. Some clarity around what is it, exactly three years and then we terminate? Or has somebody done some level of detail at that project in order to reach that level of termination.

MR. ANGELL: Yeah, at Idaho Power we have terminated projects. Failure to make payments obviously would be a cause for termination. And then of course attempting to -- well, basically not constructing and achieving an online date given extensions that are already available in the tariff.

MR. BARR: Just to add, we could have a very similar scenario, as described earlier, we have had probably two-three terminations as a TO with a three party agreement with MISO and the interconnection customer.

MR. DOBBINS: Were those all based on people exceeding a commercial operation date by a certain period? Was that the only reason?

MR. BARR: No, I don't know that we had any of those. We had one that was tied up here for quite some time and that was eventually terminated. We had another that for whatever reason the customer was unable to bring things together enough to push the project forward. And then the other, I think, I'm at a loss for cost.

MR. HENDRIX: And I think we've been involved in the termination of several GIA's, the most common is the nonpayment for construction of the facilities. When the first milestone comes up, I mean, a lot of the customers will go into suspension, so the second-most probable terminating event is when the suspension is up they don't ask us to resume construction, so the payment and some suspension and then recently in our most recent reform we did add a requirement to build, make sure all the generations are built at least within three years of the GIA commercial operation date and the GIA. That has not been in effect long enough to really determine anything from that perspective yet.

MR. KELLY: Paul Kelly with the MISO Transmission Owners.

I would just say that collectively as the owners, I don't think we've had enough of these situations occurred where we've gone forward with an approved GIA, and things have been made, and then all of a sudden somebody couldn't become commercially operational. I may be speculating that, they're solely addressed in post-conference comments, if that's inaccurate. But I think the more-regular situation is just kind of a situation where you get into the signed GIA but the payment doesn't come and then it just naturally terminates from that point forward.

MR. MARTINO: I think the termination provisions really has to be looked at with respect to the RTOs. When it comes to extension of COD's, in our experience, there are a number of projects that are on similar situations but they have been treated differently. And I think that having a project with an executed LGIA with interconnection and transmission facilities built into the system, which other customers can take advantage of and that price is terminated, I think that's something that has to take us back and see who should be reexamining the termination provisions in the tariff. Something we would like to see, as I mentioned earlier, is the COD extension criteria that we saw in the California ISO where if you go past a certain window you're not automatically terminating like in the case of MISO that they're very concerned about the three-year time period. You're active, including LGI payments, network facilities, and transmission facilities, but you're also pursuing a contract then you can show that, I believe the California ISO does grant extensions based on those facts. So I think that's a gray area and I think we really need to reexamine it and something I would like to see is consistency between RTOs. I think it's unfair to that one RO would have termination criteria very different from another RTO, that's something that I think should be consistent all across the board.

MR. DOBBINS: All right. Thanks.

So that wraps us up for panel 5. There was no break scheduled between, I'm sorry, that wraps us up for panel 4. There was no break scheduled between that and panel 5. So we're going to take five minutes to set up for the next panel.

Okay, thank you.

(Whereupon a short recess is taken.)

MR. HERBERT: All right, let's talk about energy storage, or electric storage resources as we've been more affectionately referring to it lately. I like to thank the panelists for coming to talk to us, the audience for persevering to the end or showing up especially for storage. Either way, it should be interesting conversation.

We do have a relatively aggressive agenda for this panel. We teed up five topics in the final agenda, as you guys have seen. We'd like to allocate about 10 minutes each to those. Kaitlin here will help me keep on track, if we're over time on something, move onto the next topic. But as Tony said earlier, if people can keep their responses to about a minute each, I would like to try to give everybody an opportunity to speak on the panel. And again, apologies in advance if we don't hear from everybody on every topic. But we'd like to kind of try to cover the front as much as possible.

So with that said, I'd like to thank the Chairman and Commissioner LaFleur for showing up. And without, I guess, further ado, we can go ahead and do the introductions. As before, you'll have a couple minutes. And we got this nice clock down here letting you know when your minutes are up.

So, Dave, if you want to go ahead.

MR. EGAN: Dave Egan with energy interconnection project with PJM.

Regarding storage facilities, PJM has had a lot of experience over time starting with CAISO, with flywheels, and now battery storage. We interconnect these facilities using our generator interconnection procedures. We also model them as a load, since they do both activities and it's based on the inverter and the power delivery and power receipt, not necessarily the storage size of the battery that we study.

We allow for distribution level interconnections to participate in our markets. Some of the issues that we have on that, they'll get into whether the storage facilities participating in retail or wholesale and the timing of that, so one or the other at any given moment. Combining of battery storage with other generation fuel sources, we have no issue with that. We treat, again the incremental increase in the power output is what we would study, and we would also again review the delivery power to the battery as required.

MR. EMNETT: Good afternoon. I'm Mason Emnett on behalf of NextEra Energy Resources. I also want to thank the Commission for the time and attention to this topic.

I think all of us are relatively low on the learning curve of how to integrate storage, develop storage facilities, integrate them on the interconnection process, and then operate them on the system. So I think it's great that the Commission is taking the time to focus, not only on the interconnection side, but also the market rule questions that the Commission has out.

So NextEra has four operating energy storage batteries in the PJM market, and we've got projects active in development in all the other RTOs.

So in our experience in navigating the interconnection process for the battery has really informed our experience with the wind and solar side, which, as Mr. Gosselin explained, well, several panels. There are issues to deal with in terms of navigating that process, the timeliness and accuracy of studies, and the delay, and all that good stuff.

As we think about developing battery storage as a large generation owner, we first wanted to co-locate our batteries with the existing generation projects to figure out where is that extra unused capacity, or frankly even land rights, where can we go and plop on an outset? And as a highly-controllable device from a battery's perspective, we can control anything. We can use the excess interconnection rights, we can oversize the project and just never exceed our interconnection rights. But as we've gone through the interconnection process, typically the way the RTO could consider our project is as an incremental addition. So we get studies based on the total injection.

And what we would like to see for co-located projects is to really focus on what it is that the customer is requesting on the actual injection rights. And so that's the main path that we have today and we look forward to discussing all the other issues with you.

MR. FERNANDES: Good afternoon. Chairman Bay and Commissioner LaFleur, thanks for joining us. And thanks to Staff for the invitation to speak and for sticking around late on a Friday.

John Fernandes, policy director for RES Americas.

Within RES's of 10 gigawatts of global energy projects, we have about 100 megawatts of storage that's in operation or under construction in four different countries.

When I think about the strides that we made within energy storage, especially over the past couple of years, I think a lot of that has been predicated upon the speed and accuracy of a storage plan. And I think one thing we have ignored is the speed and accuracy of the control platforms that sit behind the storage plan. And it's those control platforms that set the parameters within which storage will charge and discharge, fully automated. And a lot of times we're frequently developing plants to operate that charge and discharge around net zero, not at a full discharge and not at a full charge.

So I think as we consider that a little bit more moving forward, especially inform system operators, RTOs, and coming utilities, really on what is that storage project going to be doing and what are the real interconnection needs for that plan? So I look forward to discussing that at little bit more today.

MR. GABBARD: Good afternoon. I'm going to reintroduce myself.

My name is Dave Gabbard, I'm director of electric generation and interconnection for PG&E. I'm responsible for inter-connectional traditional renewable and energy storage generation to PG&E transmission and distribution system.

PG&E is in partnership with California ISO. The stakeholders have put a significant amount of effort into looking at the interconnection process for storage generation to PG&E's wholesale distribution tariff and California ISO interconnection process. To date, PG&E has over 1,400 megawatts and 2,800 megawatts of active storage under the CAISO GIDAP and PG&E WDT processes, respectively. That's actually a number before our cluster 9, which has just closed, so that number has increased.

PG&E has progressed stand-alone and renewable-paired storage generators through the current interconnection study process. Under the direction of the California ISO, PG&E has also successfully studied the addition of energy storage to existing generation through an accelerated material modification process.

CAISO-driven collaboration across PPO's and storage stakeholders was fundamental in enhancing the interconnection process to evaluate the impacts of both the generation and negative generation aspects of the energy storage generators. PG&E agrees that the California ISO interconnection process is sufficient and safely and reliably interconnect to energy storage through PG&E interconnection systems. However, PG&E

believes additional work is needed to establish a process in evaluating the aggregated distribution level storage participating in CAISO's market.

PG&E is concerned that existing distributing interconnection processes may not fully evaluate whether any safety or reliability issues arise when a significant number of DER's, Distributed Energy Resources, responding in an aggregate manner to CAISO market signals and dispatch instructions. PG&E believes that the distribution of energy resource aggregator should be required to complete an interconnection study process before operating as an aggregation of distributed resources in the CAISO market.

Thank you.

MR. McBRIDE: Good afternoon. Alan McBride again with ISO New England.

I want to thank again the Commission for the opportunity to speak today. My comments are focused on the interconnection aspects of storage.

ISO New England is currently processing interconnection requests for the addition of storage devices in New England. These requests include the additional storage to existing generation facilities and the inclusion of storage devices among other types of generation of new generation facilities.

While the ISO believes that the existing interconnection procedures are adequate to manage these interconnections will continue to moderate stakeholders and take up discussions if it appears that enhancements may be needed.

The ISO would also like to note that most historic performance on the technology, the efficient processing of these interconnection requests is dependent on provision of a appropriately robust design. The equipment needed to meet the established performance requirements which our power factor ride-through and frequency response and power system models need to perform well and network study analysis. After the interconnection process is complete, the ultimate aspect of participation metering telemetry, et cetera, for a storage facility, will depend on the markets in which the resource has chosen to participate.

Thank you.

MR. RUTTY: Good afternoon. Steve Rutty from California ISO. I'm the director of grid assets, oversee the generation of interconnection process there.

And storage has become front and center at the ISO over the last couple of years. We have held at least four stakeholder efforts to discuss interconnection efforts, market efforts, and operation, both operational issues that go along with storage. Our queue is heating up pretty heavily. We have currently cluster 7 through 9, 77 projects with 8,700 megawatts of storage that are trying to interconnect, 34 of these are hybrid units, a couple that are flywheel.

So short opening statement. We're heavily into it, we know we have -- I am trying to remember who said it down there, we are early on the learning curve. So I'm sure we'll be making changes as we go forward. But currently, as Dave said with PG&E, our processes are allowing a very competitive market from the storage area.

MR. HERBERT: Great. Thanks a lot guys.

So the first topic we had teed up for discussion is whether the existing small and large pro forma interconnection agreements and procedures are sufficient to accommodate the interconnection of electric storage resources? So the question is, have you had any difficulties using the existing pro forma agreements or pro forma procedures for large or small generators in your region for the transmission providers or in any region for the developers when interconnecting electric storage resources? And if so, can you please explain those difficulties? And we're just go down the line from my left.

MR. EGAN: So for large generation-sized battery interconnections, no problems at all. Small generation, they have a propensity to come in under our very small gen, less than 10 kW inverter base and under 5 megawatt inverter base. The issues there, though, pure distribution, the interconnection process is not jurisdictional. So that's the only rub we have there. But we typically coordinate with our transmission owners to work through the state process and establish if they're trying to participate in the PJM market, we get them at wholesale market participation agreement so that they're able to do that upon completion of the interconnection process through the state's interconnection process.

MR. EMNETT: Mason Emnett with NextEra.

So our four projects that we're operating are within PJM, and I'd say PJM has been great and the TO's we have interconnected with have been great. But we're learning our way through the process. We've co-located our projects, so issues that we found are -- as PJM has over time kind of maybe improved upon the way or learned its way through the studying process, we see slight differences in system impact study approaches with respect to modeling, injection, as Dave said, there's a modeling of withdrawal that makes sense to us particularly in a weak area of the system, so those studies make sense. But the modeling of thermal violations associated with new injection, in some instances we've been modeled as if the battery is just a complete injection above the interconnection that the customer had, even though we were proposing not to increase that amount. In later system impact studies, it appears that's not the case, but we're not entirely sure.

So we'd like just to go forward not only in PJM but in other RTO's, just more clarity, and this kind of gets into the later issue in topic 3, but it's one that's important to us.

The mechanics, in terms of the mechanics, yes, there are kind of practical issues in working through the interconnection application and the agreement, there are some provisions that don't apply, there are questions that -- don't aren't really relevant, and there the most part we've been able to work through that. There is a little bit of a risk from the developer perspective of if you're not answering a question correctly that can lead to consequences in the interconnection process.

So we've worked with the PJM rep to say, "Is this how you're going to interpret my question with respect so a storage device" -- and they say to you "We were all good" and we get it in an e-mail and we're fine. So that hasn't been a significant issue for us. It's really more, conceptually, what is the project doing when is comes on line? How does PJM model it? And then make sure that reliability is protected.

MR. FERNANDES: Thank you. John Fernandes from RES Americas.

I would agree with Mason, the RTO ISO transmission owners, distribution owners, they've been very willing and very collaborative to work with we, the developers when it comes to interconnecting storage resources. There's been a lot of questions in both directions, a lot of studies, but that's okay, I don't think holistically there's anything wrong with the current process.

I actually want to go back to something that came up this morning. We have a generator interconnection process for supply resources; and then we have a transmission planning process for transmission infrastructure. You hear it all the time now, "We're developing storage and we're trying to stack services." And that's actually the primary business model for RES right now. We are building facilities to serve as the infrastructure for incumbent utilities. Whether it's with an RTO, ISO, or even with utilities, that challenge of, "Well, these guys over here do the wires and these guys over here do the supply," that does not lead to a smooth process for interconnecting a storage plan that's going to do both. And so I think there needs to be a more direct way to combine those conversations so we're not having it two times with similar folks.

MR. GABBARD: Dave Gabbard, PG&E again. With energy storage being -- having such diversity in technology, and like was said before being early on that learning curve, there's definitely challenges; we've encountered a handful today. As Steve mentioned, we have worked collaboratively across stakeholders to work kind of through some of those challenges, and we are effectively progressing storage generation through our interconnection process using the existing pro forma contracts. I think we're going to continue to see challenges, but the collaboration that exists in the community, stakeholder community is going to allow us to address those challenges as they arise.

MR. McBRIDE: Alan McBride from ISO New England. I would agree that the existing small and large pro forma procedures are adequate, but I think to the learning curve I think, as I think we've heard just now, that the storage development community is coming to understand what is required by the LGIP and the SGIP. We've heard examples of proposals coming forward, as we've explained with there's a power factor requirement, ride through requirements, there's a frequency response requirements. And we found ourselves with models that actually capture none of the above. And we talked about modeling this morning. We've taken some pains and we've had the recently approved interconnection improvements to very clearly lay out what are the data requirements coming in to the process for modeling. And we expect that that will help communicate to folks that how to get into projects is having models that can hit the ground running, and that's a part of what's associated with the performance standards.

MR. RUTTY: I'm not sure I could add any more than what my fellow panelists had said. Like Dave mentioned, we did meet with our stakeholders including a lot of storage interests, to really review what our interconnection process looked like, what our pro forma documents were. And it was pretty much consensus that our current process will accommodate storage. And, again, we're going to continue to watch it, we're very early, cluster 7 has just finished its phase-2 studies, we'll be moving to the LGIA phase very shortly. So stay tuned.

MR. HERBERT: Great. Thanks guys.

Encouragingly, there's a pretty high level of satisfaction it sounds like. I'll ask the next question anyway's, so it might be a quick one. But do you have any sort of suggestions for best practices, potential improvements to the pro forma interconnection agreements and procedures and how to accommodate storage? I know Mason, you said with PJM there are some non-applicable provisions provided they meet a data requirement for example.

Has there been anything that's caused enough heartburn do you think justify improvements.

MR. EGAN: Mason brought up a good point. So when you have an ISA and you have, let's say, 100 megawatts of wind and you haven't built it all up, you have 80 megawatts built you have 20 megawatts left that you want to build up, the problem with the interconnection service agreement, the way you would make a change is through -- in ours is appendix 2, section 3, which is material change to the project. While it's still inverter-based, we do do a vulnerability study on the wind. So the way we're looking at it is if you haven't built out the full hundred you, would need to come back to the queue for the this performance since we haven't completed the study. If it's not transparent when you use what we call the "necessary study" -- I think that's what's it's actually referred to in lower case -- PJM will perform a necessary study, it's not public, it's not very transparent until after you would correct the ISA. So I probably should have mentioned that the first time when we were talking about are there issues with agreements, that is one issue of the ISA right now, try to change technology that doesn't really allow for that. I think the way we're handling it is appropriate, because we do get the appropriate study in place to ensure it's adequate.

And as far as -- he also mentioned the increase, that comes to -- as Mr. Fernandes said, the technology in how you're putting the output out on the system, you need to be clear on what your output could be to the system, worst-case. So while the machine can be set to zero, they can also be set to some higher value in the inverter capability. So as the transmission provider, I have to make sure reliability of the system is the worse case. Unless we're blocking the box that allows that control so that you can't deviate from that, we would have to study the worse case.

MR. EMNETT: Mason for NextEra.

"Satisfaction" is a strong word in the interconnection process.

(Laughter.)

One of our projects, a 10-megawatt project involving partial use to sustained rights took two years. So I can't say we're satisfied with that, but we get it. We get that people are working hard on issues and some are them are contractual and some of them are study-related, and we wish they didn't happen.

In terms of kind of things to improve, yes, that ability to take full advantage of effectively what we've already contracted for, and so the studies that PJM would need to perform, part of that I believe would also load deliverability and the remaining studies relate to the type of injection rights we're seeking, whether it's energy-only or capacity. And so more -- it's not entirely apparent how going in we could define what it is we as interconnection customer are seeking as effectively a programmable device the conditions which we are willing to accept in order to avoid any problems on the PJM system. That type of -- so NextEra also, our major subsidiary is Florida Power and Light, a vertically integrated utility integrated utility, as we are thinking about integrating batteries on that system, that's the internal conversation we can have. This is what that device can do; how can we operate it; how might we want to optimize it. Well, that type of conversation doesn't fit within the PJM process because that's not the way the interconnection process is designed, which is fine. We'll accept that process as it is. But let's figure out a way to effectively, from our perspective, maximize the assets that are already in the ground because most of the batteries that we're developing at this point are in the 30-megawatt range. There are developers that are looking at much bigger, but we're just looking at little incremental additions to the system, and it seems like that could be easier.

MR. FERNANDES: So I think we've touched upon a real key challenge, not only do we know how to improve upon this. Entities that are responsible for reliability have to plan for worst case scenario; that's what's they've been charged with, I'm an ex-utility guy, I completely get it. At the same time developers, we're interconnecting a distribution to provide services to the balancing authority. When the distribution utility looked at the full charge discharge cycle of the capabilities of the storage plan, it resulted in voltage flicker-down on their system, and we were handed a $2 million bill for system upgrades. We were able to show them, we wrote a control algorithm, and we were able to show them that you could slow down the responsiveness of the battery to still provide the service that the balancing authority needed but to completely mitigate the voltage flicker farther down on distribution. And the distribution utility accepted it and didn't require one bit of upgrades. And so that's -- I certainly don't think that the distribution utility's falling short of their reliability obligations. They recognized and accepted the fact that this is a controllable resource, that a mathematical algorithm would prevent that plan from doing something where, technically incapable on paper, it was capable of going to the full charge and full discharge instantaneously, but we prevented that from happening. And I don't exactly know how to bridge that gap between those responsible for reliability and those of us that are designing these systems.

MR. GABBARD: Just quickly that I think both sides of that spectrum have been touched on, I think we really need to highlight that it's a balance. The biggest benefit of energy storage is also one of the biggest challenges is disruptibility and opportunities to leverage. That flexibility to maintain the safety and reliability of the grid, we have found opportunities to leverage control systems and other control mechanisms to maintain that safety and allow interconnection under material modification process, for example. But we've also had instances where developers want the flexibility to be able to stack those revenue streams and be able to perform in whatever potential future market that could exist at some point and so we need to make sure that we balance both sides of that spectrum and maintain that safety reliability that we require on our grid.

MR. McBRIDE: The use of existing interconnection capability and this may be something that the Commission would think more about, maybe take an example of, say, an existing hundred-megawatts generator and a new proposed hundred-megawatt storage facility. If the proposal would be to reduce that existing from 100 to 80 and then replace the top 20 with the storage device, that is certainly something that could be studied. It would avoid the thermal analysis, but we still would need to study the performance, voltage performance and things like that, to ensure there was no degradation. That's the study side.

I think there's also the interconnection service and interconnection rights question, what has actually occurred? Is it essentially a retirement of rights from that first unit from 100 down to 80, call it a permanent right? And for us in New England, that brings up capacity market questions and the capacity piece probably has to go through the capacity market and dealt with in some way. It could be dealt with maybe as a re-powering, so it's a partial re-powering of the facility where it was presented and operated before and in a different way afterwards.

So I think there are different options and we may already have all the tools for that particular proposal that we need, but it may be worth thinking through the interconnection rights piece of it to make sure what's actually achieved at the end of an endeavor like that.

MR. RUTTY: Again, going last, I don't know if I have a lot to add to what my fellow colleagues have said.

(Laughter.)

It's just the process needs to be very flexible. Developers make changes all the time. They may come in with a solar plant and then halfway through may want to take away part of the solar and add some battery storage. The battery is a little bit different than solar, so there's level of deliverability, that level might go down. But it's something we would work with them on. We allow all kinds of changes and modifications through the process, as long as it doesn't negatively impact the other interconnection customers that are there.

So that's the key that we look at, we make sure when someone comes in with a change that it doesn't negatively impact projects to put them in jeopardy. But there are a lot of opportunities to learn and meet with these developers want to put in. So it's a very creative market right now. It's a learning curve, lots to look forward to.

MR. HERBERT: Great. Thanks again.

We've largely segued to the next topic already, that is the modeling of electric storage resources. John, you gave a nice example. Alan, you talked about how ISO New England does it. Maybe you can move through those a little bit quicker. But for developers and potentially PG&E, you have any, I guess, additional experiences with the way your storage device has been modeled, either sort of unnecessarily delayed the interconnection process or did not accurately account for the resource operational characteristics?

And if so, would you recommend any improvements or best practices to have that done? That one's geared at the developers.

We have a follow-up question for transmission providers.

MR. FERNANDES: So John Fernandes from RES.

I think one of the real challenges when it comes to the modeling of storage is the only way -- that's been shown to me, anyway -- for system operators is to model the charging of a storage resource that's been treated as a load. The charging of a storage resource is anything but load mostly from a control perspective. So I think -- and maybe that's where we the developers can come together with the system operator and start to share some modeling processes, how exactly do you show the controllability of the charging of a storage asset, but also keeping in mind that frequently when we are charging a storage plant, we are doing so under the instruction of the system operator because that's part of the service we're providing. And that is rarely reflected in a load construct really unless you're talking about load curtailment, some type of demand response-type idea.

MR. EMNETT: Mason Emnett from NextEra.

Not much to add, but there was a link obviously in the conversation earlier today about when wind and solar is modeled, capacity factors. It matters in the RTO's analysis what the assumptions are in the operation of the resource. And as John and Dave acknowledged earlier, the way that PJM would study is maximum charge at the worse time and maximum output at the worse time. And that's not the way the asset is going to operate, we all know that. So then how do we get to a place where you would have some reasonable function or control around the way that the asset's going to operate.

MR. HERBERT: Dave, do you have anything on modeling? I know you're kind of the middleman between the developers and the operators.

What's PG&E's perspective?

MR. GABBARD: I don't have anything to add from an engineering standpoint. But I do want to add to what John referenced about the differences between the charging of an energy storage device and load. If you noticed in my opening comments, I deliberately called out negative generation. I think that's been one of the biggest successes in the California ISO process, to really look at how do we model and how do we interconnect energy storage. The fact that energy is intended to operate in a way that helps the grid is something that we need to take into consideration. And understanding how we can leverage the existing generator processes to evaluate the gen and negative gen is important, and it helps clarify some jurisdictional issues that also come up around energy storage and allows us to effectively use these as they stand.

MR. HERBERT: Great. Thanks.

So all of questions for the transmission providers, Dave kind of described us for California already, but you briefly described a methodology for modeling electric storage resources during the interconnection process. And specifically with respect to how it is modeled as generation, load, or both, and whether it does accurately account for the generally fast and controllable nature of these type of resources?

Dave, if you want to start?

MR. EGAN: That's a tough question, because it depends on how they're using the device. That's the rub. I think, as we learned, it requires communication with the customer and how they're anticipating using the device so we model it properly. I don't know if that covers the question. It's very difficult to have a one-size-fits-all for them to operate on the system.

MR. HERBERT: Okay, got it.

MR. McBRIDE: So in New England when it's generating, we pretty much model it essentially the same as any generation base on the technology. We'll be doing the appropriate reviews that we would do for similar type of technology, especially for inverter-based injections. The study as a load is an interesting one, at least on the transmission system in

New England. We have had storage in New England for a long time, and other reasons -- we have pumped storage. We have been trying the market mechanisms further up the road. So we have, for example, an asset-related demand, which is not load but it's the ability to buy from the transmission system and the pumped storage devices use that today when they're pumping, and then they pay the locational marginal price, et cetera.

So when we're studying a storage device we'll be doing with that in mind, so we're not going to be studying it as firm load or as network load. So a new network load, let's say 20 megawatts, would be studied under a set of conditions, it would probably be more conservative than the asset-related demand, storage-type load. But that network load is going to be aimed at transmission service, it's going to be paying for the storage transmission service. So in turn, it has a higher level of transmission service.

So the storage device, when it's acting as the load, we will have ensured there's no adverse impacts when it's essentially opportunistically taking power off the system to charge, and there could be upgrades to make sure there's no adverse impact. But other than that, it is a different concept from network load so we're studying it in accordance with the service it's going to have going forward.

MR. RUTTY: Very similar to ISO New England. We look at the charging aspect, as Dave mentioned, the negative generation, and the reliability studies we look at it to make sure it doesn't cause any issues and that our congestion management or the market signals can make it work. We don't identify upgrades based on charging as long as the unit is dispatchable, is responding to market signals, and is curtailable if that's needed. Similar to them, when it's acting as a generator it's studied just like any other generator we have in our queue.

MR. GABBARD: Real quick, one point on that just to clarify. When we are studying the negative generation or charging characteristics of the storage, we will look for upgrades required in order to accommodate firm load and we will communicate those if identified in the study report, but they're there for informational purposes only. So we will not move forward with build out of an infrastructure for a firm road because we understand that the market signals are intended to account for that, any potential congestion.

MR. LUONG: I guess just I had a follow-up question. John mentioned earlier that storage is somewhere between generation interconnection and transmission process, are you trying to say that one of the ways to connect it is the power piece of equipment, that you should look at storage and the transmission piece?

MR. FERNANDES: So we are definitely developing storage. Probably right now it's more distribution, I think most of your incumbent utilities are trying to take small bites of this. So we're looking for more infrastructure-upgrade referral-type process, but we are also looking at storage as transmission as non-transmission alternatives possibly to be submitted into ISO planning processes. I don't know that the challenge that I brought up earlier specifically related to the little piece of interconnection. But I think there's something, and maybe this is for the separate market participation docket, I don't want to get too out of scope for today, but there is an issue when we are developing storage plans that are being built to offer multiple services. And one half of these services is something related to infrastructure, whether it's congestion mitigation, reliability, voltage control, power quality, whatever it may be, and then perhaps we're collecting supplemental revenues from an ancillary services from an energy market. Those are not the same groups of people that we're talking to when we're trying to plan the interconnection and operation of that facility and when we're trying to -- on the infrastructure side, typically that's going into infrastructure rates and on the supply side that's going into the market to collect revenues. And there are different groups of people, they're different timelines, they're different studies altogether. And that is holding up the process a little bit.

So I don't know if I answered your question. Okay.

MR. RUTTY: Steve from the ISO.

That's the exact question we've been trying to ask, "Well, can it be a transmission asset?" And the ISO has to be very cautious that it doesn't get into operating an asset where it can actually change the market. And so if we did put it in as a transmission asset, it would have a very limited use and pretty much limit what the storage system could do for us if it was a market participant. So there's that conflict we've been dealing with.

MR. FERNANDES: And that's an excellent point and it's absolutely correct. And I would not go out to the market, broadly speaking, and develop a storage plant that has an operational obligation to the system operator. I'm not going to put a storage plant in rates in transmission or distribution and then go to, say, a capacity market and try to clear that option and take on a capacity obligation at the same time. There's going to be a primary driver for any storage plant that has stacked services, and that primary driver is always top of the list. And it might not necessarily be what that storage plan is dispatched for the most hours per year, but it always get the priority. So when we write our algorithms, that's what's at the top of the stack. Meeting that utility obligation or on the other hand a capacity obligation, there are markets that offer tremendous flexibility day-ahead and real-time, even inter-hourly, to come in out of that market and just begin to collect supplemental revenues, these are not the economics that are driving the overall cost recovery system but they're certainly contributing.

MR. HERBERT: All right. Let's move on to the next topic.

Next one was the interconnection of combined storage and generation facilities. We had a number of kind of subtopics identified here, interconnection service, combined facilities, operational understanding, telemetry and metering for those facilities, and the appropriate process for adding storage to existing facilities. So we'll start at the top of that list. We've heard sort of mixed opinions, I guess is one way to say it, regarding the appropriate level of interconnection service for these types of facilities, whether it should be sort of the cumulative rate of capacity of all of the assets behind the point of interconnection or whether it could be somewhat limited level of interconnection service based on how the developer actually intends to operate the device.

So we'd just like to, I guess, hear from all of the perspectives at the table, what you view as sort of the appropriate level of the facilities to be.

MR. EGAN: Dave Egan, PJM.

So the general history of where we've seen these, typically some form of renewable with the battery storage, and the issue there that drives up cost is having the meter separately. So in order to get the renewable energy credits, the renewable resource has to be entered separately. That's really the biggest issue I see. As far as everything else, it's pretty straightforward as far as that studies.

MR. EMNETT: Mason Emnett for NextEra.

I think we would agree in terms of straightforward as to the studies, we understand how the studies is being performed and what is being done. Our ask would be what is being studied actually reflects the injection that we are requesting. And so as an owner of large asynchronous resources within the system, which are highly controllable and we're attaching a battery that is highly controllable, it's not immediately apparent to us why we could not attach a battery to an existing asset, say a wind asset, that if we've got excess interconnection rights that we are not using, then transfer those over. Could be transferred over depending on our financing legal structure, you might transfer over within the existing entity, but that's kind of in the weeds. But there should be an optimization.

And then it also seems to us that you shouldn't necessarily be limited in terms of installed capacity to your interconnection rights with controllable devices. You should be able to include more on the customer side of the control down and never exceed the injection rights that you have already agreed to that, that's already been studied. Now, there wouldn't need to be studies of withdrawals, there wouldn't need to be stability studies. But the thermal studies of the injections it would seem have mostly been done. And if we can kind of find agreement on that, then one of the more complicated issues in the interconnection process, as you've heard all day long, is the linking of interconnection requests through the study process and the queues, and the dropouts causes the delay. If you could take one element of that and put it aside for these type of projects, because they're going to control in on them. And that generally has not been something that has been well-received from the RTO perspective. So if we could find comfort around that.

There are a couple of examples we could point to where the RTO's have accepted interconnection agreements for install capacity and in excess of the injection rates and the maximum facility output. And there is contractual language in the ISA saying "I understand I will never exceed this number, I have more installed but I will never exceed this number." And we understand that, we can handle that. And that would be our ask.

MR. QUINN: I guess this question is really if you had a red button that you're not controlling, we have a red button that says "if you exceed, we'll control," and then would you be comfortable with them having a red button?

(Laughter.)

MR. EGAN: I would say what we want is they would install a power flow relay that would limit the output, the problem you have is if you have the capability and you can exceed the thermal capabilities we have studied you could cause damage. I would prefer to see, if you're going to say I've got 100 megawatts wind farm and I'm putting my 20-megawatt battery there but I'm going to limit it to 100, then put something there to ensure that the system is never in jeopardy.

MR. EMNETT: And we would be fine with accepting the limitations. I think the red button is there, it's in the control room at PJM. We can be curtailed and the operators can -- they monitor us, they understand what our output is and they would call us if we were exceeding. Now, would it actually be reasonable for the operators to note for every resource the amount that they are and are going to track it? MISO has cracked the nut with net zero interconnection service, there are reporting obligations on behalf of a customer who has installed more capactiy on its side of the interconnection than it actually has interconnection rights to. Pro forma agreements which govern the relationship between the two entities, if they're separate entities on the EOI side, as well as the relationship between the monitoring, the TO, and MISO. And so it's all doable, it's just are we going to do it?

MR. QUINN: Do you have a comment?

MR. McBRIDE: Yeah. I was just thinking to myself I think all the ISOs, would want the red button regardless, and that should be in place. I think everything that Mason talked about is doable and I guess I feel like a little bit I might have jumped ahead in my earlier response to this topic. The key would be very concerned about a situation where facilities interconnected that is physically capable of injecting more than the rights that are associated with it. So there will need to be appropriate protections and assurances for dealing with that.

But along with that, I think just to reiterate the earlier comments, just to make sure the resulting service and upgrading rights and descriptions are very clear and implementable on all sides.

MR. FERNANDES: I guess maybe I had my own follow-up question. So for the system operators, I understand the assurances you got as far as we'll give you the red button to put into your control room. As far as again going back to the control platforms that sit, just loosely speaking here, they sit between the actual storage plant and then the SCADA system, is that something different than the red button? Is it the same level of assurance as the red button what I've shown you a control algorithm that technically prevents that whatever is behind that point of interconnection from injecting beyond X or withdrawing?

MR. EGAN: My comment is that would be you'll have to show me that failsafe. In other words, it can't be overridden by you, since you're in control of it, you're injecting on my system. That's why where said if you could padlock it and it could never break, I think I could trust it, otherwise, I think I'd want something.

(Laughter.)

MR. HERBERT: Anyone else?

Dave or Steve. Either.

MR. RUTTY: I agree with them. I agree with what's been said. California ISO does require that the flow is limited to that maximum amount, whether it's by protection scheme or a device, or other, as proven to be failsafe we're not going to put the grid at risk.

MR. HERBERT: We'll jump to the next question. This one is for the RTO's and maybe PG&E as well.

What are your primary operational concerns of these combined storage and generation facilities?

Dave, I know you mentioned earlier modeling discussion, you don't necessarily know how to model them, or maybe you do.

MR. EGAN: I think we know how to model them. It's just if you're going to set it at zero and never inject a lot of energy, I think that's what you're getting at with that. The problem is if he's controlling that, it could inject a lot of energy, so it's really a function of what you're installing, and I would want to make sure my system could handle -- suppose somebody one day went in and messed up the controls and put power out. I need the study so my system is not damaged, that's really the issue. How do we get past that? I think it's just a communication, talking to each other, so this is all new stuff, so.

MR. McBRIDE: If your question was in terms of modeling the proposal and identifying scoping out the study? I think we can do that.

Was that what you were asking.

MR. HERBERT: Just generally whether you have kind of operational concerns with these combined facilities.

MR. McBRIDE: I would say, other than the stuff we've talked about, I think we can study a proposal and we can identify the appropriate interconnection. You asked about very quick ramping, for example, if that was something that needed to be studied, and we have not yet -- to this point identified a system impact study issue that would be associated with that, it's just an attribute of the system that will be there when it's operating. So we don't have a concern for that particular aspect, for example from a system impact study perspective.

MR. RUTTY: Yeah. On the same line, we're very pro having this type of facility come in. And it really helps us with the operation, especially getting on the ramps for the peaks and extending the life/the output of a solar plant or a wind plant, being able to take over when the clouds come over, I mean, it's definitely a very huge benefit to us, so we're looking for any way to accommodate and bring these type of facilities on line.

MR. GABBARD: I just want to emphasize that as a PTO, we have an interesting position where we're balancing multiple assets on the grid, both safety and reliability and affordability for our customers. And so most of you were here earlier today and we clarified that in the California ISO service territory network upgrades that are triggered by generation are ultimately funded by ratepaying customers. So we are always looking for opportunities to minimize that financial impact on our customers, we always look for these opportunities to avoid overbuild of our system. But at the same time, we want to make sure whatever assurances we're relying on are sufficient to maintain that safety and reliability. So not only do we have that balance and make sure we are good on both fronts, that's just the predicament that we're in.

MR. HERBERT: Okay, let's go ahead and jump to the next topic. The next one was the potential processes to facilitate the interconnection of electric storage resources. I don't think it's any secret that every developer would like to have their asset on the grid as quickly as possible. The Commission has in the past sort of acknowledged differences in technologies. We have a fast-track process for small generators.

We have a 10-kilowatt inverter process for small generators, there are the network provisions that you mentioned, Mason.

We have provisional agreements. A lot of these were developed both out of, I guess, acknowledging the technology differences and also sort of the need to bring these resources on line faster. So I guess how could -- if we were to decide that that need did exist, how could the Commission justify sort of facilitating the interconnection of electric storage resources? And also, if we did, what would be the best means to bring those resources on line faster? We can go ahead.

MR. EGAN: I'll start with the last part of that, because the first part I am not sure I can even answer. The last part about moving faster, we have an issue, I brought it up in the second conference discussion earlier today. At PJM, the small gen several years back requested that anything under $5 million be allocated within the group. So the problem with that is it actually clustered together everybody in the queue. We have to wait for a queue so we can determine who would get cost allocation if it gets pushed -- if a facility gets pushed over a hundred percent, they will all share in it. So we can't move anybody fast. And that's a tradeoff between seed and cost share. So, to me, that's the biggest issue right now in our footprint would be the under $5 million cost allocation rule. And coupled with that is our alternative queue study process that says if anybody is sharing in a facility overload, we have to wait for the queue to close. So both of those provisions that were added, I think were around three to five years ago in our tariff, are obstacles, very fast in interconnection small generation.

Did you want to clarify your first part of that better.

MR. HERBERT: I guess it's just, if there was an inclination to do this, I mean, we've heard that these are, for example, fast controllable devices, operational requirements in the grid are changing.

From an operator's perspective, could PJM sort of philosophically justify bringing these resources on line quicker or operationally? What would the requirement be?

MR. EGAN: I'll pass on that. That will be in our comments.

(Laughter.)

MR. EMNETT: Mason Emnett for NextEra Energy.

Not having to operate, at least that system, that's kind of where we would come from the developer of storage within a RTO market, is within a region that is big and complicated and involving lots of effectively interconnecting resources. Moving through the interconnection process because of the way the studies were performed, a way to distinguish between relatively small -- you could do size requirements, you could do stability requirements, a shifting of risk between interconnection customer and coming along the battery developer, and saying, "I will move more quickly through the process but I will do that at my risk. If I sign an interim ISA now and go ahead and get faster service, then I'm subject to the outcome of whatever the studies may be at a later point in time. And I understand that and I accept that that's a possibility." I think you would justify that with essentially that sharing of risk and being able to control around whatever the issues or constraints might be in the interim or the concerns, that would have to be managed the parallel study process that would have to be managed within the RTO, and that wouldn't be easy I imagine. But if it would be a way to pull some resources out of the queue, and might have other benefits just in terms of trying to clear out some of the term that occurs.

Because another point that was made earlier in the day in changing technology -- and I think somebody referenced it on this panel -- storage developers have that same issue. By the time you get through two-year process, the technology has changed, it just has. So what you thought you could order a couple years ago, you can't order anymore. So you got to go through the process of just making changes. Is that material or not? Is that going to go? It's a lot of the things you find applied to a different technology.

MR. FERNANDES: That last point was a real good one. John Fernandes from RES.

Unfortunately, haven't done enough of these within one market or with one transmission owner where I can point to a spot within the interconnection process, a contractual agreement, the modeling, our control algorithms. But I think hopefully we can start to identify somewhere in those operating parameters where we show this is not every system at max gen and especially max load at the worse possible times. I think that should be able to advance a storage interconnection farther down the road maybe through a faster-track process. I really think it's going to come down to the operator's trust in the control algorithms and what we as the developer, why are we building that plant? What are the contractual obligations we have?

MR. GABBARD: So over the last 10 years, we've done a lot of work in ways to look at the acceleration process. We have a strategy and facility process, we have the material modification process to modify an existing generator. But I want to caution the Commission. We are talking about large-scale generators. We have a generator interconnection process for a reason, to evaluate the impacts on the grid and maintain safety and reliability. While we're going to continue to partner with stakeholders to identify ways we can tweak those existing fast-track processes and other processes to accelerate interconnection, we want to maintain that safety and reliability.

And I want to clarify a couple of things that were called out earlier today. The folks referenced the long study process or the long interconnection process. My comrade earlier from California ISO referenced the two-year study process that we have in the state of California. But I want do clarify that the actual studies being performed by the PTO or the RTO are a matter of months. Through the study process and through the interconnection process are iterations of tasks that are on the PTO, RTO, and tasks that are on the interconnection customer. A large portion of timeline through the overall interconnection process are periods of time when we're waiting when the interconnection customer's working to get a PPA, financing for their project, and other aspects. It's a natural flow. And so understanding where there are things that are not working, we definitely need to come together as stakeholders and find ways to fix those. But some of the timeline is actually more effective, it's actually a more tortoise and hare situation where it's effectively moving through the process at a pace where we allow developers to effectively develop their projects, and ultimately reach our goal which is getting more generation on line whether renewable or otherwise.

MR. McBRIDE: To answer as the open access transmission provider in New England, I don't have a reason -- with respect to interconnection perspective or reliability perspective, a reason why these proposals would be treated differently than other proposed requested to interconnect to the grid.

MR. RUTTY: In consideration of time, Dave pretty much took every note that I had written down to answer that question. The only thing I can say is the material modification has proven very valuable to the ISO where we've been able to add storage to existing projects, ensuring that it didn't add a major impact to the grid or to other customers.

So being flexible in that environment is pretty important to us and how we accommodated a lot of changes to existing or near-existing plants. And the re-power process as well has allowed existing generation among others to re-power with batteries and other types of resources. So again, we have to look at it for reliability, we have to make sure it's a reasonable solution, so it's been fairly flexible for us.

MR. HERBERT: Commissioner LaFleur, do you have a question?

COMMISSIONER LaFLEUR: I wanted to ask a little bit of a philosophical question. I mean, when I used to run a distribution company, I would ask people if you lost the whole system and you had to start from scratch, what would you put up? Because I know it would look nothing like what's out there. Because if you don't know what an ideal is, you can't even make incremental progress. So the situation right now is, just the reality, is storage is a product in limited quantities that being -- we're trying effectively to graft on to a system that was built for transmission, distribution and generation. So in the time that we had the critical mass of storage and you were building a storage-centric to compensate it or whatever, would there be a parallel set of a grievance to what we have now, I mean, what would the future look like, if anyone has any thoughts, when storage is really big? Would it be like generation and we would be like a another sort flavor of generation that we would just pay that way, or is there some way of thinking about this that we're even missing in the way we think about paying it? Because I think every time we think of storage we're trying to fit it in another peg. Everyone doesn't have to answer, but we have all these experts here, if anyone has any insights I would welcome it. Because my mind doesn't go to where that is, it just goes to where we are now.

(Laughter.)

MR. EMNETT: Mason Emnett from NextEra.

It's a timely question. Yesterday, about 100 people from our company were together and we spent six hours together on storage, as a where-have-we-been-and-where-are-we going conversation. And that's not an easy question to answer. There really is no kind of current answer other than the way we've thought about it is. As an organization that has a large vertically integrated utility and an emergent side of this outside of Florida, we answer the question differently depending on which side of the house you're on. Right? And it is much easier, frankly, for the FPL side of the house to step back and think about how would I integrate this resource that does multiple things for me? And I have a rate base. I have a transmission rate base and I have a generation rate base. Allocation between those with respect to cost recovery, which then takes me into what's the function and what the benefits I'm getting out of it and can I demonstrate the value of that investment. Getting more value than I am for the investment itself for purposes of rate recovery.

When you move into the organized markets, it's extremely difficult to think about how you stack those functions and values in a market structure that is designed for generation. And it's designed for a generation in a way that makes sense with the physics and the operation of the system, but then a resource that steps across all those boundaries is tough. And I think that's the question that, frankly, we all need to answer and we'll need to answer it probably in the next three to five years.

COMMISSIONER LaFLEUR: Because we're making decisions now that are putting us in a path to where we might be when storage is bigger.

Do you know what I mean?

MR. EMNETT: And that is the way that we are thinking as to storage. Right now we're operating projects provide frequency regulation. And that is nothing of what these resources can do, but it is the product that is compensated and it justifies the investment. And we're learning, we're learning from the operation of those assets from going through the interconnection process and figuring out ways to manage it. And then we're looking forward to, what are the additional things we can do? We haven't gotten there yet, but hopefully we will and then we'll start to stack the things out and hopefully get there.

MR. FERNANDES: So I'll use Mason's analogy of what we're doing on the corporate side. Our wind guys don't do storage. Our solar guys don't do storage, our transmission guys don't do storage. Our storage guys do storage. We have a dedicated global storage team. And when I said I was taking Mason's idea, I believe he brought it up in a conversation that a storage contingency came here to the Commission years ago when demand response first started taking off. We tried to put it into these existing constructs and that was an absolutely horrible fit. And this Commission finally said: "Create rules for the demand response." And I am not trying to add to the tariff books, someone is going to stab me with their pen, I know.

(Laughter.)

It adds more paperwork, more operational complexity, more market products and everything else. But storage is very much its own asset class that touches just about every other asset class that hits the grid. So I think that really begs the justification for let's stop talking about storage as generation, as a negative gen, I get it but those are still dangerous semantics. Storage to storage, and I think it would be really want to be able to accommodate storage at a large scale five or ten years from now, those rules need to start going into place now.

MR. McBRIDE: I was just going to quickly offer because my own boss talks about it this way a lot. We have had storage in New England markets since the beginning.

COMMISSIONER LaFLEUR: Pump storage.

MR. McBRIDE: We have pump storage. And it's almost 2,000 megawatts, which is relatively large for our system. What I understand is that that storage was originally installed to capture essentially what we now call "energy price arbitrage" where it would pump during the night when prices were low and generate during the day when prices were high. And it still can do that, but now instead, for the most part, it participates more in reserves and regulation markets. So that evolved by itself, and there's been some adjustments in our markets to deal with that. So it could be that the technology will come forward and the technology will tell us how it wants to competitively participate.

COMMISSIONER LaFLEUR: Well, thank you. I'll let you get back to interconnection. It just seems like we keep going around this loop.

Thank you.

MR. HERBERT: If anyone else have anything? I think in the interest of time and with respect to everybody's weekend plans, maybe we'll just call it right here. We're already a little bit over. So thank you again for coming. I think this has been a very interesting conversation. I think it's the beginning of a very interesting conversation. We do have a couple of closing remarks from Adam, so don't get up just yet. But thanks again.

MR. PAN: I'll be brief. It's been a very interesting and informative technical conference we've had today. We thank everyone for attending. We thank all of our panelists who came out and participated today, especially for you who traveled from somewhere to get here.

In terms of next steps, to better organize issues that are being considered, Staff is looking to put out a targeted request for comments sometime soon. To the extent that includes questions, we ask that you respond to the specific questions. And please continue to monitor the docket and look out for that.

Thank you.

(Whereupon the technical conference is concluded at 4:54 p.m.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding:

REVIEW OF GENERATOR INTERCONNECTION AGREEMENTS

AND PROCEDURES

AMERICAN WIND ENERGY ASSOCIATION

Docket No.: RM16-12-000

Place: Washington, DC

Date: Friday, May 13, 2016

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

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Official Reporter

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of :

REVIEW OF GENERATOR : Docket No RM16-12-000

INTERCONNECTION AGREEMENTS :

AND PROCEDURES :

AMERICAN WIND ENERGY ASSOCIATION:

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, Northeast

Washington, D.C. 20426

Friday, May 13th, 2016

The technical conference in the above-entitled matter was convened at 9:00 a.m., pursuant to Commission notice and held before:

CHAIRMAN NORMAN BAY

COMMISSIONER CHERYL LaFLEUR

COMMISSIONER COLETTE HONORABLE

COMMISSIONER TONY CLARK

FERC STAFF:

JOMO RICHARDSON
THANH LUONG
ADAM PAN
THOMAS DAUTEL
TONY DOBBINS
MICHAEL HERBERT
JESSICA COCKRELL
JULIE GRAF
MICHAEL CACKOSKI
ADRIA WOODS
ARNIE QUINN
MELLISSA LORD
ANUJ KAPADIA
JOSEPH NAUMANN
KAITLIN JOHNSON
KATHLEEN RATCLIFF
FRANKLIN JACKSON
JORGE MANCAYO
LESLIE KERR
MARK BYRD

PRESENTERS:

PANEL 1:

Tim Aliff, MISO
David Gabbard, PG&E
Dean Gosselin, NextEra
Alan McBride, ISO-NE
Steven Naumann, Exelon
Rick Vail, Pacificorp

PANEL 2:

David Angell, Idaho Power
Jennifer Ayers-Brasher, E.ON
Joshua Bohach, EDP
David Egan, PJM
Charles Hendrix, SPP
Randal Oye, Xcel
Stephen Rutty, CAISO
Kris Zadlo, Invenergy

PANEL 3:

Tim Aliff, MISO
Dean Gosselin, NextEra
Paul Kelly, NIPSC
Omar Martino, EDF
Alan McBride, ISO-NE
Stephen Rutty, CAISO
Rick Vail, Pacificorp

PANEL 4:

Tim Aliff, MISO
David Angell, Idaho Power
Jennifer Ayers-Brasher, E.ON
Daniel Barr, ITC Holdings
Charles Hendrix, SPP
Paul Kelly, NIPSC
Omar Martino, EDF
Steven Naumann, Exelon

PANEL 5:

David Egan, PJM

Mason Emnett, NextEra

John Fernandes, RES Americas

David Gabbard, PG&E

Alan McBride, ISO-NE

Stephen Rutty, CAISO

Court Reporter: Alexandria Kaan, Ace-Federal Reporters

P R O C E E D I N G S

(9:00 a.m.)

MR. PAN: Good morning. Welcome to the Review of Generator Interconnection Agreements and Procedures technical conference. This conference will focus on select issues from the AWEA petition on rule-making, and other interconnection-related issues including interconnection of electric storage. I'm Adam Pan with the Office of General Counsel. This is a staff-led technical conference and any comments made here represent the views of Commission staff and do not necessarily reflect the Commission's views. A final agenda is available for attendees at the meeting room entrance. There a few minor changes in the biographical information.

We have a few housekeeping matters to note: Please turn you mobile devices to silent. We also note in the Commission meeting room no food or drink other than water are allowed. If you need Wi-Fi information, there are forms at the meeting entrance. You need to sign the forms before you sign in. We will break for lunch from noon to 1:00 p.m. There will be a morning break from 10:20 to 10:30 a.m. There will be an afternoon break from 2:10 to 2:20 p.m.

Speakers, please be sure to turn your

microphones on and speak directly into them so that audience and those listening to the webcast can hear you. Please turn your microphones off when you are finished speaking. Panels 1 through 4 will be moderated by Tony Dobbins, panel 5 will be moderated by Michael Herbert. Thank you.

Commissioner Honorable is here. I don't know if you wanted to take the opportunity to say a few words.

COMMISSIONER HONORABLE: Thank you. Good morning everyone. I'd like to thank the representatives here from the various stakeholders groups, and in particular there are a number of you that I've known for a number of years, so you've seen me try to transition from being a state regulator and now a federal regulator. And more importantly, I appreciate the ways in which you've attempted to educate regulators about, not only the important resources that we're attempting to ensure stay not only in the queue but integrated well, but also ways in which you're educating us, and me and my staff in particular, about the barriers of some of the concerns and issues that you're having in the interconnection process.

Generation interconnection queue issues have the potential to negatively affect the competitiveness of our markets and the reliability and resilience of our grid. And I believe that these processes can not and should not be a barrier to entry for needed generation capacity, for variable resources, or energy storage, if we are to maintain a robust and reliable power system.

In particular, during my tenure here at the Commission, I've had a number of very robust discussions with a number of you regarding experiences that you have had navigating the interconnection queue process, and I have heard you loud and clear, as have my colleagues here at FERC and my staff, and I'm very pleased that under the direction of our Chairman and my colleagues, we have approved this technical conference.

I'd like to thank our very capable staff who have worked very, very hard, as you can tell from the agenda, we will cover a lot of ground today, and that's why we're here an hour earlier, so thanks to those of you who actually read the notice.

But our purpose here today, and in particular I'm interested in hearing about not only concerns and issues that you're experiencing with regard to the queue process, with interconnection agreements, also I'm particularly interested in hearing about the study process in ways we can improve this work. I was joking I think with Rob Gramlich that we are looking to you all for the silver bullet. Maybe there isn't one, but I'm hopeful that through our dialogue throughout the day that we will hear from you. You all are the experts, maybe proposals for the solution, because I think we all share in common that we want this to work well to ensure we have robust markets, and ultimately that we are providing diverse, reliable, and affordable energy for the people that we serve.

So I'd like to thank all of you for your attendance here today, I look forward to hearing you comments, and thank you for the opportunity to participate.

MR. PAN: We'll begin our first panel at 9:20. So we ask that all staff and panelists be seated and prepared at that time.

MR. DOBBINS: We're going to go ahead and start panel 1 at this time, which is to discuss issues related to the current state of the generator interconnection queues. We are starting five minutes earlier than in the agenda, so everyone please take note of that. I'm sure that additional five minutes will be well deserved for a topic such as this.

We will ask panelists to introduce themselves and present their prepared remarks which were submitted to the docket or mention the one or two most important points they would like us to come away with today. Please keep your remarks under two minutes. We will use the timer, which the panelists can see upfront, to let them know how much remaining time there is. And we'll start on my left with Mr. Tim Aliff.

MR. ALIFF: Thank you. Good morning. My name is Tim Aliff, I'm director of reliability planning with MISO. My purview includes the generation interconnection process.

MISO has always been looking to improve the interconnection queue process; we've done that over the last almost 10 years, including three different queue reform proposals that were successful in moving the process forward, making the process better. Today we're experiencing challenges in our queues specifically related to delays and how long it takes for units to move through the queue process. And we are working with our stakeholders continually and through our interconnection process task force and then also working with the Commission and the guidance that we received through the Commission on how we can make our process better.

One of the things related to being at the FERC level here is that we want to point out that each of the regions, each of the transmission providers, have unique differences that need to be at least respected, if you will, in the interconnection process. One size doesn't fit all from an interconnection queue process, something that works in a one-state RTO may not work in a multistate RTO such as the MISO.

And specifically within the MISO, the multistates, each of the states has their own view on renewable portfolio in that state. And so recognizing that difference and also the flexibility that provides to each of the regions and being able to move that interconnection queue process forward and to the benefit of the stakeholders moving through, and also to ensure the reliability of the transmission group going forward.

MR. DOBBINS: Thank you.

MR. GABBARD: Good morning. My name is Dave Gabbard. I'm director of electric generation and interconnection at Pacific Gas and Electric Company. My team's responsible for interconnection generation to both PG&E's transmission and distribution systems. First, I want to thank the Commission for the opportunity to participate today.

Under the direction of the California ISO, PG&E has safely and reliably commissioned over 6,200 megawatts of generation over the last 10 years. We have an additional seven gigawatts of active generation in the CAISO queue progressing towards interconnection on the PG&E transmission system. In addition PG&E has interconnected over 400 megawatts of distribution generation to its distribution system under its wholesale distribution tariff, and has an additional 400 megawatts of generation in its queue.

PG&E has both witnessed the legacy issues impacting the transmission interconnection process and the tariff reform led by the California ISO to mitigate these issues. PG&E commends the California ISO for its efforts to lead industry collaboration and stakeholder processes that result in an enhanced interconnection tariff, that helps mitigate queue management, backlog, and transmission overbuild challenges. That said, the solutions developed within the California ISO territory are unique to the environment and stakeholders involved within the CAISO interconnection process.

While PG&E supports benchmarking across regions for lessons learned, PG&E does not recommend forcing region-specific solutions across other RTOs and stakeholders. Maintaining a regional flexibility at the interconnection process will allow RTOs, PTOs, and generator stakeholders to continue to refine processes and tariffs to accommodate transmission generation interconnection in an evolving market landscape. Thank you.

MR. GOSSELIN: I'm Dean Gosselin with NextEra Energy Resources. I'm vice-president of business management transmission services. We are a developer owner operator of renewables across the country. What we find is the process of the system impacts study on the interconnection queue process' result is a key input to every one of our projects; its costs and the timing of those facilities, are necessary to make a determination of whether a project is viable or not.

So at the beginning of a process when we think about entering a queue, what's important is that we have valid solutions coming back to us in a timely manner and that they're accurate, that they're accurate in what they say.

The issues that we see is there's lots of restudies going on now. So at the initial offset of a queue or of a group study, there's a lot of generators, new generator requests, that won't be built. And as the queue progresses and they begin to get answers back, they drop out. And that destabilizes the queue, and then the queue process starts again.

So what we're seeing is more and more entrants, more and more megawatts coming at any given study queue, and then many restudies having to drag out the process of determining ultimately who's left and what are those costs and schedules for system upgrades. So what we need is an optimal solution, that's the tough part. Right? I don't think anybody in the country has an optimal solution today. There are pieces of good, everybody's working towards it, nobody's trying to impede it. But it's difficult when that queue is not stable, at least the study entities are not stable. Thank you.

MR. McBRIDE: Good morning. My name is Alan McBride. I'm the director of transmission strategies and services at ISO New England, and my responsibilities include the oversight of the interconnection queue. I want to thank the Commission for the opportunity to speak here today.

ISO New England has been working with the interconnection issues with our stakeholders. And the ISO's recent filing with the interconnection improvements was approved by the Commission on April 15th. That filing contained important clarifications of data modeling, requirements for new generation, in particular for inverter-based generation. It also included the clarifications of the ISO's material modification review process, as well as the establishment of dynamic reactive power factor requirements for wind generation.

The ISO's continuing to work with stakeholders on interconnection improvements. We're currently undertaking a discussion of different approaches to clustering, and we are investigating the identification of new transmission infrastructure that could be used to interconnect multiple interconnections.

Our considerations have included a survey of clustering approaches used by transmission providers including ISOs and RTOs throughout North America. The surveyor identifies some useful features and practices. It also highlighted the importance of regional differences in the appropriate design of interconnection practices, as there are different needs in each local area driving the development.

For example, in New England, the interconnection process is integrated with the forward-capacity markets, and that is an integration that is working well; I can talk about that later if we need to. The ISO also noted meaningful differences in approaches to ratepayer support for network upgrades in different regions.

Within New England, the ISO has identified differences in the rate of progress of interconnection request depending on the technical challenges. There have been a large number of requests that are geographically concentrated in a over-subscribed area of the system that is already at its performance limit. So our current work is to identify potential solutions and move that process forward. Thank you.

MR. NAUMANN: Good morning. I'm Steve Naumann, vice president of transmission policy at Exelon. Thank you for asking me to speak here.

As you have heard, there have been a lot of improvements in the processes since 2003, especially within the ISOs and RTOs and they've been working with their stakeholders. We agree with some of the requests, such as increasing transparency, having access to the models. But many of these requests would result in asymmetrical shifts and risks from the interconnection customers, and that's something we do not agree with.

While there have been improvements, the system has also changed since 2003. We have serious concerns about implementation process for ERIS interconnections because of the impact on existing resources. The ERIS generators use "as available transmission capacity."

But in midbase market environments without proper analysis, it matches the way the systems operate.

These generators can be allowed to cause additional congestion, and that congestion has caused harm to existing base load units that can no longer withstand the financial harm that is being done to them.

To be more specific, along the lines of not harming existing customers when considering new interconnections, new interconnection resources that are most likely to impact the system need to be, as I said, studied as they operate, not necessarily at peak load.

So what you need to do is look how they're operated, and obviously combined cycle may be on a peak load but other intermittent resources are not. And in those cases, light load needs to be studied for congestion and reliability. This is a best practice in PJM, and it's also being done here. Thank you.

MR. VAIL: Good morning. I'm Rick Vail, I'm the vice president of transmission with Pacificorp. Some of the areas under my responsibility are generation interconnection queue, the transmission planning staff, as well as all of the capital budgeting that's associated with the transmission system at Pacificorp.

So Pacificorp has what I would call a well-established queue process. I will say we're under that mode of continuously evaluating it, getting feedback from our customers, and trying to improve what that queue process is. It is a serial queue process; Pacificorp is not currently part of any regional ISO, so it may be a little bit unique or different perspective than some of the other entities here.

Pacificorp has processed roughly 750 interconnection requests, about 20 percent of those end up going into service. Over time we've had a higher percentage of the projects go into service, a lot of the requests that we get seem to be a little bit of a fishing expedition in trying to determine where within the transmission system is probably the most appropriate place to attach for generators.

I think one of the main issues or concerns from a Pacificorp perspective is that we get a significant number of requests in small geographic areas, and that can put a lot of stress and pressure on the existing system, especially from a reliability standpoint.

So some of the kind of suggestions that we've looked at is trying to minimize what the suspend status of higher queue projects is, that really can have a big impact on the uncertainty that developers face when higher queue projects drop out, and I'll talk a little bit more on that as we go forward.

One other concept we have to consider is just trying to increase the deposit requirements and financial security backing as some of these developers come in. The more sophisticated developers are very well-aware of what the requirements are, as we get some more sophisticated developers that can kind of bring a lot of volume to the queue that may or may not end up going forward. So thank you.

MR. DOBBINS: All right. Thanks to all of our panelists on panel 1 for their time and participation for today and their opening comments. And I'd also like to acknowledge Commissioner LaFleur who has joined us, and we thank you for your attendance and participation. And before staff moves on to ask questions, I wanted to see if you would like to make any comments.

COMMISSIONER LaFLEUR: Well, thank you. I am happy to be here. I had an appointment out of the office; it's hard to find a day when there's no tech conference to schedule things. Sorry I missed the first panel, but I look forward to the conversation. I think the topic of today covers a lot of important issues, so look forward to hearing it. Thank you.

MR. DOBBINS: Okay. Well, now we're going to move on to our staff here from FERC asking questions. Panelists, please limit your responses to around a minute so that other panelists will have time to speak and we can cover as many topics as we can. And apologies in advance if we aren't able to hear from everyone on every topic.

I'll start us off with the first question. We've had, through your comments filed in the docket and also some of your remarks and introduction, an indication of improvements made in the queue process, but also areas where, you know, there are challenges. We would be interested in getting your general overall thoughts on how the queue process is working and if there are any clear areas for improvement, if you've targeted solutions there. And we'll start off on my left with Mr. Aliff.

MR. ALIFF: Thank you. So first, how is the current queue working? As I mentioned in my opening remarks, we understand there are challenges related to delays in the queue that's mostly related to restudies, as you heard in some of the opening remarks, projects withdraw and then be have to restudied. We're seeing withdrawal rates over 50 percent in lots of parts of the queue, specifically in our northern areas where it's more congested.

As far as metrics that we've implemented, we measure the cycle times, how far behind are we on our queue, and we're currently on it close to about a year behind in our queue processing. So some ways that we present that make that clear, transparent to our stakeholders as we provide that through stakeholder meetings, we provide that on our website so you can see how far behind we are in the projected dates for completion of the queue.

As far as the process improvements, discouraging non-ready projects, the projects that are likely to withdraw moving through the queue, reducing the amount of restudies, having more scheduled restudies in the process rather than unforeseen restudies. Also, clear requirements related to everyone involved. Clear requirements for the interconnection customers providing information, the transmission owners performing studies, and then MISO as well performing studies and meeting timelines. Thank you.

MR. DOBBINS: And before we move on to our next response, I just wanted to get a clarification on your saying over 50 percent withdrawal. Is that, in your opinion, mostly due to projects who aren't really ready to move forward and were testing the water, or is it projects that they got in the queue, found out that information they need, and from a business standpoint have decided it's not a viable project moving forward?

MR. ALIFF: It can be both of those scenarios, projects that aren't quite ready, there are various things that impact a project, the permitting process, regulatory approval, et cetera, from a project's perspective. Also, it's not known until a project enters the queue what other generators are in the queue. We study a group so we group resources together and we move the group through the process. So the individual interconnection customer doesn't know who's in that group until they've actually entered the queue and moved forward.

And that picture can change if someone else in that group withdraws, that impacts another party in that group and can change their cost related to that interconnection request.

MR. DOBBINS: And just one last followup. Is there any percentage of that group that express to you that they're withdrawing for more reasons of time, that the process is going too slow so they're not able to advance their projects in a timely fashion rather than a cause or a fishing-expedition approach?

MR. ALIFF: We have not heard anyone say that they are withdrawing because the process is taking too long.

MR. DOBBINS: And we'll just go down the

line of the panel to see if anyone else would like to address the original question, which was: Your general thoughts on effectiveness of the queue and if there were areas that are easy areas for improvement. And please understand we have your responses, which have been filed in the docket. So if you don't want to -- if you haven't addressed this in your docket, also please feel free -- sorry, in filing the docket -- please feel free to offer any information here.

MR. GABBARD: Again, I'm Dave Gabbard, director of electric generation at PG&E. I just want to touch on a couple of points. I think the specific enhancements to the interconnection process in the California ISO service territory are unique to the configuration and different characteristics of operation in that territory.

But I do want to call out and acknowledge the process in which we have evolved the interconnection processes over the last five years specifically. There have been macro reforms to the tariff, but also the California ISO has led interconnection processing enhancement stakeholder discussion that have allowed us as a collaborative set of stakeholders to identify issues and then find solutions that work for all parties. As a metric for identifying the success of those enhancements, I would acknowledge the amount of generation that is being interconnected on an annual basis.

I don't think that fallout is a good metric for whether or not a process is successful other than the fact that fallout of nonviable generation earlier in the project is proof of success. So the process we have in place within the California ISO service territory and specifically within the PG&E service territory allows for generation to come in and identify the impacts to the grid from interconnecting a proposed generator. But it requires a certain level of commitment with respect to the process and allows generation that's nonviable to withdraw earlier in the queue, allowing more viable generation to successfully progress through the queue, effectively without too much overheated and overbilled challenges going forward.

From a timeline perspective, both on our WDT side, the wholesale distribution side, as well as within the CAISO process, we are up to speed with tariff timelines and progressing interconnection queues and serial request in a timely manner in compliance with our tariffs. And we have seen those projects successfully move forward to completion. The delays that are experienced within the process have happened on both sides, the interconnection customer who participated and transmission owners. It's at various stages. Need for financing and other things naturally cause certain delays at certain phases, but the overall progression towards cooperation continues through actively and our processes are set up to support that. Thank you.

MR. GOSSELIN: Dean Gosselin with NextEra Energy Source. I'd like to just talk about what is optimal. We were thinking about it, as a developer we were bringing a new project idea and trying to advance it to fruition, "fruition" being completion of the project. I would say for the interconnection queue that the initial results closely match final results in a defined and reasonable timeline, that would be my definition.

So all of the RTOs really provide us models, they give us their models and they're repeatable, they're accurate. The problem with us running the models -- and we do that in advance of submitting a project, and we look at the results and if they look to be expensive or costly and a long schedule to do upgrades, we are not putting in a request because it's not going to go anywhere, it just doesn't work; not in our schedule, not in our cost, and not in the RTO's.

However, what we don't know is who else is going to enter that queue with us, and what is the cumulative impact of that group. And we can't know that, it's unknowable at the time in which we put in a request. And that is I think one of the fundamental issues with queue timing and schedule and accuracy of the study process coming out of it. That's obviously the area of challenges: Stabilizing the group to the point where the study that goes on, the final study that goes on, gives you valid results.

And the results are, I don't think any of us -- certainly NextEra does not believe we're getting invalid results, it just believes we're getting a lot of restudies that stretch out the timeline. And we have a saying in our world of development which is time kills all projects. So the longer it takes, the more unlikely it is that a project will be valid and go to fruition. Thank you.

MR. McBRIDE: Alan McBride, again, with ISO New England. Many of us have been thinking through your question, we want to make sure we were careful to identify what was working well and what was not working well, and not approach it from just generically "there are queue problems."

In New England, we study energy interconnections in serial queue order, and then we integrate the queue with the forward-capacity market and what's effectively an annual group study or annual cluster. That would be very important that that works well, we have a sufficient number of generation that's seeking to participate in the forward-capacity market successfully, be able to qualify and do so, and that has been going well over these past few now 10, going onto our 11th, forward-capacity auction.

The problem we do have is in a specific part of the system that's already at its performance limit, we have a significant number of interconnection requests, mostly are pretty much exclusively for renewable interconnections. So that is the diagnosis of the problem, and then we went down the path to see what would be appropriate solutions to that.

The first step was we did identify some issues with the performance of the particular type of generation and we saw some benefit in making clear that we were communicating appropriate expectations for what the modeling and data should be that should be provided that we can plug those into the models and get the study done quickly, and we're already seeing some benefits from that.

And then the remaining part of the solution is the infrastructure challenge. It seems like it lends itself to some kind of either a clustering solution or some other solution to bring infrastructure to integrate the requests that we have for that situation, and that's what we're working on now.

MR. DOBBINS: And before we move on, I just want to clarify you're saying moving to a clustering-solution region why are you looking for a way just to cluster the geographically constrained or concentrated area?

MR. McBRIDE: I think that's exactly the question we're asking ourselves and that we're going to be working with with our stakeholders. We are very cognizant of some of the difficulties of clustering and with restudying and uncertainty. So we're looking at ways, seeing if we can find a way to minimize the uncertainty and the restudy and present something. It could be specific locational and it could be something more problematic. But we'd like to come up with the best design possible to answer that very question.

MR. NAUMANN: Quickly, one improvement that we're seeing in PJM is more clear requirements at the beginning. So, for example, if a request is deficient, it just gets kicked out of the queue, you don't have to start working on it. But I think you've heard a theme here, that is we need to have a robust and reliable transmission system to integrate new generation and provide reliable service to customers.

On the other side of that is the serial impact of new interconnections and the option now that was mentioned that earlier queue projects when they get their results for any reason or no reason at all, and it could be many reasons, maybe they put in for alternatives; they only intend to build one, then three of them will drop out. The higher queue projects drop out, all those studies that were done now have to be redone. And now if you get -- now you're shifting the cost of the upgrades to somebody else and you may get more dropouts or something.

That's the challenge. I don't think there's a generic issue unless you start looking at a completely different solution than what you're looking at. But short-circuiting that process to say, "We're going to take the initial answer." Well, that could mean you're building more than you need, which might be good in the long run, or, "We're going to kick people out before they want to because they're "speculative." None of those are necessarily good answers. So it's a tough answer and may have to look at how do these upgrades get done and how do they get funded?

But the first thing that needs to be agreed upon is that there will be a robust and reliable transmission system both for the interconnection customers and for the load customers who ultimately pay. Once you get that process, you can start debating about how you make the other process faster or more optimal to use the tariff. But we need to start with a process that gives us that reliable, robust transmission system; don't build congestion into the system, don't build reliability problems into the system. It's not necessarily a target enhancer, but I think it's a high level identification of the issue.

MR. VAIL: Rick Vail with Pacificorp. I probably echo a lot of the same comments I heard on the panel here, no question about it. I think one other thing I would probably add into that is one of the responsibilities as a transmission provider is to make sure we're not passing on some of these costs to connect additional generation, especially if it's not required for load service of native retail customers onto our other transmission customers. So we're very customer-focused for both, not only our transmission customers, but any of the generators that want to connect to the Pacificorp system.

With that being said, though, I think having the time and the effort that goes into all the restudy of impacts of higher-queue projects dropping out is probably one of the biggest concerns, especially as I mentioned in the opening comments when we have a smaller geographic area where these renewable requests are coming in and they're concentrated on a small geographic area.

I think it also get complicated a little bit more just because the way Pacificorp is set up, we're very rural, the majority of the generation in our system is hundreds, if not many hundreds, of miles away from our load center. So you certainly have different areas where you have transmission constraints but those also continue to be the areas where we are often requested to connect to the system as well, so.

MR. DOBBINS: I guess along the same lines, understanding that there aren't generic issues across regions, I have a question for Mr. Gosselin and Mr. Naumann. Are there queue practices that you've seen that work well that you would like to see implemented across all regions?

MR. GOSSELIN: Dean Gosselin with NextEra Regional Resources. One of the things that we find is successful, is not used by all regions but at least a couple of regions do, is they set forth fairly stringent requirements, and one of those requirements is a show of land control, that you have control of land to be able to build a project that you're saying you want to interconnect. That seems to work decently in terms of keeping even our own projects that we would otherwise have submitted out of the queue and keeping it from clogging up from the initial standpoint. But in and of itself, that's not sufficient.

I think from there on the stringent -- as the study process progresses, stringent requirements and basically financial liability certainly acts within NextEra and our decision making process. It keeps us very disciplined about what we keep in the queue. So if we're at a point of process where we're responsible for system upgrade costs, regardless of whether we go forward or not, that is a true -- a point of decision for us on whether we want to stay in or not.

Now, unfortunately, the interconnection results, the cost and schedule, are important to decide whether or not a project is viable, especially in today's competitive markets where we're competing with cost on everything. And our customers we're selling to are suffering as well. They want to know there's a valid interconnection and they're not signing up or looking to enter into a power purchase agreement or some form of commitment on a project that's not going to go forward, they want projects that go forward as well.

So it's kind of egg and chicken here and what goes first. Right? And until that group stabilizes -- any tools that stabilize the group quicker I think are necessary to get the valid results in the timely fashion. Thank you.

MR. NAUMANN: Just to add to that, I think I mentioned having clear requirements -- this is true at PJM -- that the customer knows about, and that if you don't meet them you're out of the queue and no one is spending time doing evaluations on something that's not quite right. Just to give an example -- and I know you're going to talk storage in the last panel, but it's an example of interconnection -- you get a customer, you go through the study, study phase, several studies, then they change the manufacturer of the inverter and it has different characteristics.

Now you have to redo -- this isn't dropping out, this is technically you have to redo the flicker study. This is another study that has been occasioned by a change that had that not been done you wouldn't be spending your time. The other thing is not so much a requirement, but it's really -- and it's something we see as the transmission owner at PJM and also on the other side as a generation owner, is continual meetings between PJM, the TO and the customer on a regular basis. Where you are; where the study is; where a problem is showing up trying to short circuit the problem; making sure everybody knows what's going on so you don't come toward the long end of a study, and say "Oh, here's the study. Oh, by the way there's a problem so now you have to redo things over again."

So throughout the process, keeping in touch and then taking the feedback where there have been problems and feeding that back into your system to make corrections. I think in addition to having stringent requirements, communication becomes very important to avoiding problems.

MR. DOBBINS: Thank you. I now have a question for the transmission providers. Earlier, Mr. Aliff, you referred to a withdrawal rate of about 50 percent and one-year delay in cycle time. I'm interested and we're interested in knowing how all of you evaluate your interconnection queue operation and what metrics are used to evaluate the performance?

MR. ALIFF: So today we're evaluating the delay, the time delay, as I mentioned before and we are looking to develop further metrics related to that. But today that is the metric that we are monitoring today. Because of the interest in how long the process is taking and we wanted to provide transparency to that metric. We also provide other metrics that aren't really related to the performance but what type of units are coming into the queue, where are those projects coming in -- so we see projects come in to our northern part of the footprint, more because that's where the wind-rich areas are, if you will, as we see a number of projects coming into that area.

But we are seeing an increase of solar coming into our southern part of our footprint and an increase in gas with the changing fuel mix, if you will, that we're expecting over the next several years. That's something we keep track of and we provide that transparency to our customers, but it's not really a metric per se on the queue performance.

MR. DOBBINS: So in terms of a metric to evaluate how well you're doing, would the withdrawal rate and cycle time be the primary ones?

MR. ALIFF: Withdrawal rate provides some information. As mentioned before, it can be a little misleading depending on where that is being measured. So a withdrawal rate late in the game and towards the end of the study process is certainly more concerning than a withdrawal earlier in the process.

If you can provide those, as mentioned

before, the site control or the milestones to prevent that, the projects from entering the queue at first, then that withdrawal rate should go down. But it kind of depends on where it is in the process.

MR. DOBBINS: And we have that same question for the other transmission providers: How is queue performance evaluated and what are the metrics used for evaluation?

MR. McBRIDE: So the headline metric for us would obviously be the time from the middle of the interconnection request to the completion of the system impact study, that's the one we focus on the most. But when looking at that headline metric, we look beneath to see are there differences in different geographic areas? And I talked about those a little bit. And are there differences based on technology or technology type?

We did find differences in time taken complete studies and restudies, data requests, deficiency requests, based on technology type. The newer technology, mostly inverter-based renewable technology, is new. A lot of the manufacturers are less acquainted with the data and modeling requirements that are needed to get through a system impact study. It's different from the traditional equipments that have well-established data models and performance models that have been in place for some decades now.

So we have put together some clear guidelines and requirements, the tariff portions were approved, that we think that were already helping that. So for that situation where underneath the headline metric, you have a particular, troubling area, we think we can move that forward.

In terms of withdrawal rate, the withdrawal rate in New England is quite low during the system impact study phase. There are some cases where you'll hear of a withdrawal because of a fundamental change in the circumstances like a pipeline no longer being built or no longer expected, might cause a gas generation to withdraw. For the most part, we see withdrawals after the system impact study, sometimes if the interconnection upgrades are more than what was expected by the interconnection customer.

We also see withdrawals after a resource might have participated in the forward-capacity market maybe one, two, or three times. If it's not clear about that modification then we'll withdraw the project, and that would be the end of the endeavor.

MR. VAIL: Rick Vail, Pacificorp. So from Pacificorp's standpoint, we have dedicated project managers who track each of these security parts all through the different processes. We also have established timelines in our open access transmission tariff that we have specific timelines to meet.

So we're tracking as this goes through each of the different processes from a timing perspective. We also track at what stage each of our interconnections is at, so the feasibility phase, impact study, or full facilities study, and then where they are in the process as far as getting billed. So there are a lot of metrics around our process and over time we have continued to add additional metrics. We do track in order to, again, try to improve processes as much as possible.

I think the one area, as I've kind of mentioned, when you start getting significant movement in higher queue projects, especially in a specific geographic area, I would say that's the one time from Pacificorp's standpoint is a real challenge to the meet the timelines that we're required to meet on a steady process.

MS. COCKRELL: So thank you for your participation. A couple of times the production kind of impacted those discussions. So I wanted to drill down on that a little bit more and better understand to what extent some of the backlogs you're saying are directly related to projects being geographically concentrated, and whether you come up with any reasonable solutions or you're working on reasonable solutions to account for the fact that there are a lot of requests, it sounds like in certain particular areas and how to address that.

I guess that's probably more for the transmission providers on the panel more so than others, but anyone can answer.

MR. ALIFF: Maybe I'll go first. Tim Aliff, MISO. So we do see differences from the geographical standpoint. It's usually related to where a lot of projects are trying to move into an area that there is a lot of congestion that the transmission system is not necessarily built at the time if you will to support all of the projects coming in. So it takes a little bit more time developing the network upgrades, for those projects to interconnect reliably.

And then there can be even more impact in that area when a project withdraws, as you've heard several times today. Those projects withdraw and then have a greater impact on other projects and their network upgrades costs. Areas that aren't so congested, projects can withdraw, there's little to no restudy through that. So it kind of varies.

One thing we've done at MISO is to split up our queue process by geography so we have four different areas that we're looking at in our footprint. So the areas that aren't as congested can move quicker than areas that are congested. Outside of the queue process, MISO has taken steps to build that transmission system to support those interconnection going forward specifically related to our multi-value projects that are looking to come in in the next several years that would increase the ability in the north region upwards of 26,000 megawatts of generation to interconnect in that area, so outside of the queue process that is being done as well.

MR. GABBARD: This is Dave Gabbard with PG&E. I will just take the opportunity to give one example of where we have a very overheated queue in a geographical area and we were able to proceed forward and continue to move viable generation towards interconnection.

In our queue cluster 3 and 4 in the California ISO service territory, we had a significantly overheated queue in our Central Valley Area in Fresno, California, triggering over a billion dollars worth of upgrades to our transmission system. But through the iterative process of the phase 1 study, phase 2 study, and then subsequently annual reassessment, paired with the financial security obligations of the process, we're able to see viable generation post financial security to proceed through the process, and then our iterative cluster study reevaluated the impacts on the grid from the less-heated viable generation queue.

And we have continued to progress generation from that queue cluster towards completion. So the iterative queue cluster process and the financial security obligations embedded in our process have allowed us to successfully mitigate that geographical challenge. Thank you.

MR. GOSSELIN: Steve Gosselin with NextEra. I don't have a lot to add on just the terms clustering and how you deal with the clustering of resources in a certain subregion. But I did want to just emphasize that locationally constrained resources like wind, it matters tremendously in terms of the overall cost per-unit of production, as finding a windy area is very meaningful to that equation. So the windier it is, the lower the price, the cost, the lower -- and price matters in the marketplace. So clustering usually happens because of that, because there's a good wind resource in some spot.

MR. McBRIDE: Alan McBride with ISO New England. To drill down a little bit more on the geographic piece, there is, of course, the first piece is just a lot of requests in the same part of the system. But, for example, in New England, we have that in Maine, and I've talked about that being a challenge, but we also have that, a lot of requests, in what we call southeast New England, and those requests are in response to that being import-constrained zones in the forward capacity market.

And there is a relative difference even there in terms of the rate of progress of those, and comparing to each other. And what drives that is not just the oversubscription, but the nature of the system in the particular area. So in Maine, it's a system that's already fully stressed and hard to bring in imports from New Brunswick. But it's also these requests are very different from load, they're very different from the existing transmission system, and they are inverter-based in nature. So it's the level of subscription but also the underlying technical characteristics of the system that the interconnection customers are seeking to interconnect to.

MS. COCKRELL: Any other responses?

MR. QUINN: So I wondered if anyone had thoughts on the degree to which the transmission planning process can address, or be concerned to having to address, some of the challenges that you get with geographically clustering resources?

MR. NAUMANN: Well, this is what I was trying to allude to. MISO stakeholders have chosen to do this and at PJM we have a different process that follows the but-for process that the interconnection customers should be the ones to pay for the upgrades. So as Rick said, so that the load customers don't end up paying for it. That's a philosophical difference that maybe the Commission has to look at again.

I'd be glad to have that conversation, I'll tell you now I'll come out on where we are in PJM, but I think it may be worth having that conversation because, as I said, and I think everyone agrees, to interconnect and to run the system you need a reliable system, a robust system that matches how you operate the system.

Against that, as people have said, especially locational-restrained resources, are generally being connected to a system where it's weak, and they require a lot of upgrades, and a lot of upgrades are expensive. And then as the first customer in the queue says that's too expensive, drops out or part of that queue shifts it to others in the queue, you now have to have restudies.

So it may be the time to generically look at how do you plan? But if you do that, you need to understand that may end up shifting those costs, possible overbuilding, to the load customers. And that will have consequences, I would suspect, state regulators would like to be present at the panel to discuss that. I'm not saying that's not a solution, but you need to start "what do we need?" And after you say "What do we need," how do we get there? And then you create other issues on how you get there.

So it works for MISO, they've had buy in from their stakeholders, and that may be a unique solution to that area. That's not where we are in PJM. But it might be worth looking at something in between in order to get a system that you don't have this upgrade by upgrade.

MR. GOSSELIN: Dean Gosselin with NextEra Energy Resources.

So I have a different view on that. As I think the MVP projects have been -- certainly I can tell you that projects we considered a decade ago that were not valid projects at that time because of upgrades and not being able to move them on the system, have become feasible again and we're looking at them and dusting them off and saying are they projects for the future?

So we think it's a good idea. We saw that in ERCOT CREZ where they built major backbone transmission in advance of resources coming on, and that has brought the price of the cost of the market down, pricing of the market down and that's good for America. And we think transmission enables that, especially with this certain progression of renewables that we're seeing. Thank you.

MR. VAIL: Rick Vail with Pacificorp again.

Just from a transmission planning perspective, I would say the planning process is already pretty robust in looking at -- it's no secret where the main areas core renewable development are going to be, from Pacificorp standpoint, looking at Eastern Wyoming and the wind capacity out there. One of the difficulties starting with that planning process is the time it takes to build a significant transmission infrastructure. If you go back to 2005-2006, a lot of load growth, there was a lot of wind development that had the potential to happen.

Then the economic crisis hit us. So a lot of those projects and a lot of that load growth slowed down and things were generally put on hold. And Pacificorp has been in the middle of permitting some pretty significant transmission infrastructure. But you do have to take into account that long timeframe to get a significant transmission improvement permitted and built.

And I think that brings definitely some risk and uncertainty not only to the transmission provider but to the developers as well. And again, I just go back to another comment you have to make sure that throughout this long process that those costs are not being borne by the load serving, the load customers.

MR. DOBBINS: Are there any other comments on this topic? If not, before we move on, I'd like to acknowledge the attendance of Commissioner Clark, and to thank you for coming. Right now we're talking about general queue effectiveness metrics and geographic concentration. Did you want to make any remarks or ask any questions on this topic?

COMMISSIONER CLARK: Having just got here, I don't have any questions at this point. But just welcome to everybody, thanks for being here and everyone in the audience as well. It seems like generator interconnection issues and queue reform issues have been something I've lived with for about 16 years because I happened to be on a state commission, as about 1,500 megawatts of wind power connect into the state's grid over the years.

So I was there, and then since coming to

FERC it's been one of those things we hear about from time to time. It's one of these issues with the advent of renewable resources that we're seeking to interconnect on the grid that I think we just need to stay on top of and to ensure that the rules are working as they're intended to. Every now and then, I think we just need to make sure that they are and make sure the queue reform process were appropriate.

So I thank the Chairman for scheduling this, for the staff for putting it together, and looking forward to having a good record.

MR. DOBBINS: And I believe we have a question from Commissioner LaFleur.

COMMISSIONER LaFLEUR: Well, thank you, Tony. Arnie and Steve kind of teased out what was is going through my mind, which is where does the interconnection process leave off and the transmission planning process start? And with the references to MVP and CREZ? And I guess picking on Alan from ISO New England, where you see a clustering of continued requests interconnection in a particular region with a renewable potential -- I presume you're talking about Maine in your comments -- is there any feedback loop from the interconnection process and the queue to the transmission planning process where that may be an opportunity for regional transmission line driven by public policy requirements that could be like the facilitator then of the specific interconnections in the same way that an MVP was in MISO? And I guess I'm wondering if there's any connection between these queues and that process and then the planning process?

MR. McBRIDE: Thank you, Commissioner. The cost allocation discussion in New England, I think like everywhere, is a big discussion when it comes up, and going back over the years of the framework that's becoming developed. In New England, we have the interconnection space, we have the but-for, the interconnection customer will pay for only the upgrades that are needed but for its interconnection.

Along with that, in New England, interconnection customers do not pay for transmission service. And just to kind of throw out some commentary on that some of the thinking behind that was that would lead or incentivize generators proposing resources to locate in a place where there would be fewer upgrade requirements. It would be easier to upgrade. It would be quicker to upgrade, especially would align that incentive and to keep their upgrade costs down.

But as we've seen and discussed, that doesn't always work, especially when the resource is just far away from the transmission system, which is what we have in Maine. So we are looking at clustering approaches, first of all, to see if a clustering approach would work in that context through the interconnection process. We don't have a design -- in our current world, we don't have such a thing in our interconnection process.

So we're seeing if that's achievable, and other regions could have something that would support it. Transitioning then to the public policy piece that is under Order No. 1000, we're going to be kicking off our first round of public policy next year at the beginning of 2017. And that may be, under our process, something that people bring up and want to talk about, and it would be discussed in that context.

COMMISSIONER LaFLEUR: Thank you very much. I would just comment that if you were building out your system in what we'll call it traditional approach for reliability where your transmission was keyed to where your major resources were your population centers, the concept that many people pay for interconnections by where they locate because you want to incentivize them to locate in an efficient place -- that's how it was always done, that makes perfect sense.

When you start to overlay building out your systems to meet public policy requirements, the Clean Power Plan -- I forget what they call it in Massachusetts, the Global Warming Solutions Act if I'm not mistaken -- and a host of other environmental aspirations. The paradigm that if you just hook into the existing system you'll get what you need, just seems to not maybe work in the same way. And that's why these breakthrough process like CREZ or MVP are having that impact, to the extent that there's a decision on the part of society that meet those public policy requirements. I think that's more of a comment. Thank you.

MR. DOBBINS: Yes.

MR. NAUMANN: I think the difficulty in what Commissioner LaFleur described is a general change in the philosophy of planning from the but-for that many of the regions use to almost an integrated resource planning. It's worked in several regions, and ERCOT of course that's a single state, and MISO there's a lot of buy-in by the state regulators. You need to have all of the states come together and say we're going to accept these charges on our customers.

And that is I think, someone who's been involved in litigation on one of these things for 12 years at least, is difficult. So you're going to have that kind of paradigm shift. And, again, I want to come back you want a robust system that doesn't end up with a reliability or congestion problems.

And that out of paradigm shift, you're going to have to get the state regulators here. Because in the end, you can plan anything you want, but if they don't site the lines it's not going to matter. So you're going to need them at the table to have that discussion. In PJM, the public policy is handled through a state agreement, where the state would say, "I have an RPS requirement and therefore I want this transmission built and I am willing to have the customers in my state pay for them."

A little harder when you start impacting multiple states. So it is a further conversation, and I would suggest not an easy conversation but maybe one that is worth happening, if the goal is to end up with a reliable system that doesn't introduce congestion. And in the end just to say again, kicking off some of the diverse resources that you're going to still need to keep your system running at peak load and get you essential reliability sources.

MR. DOBBINS: Would anyone else like to comment on this? If not, staff, are there any questions from FERC staff on this topic before we have a break?

No additional questions. All right.

At this time, we're going to take a 12-minute break until 10:30. At that point we will have our next panel. All right, thank you.

(Whereupon a short recess is taken.)

MR. DOBBINS: If everyone will take your seats, we're going to jump into our next panel. So we welcome everyone back. We're going to begin panel 2, which is Transparency and Timing and Generation Interconnection Study Process. We're going to ask the panelists -- sorry, please hold on for one moment.

We're going to ask the panelists introduce themselves and make the prepared remarks that they submitted in the docket or just to indicate the one or two most important points they would like to make today. Please keep your remarks under two minutes. We will use a -- there's a timer at the front to let panelists know how much time they have left.

And, Mr. Angell, please start.

MR. ANGELL: Thank you for allowing us to be with you today. I'm Dave Angell, I manage planning for Idaho Power Company. We're a company that serves Southern Idaho and we're vertically integrated. And we've been processing 500 interconnection requests since 2001. And we found that if we hold ourselves and the customers to the timelines given by the FERC existing process, we're able to manage the queue.

And we started with some flexibility in the beginning but found that by providing that opportunity, it gets abused and one can't really manage a queue. We also find that we do have quite a bit of churn in the queues as well, we only take about 20 percent of the projects to construction and service.

So there are restudies that we do undertake, and that restudy process, though we are typically able to manage that within reasonable periods of time and not having to extend the queue. Mostly the extensions of time -- so our time range ranges from about 18 months to about 24 months -- to process through the queue. And the variance there is, quite frequently or mostly, caused by the interconnection customer providing inaccurate data, insufficient data, or changing their interconnection request itself. And with that, I will leave it for the rest of the panelists.

MS. AYERS-BRASHER: Good morning. My name is Jennifer Ayers-Brasher and I'm the transmission and market analyst at E.ON Climate and Renewables. And we have over 2,700 megawatts of renewables in service across the country. And we want to thank the Commission and staff for the opportunity to speak here today and hold the conference.

One of our primary takeaways for today is the need for higher accuracy, accountability and transparency in the interconnection process. Delays and lack of transparency are harmful for generation. E.ON has projects that have been in the system for five years, and in that, as an example, limits our opportunity to move other projects forward. We've also had to withdraw projects due to lack of transparency. One example would be when affected system costs were brought in very late to the process and increased the network upgrades by 14 million dollars in addition to what we were already expecting, which made the project unviable -- from the queue, and that's not ideal to the system.

And so those transparent issues needed to be brought up early. And these are just a few examples that we've experienced. The interconnection process has some flaws, and there have been improvements, and there have been reforms and we appreciate that. We need more improvements and we think the forum by FERC will definitely move things forward. Thank you.

MR. BOHACH: Good morning. My name is Josh Bohach. I'm senior development manager for EDP Renewable North America. EDPR North America and our subsidiaries, we develop, construct and operate wind farms and solar parks throughout North America. We have approximately 37 wind farms and solar parks across 12 states and we operate more than 4,600 megawatts of clean, renewable generating capacity.

In my role, my capacity of the company, I lead development activity for multiple wind projects across the central region, primarily the MISO and SPP regions. Among various aspects that I manage in the development process is the projects generation interconnection studies and ultimately working through the interconnection agreements with the appropriate ISO.

I hope to bring to the panel a practical generation interconnection experience in both of those footprints, having recently experienced ramifications of interconnections study delays and how they affect the project on the ground level. My objective is to help the Commission work towards a solution that will allow wind generators to interconnect in every ISO in a timely, non-discriminatory manner. I'd like to thank the Commission for holding this panel and this conference and the opportunity to present our views. Thank you.

MR. EGAN: Yes, my name is Dave Egan. I'm the manager of interconnection projects for PJM. My department interfaces directly with the interconnection customers, transmission owners, internally our legal staff as we do all of the agreements, as well as our study staff. So we deal with both the technical side, as well as the legal side, as well as all of the project management issues. From a transparency perspective, PJM posts loads of market and operational data, our planning models are available as are our reports and agreements.

One of the issues we have and I believe in the first discussion that was brought up is there are a lot of entrants into a queue. Some are savvy and some are not. So having a lot of data available can be a challenge for a new entrant because they're not aware of where to go on a website, so PJM is always trying to improve access to data too. So just having data is not necessarily the answer, also having access to it, and we do a lot of time, my staff, talking to customers to guide them, to show them what's available.

Regarding backlog, in the first session Mr. Naumann mentioned communication, we're finding that to be key to reducing our backlog. My department, we go out and try to meet annually with all of the transmission owners. We have new staff just from turnover, as well as just showing them what our process is, what we expect from them, and then talking about their issues of timing.

The first 30 days of a study we do our analysis. What does it look like when they receive it and how quickly are they able to turn it around? We show them our needs at the end to be able to potentially restudy, so if they provide us with a result that doesn't solve the issue, we get into potentially looping, and that can result in the delay. So we've been better at communicating that.

The other thing Mr. Angell -- is that how you pronounce your name? -- Mr. Angell brought up the issue of interconnection requests being deficient, and it was also brought up in the first -- we have a stakeholder process right now at PJM trying to be very strong on those rules.

Finally, on the delay causes it was also brought up in the first, we see a lot of equipment changes with new technology. The customer enters the queue, by the time they get to their study there have been large changes in the technology that require restudies.

MR. HENDRIX: Charles Hendrix, manager of generator interconnection studies with Southwest Power Pool. My group administers the interconnection procedures from accepting new requests through the interconnection agreement. I appreciate the opportunity to participate in this conference.

SPP's, our interconnection process, functions pretty effectively since our last queue reform in 2013. Our first cluster in that queue reform started about 18 months ago, we had one outstanding request within the interconnection agreement. The second study that started 12 months ago, we had three requests that are in facility restudy. Both of these clusters start out with 7,200 and 5,200 megawatts of wind and oil generation respectively. Furthermore, this has been achieved in light of significant growth of wind in our region. Through these processes, through our transition to a energy market and our consolidated balancing authority, and regional planning process, SPP has now installed over 12,000 megawatts of wind.

However, despite the successes SPP has experienced, the continued interest in wind has resulted in obstacles to the efficiency of the execution of the process. The volume of requests just continues to grow and our last cluster from last September we had 11,000 megawatts of generation coming in one cluster. That cluster that all went through one impact study, 7,700 megawatts went into the facility study in that one cluster. So we're thinking the obstacles to go into the facility study are not quite high enough. This past study window that closed we had 11,000 megawatts of generation come in. So now we've got 19,000 megawatts of generation that are pending, that we really are in a pickle to determine how to analyze that.

With the minimum loads that SPP sees and with the wind operating at minimum loads, we are very concerned about our wind penetration levels. Minimum loads at SPP are about 20 gigawatts. So we're looking at clusters of 20 gigawatts. Thank you.

MR. OYE: Good morning. My name is Randy Oye. I'm a transmission access analyst for Xcel Energy working on generator interconnection issues, and also the chairman of the MISO interconnection process task force. Xcel energy is a facility holding company composed of four subsidiaries with operations in MISO, SPP, and the western interconnection. Xcel Energy participates in generator interconnection activities in all three regions. MISO and SPP, Xcel Energy functions as a transmission owner with the RTO acting as the transmission provider. On the Public Service Company in Colorado system in the western interconnection, Xcel Energy functions as the transmission provider. Xcel Energy is also an interconnection customer in all regions.

Xcel Energy agrees that generation interconnection queue reforms are necessary but does not support a standardized approach across all regions and transmission providers. Xcel Energy believes that the stakeholder process in each region is the best venue for reform. Xcel Energy urges the Commission to take timely action to implement reforms, especially in the MISO region, and believes that MISO's recent queue filing which the Commission rejected without prejudice included a number of improvements that would greatly enhance MISO's generation interconnection process. The improvements should include adding multiple scheduled restudies with off-ramps to allow interconnection customers to assess the viability of their projects. Xcel Energy also believes creating milestone payments structured to reward projects who select the most cost-effective locations with the best transmission are needed. Tying milestones to the cost of the transmission network upgrades identified in system impact studies could accomplish this. Thank you again for allowing me to participate in the conference.

MR. RUTTY: Good morning. My name is Steve Rutty. I'm the director of grid assets at California ISO. One of my duties is to oversee the generation interconnection process for the ISO. California ISO appreciates the opportunity to participate in this proceeding and in this conference. The ISO and stakeholders have greatly benefited from the mutual flexibility that the Commission has afforded us, and we encourage FERC to continue down that path.

In 2008 when the ISO made a big move to cluster studies, we have studied over 800 projects for over 120,000 megawatts, and this is for a system that has a peak load of about 50,000 megawatts. Most recently we've disclosed our cluster 9 window that had 125 projects for another 25,000 megawatts. But under the recent flexibility you've afforded us, our stakeholders and California ISO have been able to develop a process that allows us to run through 100 projects in a year, and aligns very well with our transmission planning process and where we developed the appropriate transmission for reliability economic and policy needs: As Commissioner LaFleur mentioned earlier, it aligns well with the distribution owners' studies that they do for their distribution-connected assets; it provides our interconnection customers with fixed and anticipated annual studies and schedules, and the annual costs for those studies as well, and it has no restudies; and it provides cost certainty for network upgrades to alert the interconnection customers very early in the process.

The ISO continually works with the stakeholders to identify enhancements to the process, as you're probably well-aware of our annual interconnection process improvement efforts. So with that, the ISO respectfully requests the Commission continue to ensure each region maintains the flexibility to adopt interconnection procedures that fit their needs.

MR. ZADLO: Good morning. My name is Kris Zadlo. I'm a senior vice president at Invenergy. Let me start by saying that Invenergy supports the AWEA's petition. The interconnection process continues to impose significant barriers to generation development, in some case delays of up to six to seven years. Generic reforms are necessary to overcome these barriers, RTOs and utilities should be required to show that they have adequate resources available to accomplish their obligations, and they should be required to clearly enumerate study assumptions up front before commencing on the studies.

TO should be required to abide by firm deadlines or to state in writing why they cannot. Meaningful Commission oversight, along with timely and expedited dispute resolution mechanism, must be built into the process. Greater Commission involvement in the

RTO interconnection process is sorely needed. Each time an RTO deviates from a generic reform or Commission-approved best practice, the RTO should be required to file a notice of untimeliness or noncompliance to explain these deviations. The Commission should review these reports where appropriate and investigate them.

Just as the market monitor and the Commission enforcement staff scrutinizes outlier bids, they should also scrutinize outlier interconnection practices. The Commission should also require each RTO to establish an ombudsman with direct access to designated FERC staff to provide a venue for timely relief when customers are at an impact or have a dispute about matters affecting studies. These measures should not prove unduly burdensome to any RTO that's doing their job, because if it is no reports will be required or calls to ombudsman necessary. Thank you for this opportunity to speak today and I look forward to the Q and A.

MR. DOBBINS: All right. Thank you again to all of your participation and for your opening statements and remarks. FERC staff will now begin asking questions. Please limit your responses to around a minute so that other panelists have time to speak.

And once again we apologize in advance if we aren't able to hear from everyone at the table on every topic. We'll start off with a question of -- talking about time frame for studies. Are the completion time frames and the pro forma LGIP and regional tariffs -- sorry, are the completion time frames of the pro forma tariff and regional tariff reasonable in regards to the amount of time provided for completing an interconnection study? And we'll start on the left and move down towards on the right.

MR. ANGELL: Yes.

(Laughter.)

MS. AYERS-BRASHER: I can't comment to whether the RTOs and TOs feel like they have enough time, although I think we just heard from one that they do. However, following those timelines and the documentation of those, then we can plan with those, so it goes both ways. And we have those laid out, we plan based on those. So if they need to be different, we need to know what those are.

MR. BOHACH: Along those lines, I'm speaking for the time to put a study together, but from the operator. And knowing what -- those timelines and being able to plan around those for a project development, those are sufficient timelines if we're able to adhere and bank on those timelines.

MR. EGAN: At PJM we have timelines for both large gen and small gen. And the issue we run into and I think might be part of some of the issues the generators have, in 2008 and '12 we've had reforms through the stakeholder process where, for example, the small generator said "We don't like the but-for cost." If you look at a distribution circuit and three projects ahead of us use up the existing overhead on that, we end up the fourth project picks up the overall cost. So they requested for under $5 million upgrades to have those socialized within the queue so everybody who contributes to the overload pays for it.

The problem with that is now you have to wait for the queue to close to be able to study everyone. So it actually -- where before, the smaller generators could have been moved along quicker, because if we analyzed it and saw there was overhead, we could give you your agreement and move you along. Now you're bundled together. So it's a clash of cost sharing versus timeliness that I see right now at least on the smaller distributed generators.

MR. HENDRIX: At SPP, we had a number of stakeholders processes where we decided instead of timelines ordering the impact study, we also put in increased milestones to get into the impact studies so we were compressing time frames and we would have fewer projects in the studies. As it turned out, I just mentioned the studies have doubled and tripled in size, so we're now finding that the timelines that we have are very difficult to meet.

MR. OYE: Xcel Energy is comfortable in the timelines to complete the interconnection studies. I guess issues that have come up is when they start. Lately, they've been delayed quite a bit, and that is an issue. And as Charles said, there's a lot of projects in the queues so they take a lot longer to complete because of the restudies and others. So that's it. Thanks.

MR. RUTTY: So at the California ISO the queue cluster process takes about two years to get through the study process, that's the phase 1 and phase 2. There are a couple of faster options if the generator can show they have a demonstrated viable need to move quicker and they are determined to be independent from other projects that would be sharing their cost. But the cluster side does take about two years. It is fully integrated with our transmission planning process. The timelines are in our tariff, we can't miss them, and so far we've been able to meet all the timelines. We don't have a study backlog. The tariff requires that -- the transmission owners to meet tight deadlines as well. So, so far so good. It doesn't mean things won't change.

The deadlines that we have in there also provide the interconnection customer time between studies to make decisions as to whether they want to move forward and how they're going to finance their project, if they're going to get a PPA in time and so forth, a power purchase agreement. And so the study has that built into it as well, the whole -- the entire process. So it's a give-and-take with the customers to make sure that we have time to provide them a study that gives them what they need to move forward, and that they also provide financial security along the way to make sure they're in the game as well. So --

MR. ZADLO: The problem is not the timelines, the problem is the lack of rigor going through the process. I'm going to give a shout-out to Mr. Hendrix. When we enter the queue in SPP, we're reasonably assured that within a year and a half to two years we're going to end up with an interconnection agreement. That can't be said with other ISOs. Cal ISO also meets their timelines. Can't say I'm happy with the length of their time, but at least after two years I know I'm going to get an interconnection agreement. I can't say that for other jurisdictions.

This is 2016, folks, this isn't 50 years ago where engineers were doing power flows on punch cards and using slide rulers. We have phenomenal models at our disposition here where you can model the whole entire eastern interconnection, have 100,000 contingencies analyzed in under a couple of minutes. So the RTOs do a phenomenal job managing their markets, but on the flip side, on the interconnection process, I think there needs to be a higher standard there.

MR. DOBBINS: And taking into account the comments just made by Mr. Rutty and Zadlo about the CAISO process and the SPP process, here's a question for the transmission providers: How often are studies completed within the time frame establishing the tariff? It seems like at ISO and -- I guess and SPP, pretty often. And when these completion rates vary, what generally accounts for this variance?

MR. ANGELL: Well, with Idaho Power, again as I mentioned earlier on, the variance, we actually don't start the clock until all the data comes in. And once we start that clock, if they do come in -- well, all the data comes in and is correct. And then we start the clock. If they go and change the technology that they're using, then obviously we start the clock over. So we always meet our time, and it's dependent upon the customer providing the data as far as what that overall time will be from when they first come in.

MR. EGAN: At PJM the issues that you get into, and discussed earlier and mentioned earlier, the customer is accountable to providing the data timely. Data holdups right now, we end up -- if you look up at the 90-day feasibility study, window for our tariff, almost the whole first month is wasted in the process of getting data in and holding scoping meetings. We have some queue reform that we're getting ready to propose, but that is not in place right now. So that's one issue. As far as going to get the studies out, we still are able to get the feasibility studies out on time. We've improved greatly in the last I would say three to five years on that. Impact studies are generally out on time. The problem you get into when you issue, for example, an impact study, and you're sending them out in the cluster format, is you're going to get now people who see the results and withdraw, so you're almost automatically into some form of model cleanup and central retools as far as lining up where the obligations to build network upgrades are going to follow but-for issues. So that's one of the biggest problems.

I agree we have great modeling, but the problem is you also have business decisions that have to be made and reaccounted for after they're made. And they are in queuing order, so --

MR. HENDRIX: In SPP, it can take over a month to six weeks to validate all of the generator data. And we have been pretty rigorous in withdrawing requests that haven't met those timelines once we've been able to validate that. However, the way our tariff is and our studies, timeline starts as soon as the window closes, so that's really counting against us while we're evaluating all that data. Despite that, we have a pretty good percentage of completing the impact studies on time. SPP is pretty -- we have a large region, the western part of the region we kind of study separately. That's where a lot of -- where wind is, that's where the transmission system is not near as robust. So what happens is that -- and there seems to trail, we will have more restudies there with withdrawals, and so that -- we will that area is generally behind maybe 30 days to 60 days. With the upcoming clusters, we've actually put a hold on this latest study so we can get a better handle on the last study that had 7,700 megawatts going into facility studies. So the speculative requests that appear to continue going forward even in the facility study are going to cause greater delays going forward.

MR. DOBBINS: Feel free to skip this question. Since you answered this in the last -- did anyone else want to speak?

MR. ANGELL: I just had one more comment. And so as a fairly small utility, we augment our staff with consultants in order to meet the time frames that are in the tariff. And so augmentation is always required.

MR. DOBBINS: Thank you. We have a follow-up question.

MR. LUONG: Yes, I had a question regarding the input data. Is there any way you contain the -- how to improve that between the transmission provider and transmission customer, along the way help to -- help out the good data, get the thing right away and meet -- up front? And then we hear about a lot more new technology from modeling. Is there any way that in the industry can work together with the manufacturing, try to come up a lot of new model and then onlook -- go with a vendor for the tool so you can shut down the issue about your data at the beginning of the input --

MR. ANGELL: So in the western system, WECC has the nearest models that are approved and defined. So that information is provided to the interconnection customers, and then it's up to them to either choose to use a generic model or provide the full data with regard to the exact equipment that they're supplying.

MR. EGAN: Regarding your issue improving the process, we are trying to make tools so that it's very clear what the customer needs to provide coming in, and tightening up the rules so that if they do put in bad data or don't provide the data, that they really don't get to participate in the queue or hold the queue up.

MR. HENDRIX: In SPP, similarly we've been working with customers the front end, and we've got a checklist. Many of our customers who have been through the process many, many times. So they're well-aware of what's needed, yet sometimes they still don't provide everything. It's just when our window closes, let's get everything in there that we can, and hopefully let's get things sorted out. So to an extent, that's an obstacle.

MR. EGAN: I'll add one other point here. A comment on working with the manufacturers: Some of that actually comes from the customers, too, as far as if they keep updating their models, they need to be providing models that the transmission providers can use to study. They're the ones that would have the financial leverage to get the manufacturers to provide that, so --

MR. DOBBINS: How much has this been an issue, not getting the technical information from the manufacturer?

MR. HENDRIX: It's very difficult when you're doing the dynamic studies to get the dynamic models. And the issue there, that goes back to what I was saying about the speed at which some of the newer technologies are being updated all the time, the manufacturers have to also be in parallel updating their models, and that's been an issue.

MR. ANGELL: And I might add to that as well. Sometimes it has to do with these new designs, confidentiality around those designs, and the manufacturers have definite concerns there and will withhold information, or try to.

MR. ZADLO: I just want to provide some color to this topic. The interconnection process takes way too long. And we know today, if I submit a request today, I know by the time I get through the process the equipment that I submitted my request with is obsolete, it will be no longer in production. So you all need to keep that in context, and that's why those material modification requests are so needed, because technology is evolving at a rapid pace. So there needs to be flexibility and you need to consider that, that this isn't a stagnant "Okay, I submit this and this is what I'm going to eventually interconnect."

MR. DOBBINS: Is there anything in terms of information and transparency that can be done or changes that could help that process if there's an issue of when I start the process, here's what I'm presenting throughout the process, that they may be changing some part of it is information flow, part of it is just timing, as you get updated and -- yes or no? What can be done to improve that process so that everyone is aware as soon as possible about any changes in a project and other projects, what sort of helps with that?

MR. ZADLO: So what I will say is I think the bar for restudies is set very low. I think a lot of these restudies are unnecessarily performed or they can be performed in parallel with the queue. And I mean unnecessary, there was an instance where we had to move the substation 500 feet, okay. The transmission owners said "We got to re-perform all the studies."

Good engineering judgment would say that's not necessary. With the situation with the equipment changing, rarely has that caused or flagged additional upgrades, all right. So if that's the case, let's have a separate group that performs re-studies on change of equipment in parallel while the interconnection analyses are being performed; that's another way to deal with it. Goes back to my original comment that there's not enough resources studying interconnection. The same individual who is studying the interconnection request is the same individual that is doing the restudy.

MR. DOBBINS: Would anyone else like to comment on this before we move on? Okay. Sorry. I thought I heard a click of the microphone. In the event that there are delays in the study process, how are those reported to interconnection customers?

MR. ANGELL: So the delays in the study process are recorded by a phone call, e-mail, and of course hard copy letter. And with that, we also identify the cause for the delay and essentially the party that has the action item to clear that delay, whether it's either the customer themselves or the utility and a timeline for that.

MR. DOBBINS: Would that include information on other projects, maybe that they're somehow involved?

MR. ANGELL: Yeah, sure. If it's a restudy effort, yeah, project in the queue, senior project dropped out, that is correct.

MR. DOBBINS: I'm going to have the same question for everyone else. How are they reported in the clauses?

MS. AYERS-BRASHER: I think our experience has been that some places give you a reason why, some don't. Sometimes it's a phone call and sometimes it's an e-mail. You might hear about it. Sometimes you hear about the delay before the study's even started, and sometimes those have reasons like the project -- the queue ahead of us and sometimes they don't. So there's no consistency. We don't have -- and it may be consistent within a region, but it's not consistent across. We don't always know what's going on what the causes of those delays are, and it makes it difficult, again, to figure out what we're doing on our side and where we need to slow down or what we need to do.

MR. BOHACH: The inconsistencies, to go on what Jennifer said, the issue regarding the notifications, there's lots of venues depending on which ISO we're operating in. Websites are obviously a tool. We'll get letters, stakeholder or ad hoc groups to meet with or discuss delays. But those will often ebb and flow through the process. Frankly, what we sometimes find is just our inquisition with the ISO, that is often where we find it on the one-off e-mail or phone call to discuss a particular study or group project on that, or hearing from potentially another person in that group or something. So consistency I would say is one thing that's lacking in that notification.

MR. EGAN: At PJM we have for each transmission owner a project manager so the customer will have a direct line with someone on my staff to be able to contact. We issue e-mail notification if the study's going to be delayed. Part of the process, when you have a tight process, for example, 90 days to do a feasibility study and 30 days get eaten up upfront, so you're looking at about a 60-day study, I think some of the issues the customers have is, from what I've heard from them when they call me to complain about it, is that we're notifying them just before the study's due. That's about when we're hearing from the transmission owner that there's an issue or they're going to be behind.

So I think that's part of the rub, is that you're finding out late in the process, but that's just how the process is set up right now. It's very tight time so therefore you're at the end before you know that you're going to be delayed.

MR. HENDRIX: We'll send out e-mails to the customer as - generally as soon as we know and as soon as we're reasonably sure we're going to be late, we'll let them know. And sometimes that's early and sometimes that's late in the process.

MR. OYE: Our experience is usually it's through e-mails, we'll receive an e-mail, and then stakeholder meetings. So there's usually updates on what's going on. So those are the primary ones.

MR. RUTTY: At the California ISO each interconnection customer has an interconnection specialist assigned to them, and they communicate all of the schedules for the study process, all the due dates for financial security, for postings, to provide additional information after phase 1 and before phase 2 to accommodate their needs for any material modifications that they may have. So we have a single individual for each interconnection customer on that. And as far as communications, it could be a variety of things. It could be a letter with receipt required or it could be an e-mail or a phone call.

MR. ZADLO: It varies across the board. Some transmission owners, it's a black hole, you get no feedback. Typically, it's just an e-mail with little explanation as to why the delay is occurring. What's more interesting is when you do get an explanation as to the why the delay is occurring and usually it has to do with that resource that's studying your process that is being diverted to something else. And that's when it gets really interesting because you clearly get a view that the interconnection process is not a priority to that transmission planner. We've gotten explanations that, "Well, we have to do the transmission expansion plan by the end of the year, so your folks studying your requests has to now work on the transmission expansion plan," which always gets done on time with every RTO. There's hundreds of different scenarios and upgrades being studied, yet when it comes to one generation interconnection request it's difficult for them to process that in a timely fashion.

MR. OYE: Just kind of general on this topic. The delays aren't -- there's a lot of reasons for the studies being delayed. The transmission provider, getting the studies done and having enough people to do it, you could maybe say, "There's something to that but they could do better." But our experience is there's -- especially in our area, Minnesota, North Dakota, South Dakota, it's a very good wind area, and we have tens of thousands of projects coming into the queue. And there really isn't the market for that many.

So the projects come into the queue, they're studied, a lot of them drop out. And they tend to drop out at different times in the process, so they're not all dropping out at once so it's not just one restudy. The August 2012 cycle in MISO, there was six restudies, and that was because projects just drop out at certain stages.

And so really there's reasons for the delays and why things are behind, and a lot of it has to do with just, my opinion, our opinion, the company opinion, there's -- the financial milestones are not appropriate, MISO, I've been involved in three queue reforms and every time we've done it we make it a little harder. The first time we said if you have turbines, and then everybody managed to get turbines. That was a milestone. The second one we made it about money, and again, still there was a lot of projects coming in. And we keep upping it, and it usually works for a little while and it works for a couple cycles, but it doesn't necessarily solve the problem.

So our opinion is really what MISO came up with recently, it gives you three shots to get through. You do an initial study as a cluster, which kind of gives you a better idea of what your upgrades are; and then you have a choice to move forward or not. And we think those milestones, what's important is they're tied to transmission upgrades. If you're a 100-megawatt project and you've got 10 million or five million transmission upgrades, your milestone should be a lot lower than if you're a 100-megawatt project, 50 million upgrades. So we really think that there's some structural things that could be fixed in the interconnection process that would help with the restudies, would get some of the things, the timeliness and completion done, and better approval. Thank you.

MR. DOBBINS: I think that's a good time for -- FERC Staff has a few question on restudy, so I think we'll jump in on that.

MS. GRAF: Thanks, Tony.

As we've seen restudies, the problem of them, the stability of the queue is an emerging theme at this tech conference. So we were wondering, especially for the transmission providers, how often do you perform restudies or is there a set procedure for how often you do restudies? And for developers and those that operate within different regions, whether you see variations and how restudies are performed or how commonly they're performed?

MR. ANGELL: So first I'd address -- so Idaho Power did operate a cluster many years ago, and in that cluster we did have multiple restudies that occurred at that time. Since then we've tended to avoid a clustering of studies. So the restudies for a group have definitely diminished relative to that. However, for, again, those entering the queue and then dropping out, only 20-percent conversion rate, there are restudies, but with regard to our system and our staffability, the restudies are done within the time frame so it's not extending the project's time.

MR. EGAN: PJM, our tariff defines when we do the restudies, so if you have a withdrawal the IROT has to restudy everybody else after it to find out if the obligations to build the network upgrades shifts. The issue with that is, when you issue a study you got to tell a customer, right now you may actually fall through our cost allocation rules and not have a cost allocation. But if you're after someone who has caused it, you'd ultimately have to include it in there because if someone withdraws the stack-up where the hundred percent threshold crosses may fall on that customer. So any time you have that you have to restudy to make sure the but-for costs are being applied to the right customer. So it's a lot of work to do restudies, but it's a required work to do for analysis.

MR. HENDRIX: Restudies will trigger higher withdrawal, we know we're going to have restudies after every impact study that we could, and our new procedures pretty much have that built into it. We're pretty much agreed again to have another restudy, once the requests are going into interconnection agreement. But even after that, there's really no set time of when you know somebody is going to withdraw, it just happens any time after an interconnection agreement that you can terminate that agreement. And so you just have continuing restudies, we've had one cluster with seven or eight restudies due to withdrawals. At some point in time you can have a withdrawal and determine that this is an area that we don't have to restudy. But in our western footprint where more wind is, there can be several restudies.

MR. OYE: If it's okay for me to speak to MISO, MISO's tariff has three conditions where restudies will be performed.

MR. RUTTY: So the California ISO, we have a process, it's a two-phase study process. Phase one study is done the first year where we identify upgrades that are going to be needed for that clustered route. Each interconnection customer within that study receives a cost cap, which throughout the rest of the study process that will be the maximum cost responsibility they will have. It helps them to decide whether they're going to move forward or withdraw.

When we go into the phase 2 study, we go into a much more detailed study. The study now has already taken into account for the withdrawals of the phase 1, and it's just the interconnection customers that moved on into phase 2.

Now, they'll get a new cost allocation, but if it's higher than the phase 1 they're still protected by the cap that got in the phase 1 study. This has helped a lot in reducing the need for restudies and makes decisions to move forward, post-financial security, and move on. But if we do have additional withdrawals after the phase 2 and we do an annual reassessment where we look at who's left in the entire queue, all the clusters together, and identify where, based on withdrawals or projects, where network upgrades can be removed -- and usually it's the case that upgrade networks are removed from the clusters and from an interconnection customer so that their costs continually go down -- they get a new what we call "cost responsibility." Ultimately, they only pay for what they need at the end.

So through this process, it's really eliminated the need for a restudy; we're allowed to continually move the clusters through the process and reassess them annually without a need for what we call a "complete restudy" that would completely throw an IC's financial book out the window. That consistency and security that they have from very early in our study process.

MR. ZADLO: If I'm batting .300, I'm not a bad guy, I'd most likely go to the All Star game. So there needs to be an understanding of the development process. And when you build something in many jurisdictions, okay, your special use permit is only good for two years, all right. So I've constantly playing this game of trying to marry up my construction permit with the timing of the interconnection process. And unfortunately it's the interconnection process that's along the items in developing power plans, all right. So I can't move forward with the permitting process until I have line of sight on my interconnect, make sure I can get that project across the line. That's just one of the many things that I'm weighing here. Right? So just because people drop out, it isn't because they have bad intent. Why would have spend hundreds of thousands of dollars on an interconnection request just to drop out? Right? So I want you guys to keep that in context.

The other thing you all should keep in context is that there are RTOs and ISOs out there that have phenomenal dropout rates and are able to deal with it. PJM and SPP, they have large dropout rates, and they're able to do it because they know that during the different stages there's a certain dropout rate, and they do a probabilistic analysis knowing that, okay, these folks in the feasibility study only 70 percent -- or Dave can tell me -- 80 percent will go forward. Once you get to the system impact study, 50 percent go forward, so forth and so forth. So they're able to deal with the issue.

MS. GRAF: Some of you mentioned some of the tariff triggers for restudy. For developers, do you find that the triggers for restudy and the procedures or the tariff are sufficiently clear? And do you see variances between the regions?

MR. BOHACH: So we do see variances between the regions, the difference between RTOs, ISOs and all that. As Chris had mentioned, for example operating in SPP, we know when those are going to occur, we can plan for those and make those good, sound business discussions based on that, knowing whether we'll see restudies. So that's a good case scenario in our experience operating in SPP with the tariffs. Those restudies get drawn out and then you have -- you lose that cost certainty, which now a project that maybe didn't affect my project drops out and there's something that now attaches to my project now, which potentially calls into question the viability of that project. So we do see the variance, some good and some bad.

MS. AYERS-BRASHER: Yeah, we see the variance and it is somewhat defined in the tariff, the higher queue project drops out, we see that, we understand that. But I think there's got to be ways to either have the restudies perform quicker or ways to accumulate the data that allows to have a quicker understanding. I don't know if a full restudy is necessary, possibly what California ISO does, that limits those restudies. There are options and ways and we just need to find those and make them work. And they may be slightly different for each region, but we need to find what those are and fix it. Because those restudies do make it difficult. Earlier information could make things -- if people had a little bit more information in the feasibility study, maybe they'd drop out sooner. So that when you get into those longer studies that take more time and also cost us more to complete, there's a little bit more uncertainty at that time as well.

MR. DOBBINS: We have a question from Commissioner LaFleur.

COMMISSIONER LaFLEUR: Thank you.

Listening to this conversation, I'm hearing a couple high-level messages that are in conflict or in tension with each other at least. One is that there's considerable disparity among the regions in their ability to work through their queues and meet their timelines, the way the processes work. And the second is, in the opening comments I heard a few pleas for regional flexibility and leading the regions in different ways, which seems to be a little bit in tension with having best practices spread through the generator interconnection or otherwise. In the interest of stability, you want regional flexibility, if you could expand on why you think that's important and where you think we should kind of -- how do you think we should look at this tension, because it's always a tension in so many things, in posing the best way to do it or letting people do it differently? And we've heard a lot of different things. Thank you.

MR. DOBBINS: We'll begin on the left and move down the panel.

MR. ANGELL: For one of the first reasons for regional flexibility in the western system is not a full market throughout, so there's a starting point. Additionally, having worked in a lot of stakeholder processes at the local level with Idaho Power itself, at the regional level through the Pacific Northwest, we find that stakeholders' involvement locally allows us to engage with those individuals and make reforms to the benefit of -- where we can essentially compromise and come up with the best solution. But I do understand best practices throughout industry are always important to take throughout. The question is what's the right level of -- not heavy-handedness to enforce things -- but to allow it to grassroots grow.

MS. AYERS-BRASHER: Maybe just a quick comment. While we feel there should be more commonality, maybe across the board especially where there's more markets, we understand there might be some need for flexibility, but we would like to see a lot more consistency.

MR. BOHACH: We're consistent with that view as well. Commonality across would help on the operator end.

MR. EGAN: I guess I would mirror David's original comments, though, the issue with markets, how the markets interface with regional areas makes that somewhat difficult.

COMMISSIONER LaFLEUR: Even between organized market areas, I can certainly see bilateral market areas and RTOs having a different paradigm as Mr. Egan said, even among the market areas.

MR. HENDRIX: The different states, as mentioned earlier, have different appetites for renewables. And SPP stakeholders have approved a lot of regional transmission that's facilitated our queue greatly. So that's one main regional difference. The markets work differently as well, so I thought I'd bring up what those regional differences are, are important.

MR. OYE: Our Colorado system, it's not a market, it's one state and it's worked really well. Whereas in MISO in our area, there's just huge amounts of renewables, wind in the process. I don't think -- SPP is also in that same situation, but I think the East Coast -- I don't think they have that kind of amount of renewables. And in our area for every 5,000 megawatts or 2,000 megawatts of PPAs or off-takers, we might get 20,000 megawatts of requests. So the market doesn't support all the amounts of queues or prejudices in the queues, so I think those areas should be handled just a little differently than others, so regionally I guess is the answer to your question.

MR. RUTTY: Yeah, I believe the ISO has a similar view points to the panelists. We've were able to create an interconnection process that's worked well for us. The serial approach was just unworkable. And so allowing us that flexibility to move forward with solutions that worked well in California was key to being successful. Now, that -- it's no hidden secret that the ISO is looking at regionalization possibly in the future, and this could change our game and we'll have to be able to be very nimble on our feet to adapt to that as more states may join in and move forward, so just having the regional flexibility to allow us to really listen to our stakeholders and provide a solution is very key for this.

MR. ZADLO: I personally dislike the deference that's given to the RTOs. Many times many of our requests are, let's say, on the scenes where it's unclear whose RTO or TOs reliability standards apply, are we meeting this standard or that standard? So there are issues when you start diverting from the standard pro forma. The other issue is deference is okay, if they're meeting their timelines, if they're not meeting their timelines then they should be required to take on best practices.

The last thing I will say is just because something's been performed in the past doesn't mean that's the best path moving forward. Again, there's lots of regions where it's taken six to seven years, and to say, "Well, this is our regional practice, this is how we've done it for the last 50 years," well, if this is how you've done it for the last 50 years and it takes you six or seven years to get through the process, then maybe it's time to change it.

COMMISSIONER LaFLEUR: Thank you.

MR. DOBBINS: Commissioner Clark?

COMMISSIONER CLARK: Thank you.

Just quick followup on the last question because it's very similar to the question I had. And I think this is mostly a commentary for a folks who are going to be submitting comments to the Commission post record.

I would really appreciate some focus on that particular issue from those folks who are arguing for lots of regional flexibility amongst the organized markets. I guess the bilateral markets are different. I think there's some reasons you could separate that issue out. But with regards to the organized market, if you could give me some examples of why different market constructs really impact a process management issue -- which is how I see this -- that would be very helpful. I understand from the purely market issues like one region has a capacity market because we have certain state regulatory regimes in that area and another region doesn't, and on its face I could see why you would have regional flexibility.

When it comes to just a process for doing engineering studies for how different projects interconnected with the grid, to me it just seems like obvious on why a market-to-market difference would dramatically impact that. So if you could give some examples on why that's the case, that would be very helpful.

I understand that there are regions in the country that have -- my own region in the country where there's tens of thousands of megawatts in the grid -- which is different from another region of the country. But from a process standpoint, I'm not understanding exactly why there has to be a great deal of flexibility if there are indeed ways that we've found that you can process that better than others. So if you can provide examples to that, that would be helpful for me.

The question I have, it's come up in a few different comments. It seems like one of the real challenges, especially for regions of the country that have a large amount of especially renewables that are seeking to be interconnected is this kind of almost Oklahoma land rush issue kind of issue that we've run into for well over a decade now, which is you have lots of developers who are out there trying to develop projects -- and God bless them for trying to do it -- but we all know, realistically, not all of that can come on to the line, there are going to be market issues why you can't have that sort of thing.

And the gentleman from Xcel who's talking about the threshold that's going on -- not to be cold-hearted about it -- but is there anything wrong with just as a means of trying to deal with that issue to continue to ramp up those requirements? It might be kind of Darwinian, but does it become something where if there's that much wind power, for example that's trying to get down to the queue and get through the interconnection process, could you simply add to that high bar to weed out projects that realistically don't have a chance to getting on? And is there a way to do that in a nondiscriminatory way so that you can clean up the queue? And what would that bar look like, how high does it have to be? Are there sort of -- I'll leave it open. Are there outside-of-the-box ways we haven't thought of to weed through the project so that in a non-discriminatory way only the fittest do survive?

Go ahead.

MR. OYE: I'm not sure who you were asking. We agree with that. And I think at MISO they recognized that years ago and we just never set the bar high enough. So yes. And there's been a lot of discussion since MISO filed their queue reform, and there was a lot of discussions on what the milestone should be. And it's really hard to determine what is right.

But through discussions and working on it with a lot of stakeholders, our opinion, my company's opinion and some of the other stakeholders, that if you tied it to the network upgrade -- and it's been mentioned about models and somebody I think on the earlier panel mentioned that you can get a model, you can run studies, you can get an idea what your project look like, but until it's run with all the other clusters you really don't know.

So if you did the first cluster study and you identified the cost of the network upgrades, and you somehow tied the milestones for the next step that you had to pay to go further to what your upgrades are, and the logic behind that is, if you're in a spot and you have 100 million in upgrades and you're a 200-megawatt project, you probably should drop off. But if there's no milestone payment, maybe you don't. Maybe you think, "Well, I'm going to stay in but all these other guys are going to drop out."

And we used this -- in my opening

statement we used the term "we do the good projects." So if you set some threshold that you didn't have to pay -- you pay your initial milestone to get in the process, your next milestone you would not have to the pay more if your network upgrades were under some threshold, likely based on your size. So much $100,000/megawatt, if your network upgrades are below that you don't have to pay more. But if your network upgrades are above $100,000/megawatt, you pay some percentage of that amount. And as you step through it, we actually ran some simulations on some of the MISO queue reforms and we applied that criteria to projects.

And after we ran through it three times, a lot of the projects didn't have any upgrades. And most of the projects that survived -- again, you don't know what the project is going to do -- it seemed like it could work. And again, if you get to discriminating, small developer in a bad spot, if he's got a lot of network upgrades, we don't think that would be discriminatory. So again, tying it to network upgrades seems like the reasonable.

The other thing that I think you have to do is I think you have to have firm deadlines and firm timing, that somebody can't sit in the facility study so the last point and kind of -- because I think projects, there's an incentive to stay in as long as they can. Everybody's trying to get a PPA or sell their projects, so there's incentives to be there until the last moment. So anyway, that's my thoughts.

COMMISSIONER CLARK: Thanks.

Anybody else who want to take a stab at that?

MR. RUTTY: I'd like to take to respond to that. The California ISO put in very high bars for financial security. And with hundreds of projects competing to be that five or six that actually complete the whole process, even with a high bar we see a lot of people putting down financial security and in the end withdrawing. So that was a loss for them because they lose some of their financial security if they drop out.

One of the things we did in this last big change was to move the delivery network upgrades that allowed a project to become deliverable and meet our RA requirements, the resource adequacy requirements in California, was to once they finished the pay-to study, if they said, "Hey, I don't want to pay for any of these upgrades, I'm only going to take what's available to me," they actually compete for those based on milestones they've met.

So putting in milestones such as do they have financing, do they have a power purchase agreement, do they have permitting, rank them up to be able to be awarded the deliverability from the transmission network and they came out of their transmission planning process, that was a big part of integrating it.

Yes, having a high bar did get rid of some, but it wasn't the whole solution, it was a multiple of solutions. One was financial security; as well as they needed to progress along as well to be able to achieve the deliverability allocation at the end of the process. And if they didn't, they could continue on as an energy-only project or withdraw at that point.

But in California -- I know others are seeing the same thing, I believe our dropout rate is 80 percent or more. It's very competitive out there; and that's not a bad thing, but it's tough on the developers when they realize they're one out of 10 that are going to succeed.

MR. EGAN: The issue of every customer, the speculative customer, every customer when they come to me tells my how real their project is. So to say that we can find a bar to get rid of a speculative project, I don't think is possible, at least I'm not sure how you would do that. The marketplace, I think, will clear projects that aren't real. When they see a cost that's not going to be economical they'll withdraw the project.

And I think it's tied together, as the issue Kris mentioned, six- to seven-year project delays, projects become coupled together. The longer you have projects in your queue or backlog, the more they get coupled together. In other words, you need the first project to make a decision, the second project to know what their costs are going to be. If you get a complex project upfront that's drawing that out, that gets to be very problematic for everyone else.

So working, and this was talked about in the first session with communication, I'm finding that if we can keep the transmission owners working, projects in parallel, even if the TO thinks, "Well, that project needs to make a decision first," still go ahead and engineer all of it. We have the facilities studies. And the one studies process we haven't mentioned today, we talked about feasibility impact studies, the facility study, the tariff really doesn't have a set deadline for that. It says it should be completed in 180 days. And the issue you get into is putting the planning resources, generally once you get to the facility studies phase, you're working with the engineers that are working in the field. Feasibility impact studies are generally desk-side studies.

So to get the transmission owners, even if they don't have enough staff working in the field, to augment their staff -- and I've heard others say they're doing that -- to me, that's the big thing that has to occur to get rid of these backlogs, allow people to make their decisions on the economics, and then if you have to restudy a restudy, but things will be moving along faster because you've done all of the studies and know what has to be done.

MR. HENDRIX: At SPP, I think our deposits are pretty good. We still have too much room for those to be refunded. At SPP, I mentioned we have a restudy built in after the impact study. We're pretty much giving the customers a free look after the impact study to get all their deposits back. They can reduce the size of their interconnection request; they can drop network resource interconnection service; anything they want to do after that impact study. But going into the facility study, we require a higher deposit. But the intent of serious projects going into the study, they go and get that money back, but there are still avenues for getting that money back, so we probably would like to tighten that up so we only have viable projects going into the facility study. The problem with tying it to network upgrades is you may have -- it's like if a new

345 line gets built into the planning process and you're the first customer to interconnect that 345, you may not have a lot of network upgrade, doesn't mean you're not clogging up later queue projects. Thanks.

COMMISSIONER CLARK: Did you have a comment?

MR. ZADLO: Yes. So what higher deposits do is essentially limit throughput. If you look at the two RTOs with the lowest deposit requirement going in, I think it's PJM and ERCOT, and they have the highest throughput as far as interconnection studies go.

COMMISSIONER CLARK: When you say "throughput"?

MR. ZADLO: The amount of interconnection studies processed, okay. So I think by raising the bar -- when I say "bar" raising the deposit bar -- you're not addressing the underlying issue which is lack of expediency of the analysis. That's ultimately the issue there that needs to be resolved. The second thing is you raise it to high, you get into a discriminatory situation where only the really big companies or the vertically-integrated utilities in those footprints are the only ones that can move forward.

Let's look at ERCOT for instance, with PJM in the Marcellus Shale, they have low interconnections amounts, right, but yet ERCOT over the last five-six years interconnected over 10,000 megawatts of wind.

Now, it's buyer beware because a lot of those interconnection requests in those facilities that got built were in the panhandle or behind the panhandle stability limit and get curtailed a lot. But the onus is on the developer to make sure that they're in an area where they can deliver their output to the market. So I guess what I'm saying is you can have the market -- the better way to do it is to let the market decide.

COMMISSIONER CLARK: This is actually a really fascinating topic I think. Because it doesn't seem like it should be something that should be impossible to solve. I mean, it's process management, and maybe the box we've been looking at isn't exactly the right box, because we seem to keep having these same issues come up over and over and over again. Maybe there's some other way of looking at it that we can -- we have lots of smart economists in the room and folks who might be able to come up with some way to price this particular issue in the sense of scarcity that we see.

So anyway thanks to everyone who's been here and look forward to the comments in the record.

MR. DOBBINS: All right. We have a question from Commissioner Honorable.

COMMISSIONER HONORABLE: Thank you.

It's really more of a comment. And I think the gentleman with the last comment really summarized what I wanted to say. We have to find the sweet spot, we dont want -- I have to link to the comment, I think it was, the gentleman from NextEra who said stringent requirements are good, make sure they are serious projects in the queue. But we don't want to make it so difficult that they could be smaller players, but they have viable projects. So I appreciate Commissioner Clark's question, it really gets to the heart of the difficulty in finding the good place, making sure, yes, that there is throughput, that they're getting through the process, but making sure that the projects that are viable are getting through. So thank you.

MR. DOBBINS: And before we move on to questions about information, content, and transparency, I had a follow-up question for Mr. Angell. We've heard comments about the restudy process and how that can result in delays in getting information out. Earlier you commented that even when conducting a restudy you'll still complete the study process within the allotted time frames. Would you just maybe give more information on how that is accomplished?

MR. ANGELL: Well, and I also mentioned about having augumented staff, the comment about having augumented staff.

Well, it's just about juggling resources is, really all it's really about. And if one makes a commitment to study times and sets up their process and resources in order to meet those times -- again, it depends on when their restudy occurs. If the trigger of a higher order queue falling out at the very tail end a week before the study is due, obviously you're not going to make those times. But in general our planners are able to quickly remodel the system and come up with those study parameters. It doesn't generally take -- it doesn't take months to perform these studies.

As was mentioned by the gentleman that far end there, the processing power of the tools are very great and do many things. It's a matter of having the resource to be able to analyze it. Because again, at the end of the day there's data and then there's information and then there's taking information and writing a report that provides the customer with what they're looking for. But in general it's about resources and committing those resources.

MR. DOBBINS: All right, thank you very much. If there are no other Staff questions -- are there any other Staff questions on this topic?

MS. LORD: This question is directed to Mr.

Oye. You were talking about the Midwest ISO in the latest round, and you were talking about the off-ramps that were part of that reform proposal. I was wondering if you would talk a little bit about -- where you have seen that work, off-ramp specifically, and maybe what we've learned in various regions? You're part of SPP, part of MISO, you're involved obviously in Colorado.

MR. OYE: I think SPP -- MISO doesn't have off-ramps right now built in, they don't. The process that exists today is you can withdraw, but there's not really a point that -- they run a study and you can look at it and go "I want to withdraw and go forward."

So that doesn't -- and I think Charles can probably explain this better than me. SPP kind of has that, they got a two-step. It sounds like Cal ISO does, too, I'm not familiar with the Cal ISO. But yeah, MISO, I think this was proposed at a stakeholder -- I'm not sure who came up with it, MISO -- MISO came into the meeting with this idea, "Hey, let's give a restudy automatically for everybody." And then during processes it expanded well, probably need two restudies.

MS. LORD: Actually, I was just thinking I probably should have directed my question to Cal ISO. You're the RTO with experience on the scheduled restudies. And I was wondering if you've learned anything from that over time?

MR. RUTTY: Well, it seems to be working well at this point. Before we implemented that for a couple years. And the whole integration of the study process, the phase 1, phase 2, the transmission planning and the restudy, all are done, in coordination, so the phases that are developed before those studies, are the same, are in harmony. So as we move forward they all move forward together.

As off-ramps, after someone completes phase 1 study if they want to withdraw because their costs are too high or it's one of 20 projects that they don't want to move forward with, there are options for them to get part of study process back. If they decide not to, continue -- if they decide to continue on -- then the risk ramps up, they may not get it back. The study deposits aren't really the big one, the big one is after phase 1 they're going to move forward as posting that first financial security which is at risk, that's a major percentage of their upgrades. So -- and then it ramps up again after phase 2; 15 percent after 1 and 30 percent after phase 2. So it's ramping up their commitment and our commitment to them as well as we move forward. I'm not sure if I answered your question.

MS. LORD: You did, thank you.

MR. DOBBINS: If the Commissioners don't have any other questions, we're going to move into questions -- Commissioner Clark?

COMMISSIONER CLARK: This isn't a question. But indeed flipping through the filings I noticed Mr. Oye is a graduate of North Dakota State University. And I think deserves to be recognized for that.

(Laughter.)

MR. DOBBINS: We're now going to move into questions on information and content and information transparency.

MS. WOODS: AWEA made an argument that curtailment risk information should be provided on the transmission provider's website under interconnection studies, and we had several transmission providers that argue that this information is already sufficiently transparent. So the question is: What information is currently provided that allows interconnection customers to discuss congestion in order to reach curtailment and what additional congestion and operational data would be helpful?

MR. DOBBINS: Sorry, and we'll begin on the left and move down the panel.

MR. ANGELL: Yeah, so again in the western system, the posting, again bilateral markets and whatnot, the posting of available transmission capacity, that's on the Website. So if the project knows where they're going to -- a customer is going to know where they would like to site their project relative to transmission plans that are identified in the West consistently, we'd get an indication of where congestion may be based on that information.

MS. AYERS-BRASHER: Some of the data is posted, we can find it. But for those that are newer to the queue or not as -- we do a lot of economic studies currently, but not everyone does. And so they need to have that data posted where they can find it, but they shouldn't have to search it out, so it should be very clearly posted or linked on the interconnection site so they are also aware, and right in front of them. In addition having access to the cases earlier and through NDAs and even a small cost, if they can have access to the economic cases, we can either -- if you have a consultant or the internal -- have those products to run those studies, you can do more work. But without the data easily accessible and there, we can't do those things. So some if it's there, but I think it can be improved significantly.

MR. BOHACH: Some of the data is out there, for us to do modeling. But the full assumptions that are used to in the ISO modeling helps for us to do those calculations, as well as knowing what conditional study or conditionality you'll have at your GIA or when you're operational. Knowing that early on -- for example, we'll have certain projects, certain transmission projects, that will be conditional on our interconnection, but we won't know the full extent of what that means operationally. What would be the project on until essentially the facilities study when we're going into the GIA. And that can have real impact to the viability of the project based on the finances. I can only inject 75 percent or 50 percent or something. As an IPP, it's that generation that really makes these projects viable and not knowing that until -- I mean, essentially going into it receiving your GIA really hampers being able to make that decision in a timely manner on the viability of your project.

MR. EGAN: At PJM, we provide in our studies, we're providing a reliability study, not a market study. But we do provide wind and solar, for example, renewables are getting a capacity so they get 38 percent for solar and 13 percent, unless they want to argue more from a technical perspective. So with the upgrades that you're requesting a resource, you would need to build for would be based on the 13 percent portion of your power output. The remaining portion we identify in our studies. These are optional for you to build, you need to come in with a merchant transmission project to upgrade them. The risk would we that you upgrade it and someone else comes along and patches through it and passes the resource and uses up -- so that's the risk for the renewables on the energy portion.

The other thing I think is a bit of a chicken and the egg, is that their capability for capacity to prove it once you've interconnected is based on your overall output during the summer period. So if you're curtailed, that would reduce your overall capacity. There are issues on this topic.

MR. HENDRIX: SPP, the market monitor would post flowgate data at the most congested areas. As far as the interconnection study process, or a reliability study process, we don't look there at the curtailments on that. We would have customers that have requested NRIS, network resource interconnection service, which would give them a look at constraints that would impact their curtailments. What we've seen, though, is going into facility studies most generators will stick with energy only, knowing -- having that look at what curtailments would do, they chose to go with energy only.

MR. OYE: When we -- we buy a lot of projects and we sign PPAs and stuff. When we're evaluating those, we use historical LMPs and information that's already available from MISO, and we feel that's sufficient to do most of our analysis. The other side of this is our company doesn't think transmission providers should be put in a position of projecting future congestion because of variables and uncertainty involved in such assessment. Thank you.

MR. RUTTY: I don't believe this has been a big issue with a lot of our interconnection customers, I haven't heard it, that we're not providing enough information. We did post our base cases for all of our studies as soon as they're available, it's only available to market participants who signed nondisclosure agreements with us. That is available right at the beginning. We have an annual process with our transmission owners where we identify pre-unit costs for typical upgrades that are available. So if an interconnection customer wants to do their own study and it identifies different upgrades, they can actually use these costs to kind of estimate what their costs might be compared to what we come up with.

Our transmission planning process does

forecast congestion for economically-driven transmission analysis through that type of analysis. And I know our markets put out a lot of information that's available online, but again it really hasn't been an issue that I've personally heard, that we're not providing enough information for folks to come into the queue, so --

MR. ZADLO: Historical LMPs are insufficient to finance a new power plant. What you have to do in order to finance a new power plant, you have to show to the banks and independent engineer, you have to do two things. You have to do a reliability study, which includes a power flow analysis to prove to them that facility can be interconnected reliably; as well as the other thing you have to do is production modeling case where you're doing an LMP analysis, 8760 in the future, not what happened in the past but in the future.

That's the two things we need. We need the power flow study and we need the production modeling study in order to move forward. It's very clear in the LGIP that the transmission owner/RTO are supposed to provide the power flow cases. I forget what section it is, 4.4 or something like that.

Getting those cases is always an issue, always an issue. They say it is CEII, they say it's confidential information, whatnot. We've had to, we actually go as far as call the FERC hotline in order to get the case. So transparency is very lacking there, okay, in the power flow stuff and the production modeling.

Production model is a little bit different, we understand, much more sensitive because you would have other generator data and economics in there. But again, certain RTOs are able to mask that information. Again, those are kind of the two sets that are needed for us to project finance the power plants.

MR. DOBBINS: Thank you.

MR. RICHARDSON: I have a question for the developers in the panel. In your experience in entering the interconnection process, is it your experience that the interconnection procedures and study results sufficiently communicate the assumptions used in the studies? And if not, what changes to the process would you like to see?

MR. BOHACH: I would say it really depends on who you're working with, which ISO on that. There are some that, yes, they're sufficient, we know that the tariffs would be able to make those decisions moving along. There are some that we operate in that we're not able to essentially replicate or duplicate the study to be able to forecast and make those business decisions, especially on the timelines that we need. So one thing we would like to see is having the full assumptions and having access to that data to be able to replicate it to mirror/validate what we're seeing and what we're getting back.

MS. AYERS-BRASHER: And I'd agree with that. When we work with a consultant to get an upgrade done, we know what all the assumptions are. We're paying for these studies just like we're doing that for the consultant, so we really should know all of the assumptions that are going into our study and we should be able to replicate those studies. And we also cannot always replicate those studies to ensure that there aren't errors in the cases, because we've had experiences where we've had to deal with that. So if we're also -- and it allows us to have that communication back and forth, if there is a question -- because nothing is necessarily perfect -- but we need to be able to ask those questions. And without those assumptions, we're not able to always do that as well.

MR. ZADLO: I'll say this as a former transmission planner. Assumptions will dictate what your study is going to uncover. You can make any overload appear or disappear based on your generation dispatch and your load assumption. And transparency on how these cases are developed upfront before the analysis happens is paramount.

MR. DOBBINS: Would anyone else like to comment on this topic? Sorry. Would anyone else like to make a comment on this topic?

MR. RICHARDSON: And in an AWEA petition there was some comment in regards to capacity factors used to model generation. So the question for everyone would be how were those capacity factors determined? And for the transmission providers on the panel, where are those capacity factors located? Are they in the tariff or are they in a business practice manual or are they available to developers?

MR. ANGELL: So for Idaho Power, capacity factors are not in the tariff and not in a business practice. However, the capacity factors being used are discussed during the scoping meeting at the very beginning. As far as the reliability studies, this was mentioned earlier, power flow, within the localized area we use a hundred percent capacity factor such as we know when the wind project or solar project is producing their sufficient capacity in the area to transmit. However, once you move away and get into again talking about the western system paths that are defined, we look there and we look at historical capacity factors of the other units in the system and we apply those capacity factors along with this project as it's coming through. And, again, when we do those studies, one of the things we do look at on those particular paths, we ensure that this project does not limit the path capability that previously existed, so we won't let the project adversely impact those paths.

MS. AYERS-BRASHER: So we're able to find them in a general comment that's posted. And that's fine, as we know what they are. However, there are certain allowances that we can elect for a higher level. And in that case, I guess the only thing there would be is if we elected a higher level and we moved forward at that level, then that needs to be held for future studies and future generators and then not put -- in some cases we are then dispatched in the wind projects for instance, and if we had elected it at a higher level that should be held, we shouldn't just be dispatched for everyone else's.

MR. BOHACH: Regarding specific NCF moving forward, we would probably put that in our post-conference comments.

MR. EGAN: I believe I mentioned before 13 and 38, wind and solar, that is in our manual the customers can request higher, so if you had, for example, solar with tracking, we see as high as 67 percent capacity factors on solar. And if we study them as capacity, they're entitled to that as a capacity output. So the issue gets into, and that's the energy portion, in the coupling of that to maintain the capacity, that does become a difficulty for the developer, but that's not an easy solution.

MR. HENDRIX: In SPP, we felt this was a reliability study. We will have all the generation in the local area as full nameplate, and then for variable resources beyond the outer areas we'll have little over 20 percent. And the week after that, the studies, I believe we have it posted on our website.

MR. OYE: I really don't want to comment on this one for MISO because I don't remember exactly what they are. But my memory is that I think they used historical values to come up with stuff, and they have run studies to kind of see what real-time operations that they looked at to kind of set it, so --

MR. RUTTY: Very similar to the other panelists, the ISO, we don't post it -- I mean, we don't have in our tariff, we don't have it in the BPM because they do change. The technology is getting better, solar output is getting better, weather patterns have changed. We've noticed changes in the different regions. So we do discuss it with interconnection customers at the scoping meeting, what we're setting their unit at. And it varies by region, Northern California versus Southern California versus the desert areas. But we do utilize capacity factors so we don't overbuild the system. And I guess that's about all I have to say on that one.

MR. ZADLO: I think it's a little less important exactly what number those capacity factors should be, we can debate that. I think it's more important that those study assumptions be established before the study takes off.

MR. DOBBINS: And with that, we plan to break for lunch, unless there's any questions or comments from our Commissioners.

So we will restart questions -- panel 3 at 1:00 p.m. There are a lot of great options around here for food. We have a great cafeteria in the building as well. I've just been told it was closed, so there are a lot of trucks outside, food trucks nearby.

(Whereupon a lunch recess is taken.)

MR. DOBBINS: Okay, we're now ready to start panel 3 of today's conference. This panel is on certainty and cost estimates and construction time. We're going to ask the panelists to introduce themselves and make their prepared remarks, which were submitted into the docket, or just to tell us one or two points they would like to make today. Panelists, we ask that you please keep your remarks under two minutes. We have a timer at the front to let panelists to know how much time they have left. We'll start on the left and move down the line.

I'm sorry, real quick before we start, I just wanted to acknowledge Chairman Bay who just joined us in the room and ask if he wanted to make any comments or any questions.

Okay, and with that, we'll start.

MR. ALIFF: Thank you again. As I said before, my final is Tim Aliff, director of reliability planning at MISO and my purview does include generation interconnection process for MISO. As far as my opening remarks here, MISO's looking at the technical conference as a way of gathering best practices. And we've heard a lot of practices that we have brought with our stakeholders already and we look forward to continuing that discussion with our stakeholders as well as the guidance that the Commission has provided us.

There was some questions earlier about regional differences, I just wanted to comment on that a little bit. Regional differences should be allowed, but where there are conflicts in those differences, that's really where the focus needs to be addressed and that's where the effort and time needs to be put in, not just making everybody have a uniform process.

As far as that cost estimates and the construction time, there can be tradeoffs with providing more accurate results quicker. Right? It takes longer time to produce those more accurate results, which then also leads to longer time in the queue. You can provide cost estimates quicker, but then it's not necessarily the most accurate.

And finally from MISO's perspective, and specifically, MISO has a provision in our tariff that allows for a customer to withdraw if those costs exceed 25 percent between the system impact study and the facility study phase. And we have had very rare cases where that cost has exceeded the 25 percent. We've seen costs go down, but in a few instances we've seen that occur greater than 25 percent. Thank you.

MR. GOSSELIN: Dean Gosselin with NextEra Energy Resources.

This morning we had comments around the interconnection study process and the certainty and timing of those outputs from that process. For this panel my comments go generally to what happens after the study process. So we saw network upgrades and those network upgrades have a proposed cost and an estimated cost and a proposed schedule. The way that the construct works today is the transmission owner that we're interconnecting into cannot meet our schedule, we can challenge that and schedule and ask that under the option build them ourselves. We're really talking about generally about direct assignabilities, and those that have cost responsibility 100 percent of and they're typically the switchyard or the point of interconnection on the system where we're cutting into the system to put a generating plant on line.

And where -- we've had several instances where the transmission owner has tendered us that option to build it ourselves, and when we're taken it what we've found is our costs are well below their estimates, even with our contingencies in it, and our schedule is much as half of what their schedule is. So what we're asking for here today is the idea that we're able to self-construct, that we're given the absolute right to self-construct those facilities where the direct assigned, and a hundred percent our cost responsibility. Thank you.

MR. KELLY: Good afternoon. My name is Paul Kelly. I work for NISCOT out of Northern Indiana. And today I'm here on behalf of the MISO transmission owners as vice chairman. I'd like to thank FERC for taking the opportunity today to pick up a very important topic. We'd like to make three points today across the two panels I'll be speaking on, and I wanted to refine the concept around respecting regional differences. We've heard a lot from the panel on that today. And the one statement that we make is that, particularly from MISO I think a lot of the best practices in the opportunities to optimize and draw some efficiency in the GIP, has been presented today and also was reflected in a lot of the reforms that were proposed at the end of 2015.

We thank FERC for the opportunity to circle back to those because it was dismissed without prejudice. So with the opportunity for regional differences to take the direction from FERC that we take from this technical conference and then be able to take that through our stakeholder process and having enough time to implement that as would be able to fit the market there for MISO.

The second statement would be that I know one of the driving features for part of this technical conference were some proposals. And from the owners, we just wanted to ask that FERC respect the reality that there's a difference between approving a process and driving efficiencies, versus shifting risk onto different parties. And as FERC recognizes the issues, I think, that have been considered in the past, there are inherent risks for certain business activities and there can't be a guaranteed insurance policy. So to the extent that today is about finding those efficiencies and best practices, the owners are very supportive, but also recognizing that a balance has to be struck and that certain risks can't be mitigated entirely.

And then finally just to recognize, and I think it's already been mentioned here today, that there are tradeoffs and there are tensions, and that we want information to be timely and accurate and cost-effective, but often to influence ones will show there's other variables in it as well. And so the owners would recognize again there a balance has to be struck and that part of the procedures that we have in front of MISO recognize at a different phase as we have different escalating levels of commitment. We thank you for the time and look forward to the discussion today.

MR. MARTINO: Good afternoon. My name is Omar Martino, I am the director of transmission strategies with EDF Renewable Energy. EDF Renewable Energy is a subsidiary of Electricite de France, a French utility electric company. In North America, EDF Renewable Energy has developed over six gigawatts of generation since 2012. EDF Renewable Energy currently owns 3.1 gigawatts of generation and we have approximately 1.1 gigawatts under construction and 10.5 gigawatts under operation of internal services agreements. I want to thank the Commission and also Staff for inviting me to speak here today.

One topic of concern is the ability to get accurate RTO cost estimates earlier in the process. The RTOs usually provide cost estimates of a study stage that is based on per-unit cost without full knowledge of what the transmission owner will actually require. When the transmission owner pays close attention at the facility studies stage, new costs may arise that were not communicated earlier, and some of these differences can be quite large and dramatic.

The generation developers must also have the ability to assess congestion risk. Interconnection studies are not being provided this information; we have seen on several occasions where generation projects interconnected the grid, they followed the GIP rules, and then they severely faced congestion, and the only option for those projects at that time is to fund upgrades outside of the interconnection process. And some of these issues are discussed in earlier dockets that were filed at FERC.

One of the means that we think that we can propose to address congestion and curtailment at the RTO is the fund load is reasonable factors on a standardized concept such as, for example, below five percent. We believe that if these studies, these standards are applied consistently and continuously, the grid will not be underbilled and it will be able to accommodate new projects while protecting some of the existing assets.

To conclude, we think there are several ideas we can utilize to enhance the process and improve the process. I believe that reducing the interconnection time frame to 12 months can reduce the risk of construction delays and cost estimates. We believe that having a three-process milestone can also reduce the risk of withdrawals, one milestone for entry, one milestone for exit, and one milestone in between in the process to make a decision. We also believe that, giving the interconnection customers the ability to self-fund interconnection, facilities and specifically transmission facilities can reduce the uncertainty and the withdrawals that the customer is faced by having longer schedules. And at last we believe that congestion is a significant issue of the grid level and we have to have a process where it takes a look at congestion and resolve the issues for both existent and new asset integrating into the grid. Thank you.

MR. McBRIDE: Good afternoon. My name is Alan McBride. I'm the director of transmission strategies and services at ISO New England. My responsibilities include interconnection queue. I want to thank the Commission for the opportunity to speak today at today's technical conference.

The edification of cost schedule estimates for interconnection upgrades is an important part of the overall interconnection process. The ISO, however, depends on who see estimates, however, does not produce these estimates. This work is performed by the New England transmission owners. Once an upgrade has been identified, the ISO knows that there is a clear tradeoff between the desire for cost and schedule adversity and the time cost taken to prepare the estimate. It would seem appropriate that, in order to keep the study process moving, estimates should not be meant to be highly accurate during the study phase. It may be worth considering whether different study management designs contribute to cost and schedule uncertainty.

As noted in the AWEA petition, some redesign can result in significant re-estimation of costs, especially when earlier queue projects withdraw. In New England interconnections are energy studied serially. In addition, generators do not receive capacity interconnection service until they have achieved commitment in the -- forward capacity market. As a result of these features, it may be the case that New England appears to incur less uncertainty from an upgrade cost perspective. Thank you.

MR. RUTTY: Good afternoon again. Steve Rutty from California ISO, director of grid assets. We went through that in the earlier sessions, so I won't bore you with all that again.

For this session just a couple of points. The interconnection process we developed at the ISO was an evolving process, it took many years. There was a lot of give-and-take by the stakeholders to make it work. For instance, the interconnection customers have agreed to post-financial security, serious amounts of money to move forward. At the same time, our transmission owners have stepped up to provide cost caps early in the process that allows the interconnection customers certainty to move forward. If the actual cost of these upgrades go above that cost cap, the transmission owners are then required to fund it. So getting all the parties to give and take through the process was very important and makes our process work.

The only other thing I wanted to say was, based on how accurate the studies are early is a direct relation to the amount of time that we allow for the studies and to put out accurate estimates. So that was another give-and-take. There was a need for the interconnection customer to have their studies early and quick in the process done, and then there's also, "Hey, I want it to be accurate." So coming up with a good balance was very important there as well, so --

MR. VAIL: Rick Vail, vice president of transmission with Pacificorp. Just a couple of points when it comes to cost estimates and the certainty around that. Pacificorp has about 16,000 miles of transmission line, so building projects and interconnecting things to the transmission system really is something we do every day. So when you start looking at the queue process, we have a lot of experience on what the costs should be, even if it's at a per-unit or a lock level. Quite a bit of certainty on the timing, at least from the Pacificorp experience, how long it takes to construct some of these facilities. We certainly have developers on a quicker timeline, not only on whether it's going through the queue process but also the construction process as well. And we do work with them as long as they're following our standards, and they can do some of their own construction work.

But just like anything, the more detail you want, the more certainty you want or around those estimates, the more time you have to spend around it upfront. That's the kind of same thing with the construction. And again, it does depend on where it's at, what are the purviewing activities that are required to get something built.

So there's some variables there, but I think as long as you're communicating all this upfront, at the very beginning of a project, that first project scoping meeting having those conversations and making sure you're detailing out that these expectations are with each other, to me it does seem very critical when you get down the road. If you are not communicating that this is a plus-or-minus-30-percent estimate to a customer and then you provide it and then they come back and now you're saying it's going to be 30 percent more, that is probably about the worse thing you can possibly do. So I think having that communication and being very explicit of, "Here's where we think we have our expertise here, what are assumptions are," what we base it on, and do that upfront, goes a long way to working through issues on the back end.

MR. DOBBINS: Once again, we'd like to say we thank all the panelists for coming and participating and providing their opening remarks. At this point Staff will now move into asking questions. We ask that you please limit your responses to a minute so that other panelists have time to speak, and apologies once again in advance if we're unable to hear from everyone on every topic.

What is the frequency of disputes regarding interconnection configurations for direct assignment and network upgrade calls? How are such disputes typically resolved? And do you have any suggestion for how they can be avoided?

So we'll start on the left.

MR. ALIFF: So for MISO, we typically don't encounter disputes related to interconnection configurations or network upgrade costs. But when they do arise, we try to resolve those on a more informal basis, working with interconnection customers and the transmission owner to work through those areas of concern. And if that process doesn't work, then we do have other opportunities to escalate that and to provide more formal matter to work through the dispute resolution processes. But for the most part we handle that through the informal discussions. How can you resolve some of that? You're providing information, like has been discussed earlier, additional model review and further discussion through that time frame, maybe upfront, maybe during the process depending on where the concern or issue is coming from.

MR. GOSSELIN: Dean Gosselin with NextEra. So we do have disputes. We have disputes over what is the configuration of which yard we will build and interconnect into. And what we find is different standards amongst different transmission owners, and they want us to build to effectively up their standard. There's very little latitude or any leniency in terms of what is that standard? Even though we may be able to show them that within the same RTO footprint amongst another transmission owner, we're able to build a cheaper facility. And I talk about things like ring bus versus a breaker-and-a-half scheme, and it's just the amount of equipment and the amount of cost that goes into each of those.

And most of it is about providing future flexibility. Well, in our case, we clearly don't care about future flexibility, we care about interconnecting our facilities into the grid at that moment and providing the necessary reliable operation of it.

So the dispute resolution is a discussion with the engineering groups of the relevant transmission owners. And ultimately we lose, because if you hold out nothing's going to change. No standards change. And therefore you don't get your project done, so you have to perpetuate. I don't think there's a real sense of building prudent practice, as opposed to this is our standard, we're doing it this way, there's no latitude. Thank you.

MR. KELLY: Paul Kelly for the MISO transmission owners. I was listening to Dean's statements and it was occurring to me that, because of the companies that are collectively represented in the transmission owners, we're sympathetic in a lot of areas because many of us own generation, been through the queue on that side, versus those of us that own transmission as well. So we've seen both sides of it.

I would say where we come down on it is that when you're going through the GIP it's a reliability analysis and you're trying to make sure that the grid can provide the level of transmission service necessary for the level of the interconnection that's being requested. So that's always for us has continued to win the day. And as far as the number of disputes I would say experienced at the collective level, it's a mixed bag. But I was even, in reviewing Order 2003, just reminded that I don't think that some of these issues have gone away, really it just comes to the scope the work that's necessary to provide a reliable service, the cost related to that to that.

So for the owners, I think we would say we understand, on the interconnection side wanting to have a cost-effective solution, because you are entering a competitive market in these opportunities and you want to be able to be competitive, so lowering your cost of entry is always important. As somebody that wears the TOP hat at on the other side of it, we'd say that it's very important that we maintain reliability. And I understand the words like about the "overbuilt" come into it, but at of the end of the day we're trying to make a decision of what do we need to do to the system now so the asset which is going to live for decades can reliably serve. And when you have to try to make that decision at a point in time, I think reliability needs to continue to remain the same decisions. Thank you.

MR. MARTINO: This is Omar with EDF. We do see disputes. Both of the disputes are both on costs and schedules on the interconnection facilities. Now we're experiencing, our review, some of the RTOs are not very flexible in meeting the requests of the interconnection customer. They don't provide the flexibility to achieve a certain date or to have more discovery on the fundamental reason of the changes of the costs. For example, what we have experiences that -- in MISO, for example some of the TOs will not get involved at the system impact study stage, at the level of detail and the level of expertise and we see it more at the facility study stage. So some of those costs can change dramatically between system impact and facility study.

And also the utilization of per-unit costs rather than an actual construction, actual material figures, earlier in the process. We also see that the disputes often on schedules are due to having a lack of participation of effective systems.

In fact, again, from our experience we have a number of LGIAs that are closed, they're executed, and there's no or little information about effective systems. And the risk or exposure that some of them are experiencing are either not identified or they're identified but they're essentially not costed, because the affected system simply does not provide that information. So providing that information earlier in the process would be key to relieving some of these cost disputes and construction schedules.

And one last comment to end, we really think that having the flexibility to build interconnection facilities and to build transmission can reduce some of these disputes, both from the interconnection side and on the transmission side, and also will provide interconnection customers with the flexibility needed to achieve a particular COD.

MR. McBRIDE: Thank you. In New England, to deal with the interconnection configuration discussion, we have some planning procedure guidance on standard substation design and standard substation requirements for new generation interconnections. So those are known to everybody as they come to the table so people know going into the process what their direct interconnection is likely going to look like. I think that helps people's understanding of what they're heading into. I think overall in New England disputes have been rare, there are probably a number of reasons for that. We have built an amount of transmission in the region over the past recent years, so I think that's given transmission owners a lot of experience in preparing estimates and in preparing schedules.

So for the most part things work out. In the case where there is a dispute that we would seek to help communications between the interconnection customer and the interconnection transmission owner and work through the various mechanisms that are provide in the tariff. There are cases, and I think there was a recent case where the issue may come down here in the form of an unexecuted interconnection agreement and then resolved through that process. So that is something that has happened. But that's just one recent example I can think of for that process.

Finally, I think I'd agree that communication is important and does help. If in presenting an estimate and a schedule, if it's explained, the level of accuracy that was involved in the schedule, what would happen next as the project moves forward to more certainty and more completion in terms of estimate updates, all of those I think can help give customers the understanding of how the process is going to evolve.

MR. RUTTY: Very similar to some of the other panelists. The ISO holds results meetings with all of our interconnection customers to discuss study results. We bring into those meetings the engineers that did the studies for both the transmission owners and the ISO. We have our interconnection specialists there to be able to log and note any discrepancies, anything that needs to be resolved.

And pretty much it's a very open, interactive process and concerns are resolved fairly quickly. I would say that we really do not have too many problems, and a lot of that is because it's a transparent process upfront where we post the base cases, where we post our per-unit cost guides, we discuss what the scoping meeting might be, how they're going to be studied and to what factors and so forth. And if there are any disputes -- so we do have our dispute resolution process that runs through our executive team. But again, I think it's been years since we've had to use that:

One point on effective systems, one thing we did hear loud and clear from our interconnection customers was that very issue about bringing effective systems into the process early. And we advised them at the very first scoping meeting, we post on our website what the effective systems on the various areas are that you might be trying to interconnect to and who you would be likely dealing with. The ISO is not in a position to steady effective systems, but we do bring them, very quickly identify them, and allow them to identify themselves in study process if they are truly affected and to work with our interconnection customers to resolve those issues. Thank you.

MR. VAIL: This is Rick Vail. I don't have a lot to add to that, again I would just say, trying to get to those expectations upfront, I think one of the most important things is it's truly a reliability assessment upfront. And so from a Pacificorp standpoint we don't find ourselves in a dispute situation very often. Certainly, if there are any issues that come up, and again address that head-on with the customer right away and make sure you're communicating.

But having that reliability assessment and ensuring the reliability of the system I think is very important. And one of the difficult things is trying to communicate to developers sometimes the requirements that we are under, whether it happens to be a NERC reliability standard and along with that standard comes a methodology, and that methodology you've been through audits with your regional entity with -- so changing a standard, on the face of it I don't think any standard should be overbuilt or you should have way too much of a safety factor built in. But it is not simple or easy for a utility to just change their standard if there is a whole line or sequence of other processes or requirements that go along with that. So that was my speech on that one.

MR. DOBBINS: I had a followup question for Mr. Gosselin. You indicated that there is at times a push for you to change or do your configurations based upon future flexibility. Just to clarify, are you saying future flexibility in case of your actual operations are different than what you have modeled, or is this in anticipation of other projects being on line and needing to use those facilities?

MR. GOSSELIN: Just a couple of examples. We've had one recently where the transmission owner has tendered us the opportunity to self build. And it looks like our costs from their estimates, original facility study estimates, are going to be two-thirds of what their cost was. However, in their standard they had an additional 10 acres of land, including prepping that land. And that's expensive, so you have to buy the land, you have to prep it, so new service. And presumably ground grid and other things that also add expense and fence it.

When we're building it we're building it for us and only us and our future. Their idea was they would expand it in the future and potentially tie someone else in there. So there's a gap in expectations right there. Ultimately we resolve that piece of it fairly simply by saying we will option the rights for the land for them if they want to expand in the future, and it's their cost, not ours. So we're restricting when I say we want facilities that serve our needs of our facilities that we're asking to interconnect now until the end of that project. There's other instances where I talked about a ring bus configures versus a breaker-and-a-half scheme. So in this case three breakers versus five breakers. And about two more breakers is more than a million dollars to install, plus -- plus work and other things associated with those.

And ultimately we lost on that, and that was really because they said, "That's our standard, we're not going to let you build a ring bus on here," even though we built a very similar interconnection the prior year within the same RTO's footprint for a different transmission user that allowed us to do a ring bus. So in some cases we're able to work through, in other those cases, they insisted for their own standard.

Certainly, breaker-and-a-half schemes are more easily expandable in the future than a configuration associated with a ring bus, but they clearly weren't thinking from the perspective of what is adequate to meet reliable electric service on the grid? Thank you.

MR. QUINN: I guess I have a question about the degree to which you'd have these discussions between interconnection customer, how much the ISO can play a role to mediate those disputes? And if there's not much of a role, the independent entity variation that we use to justify deviations from the pro forma for the RTOs is premised on this idea that there's independence and that the independent system operator has no incentive to do anything for the disadvantaged customer if the RTO can play a role to help mediate inner disputes. Are there parts of the LGIA where we should grant the independent entity variation because it really is the transmission owner that has most of the control over the process and so the underlying premise of independence, the variation doesn't really kind of stand up?

MR. GOSSELIN: Dean Gosselin again. Specifically with regard to the two situations I just laid out for you, which truly happen: The RTO basically had no dog in that fight, they said, "We're not going to be a party to dispute resolution, deal with it directly with the transmission owner." And so for us, you can think of it like the shop clock's running, we buy equipment, we're spending hundreds of millions of dollars in these particular cases in terms of advancing our project and our project development. We don't have time to take it to arbitration, take it to you, take it to someone else, right; we lose, we have to capitulate and move on, we have no choice. So as far as the independent variation goes, there are different standards out there, we recognize that. However, do those standards truly meet pre-utility practice tests that we all have to apply as well?

MR. MARTINO: This is Omar with EDF Renewable Energy. I believe the RTO does have leverage to resolve the disputes. However, they don't use their leverage or they don't usually get very involved in the matters. What I mean by having leverage, the RTO does require the TO to become more involved earlier in the process. There is no justification, if you will, to have a TO in an affected system not participate in the study plan or not participate in the interconnection process, and as a consequence of that, have executed LGIAs and risks given to the interconnection process. Because the RTO, in that case indicates that we're not going to deal with the affected systems, this is going to be the building of the interconnection customers, and if the affected system is not willing to be dealt with then it's unresolved. But I believe there are ways to do that, and also there are ways to do that as well with no jurisdictional entities.

The point here is that the RTO plays a very neutral role, but I believe they do have the leverage to mandate participation and to mandate closure on some of these disputes so we can de-risk some of the issues that the interconnection customers are facing. Similarly on the standards issue, the RTO will play no role whether a breaker and a half or a ring bus is the right solution, because that's the standard of the TO. I can personally respect that.

But on the RTO level, the RTO should have a say and should have a clear indication and criteria to be able to say that ring bus or breaker and a half is actually justifiable for that part in particular as a reliability entity. So the point there is whether or not there are standards by the TOs, by the utilities, the RTO as a reliability entity should be able to say whether that standard in that particular case makes sense, and therefore take up decision on the issue.

MR. DOBBINS: Mr. Kelly.

MR. KELLY: Paul Kelly with the MISO transmission owners. I just wanted to say from past experience, the owners have worked with the RTO in resolving matters like this. I think the other piece is to recognize there are dispute resolution procedures that are part of the GIP's generally. It's not that these are wholly absent, and I'm just recognizing that certain parties have said, "We had a dispute, we didn't like the outcome, we chose not to avail ourselves of that particular procedure and we weren't happy with the outcome." And I understand that, because, again as a transmission owner, I think with different business models here, we've seen both sides of that equation. But I just wanted to highlight the fact that there are different dispute resolution procedures available. Thank you.

MR. DOBBINS: Mr. Aliff?

MR. ALIFF: Tim Aliff with MISO.

So I do think the RTO does play an important role. And the fact that we don't have a dog in the fight I think is a valid reason why we should play a role. Because we're making sure the reliability of the system is maintained. And also there is the equity issues too. If we start allowing individual interconnection customers to mediate from planning standards, then you end up with a previous customer built to a level that a later customer did not build to that same level, which could have a reliability impact down the road. And also from an efficiency standpoint, building substations that have future ability to expand on may be a cheaper alternative down the road for all other customers, and MISO does have a provision that allows for in those type of scenarios, shared network upgrade costs to be -- those upgrade costs shared amongst others that come in behind the initial interconnection customer.

MR. DOBBINS: Are there any other comments on this topic?

MR. McBRIDE: I think there may be a specific difference here in New England on interconnection configurations, and I think it's an example of the RTO or ISO can play. Even though we have several transmission owners in our footprint, we do have a common substation design and interconnection configuration standard that would apply across our system. As I said, that's in our planning procedures and that's known to customers when they come into the process. And I think beyond that -- and I think I'd agree with the way Tim put it -- the ISO is a party to the interconnection agreement and obviously oversees the overall interconnection process.

So we can convene with the interconnection customer, the interconnection transmission owner, and we do that. And we'll ask questions of why something might seem different in one part of the system versus in another part of the system, and it could be there's good reason for that. But that's the kind of question we can ask with the visibility that we have throughout the region.

MR. DOBBINS: All right. If there aren't any other comments, we have a question for the two -- on the panel. Are there any elements that you commonly received inaccurate estimates? And how do final estimates compare to the estimates throughout the process?

MR. GOSSELIN: Dean Gosselin with NextEra Energy. So the vast majority of our interconnections, it's well over 100, have come in under the estimate. So the estimate's -- inflated, but contingency is in there more than sufficient to cover them. However, we have had several what I will call "epic fails" where the actual cost came in in multiples of what the estimate was without really any -- well, in one of the cases no heads' up until after the money is spent, which may have changed a decision. In the other cases I would say as soon as they knew.

However, by that time it's too late because we've spent this huge bulk of money trying to build a generation project to tie into the system. So we're swept in the current, if you will, and have to accept it. So it's gone in both directions on us.

Now, ultimately what we want is accuracy. Right? Because if you think about the process we're going through and the thought process of a new project, we're trying to price in every component accurately, and then we're pricing it to a customer, and if we get that wrong, high or low, we may not have one competitive solicitation or we may have built something that we shouldn't have built. Right? So it really cuts both ways, we want accuracy, accuracy is important.

I think the second thing we're not really talking about is schedulewise. We find in the majority of our cases that schedule and schedule completion is challenged against what the estimate was. And there's no consideration for that from the transmission owner, it's clearly they're mandated to build it, they don't have any liability for missing it.

But we need them to be accurate, right, we need them to be accurate. It's part of why I asked -- to the extent that it's just our interconnection facility that is affecting our cost, let us go build it because we can manage those; cost and schedule, they both matter. We don't want to be sitting there with several-hundred-million-dollar renewable facility that can't generate because the interconnection's not complete. And we find ourselves more in that situation than in the cost-overrun situation. Thank you.

MR. MARTINO: Omar Martino with EDF Renewable Energy. I agree with the previous statements. We see common issues both from the interconnection and on the transmission side, and we see them both on schedule and costs. Just to cite a very few examples on the interconnection side, I have to say that they're rare, but they do happen on cost deviations. But on one particular deviation we saw cost deviations on almost a hundred percent, and that was well after the LGIA was executed with respect to the start project. So that can happen and that can take significant financial impact to the project.

On the transmission side, we also see those very large deviations. Those deviations can be as high as 70 percent. And to that point, on the transmission side a company like EDF Renewable Energy needs those upgrades, needs those improvements to integrate. And there's no other option, there's no just simply fund those large deviations.

The schedule is a significant, issue and it's a significant but it's also a very constant issue. I can hardly say on a number of very, very few times when the actual schedule by the interconnecting transmission owner was actually met. So schedule issues are seen all of the time.

One point I do you want to say here, and see if I can try to differentiate, is that on the cost estimates I want to make a very slight distinction, but I think it's also an important distinction. On the cost estimates they essentially go into two buckets. One are the physical upgrades whether they're on the interconnection side or the transmission side, those physical upgrades they're going to have; and then on the other side, the second bucket, that I don't think we have discussed here today, is those contingent upgrades which are part of the schedule and they're part of the cost responsibility of interconnection the study process. They can be very large deviations on those contingent upgrades, whether they are required because of real studies or modifications of the queue or whatever the reason might be.

But the fact of our experience is that we see a great deal of variations just in the study process; this is not at the termination of the LGIA, or I should say the completion of the LGIA and the construction of facilities. I'm talking about through the study process we see very large variations of costs on a schedule, and I think that is an issue that is very persistent, very much across the RTOs at the national level.

MR. DOBBINS: Are you able to make choices whether to proceed or not to proceed coming out of the SIS phase based on the information that you currently receive from that?

MR. MARTINO: We as a company, we do what we call very good educated guesses. We do a lot of work on our side. Our experience, what we have seen, is that not all of the information that's needed to make a decision is made and presented at that point in time. We also understand that, even if the information that is presented at that point in time at the study phase, we know that it's going to change, we know that it's subject to change, and we know that we have seen very large deviations, just like I said earlier, on cost schedules and estimates.

So having said that, that puts a significant burden on the interconnection customers to try to figure it out or try to provide that visibility. But as far as the information that's coming from the RTOs, as far as what's coming from the TOs, at that stage, I don't think it's enough, I don't think it's adequate, and I think it could be a significant improvement going forward.

MR. DOBBINS: Thank you.

Mr. Gosselin, same question.

MR. GOSSELIN: I'd say in general, yes. However, there are exceptions to every generality. Where a system impact study where the group is still not stable, right, where they present a system impact study results to us, if it's going to get restudied we don't know that, right, we don't know that something's going to drop out and cause a restudy. But if we make a decision at this point and then that changes significantly on subsequent restudies, we're not able to make it -- we either made a bad decision, we got lucky or got lucky. Neither of them are good in this, right? You don't want to have to run your work on being lucky and you don't want to make bad decisions. So if it's a final, final result, if there really is no more changes, yes, there is sufficient information. But if not, it's anybody's guess as to what might happen.

MS. RATCLIFF: So I wanted to dig a little more into the idea of the balance between the accuracy of the studies and the time it takes to complete the studies. So I think what we've heard from the developers here is that you guys were really interested in accurate results, but I think the panels earlier this morning talked a lot about getting through the queue quickly and having these studies completed quickly. So I was wondering for the whole panel, if you could just talk a little bit to that the balance and whether it would be possible to get more accurate results earlier or if that would have a really negative impact on the time it takes to proceed through the queue?

MR. ALIFF: So there is that balance between that obviously. In the MISO process through the system impact study phase, we are providing planning level estimates. We expect -- what's an estimate for or replacing a transformer or reconnecting in a line or upgrading a line? We provide that information. But until you get to that facility study phase where you actually have someone in the field looking at the equipment that actually needs to be upgraded, looking at what the substation's actual design is going to be, you can't really get to that accurate level that maybe the developers are looking for.

And then starting that process earlier, has tradeoffs as well, because you don't necessarily know who's going to stay in that system impact study phase; projects withdraw, maybe you don't need that. And then now you have expense related to trying to develop that accurate result that you have to throw out and you have to start over again. So I agree there is that tradeoff that you have to try to work through.

MR. GOSSELIN: Dean Gosselin with NextEra Energy.

What we see is the big mover in cost is not so much the facilities estimate, it's what's in that facilities estimate, so what elements, is it multiple-line re-conductorings, and we've got to add dynamic VARs and we've got to add other shunt capacitors all over the system and change out breakers, or do we just have to do one thing? And that's what matters, right, that stabilizes understanding what it is that final groove that is -- the overloaded elements that need to be upgraded through the system upgrades are known. Once we know that, the rest moves not that much, but that's the big deal for us. Thank you.

MR. KELLY: Paul Kelly for the transmission owners. I would say our experience around the facility. Study component has been that to get the accurate information out we think that under the current MISO process, it's a 90-day study, and when you're in the definitive planning phase you get 90 days to do the system impact, 90 days to the facility study. And we think that that is probably the right amount of time if the data quality was there, but I think the owners have noticed that it can take awhile to negotiate through all that to make sure you have all the data you need in order to perform it.

And just contemplating what our recommendation would be here, we would just want to leave a thought that we think the study timelines are appropriate. We're really focusing on the overall GIP process, how can we squeeze some efficiency out of the downtimes where you're waiting to actually initiate the study, coming up with packages of information, so that rather than spending the first five, ten days or more, trying to figure out where all the right data is and making sure everybody's on the same page, because it is a balance among several parties, getting that upfront. And the other piece just recognizing the project management idea of do you want it fast, good, or cheap? Pick two of the three. It's a real issue here and so when you put multiple parties into that, that is also another consideration. Thank you.

MR. MARTINO: I think we can achieve the right balance between having timely accurate cost estimates and construction schedules with shorter time periods to study. I think what we need to do is we need to create a process that allows essentially just that. And what I mean by that is we need to have a GIP, an interconnection study process, that is targeted for 12 months, a 12-month process so that interconnection customers don't go into the queue thinking it is going to take me five or six years to get something, and therefore they crowd the clusters because they understand they will not be able to do anything for the next five or six years. If we limit the cluster the study process to 12 months, the amount of study from the time of instability in that, the study cluster would be greatly reduced, which can reduce the cost schedules issues that we face.

The other suggestion for improving the process is having a smaller number of milestones. Instead of having four, five, or six milestones during the process, have three milestones in the process, one for entry, one for exit, and one for making the decision. Introducing more milestones in the process introduces more uncertainty and introducing more uncertainty introduces a likelihood of withdrawal, therefore the complicating effects that we see on cost estimates and schedules because those projects affect each other. Those two can be achieved to mitigate that issue.

And to conclude, I believe that involving affected systems, involving the TOs earlier, moving away from using the per-unit costs, getting away or using a planning-level estimates, they should be gone away. The entity should be providing estimate, accurate and detailed processing at that point in time, because if we keep using per-unit estimates or planning level estimates the risk of having those change and impact the projects are greater. So I think we can achieve a balance, we can do that.

And fundamentally speaking, my last point is that there needs to be a significant amount of resources added at the RTO level to process the status. And having said that, it can be done.

MR. McBRIDE: Thank you. We definitely agree that there is a tension that we're hearing between the desire for the study process to go faster versus the desire for more accurate information in something like upgrade cost estimates. We actually talked about an aspect of this recently in making our own stakeholder process, and we noticed that on the reliability planning side we have kind of a sequence of development of increasing accuracy of upgrade costs.

So we have a concept level for a project you consider a concept, it's an order of magnitude-type estimate, and that's plus or minus a hundred percent in terms of what the overall cost would be expected to be. The next stage is proposed, it's further along, that's minus 25, plus 50 percent; then we have planned, minus 25, plus 25; and construction is something like minus 15, plus 15.

And to prepare a construction grade estimate takes a lot of work for the transmission owner, it's weeks' worth of work, if not months. It involves site surveys and getting bids from equipment suppliers and those kind of endeavors. In our stakeholder discussions we landed on, at least in the feasibility stage, that an order of magnitude estimate was -- our customers told us that that would give them what they needed at the feasibility phase. And we are going to think through and discuss more with our stakeholders, maybe using more of these bandwidths as we go through the project completion steps.

MR. RUTTY: I think I definitely agree with MISO down at that end, that to provide the right balance of the cost estimates and the study results with what the interconnection customer needs is key; to rush through it and give them something doesn't make sense.

So again, the way the ISO works is we have the two-phase study process, granted it's a two-year process. I know Omar would love to have the one-year process. But with 125 projects coming in cluster 9, it just doesn't make sense to go out and do detailed analysis in the field and what it would take to give a phase II result at that point. We've come to a good balance to provide per-unit cost at that point. Allow them ample time after the studies are done to decide if they're going to move forward. Do they have a PPA opportunity, Power Purchase Agreement opportunity? Are they going to be able to get financing? Do they have their sites fully secure? It gives them time to adjust as well. Not everybody that comes in our door is ready to be moved at a year pace, And so that balance has been struck in California ISO.

I do agree with Omar that bringing the affected systems in very early is very important, and we've adjusted recently to do that. I'm not sure I could add any more than that at this point.

MR. VAIL: So Pacificorp, not being part of a regional ISO, I think there's a couple points that I would make. It's certainly a challenge to hire really good technical talent. But a Pacificorp standpoint is we are processing these generation interconnection requests. The dates are very important to Pacificorp, we will meet our dates. If we don't have enough staff available in order to meet those dates, we will contract and augment our staff with consultants as well.

But it's important to note the cost of going outside of the company can be dramatically higher than inside the company. We have some pretty much dedicated staff to the interconnection review process, and they tend to be some of the highest-level experts that we do have, because again, what you're doing is bringing up this generation on the system, is doing a reliability assessment. So you want to be careful not to have too much volume through them and also you don't want to contract too much of that work out. Outside consultants may not have the same familiarity with the system.

And I think there is a really fine balance between that accuracy and detail, and I talked a little bit about what's that communication upfront and really trying to understand what level of detail do you need at that project scoping? Because I think to Steve's point, we have a real mixture of people that come in the queue, and it's great when we have a very motivated, sophisticated developer that already has their plans laid out. I totally understand at that point wanting to hit the ground running, and it's absolutely critical that we as a transmission provider try to meet those customer's expectations. We have a lot of customers that really are putting their toe in the water, and I think it makes a big difference. I would hate to put exacting processes in place, because it isn't necessarily a one-size-fits-all. And out of all of the requests that come through Pacificorp's queue, the majority of them are not large or sophisticated developers. So something to keep in mind.

MS. RATCLIFF: Thank you.

MR. JACKSON: Mr. Rutty of CAISO has

frequently referenced CAISO's study approach and how it provides interconnection customers with a cap for interconnection and network upgrade costs. Are there any other frameworks under which these costs or caps are based on study estimates? And if so, how do you account for these studies?

MR. ALIFF: I guess I'll start. Tim Aliff with MISO. So we do not have cost cap, per se, like California ISO does. And we kind of see that as shifting costs from the interconnection customer to the transmission owner and ultimately the ratepayer having that from a cost perspective I think you also touched on the phase study approach, that is something we have looked at implementing as part of our queue reform as well.

MS. RATCLIFF: Can I ask a quick followup to Tim? You said earlier in your introduction, you talked about the 25 percent cost overrun number. I just wanted to ask, that my understanding is that's not in place when it comes to restudies and people dropping out of the queue ahead of you. Is that the case?

MR. ALIFF: So it implies that the system impact study results are different from the facility study results. So it may or may not apply there in the restudy, depending on what phase that restudy had occurred.

MS. RATCLIFF: Thank you.

MR. JACKSON: Just a followup to Mr. Rutty on your phased approach. In instances where the actual cost are more than the phase estimate, how do you all deal with those situations?

MR. RUTTY: Well, like I had mentioned earlier, if the phase 1 sets the cap, original cap, phase 2 goes above that, the transmission owner upfront funds that payment. It should be stated here that our ratepayers ultimately pay for all of the network upgrades that go into our system. So if an IC ends up paying for something, they're refunded by the transmission owner over a five-year period or sooner than that. So ultimately all the transmission upgrade costs go to the ratepayer in California.

So, I mean, that's a distinction that probably should be thought about as other folks are trying to implement something like this. It's different. But the bottom line is if it does ultimately go above the cap, the transmission owner picks up that delta and they put it into our transmission access charge at that point.

MR. JACKSON: Thank you.

MR. DOBBINS: Did anyone else want to

comment?

Mr. McBride.

MR. McBRIDE: If I may? I do want to follow up on what Stephen said. I think the ratepayer component is critical in evaluating each different -- comparing each process. If -- we're talking today about looking for best practices, and we just need to make sure we're identifying what are the components of each design that actually will support and then make it work, and I think the ratepayer support makes a very big difference to the overall California process. So I think it's important to bear that in mind. As I said earlier, in New England we do not have any ratepayer support of interconnection upgrades, they're all through the interconnection customer, and so that puts us at a very different starting point.

MR. DOBBINS: Mr. Kelly?

MR. KELLY: Paul Kelly with the MISO transmission owners. I think I would just follow through with what Alan had said there, that within MISO it is not refunded. So that would be more of kind of the regional differences and to pick back up on that there, I think this would be a great example of there are certain things that support the philosophies and methodologies that are used here, but this would be one where that concern, as stated earlier around where do you put the costs that comes to the network, and in MISO the stakeholder process those that have participated in have made the decision, that for interconnecting customers that's going to be something they would have to bear the cost of that analysis.

Now, there's -- outside of the scope of that there's certainly questions around how many years out is the study, and when do you draw the line about how a particular upgrade may be needed in the future versus whether you need to get that on the system now. But I just thought that was important to point out that that balance is constructed differently. But I think it goes to the question that Commissioner Clark had earlier today of just what are those driving differences that would say this one needs to be maintained and do something? Thank you.

MR. DOBBINS: All right. If there aren't any more comments on this, we'll move on to contingent facilities, and make this the last topic area. And this is a question for the transmission providers. What is the process for identifying those facilities that are relevant to an interconnection customer for inclusion as a contingent facility and its GIA and those which are not? And then what are the challenges in identifying and in listing the appropriate facilities?

MR. ALIFF: So the process for identifying the contingent facilities that would go through the interconnection involves the generation resources impacts on those facilities, or whether those facility are needed for that interconnection to occur in a reliable manner. For example, our multivalue projects, that I mentioned earlier today, is a contingent facility for quite a few of our interconnection agreements, especially in our west most part of our footprint.

As I said before, those were implemented to ensure that large amounts of megawatts could interconnect into the system at a later date, and we're working through that process. So as far as some of the technical challenges, identifying what the impact, the criteria related to when does a resource actually impact the facility, that can be debated and discussed. On what level, whether it's distribution factor, whether it's megawatt criteria, and those types of things that could be discussed further and how those are impacted.

MR. DOBBINS: Mr. McBride?

MR. McBRIDE: Our process sounds very similar to the Midwest ISO's. It's something that prevents itself through the study process. In New England we do have an overall transmission project list that would be the defining list of what upgrades have already previously been identified. And those could be either for reliability upgrades or for other generation upgrades.

And so if it's identified in the study and then noted in the interconnection agreement as appropriate, if it's a reliability upgrade in pretty much all cases, that's going to be expected to go forward. There may be cases where the interconnection customer has to pay to accelerate a reliability upgrade, that has happened on occasion. If it's a contingent upgrade to another generator's upgrade, then we do note the circumstance if that generator withdraws it doesn't move forward, the upgrade can become that next interconnection customer's responsibility. But that would have been communicated to them through the process through the interconnection development agreement.

MR. DOBBINS: And Mr. Vail and Rutty, unless your process varies from the other two, I'm going to just ask a question to Mr. Kelly. What role does the transmission owner play in identifying contingent facilities?

MR. KELLY: Paul Kelly for the transmission owners. So I would just point to maybe the local design requirements in recognizing that each of the owners is going to have a specific design requirement on the system. But as far as identifying the contingent facilities, that's really, from my understanding, in the purview of the transmission provider.

MR. DOBBINS: Thank you.

And Mr. Gosselin and Martino, I'd going to ask you this last question of this panel. I'm going to ask you to keep your responses to under a minute just in the interest of time. How and when are you generally made aware of contingent facilities that may affect your project? And is it made clear to you why and how these projects may affect yours? The and that last piece is what I'm most interested in.

MR. GOSSELIN: So generally we're made aware that incurring a system impact study process where they said, "Okay, these other facilities have to be in place prior to you coming on line and they have been allocated to generators ahead of you in the queue, and if the generators don't move forward or suspend and if you want it you're going to have to be responsible for it." It's been okay, it hasn't hindered us or created any real big failures. But we've had a recent one where I think Cal ISO has changed their process that say any facilities that were ascribed to earlier queues that haven't come on line, you may be responsible for those costs. And now it's an open liability, I don't know how we're going to handle that yet. Thank you.

MR. MARTINO: Sometimes we never get the response on the contingent facilities. In fact, this is a significant issue for our company at the seams, specifically in MISO and PJM. In that case, as you may be aware, we had operating projects there and there were no facilities that were required for the interconnection of our project, nor the interconnection for many other projects. But in that case, there was a lack of connection between MISO and PJM which resulted in congestion at the seams, and the only result to resolve that congestion was actually the interconnection group funding 50 or 60 millions of dollars of upgrades. And we feel that's very unfair, very unjust, and is simply not an integration process that would be reasonable. So the identification of contingent facilities has been an issue for us at the seams.

In the actual footprint in the case of MISO, the problem that we have there with -- I think it is really a viability question, a viability issue, a financeability issue, is that MISO's many contingent facilities sometimes do not make any sense for the project, but they are listed on the LGIA. And the issue with that is when you try to finance the project, the risk and the uncertainty for these contingent facilities, even though they don't make any sense from the reliability perspective, but they are just listed there because they are from prior queues, makes matters very difficult for interconnection customers. So the message there is that for our experience, for our company, facilities at the seams are an issue of lack of correlation and a lot could be done there to hold congestions, of assets, and at the level of MISO reducing the contingent facilities to more reasonable levels would be adequate.

And just to close, we think we can do that by proposing the integration, the GIP integration, focusing on short-term status, and having the complete integration, like CAISO does, on the transmission planning side where the RTO would take a look at the number of the longer term and as well as the integration of economic studies as well.

Thank you.

MR. DOBBINS: Once again we want to thank all of there panelists for their participation. We're going to take a short five-minute break and reconvene for panel 4 at 2:20, 2:22.

(Laughter.)

(Whereupon a short recess is taken.)

MR. DOBBINS: Again, we are going to ask the panelists once again to introduce themselves and make either their prepared remarks which were submitted to the docket or indicate the one or two most important points they would like to make today. Please keep your remarks under two minutes. We have this very nice wood clock up here we're keeping track of time with, I know some of you have seen it already, which we will use to let you know how much time is left.

Please begin on the left. Mr. Aliff.

MR. ALIFF: Thank you again. I'm Tim Aliff, director of reliability planning with MISO. Again, my purview involves the interconnection, generation interconnection processes. And thank you to the Commission and the Staff for allowing me to speak on three of these panels. So it's my third and final one, so I won't have any more opening remarks after this.

Specifically, for this panel, coordination is very important. Coordination amongst neighbors to the RTOs and transmission providers; and then coordination amongst standard connection customers and transmission owners as well.

So that is something that MISO has worked with. We have worked with some of our neighbors to develop those processes and procedures, and we continue to look forward to being able to do that with other areas of our footprint. One of the things related to coordination to Omar's comment about the MISO's process, actually on Tuesday, a couple days from now, we are going to discuss the very concerns that he brought up about the contingent facility in our interconnection process task force. So we are listening to our customers, and I did make sure that Omar was aware of that and look forward to his feedback, as well as others that participated in the MISO stakeholder process related to that.

So that's all I have for my comments. Thank you.

MR. ANGELL: Dave Angell with Idaho Power Company. And again thank you for allowing IOUs to participate in these proceedings as well.

With regard to this particular topic, coordination with effective systems is less clear in the OATT today and the tariff, and I think there's an opportunity to clear that up just a little bit. From two perspectives: One being a utility dealing with an interconnection customer and affected system, oftentimes those affected systems have different standards, different expectations than we have as a particular utility. So whether they're different standards, and all utilities have pretty fair reasons for the standards that put in place. So trying to coordinate that effort is complicated. Being on the other side, interconnection customer is trying to interconnect with another utility. And being an affected system you have no relationship with that interconnection customer, yet there's an expectation oftentimes that that utility will have that affected system deal with the interconnection customer. So some clarity around that would be useful. And there are portions of the tariff where it appears to imply that there should be a relationship between the affected system and the interconnection customer, but it's truly not spelled out. Those are my opening remarks. Thank you.

MS. AYERS-BRASHER: My name is Jennifer Ayers-Brasher. Again, thank you for letting me participate in the second panel and holding this technical conference.

As I mentioned this morning, improved accuracy, accountability and transparency is needed. And improvement in those areas can reduce the impact on generators and I think, create a better balance. There's been mentioned today that generators have brought a lot of these issues on themselves, by withdrawing from the queue and causing those restudies and some of those issues.

But it really is a balance. If we can get earlier, more accurate information, they're going to withdraw sooner; if there's information available to do more analysis ahead of time, that would also help as well and reduce withdrawals and reduce them in the later stages where there's the most impact.

There also needs to be more accountability for the studies. Currently, in some areas we're paying higher deposits, higher milestones, and yet if there's errors in the study that are outside of our control, it's not having to do with our information, we're still the ones left paying for those. And it's most impactful to the design of the interconnection agreement, we're building the project and then we see additional costs later on. It's still harmful in the process, but at least we can work with that, and improve communication and coordination as well. Those are my opening comments.

MR. BARR: Thank you. Good afternoon. My name is Dan Barr. Thanks for the opportunity for allowing ITC to provide comment. I work as a principal engineer in system planning at ITC. We're working with generator interconnection for about the last 12 years. As the nation's largest independent transmission company, we like to think we've been successful working with interconnection customers and MISO to achieve the large growth in wind generation within the MISO footprint. With the current incentives available to the developers for renewable energy like production tax credit, wind generation capacity will continue to grow, processing that increasing number of requests will be difficult, it will be exceptionally difficult through the existing MISO queue process where a significant number of requests are competing for dwindling transmission capacity in the areas, as well as those entities. If the goal is effective processing of the queue, uncertainty needs to be minimized in the study process. Uncertainties in the process lead to wasted time and effort and restudies, and restudies are the greatest impediment to effective queue processing. Just to highlight a couple of the items that we sent in in our written comments, most importantly, we strongly support MISO's development of three separate, sequential study phases separated by off-ramps or decision points that were proposed in MISO's queue reform under Docket No. 16-675. As part of that three-phase study process, we also recommend incorporation of the cash-at-risk milestone based on the cost of network grades that was discussed a little bit earlier today. We also recommend, as was heard earlier today, providing interconnection customers with transmission models early on to incentivize judicious choices in points of interconnection, and allow them to do their own feasibility analysis, putting the work in the hands of the interconnection customer, giving them some responsibility seems to make a lot of sense.

We also encourage RTOs and ISOs to take advantage of existing information that they have and provide to interconnection customers. There's a wealth of information and facilities studies, cost estimates, taken for us, several years, and there's also access to real cost information for network upgrades. So, for example, you could take a history of Greenfield substation costs by voltage class, take all the actual costs, and post them on the transmission website.

And then finally, we encourage FERC to continue to allow individual RTOs and ISOs to address the issues within their own respective stakeholder processes. There's important differences within the RTOs and ISOs, and we think they're best equipped to deal with those through their stakeholder processes.

Thank you.

MR. HENDRIX: Good afternoon. Charles Hendrix, Southwest Power Pool owner, manager of generator interconnection studies.

As far as coordinating affected systems, that is the challenging aspect. We've been working with our neighbors, we still have some work to do on that. One of those is we're dealing with our large queue and speculative requests and now you're also having to deal with affected systems and speculative requests as well. So it's a challenging aspect. Withdrawals are primary reasons for restudies of length of time it takes to complete the interconnection process. We believe that restudies are necessary on occasion to -- not build unnecessary projects, but we believe there is too many restudies occurring due to withdrawals. We think the interconnection rules and procedures, we should further reduce the incentive to engage in speculative requests. Right now our process has to relook after the impact study so that we had the restudy built in as a -- time to withdraw, but we still see speculative requests going into the facility study. As I said earlier, we have 7,800 megawatts going into the facility study in our last facility study cluster.

After the impact study, we're allowing the customer to withdraw and get their full refund back, they can change the size of their interconnection request and they can make any other modifications as they see fit. Because the problem is their customers haven't taken advantage of this option to direct a facility study, and so we would like to see more restrictive rules for nonrefundable deposits in that department. Thanks.

MR. KELLY: Good afternoon. Paul Kelly with the MISO transmission owners. I'm thankful again to have the opportunity to participate on such a panel.

In looking at the issues in this particular panel, around affected systems, I've heard the three C's of communication, clarity, and coordination, and the owners would support that. I think in looking at working -- and particularly with affected systems, we make the recommendation -- or I'm trying to develop very clear flowcharts that kind of show timelines, I think it was a great point that was just made that when you're dealing with your own speculative projects in the queue and end up working with somebody else, that can be a mighty undertaking. But in those downtimes where there is some capacity available and people's schedules trying to work with through the major entities that you can, and so that way you can also give notice to interconnecting customers, "Here's what the timelines tend to look like between our organization or our RTO and another organization." Also as -- related to what should generate the need to restudy, we would recognize the flexibility's value. As mentioned in the past panel, we wear multiple hats for many of the owners. At the same time, though, when it comes down to a reliability analysis, that once reliability's impacted, that needs to be based on reality. So if there's a change in the ability of that generator, depending on whatever is adjusted, if it needs to be restudied, then we fall down on saying yes, we think that also needs to be upheld.

And then finally just getting back to the point around I think a lot of the discussion we heard today was encapsulated in a lot of the reforms that MISO has proposed at the end of 2015. And so I think what I had just heard here from Dan regarding the three sequential studies and pairing that with milestone payments that allowed interconnection customers to increase their commitment to the process, as well as the transmission provider to increase their commitment to the next restudy, we think that was the appropriate balance and we think that would be the right solution there. Thank you for the time.

MR. MARTINO: Good afternoon again. My name is Omar Martino. I am the the director of transmission strategy with EDF Renewable Energy. Thank you again for allowing me to speak with this panel.

Our view, that coordination is vital to an effective interconnection process, and a coordination between RTOs is vital between different regions, and as well as coordination with affected systems. From our experience, affected systems is a real concern for EDF Renewable Energy. The matter of the fact that a generator cannot even move forward through the interconnection process, through the interconnection standard, and execute an LGIA where the affected system, timing and cost schedules of the upgrade are simply not known at that time. We also want to point out that there's a significant gap in the Commission's integration policy for non-jurisdictional entities. A number of non-jurisdictional entities either don't get addressed or they don't get incorporated or are participating in the planning process or integration process, and essentially they can put a commercial viability of a project at risk. And I believe that's an issue that is a serious enough issue, and the Commission should require measures in the tariff to remedy the problem.

The second set of comments I want to say here is there are a number of different areas where I believe we can improve and a number of different items we can accomplish to improve the process. You have heard me indicate in the past that I think I really believe having a shorter interconnection status can alleviate the process, we should go for a 12-month process, we should allow interconnection customers to fund and build interconnection facilities, as well as transmission facilities. We should provide reasonable modifications to the interconnection facilities, to the generation modifications, I mean by turbine changes. Those should be more standardized -- COD extensions of generators, as well as there's a significant need to limit the restudies.

And my last point is while CAISO has done this, they have precisely eliminated the restudy by having an annual assessment, and they also have a very flexible policy on extending the COD. Because we believe strongly that should be standardized across the multiple RTOs in the regions.

Thank you.

MR. NAUMANN: Good afternoon. Steve Naumann, vice president, transmission and NERC policy for Exelon. I can't really see the clock, so someone give me a heads-up.

On the coordination issue, there's been a lot said, but I'd like to reiterate something Mr.

Martino said earlier, that others have, they've asked that congestion, which has not gotten as much discussion here as reliability, be resolved both existing and new -- this continues to be a challenge, and especially on the seams, and especially seams between RTOs. You heard Mr. Martino talk about the upgrades they had to pay. And there's a tension between what's called as-available interconnection service and later the as-available becoming unavailable and the customer not being happy and the harm to existing customers from taking the headroom with the understanding that new customers eventually become existing customers, and the same thing happens to them. We want a resilient system, and we need to do that analysis, especially on the seams. One of the issues we've seen is the congestion gets ignored because there's a filter, a high-distribution factor saying, "Okay, we got a 20-percent distribution factor, you got to put 20 percent of the machine on the line. Oh, it's only 15 percent. We are going to ignore it in real time" -- don't care about the distribution packet. And you got to look toward I think best practices, and especially on the seam, of dealing with this issue, or you're going to get kind of congestion, the customers would be unhappy. Thank you.

MR. DOBBINS: Once again we want to thank all of our panelists today for both their participation and their remarks. Staff will now begin asking questions. You may have heard me say before, we are going to ask that you please limit your responses to around a minute so other panelists have time to speak. And apologies in advance if we're unable to hear from everyone on every topic.

Earlier today I believe it was PJM who talked about their process and that transmission owners, TPs, and interconnection customers are all very involved in communication throughout the process. And I think someone else also referred to the time and resources spent in the early stages on scoping. And RTO ISO tariffs and the pro forma, their provision for scoping meetings between transmission providers and interconnection customers, do these scoping meetings normally take place within the time frames established in the tariffs? And is there appropriate information exchanged during those meetings? And then sort of compound question is: When does transmission owners end up getting involved in the process? And is that the appropriate time? And are there any challenges for that? I realize that's somewhat a long question, so if people want to go beyond the one minute, I think that may be okay.

(Laughter.)

We'll start on the left with Mr. Aliff.

MR. ALIFF: So as part of the MISO process, we call an ad hoc meeting where we pull together the interconnection customers and the group transmission owners and discuss the group and the project and move forward. As far as the question is it within the timeline, as I mentioned earlier, we are delayed so as we kick those studies off, that is when we are moving into that process. The interconnection customer also has the ability to request those meetings prior to entering the queue, to ask for details related to the point of interconnection, to work with the transmission owner, the MISO, on how to best submit their application, the data required for that application. We very rarely see that occurring from an interconnection customer's perspective. But when you actually get into the queue, we do have that process that moves through, and that stays -- that's little more of a communication we talked about earlier occurs through that ad hoc route through e-mail and then also through our Web page as well, making folks aware of that process.

MR. ANGELL: Dave Angell, Idaho Power.

Not being part of an ISO or a RTO, I don't know that we have the same sort of issues, but with regard to setting up scoping meetings with the customers, they are typically held a little bit later in time at the customer's request rather than the utilities' request. We're able to, but oftentimes they are delayed by the customers themselves. As far as information exchange, so we do focus as much information as we can on our website about process and have essentially a handler deal with the interconnection customers right up front with quite a bit of exchange of data prior to that scoping meeting so we can have an effective scoping meeting, so I think that communications even prior to the scoping meeting is critical for a good information exchange.

MS. AYERS-BRASHER: I think we find that the scoping meetings occurred, sometimes they are delayed if the queue is delayed. But we are sent meeting requests and we participate in those meetings for our projects. One of the things that probably would be useful is only the affected systems were included in those early on so that everyone is aware that there is that impact and that effect, and maybe those are even looked at sooner. But the meetings are occurring, and generally within time frames where we know about the delay if there's a delay to the process.

MR. BARR: I think in general MISO does a pretty good job of shepherding interconnection customers through the scoping meeting. They're generally very brief. Some of the transmission system in the western MISO, there's a lot of different pricing zones, there's a lot of different owners of transmissions, so a lot of questions are: Well do you own that? Is that yours? How much is that rated? So it's all very preliminary information, and again it's a pretty quick process and pretty basic.

MR. HENDRIX: At SPP it's also a pretty quick process. We -- a typical window, this last one we had 70 requests come in. So typically we'll send out messages, e-mails, saying: Who wants scoping meetings? Once we have questions, we'll initiate the scoping meetings and we make sure that that is available to all of the customers. A lot of our customers have been through the process many times, so they're well-aware. But we're always open to having the scoping meetings and we will initiate when we need to.

MR. KELLY: Paul Kelly with MISO transmission owners.

I think given Tim and Dan's extensive responses here, I think there's enough said there. Thank you.

MR. MARTINO: We don't really see -- this is

Omar Martino with EDF Renewable Energy.

We don't really see the scoping meetings as being an issue for coordination, for coordination between transmission owners, transmission customers, interconnection customers. I think when we discussed in my opening comments about the need for better coordination, the need for more effective -- and the need for really resolving the congestion, it's more of an issue not of the scoping meeting but more of the coordination of the status. And more importantly, not the coordination of the status but resolve issues into actionable items, meaning that if there is congestion in the system, if there is congestion at the seams between MISO and PJM, if there is issues for new facilities or for existing generators, there has to be a way, an avenue, whether it's tariff or a policy, to actually resolve that issue and make it into an actionable item. And that's one of the concerns that we have, is that there has been long-standing congestion in certain areas in RTOs. And it seems like different RTOs use different standards, and some of the standards are not agreed upon between the very same RTOs, so nothing really gets done on that front. There's also a concern of utilizing different DFAX, or distribution factors. Some RTO may use 5 percent, maybe MISO might use 5 or 3 or 20 percent, and PJM uses 10 percent. So there's a lack of coordination in the actual -- for the major structure of the studies and how things are even weighted.

And just to conclude, there's also a fundamental concern of getting the TOs more engaged earlier in the process and getting the affected systems engaged earlier in the process. So the point I'm trying to make here is the scoping meetings don't seem to be an issue for us, but it's really the engagement of the parties, and the actionable item that come after the engagement of these parties that lacks unison.

MR. NAUMANN: Just briefly to pick up on what Mr. Martino said, I mentioned earlier and he just mentioned, on the seams the difference in the distribution factor makes a huge difference as to whether you even see an impact or not. And so you get an interconnection, and as Mr. Martino said, there are different policies on dealing with congestion, but the fact is that, dealing with it after projects are online and people have spent money and said "I'm not happy now," but now we got a process to try to fix it, that's a timing issue. It's a bad timing issue because the facilities that are online and now have seen the congestion have now, by the time it's resolved with upgrades, have seen three, four, five, or even longer, years of harm. So it needs especially on the seams between systems, or between RTOs, it needs to be taken into account up front. Now, as I say, someone who wants the least-cost interconnection, and I'm going to take as-available, and say, "I don't want to pay for these facilities." Well, as I said before, the new customer will sooner or later be an existing customer, will be impacted by the other customer, and be unhappy. So there needs to be a serious look at how congestion is dealt with, the interconnection process up front, and that's a coordination issue. The better coordination you have, the better estimates, the better studies, and the more you can do up front to eliminate that and have a resilient system.

MR. DOBBINS: One thing I think has clearly come out of today is dealing with coordination with affected systems. Mr. Martino just indicated that coordination with affected system he would find helpful, and I guess EDF would find helpful. What are the challenges associated with affected systems, coordination, and what are the clear areas or manners of improvement? And we'll start once again on the left with Mr. Aliff.

MR. ALIFF: Yes, thank you. Tim Aliff again here. Some of the challenges related to that tend to involve the different criteria as has been brought up, and I'll address the 20 percent energy resource interconnection service which is the MISO criteria. And that is defined in our business practice manuals, and it also came from our stakeholders, it is something we discussed with our stakeholders, and we also brought up with our stakeholders last year and discussed with that. So some of that comes from our stakeholders and, as mentioned earlier, what the difference is in the flexibility. And then also there's challenges in interconnection request, meaning that if a customer requests network resource interconnection service, what does that mean outside of -- for example on the MISO system, what does that mean outside of the MISO system and what criteria is used to evaluate those resources? So those are where the coordination items need to occur. The flexibility in the timeline, we've heard there's differing timelines from six months to a year to two years. Which you have to make sure you're coordinating through those processes, and we've set up a defined schedule with PJM where we will coordinate on certain time periods and make sure we are coordinated in that process.

Thank you.

MR. ANGELL: From IOU to IOU, the standard practices, per constructions, efforts mentioned earlier about whether it was a ring bus or breaker-and-half requirements, those are some of the issues we find with the effective systems. And, again, when studying projects, what assumptions, distribution factors and those sorts of things, always come up. And there's -- it appears at this point in time, just working through the FERC tariff, the transmission provider that's working with them seems to have the responsibility to work through and coordinate those issues. And if there's some clarity that could be provided there, that would be useful.

MS. AYERS-BRASHER: Jennifer Ayers-Brasher from E.ON.

From our perspective, the affected systems there just needs to be more coordination and studies need to be run more often. The last one we had was done initially a year ago, and then they did update it the following year, and then after that we had -- our costs for the impacting upgrades go from 5 million down to 2-1/2, up to 21 and then to zero. So -- and that was in about a four- to five-month time frame. To just have maybe better coordination, have studies done more often so there isn't a long time frame, because I believe the time frame initially, that year time frame, could have caught some of those things earlier on. So it's a lot greater in our project process to make those decisions. And when it went up to $21 million, that nearly was a project-killer, and that's several years down the road. And it would have been nice to work through that earlier in the process. So just more coordination for us.

MR. BARR: In the interest of singing the same song, that's basically a coordination or sometimes a jurisdictional issue. But if there's adherence to well-defined turnaround times, that would certainly help. Outside of that again, just more of a coordination issue.

MR. HENDRIX: Coordination can be challenging with the different criteria, the different assumptions, the different interconnection service products where some provider may give essentially a deliverability product with interconnection service, in the challenge, how that analyzed for impacting on your system. Whereas, we're as big as we are as a energy resource flavor to its queue. So just trying to mesh those different products, it's a challenge.

MR. KELLY: Paul Kelly for the MISO transmission owners.

I just point out that in the current MISO GIP, we're in the pre-queue process, MISO publishes a contour map to get in a sense of this is where the saturation is in the system and this is where you can find capacity. Looking at affected systems, I think obviously when you're starting to look at geography you can get a sense of how close am I to another affected system? And I think the recommendation from the owners would be just try to give as much notice as possible to those looking to interconnect depending on where they kind of fall geographically, to have a sense of, okay, if you're here it's very likely that you're going to need to be working with the entities.

So we already talked about the scoping meeting, but just recognizing that when you start to get near another RTO's border, that they're likely going to need to be involved. And as far as the owners are concerned, we take the responsibility to make sure that we are monitoring the other potential affected systems because we always want to know how the changes are in effect. There are some I don't want to call them "failsafes," but there is active monitoring that is taking place. I just would encourage, according to as the panel has pointed out, there is more coordination/communication in trying to get through things like the flowcharting process, recommendations, just as much known as possible so that interconnection customers understand when I start to get to these areas I'm likely to run into a little bit of the slower process because now I'm going to be bringing two large processes together to try to run in parallel.

Thanks.

MR. MARTINO: I agree because I think a lot of the comments already describe my ideas. I think definitely coordination is an issue. But I think I would probably take it now to the next issue, which I think that -- the reason coordination is simply not happening is because we just don't address it from the issue, which is RTOs they have different standards that transmissions triggered and wherever there's congestion and one RTO, there may be no congestion on the other RTO, so nothing gets built because there's no common sets of standards. And the interconnection process at the right time and at the right -- the current state simply does not address congestion. The integration process allows for 20 percent threshold between the identification of the facilities and the actual location of facilities and the acutal grid improvement that are required for a particular process. Without lowering that 20-percent threshold, without having common standards between RTOs, there's going to be a perpetual congestion issue at the seams. So I think the issue is coordination, but the fundamental concern is really to have a mechanism to have an avenue to incorporate congestion and addressed into the interconnection process. And we can do that by having a common set of standards.

Thank you.

MR. NAUMANN: The only thing I would add to Mr. Martino. It's more of a common set of standards, it's not congestion, it's simply not necessarily addressed at the interconnection stage. And therefore when generation comes on it sees congestion or eventually sees congestion, as new generation comes on and now we've got a problem and you're a few years down the road now you're relying on the regional and interregional processes to fix the congestion after the fact which is years after and people have been harmed. So it really means something fundamentally changed in the interconnection process upfront to be able to actually deal with congestion.

And the second thing is, you need to also deal with the customer who says, "Okay, I will be perfectly willing to take the risk, but I don't want to pay for a single upgrade more than I have to have the reliability interconnection." On the other hand, that's harming existing customers and those customers are dealing with this fundamental issues and also the fundamental disconnect between, "I will take my chances" and the bid energy market, which doesn't recognize "I will take my chances," it simply lets flow who can flow. Now, you can change that and say, "I say I take my chances, you earn the first office as soon as I see congestion."

The point is, it should be addressed, but this is not the incremental fix. This is something major that has to be set up upfront and done right and thought about how it's going to be done. Otherwise, and I'll just give you a statistic, just last week in Zone 4 of MISO, you got notices of 3,400 megawatts of base load generation retiring. You're going to keep seeing that as the congestion harm occurs. Not that that is the sole driver, or maybe not even the major driver, but every additional harm adds to things like that, and you're going to lose your diverse generation.

Thank you.

MR. DOBBINS: I have a question for Mrs. -- I apologize if I don't get this right -- Ayers-Brasher? Thank you, you're very kind.

I think that the examples you provided was a very interesting anecdotal example of swings which may occur, if I understand correctly these things came through to, I guess, were pushed by the interconnection trying to coordinate with the effective system. Just to give it more context, what sort of information were they attributed to go from 21 million to zero as such as what the coordination of models assumptions, dropping in and out of the queue, what was sort of the rationale for something like that.

MS. AYERS-BRASHER: Our understanding was there were changes in the system. The $5 million had been there for over a year, and then it did drop down based on some changes in the system. And then unfortunately when the transmission was unable to assess the actual upgrade that was needed, they then went from two and a half to 21 million. The problem there is, understand maybe that's the upgrade that's required, but how do you go from that big swing -- and then it dropped to zero because it actually turned out that the criteria being applied was not the correct criteria for an affected system, so then it went to zero. Now, that upgrade, if it's necessary, is still $21 million out there, whether the system needs it or the next generator possibly. But those big changes are very difficult for projects to work through, especially when you're nearing an interconnection agreement.

MR. DOBBINS: All right. Thank you.

Mr. Angell alluded to possible needs of clarity in the tariff. The RTO and pro forma tariffs provide guidance for coordination of studies in the protected system. Is that guidance sufficient for proper coordination?

MR. ANGELL: Yeah, with regard to coordination I think the guidance is sufficient. How to deal with disagreements is not covered at all. And with the interconnection customer having essentially an interconnection agreement with one party and then an affected system, the interconnection customer may end up with an agreement with them as well. And there's no, I guess -- I don't know if there's any accountability for the affected system with regard to time or cost. And it seems like that might need to be addressed.

MR. DOBBINS: Would anyone else like to comment on this in terms of if the guidance is sufficient in the tariffs, in the pro forma? No. And then before we move on from affected systems, do FERC staff have any other questions on this topic?

MR. LUONG: Yes, I had a clarification question regarding the distribution factor threshold.

Is it applicable to both synchronous machines and asynchronous machines? And it is posted anywhere on OASIS clearly what is the number?.

MR. ANGELL: The distribution factor, basically not threshold distribution factor, are a factor of the system where the energy will disburse through the system and through a type of machine that's actually operating.

MR. LUONG: I think when we mentioned about congestion, you know, the way I understand the distribution factor threshold is, you know, you can see how much you impact on your distribution factor on your transmission constraint, is it three percent or five percent? So when you use that, you know, in order to do that, right? So, just trying to see that, you know, it's not like you have different number for the, you know, regular, you know, synchronous machine resource and for the asynchronous machine, you know, the transmission provider use a different number and those are available, you know, normally posted. So, I'm looking at the ATC calculation. You know, you have that kind of threshold and when you have congested, you know, then we normally in our own way we call TLR, you know, then that threshold is there and then in the West you have unschedulked flow mitigation, you know, those threshold is there. So I'm surprised to hear that the threshold is really an issue, big issue, you know, in terms of congestion for the interconnection.

MR. NAUMANN: First of all, the distribution factors vary by transmission provider. As was said earlier -- and I hope I'm not quoting out of context -- MISO has worked with their stakeholders and come up for certain cases with a 20-percent distribution factor. For those same kind of studies, PJM is five percent for the lower voltage facilities and 10 percent for 500 kV and above; that's a big difference.

Our view is 20 percent allows a whole lot of congestion be put on the system. Now, TLRs for example, that's in the operating frame. Again, the wire doesn't care what the distribution factor is, the only distribution factor is when you line up the transactions or the generators that are going to be curtailed or reduced. It's what threshold it is, which is a much lower threshold, and then how much they end up being reduced.

So, yes, there is that disconnect. But as far -- each TP deciding what it should be, either through its own process or through its stakeholder process. We just feel 20 percent is excessive and is one of the -- with respect to the stakeholders in MISO who have come up with that, we just simply disagree. We think that's excessive and has resulted, as I believe, in congestion on the seams between PJM and MISO.

MR. MARTINO: I just wanted to add that maybe the factors are established that they are the same for different technologies, so they are the same for different technologies but they are different according to the TOs, and that's especially where the issue is at the seams because we have different standards.

Just to add on to that, the congestion issue really plays into the earlier discussion this morning the need to create an operational model right. There was a discussion, and I'm going to point to that in a second when I can find it in my notes. But there was a discussion where there was a need to create a model where it actually mimics operational characteristics and having these very different factors is essentially the complete opposite. It allows for grade levels of congestion into the grid, which obviously does not get dispatched in real-time, that's where specifically wind energy at the seams get curtailed very significantly. And the importance of this matter for the wind industry -- but on a different note maybe I will just leave it there. I sort of lost my thought.

MR. KELLY: Paul Kelly for the MISO transmission owners.

I just wanted to approach this congestion question from a different aspect because obviously it depends on the type of service that you're requesting and the timing of where your project falls in and how many years go by before the next project comes along. So there's a lot in that aspect, and looking at it from a reliability question in that when you go through the interconnection process you're looking at reliability assessment. I think the owners would be supportive to the extent MISO wanted to reevaluate the philosophy around how you get generators, and the reality is -- and I think Steve is pointing it out -- depending on how you set some of those levels around the distribution factor, you can encourage the connection of a generator at a much cheaper cost than you might incur depending on where you set that threshold at.

Based on the notice in this particular technical conference, I didn't want to try to overstep on the congestion piece, but just to recognize that to the extent your reliability assessment shows that you need a particular level of upgrades based on how you stress the system. Well, if you make that upgrade, it can relieve the congestion, because you'll never run into it because you designed the system, will allow that power flow.

Thank you.

MR. DOBBINS: Are there any other comments before we move on?

MR. MARTINO: I have one last.

MR. DOBBINS: Okay.

MR. MARTINO: The point I wanted to make earlier was tied the congestion to the accuracy of the results also. And I think -- and I'll talk in a second but I think this is important -- this is important because if we get to the point that we don't get results, we have a very difficult time in financing projects, so we have consequences down the streams.

So it is very important that we get our LGIA on time and on schedule and have representation of cost estimates on a certain schedule and so on that we talked about earlier. But that the results are also accurate in the sense that we don't get a set of the studies that are not representative of system conditions, and therefore financial investment entities simply cannot rely on them or ask for more information. So that's where the congestion piece actually ties back to accuracy of results back to the generation industry.

MR. DOBBINS: All right. We're going to move on now. I know there all other questions from our staff here.

MS. RATCLIFF: Changing topics a little bit from management issues I know we've talked a lot --

especially with MISO earlier -- about preventing speculative projects from entering the queue. And I just want to get a sense from the panel from different perspectives on what the balance is between preventing a project coming in that maybe has no chance of really succeeding versus recognizing the project won't -- perhaps in Ms. Brasher's case -- that a $21 million upgrade automatically makes a project speculative in some sense? So if we could just go around and talk a little bit more about where that line should be drawn in your opinion.

Thank you.

MR. ALIFF: So I guess I'll start. I heard one of our stakeholders say that every project's viable until it is not. So that is the concepts that can change that and can change it quickly. As far as the milestones, we had a thought, and we've heard from our stakeholders on what that means -- I don't know that we have the exact answer on what that is yet -- the idea of it applying to the congestion seems reasonable because if you're likely going to -- that's going to be the outcome if you come up with a project with several-million-dollar upgrades, that it's probably going to be a point where that project becomes unviable depending on how that would work out, so.

MR. ANGELL: The speculativeness of the project is dependent upon where that project attempts to site on the system. Again, when there's congestion and if they're on the wrong side of that, any project becomes speculative in that point in time. So how to actually develop a standard pro forma tariff that addresses that fine detail, I'm not sure how to do that. But if we do come up with something, we'll put it in comments.

MS. AYERS-BRASHER: I think we're trying to reduce some speculation. There is that balance, more information upfront so people can make a better decision and based on that decision they know the congestion so that they're not going to those places. We may have made some different decisions on some of our projects had we known upfront instead of dealing with it on our back end and at a high cost.

So knowing that up front and being able to do that -- and as generators become more sophisticated we're also doing more and more of these things internally so if the information is available we're more able to do a lot more. That's not going to take care of everyone; I think you'll understand that. But the more information that's up front, and also in the first round of studies the more information that's available so that the withdrawals occur earlier, probably the better.

MS. RATCLIFF: Quick follow up with that. When you say more information up front, are you speaking about more information from the transmission owners. But getting that meeting, getting more involved, the facilities, could you be a little bit more specific?

MS. AYERS-BRASHER: Better access to cases, both economic cases and the transmission-planning cases, better understanding of assumptions, more accurate assumptions in some cases, pretty much any information that can help to make a better decision.

MR. BARR: I think in terms of viable projects, it's hard to say you know you're not viable from somebody passing judgment on it. Assuming that you all are viable and assuming that you have to process your queue, and assuming that at some point you have to do a final study to determine what's needed for projects, you're not going to want anybody in that study group to drop out. So you have, let's say 1,000 megawatts study, the impact of one of those projects dropping out is significant.

If you take it to the extreme, under the current GIP, you could be a nonviable project in the queue and your obligation financially from the point that study ends under the current process is that your only obligation is to fund the facility study.

So you fund the facility study, let's say that takes $20,000 for your project, you fund the facility study, you go forward, you're still trying to sell your project, you're the developer, you're pretty sure you have a good project but you're not a hundred percent confident. But your only stake in the game is to provide that what we'll call $20,000 for the facility.

Continue to look for your project and under the current process with the GIA, GIA takes 60 days where you have 30 days to negotiate, you have another 60 days from the interconnection customer's perspective to sign the GIA.

So let's say you take that and you put up the entire clock: You take 30 days to negotiate, you drag that out, you take another 60 days, and then you circulate the GIA for signature, you sign the GIA. And in the GIA there are payment requirements, one of those payment requirements says provide a payment entered. Another 30 days adds on there and you still haven't sold your project.

So you don't really lose anything if you don't make that payment but the process continues, there's still other projects queuing in, there's still doing other studies, so that 30 days go by.

Well, our policy is, as transmission owners, we send a breach notice if you're 30 days late, so there's another 30 days on top of it. So then after we send the breach notice, then there is -- under the tariff there's I believe 30 days for a cure. If you don't cure by then, then you have to say you're trying to cure. So you say you're trying to cure it. And then eventually when you get 90 days after that time point, then you GIA is terminated. In the meantime you've still got this study queue progressing, you still got other projects that they're basing their projects successful reliability on your project and your upgrades being there.

So if you back that out then somebody like MISO is forced to do a restudy. So under the current process there's problems inherent in the process. So making sure that when you get to that final study that none of those projects drop out is a pretty key element.

And I think that the proposal that MISO has where you give you project two chances to drop out, and when you get that second change you should be reasonably certain that you project is willing to go forward, you're willing to put your chips in the game. And if that's the case then a lot of that restudy stuff should go away, but that's not what we have today.

MR. HENDRIX: At SPP, we give customers a lot of opportunities to view this information. We have feasibility study, which is a $10,000 deposit, pre-look at the system; we have a preliminary impact study which is a full-blown impact study that the customer does an impact on the regular queue; and then going into the definitive study there is the built-in restudy there. So the customers have plenty of opportunities of what they're getting into even after the interconnection impact study.

So going into that interconnection facility study for SPP should be a critical step. And that should be the last chance when they put in that facility study deposit that we know they're going to move forward, but it just hasn't come to that yet so far.

Thank you.

MR. KELLY: Again, I think the comments have been made. I'll say that rather than focusing on the end of that process, maybe I think the question was directed of, How can you discourage people from even entering the queue if they have something speculative? And I think earlier this morning we heard discussion around if you can ratchet up the entry-level requirements and try to have some natural barriers to discourage. I don't mean to be a broken record, but I would say the owners evaluated the proposal that MISO put together, kind of had the right balance right now because facing the opportunities to go in there and do the feasibility study, get a basic sense, make a decision, "Okay, do I want to move forward or not?" And then once you start getting into those sequential studies, because you're escalating the commitment through milestone payments, we thought that was the right balance and way to start to test it out.

I think reality is, one thing I'm hearing throughout a theme today, is I'm not necessarily requiring a particular timeline but at least give me certainty I know how long it's going to take. I think if you know you're going to go through a series of restudies, we should have a particularity around that. And the owners saw that has being very valuable that it may not be the exact number of months that any particular interconnection customer may want, but at least you know, "Okay, there's a sequence of events, I can plan my business, if it's a permitting issue I would kind of have an window of opportunity that I know need to start moving the other pieces of my project."

And the last point I would make is that, it has been recognized that when an interconnection customer enters a queue, they're not shovel-ready to sell. They're also developing their pieces. And I think that type of proposal that was put out there, although tweaked and refined, it did recognize we're we're trying to land several planes on the same runway at the same time, and all of a sudden it's going to become one viable project in the end.

Thank you.

MR. MARTINO: I think the question of reliability really highlights the fact that the interconnection queue is simply not working today. And I say that because, right now, interconnection customers enter the queue thinking that they're going to be there five, six, or seven years in some cases, and by extending these very large timeframes just by itself puts viability on to projects just on the outset.

So blaming interconnection customers for lack of viability is, I think, a very unfair statement and I think the fundamental issue, which is queue reform, that targets the new era that we're living, which is competitive markets, the ability to integrate into competitive market very quickly and get your LGIA an agreement in place.

So having said that, we can reduce project's viability by having the interconnection process that is fast, that is expedited. And you heard me say earlier that a 12-month process should be ideal. Currently, the MISO process certainly is not working, and I can say "certainly" because they're delayed, they're delayed by over one year. So MISO is proposing to put more and more milestones to the process, to increase viability is simply not going to be a good measure. Increasing milestones actually increases viabilities. We have to have, not only a short process, but a very well-defined short set of milestones to increase viability.

And the last comments is that we need to start thinking of having a process that is somewhat similar to what California ISO has. And to the extent that, as much as I want a 12-month process, the fact is that CAISO is the RTO that can get this done in 18 months or 24 months. I don't think many of the other RTOs can actually say that. And that increases project viability. As well as the California ISO has a very flexible criteria in changing, changing COD's for the project, something that many of the RTO's can -- one of the RTO's actually go after interconnection customers and cancel their agreements by changing the COD. And in the case of CAISO, something as being in the negotiations of the PPA, for example, would qualify for a criteria to change that PPA to that COD. So if you want to reduce viability, we have to have a short process. We have to have very well-defined milestones. We have to have a process that incorporates into the transmission flow just like the California ISO does as well. So those are the key elements.

MR. NAUMANN: Quickly, I don't know what "speculative" is. I'm going to speak first as a transmission -- generation owner and developer. We would look at putting let's say new gas-fired generation in PJM, it may have four queue positions. And we only intend to go through with one, that's not speculation, that's trying to get information on which is the most viable. So maybe we can change the term. You start getting that information and then you drop out. But that's having multiple positions is not speculative, it's the flexibility one needs but it does create, because of the way the evaluation is done, there's nothing that says, "Evaluate this because I'm going to take one of four," they have to be all evaluated and they're added. And, again, this goes back to I think the conversation we had this morning and Commissioner LaFleur asked about it, a lot of the time, the restudies end up occurring because somebody at some point says "this is too much" or "my project is not viable for some other reason," and somebody drops out of the queue and the cost now -- it has to be restudied for two reasons, one, you may not need upgrades because you got somebody out of the queue, two, it shifts the cost of those upgrades to somebody else and they may not want the metric.

The last thing about some of the California process is understanding it's a single-state RTO. They can do certain things on the costs of the upgrades by putting them on the customers because that's where it's going to go. A multistate RTO like PJM or MISO or SPP, those things can get really controversial. So I think you may look at what California does, I would say before you put it into a multistate RTO, think of what other reactions may occur.

Thank you.

MS. RATCLIFF: Great. Thank you.

MR. MONCAYO: I'd like to ask a question. Earlier, panelists alluded a needed ability to clear projects in the queue as appropriate.

How frequently have any of you been involved in disputes involving GIA termination.

MR. DOBBINS: And while answering that, please also let us know, are there clearer standards with regards to what constitutes or what allows for a GIA termination? And we'll start on the left.

MR. ALIFF: So MISO has filed for termination of several generation and interconnection agreements. And I think from a clarity standpoint related to that, we have a provision that allows for generators to go three years beyond their commercial operation date, and if they have not achieved commercial operation by that time, we have the ability to terminate that generator interconnection agreement.

Now, there isn't a defined criteria that says what makes this project the project to terminate or not. So we err on the side that we terminate the project in that standpoint. We did try discussing that in our stakeholder groups last year. We didn't get a lot of support for that. We got a few folks that were supportive in developing a set criteria related to that termination provision, but we don't have anything. Some clarity around what is it, exactly three years and then we terminate? Or has somebody done some level of detail at that project in order to reach that level of termination.

MR. ANGELL: Yeah, at Idaho Power we have terminated projects. Failure to make payments obviously would be a cause for termination. And then of course attempting to -- well, basically not constructing and achieving an online date given extensions that are already available in the tariff.

MR. BARR: Just to add, we could have a very similar scenario, as described earlier, we have had probably two-three terminations as a TO with a three party agreement with MISO and the interconnection customer.

MR. DOBBINS: Were those all based on people exceeding a commercial operation date by a certain period? Was that the only reason?

MR. BARR: No, I don't know that we had any of those. We had one that was tied up here for quite some time and that was eventually terminated. We had another that for whatever reason the customer was unable to bring things together enough to push the project forward. And then the other, I think, I'm at a loss for cost.

MR. HENDRIX: And I think we've been involved in the termination of several GIA's, the most common is the nonpayment for construction of the facilities. When the first milestone comes up, I mean, a lot of the customers will go into suspension, so the second-most probable terminating event is when the suspension is up they don't ask us to resume construction, so the payment and some suspension and then recently in our most recent reform we did add a requirement to build, make sure all the generations are built at least within three years of the GIA commercial operation date and the GIA. That has not been in effect long enough to really determine anything from that perspective yet.

MR. KELLY: Paul Kelly with the MISO Transmission Owners.

I would just say that collectively as the owners, I don't think we've had enough of these situations occurred where we've gone forward with an approved GIA, and things have been made, and then all of a sudden somebody couldn't become commercially operational. I may be speculating that, they're solely addressed in post-conference comments, if that's inaccurate. But I think the more-regular situation is just kind of a situation where you get into the signed GIA but the payment doesn't come and then it just naturally terminates from that point forward.

MR. MARTINO: I think the termination provisions really has to be looked at with respect to the RTOs. When it comes to extension of COD's, in our experience, there are a number of projects that are on similar situations but they have been treated differently. And I think that having a project with an executed LGIA with interconnection and transmission facilities built into the system, which other customers can take advantage of and that price is terminated, I think that's something that has to take us back and see who should be reexamining the termination provisions in the tariff. Something we would like to see, as I mentioned earlier, is the COD extension criteria that we saw in the California ISO where if you go past a certain window you're not automatically terminating like in the case of MISO that they're very concerned about the three-year time period. You're active, including LGI payments, network facilities, and transmission facilities, but you're also pursuing a contract then you can show that, I believe the California ISO does grant extensions based on those facts. So I think that's a gray area and I think we really need to reexamine it and something I would like to see is consistency between RTOs. I think it's unfair to that one RO would have termination criteria very different from another RTO, that's something that I think should be consistent all across the board.

MR. DOBBINS: All right. Thanks.

So that wraps us up for panel 5. There was no break scheduled between, I'm sorry, that wraps us up for panel 4. There was no break scheduled between that and panel 5. So we're going to take five minutes to set up for the next panel.

Okay, thank you.

(Whereupon a short recess is taken.)

MR. HERBERT: All right, let's talk about energy storage, or electric storage resources as we've been more affectionately referring to it lately. I like to thank the panelists for coming to talk to us, the audience for persevering to the end or showing up especially for storage. Either way, it should be interesting conversation.

We do have a relatively aggressive agenda for this panel. We teed up five topics in the final agenda, as you guys have seen. We'd like to allocate about 10 minutes each to those. Kaitlin here will help me keep on track, if we're over time on something, move onto the next topic. But as Tony said earlier, if people can keep their responses to about a minute each, I would like to try to give everybody an opportunity to speak on the panel. And again, apologies in advance if we don't hear from everybody on every topic. But we'd like to kind of try to cover the front as much as possible.

So with that said, I'd like to thank the Chairman and Commissioner LaFleur for showing up. And without, I guess, further ado, we can go ahead and do the introductions. As before, you'll have a couple minutes. And we got this nice clock down here letting you know when your minutes are up.

So, Dave, if you want to go ahead.

MR. EGAN: Dave Egan with energy interconnection project with PJM.

Regarding storage facilities, PJM has had a lot of experience over time starting with CAISO, with flywheels, and now battery storage. We interconnect these facilities using our generator interconnection procedures. We also model them as a load, since they do both activities and it's based on the inverter and the power delivery and power receipt, not necessarily the storage size of the battery that we study.

We allow for distribution level interconnections to participate in our markets. Some of the issues that we have on that, they'll get into whether the storage facilities participating in retail or wholesale and the timing of that, so one or the other at any given moment. Combining of battery storage with other generation fuel sources, we have no issue with that. We treat, again the incremental increase in the power output is what we would study, and we would also again review the delivery power to the battery as required.

MR. EMNETT: Good afternoon. I'm Mason Emnett on behalf of NextEra Energy Resources. I also want to thank the Commission for the time and attention to this topic.

I think all of us are relatively low on the learning curve of how to integrate storage, develop storage facilities, integrate them on the interconnection process, and then operate them on the system. So I think it's great that the Commission is taking the time to focus, not only on the interconnection side, but also the market rule questions that the Commission has out.

So NextEra has four operating energy storage batteries in the PJM market, and we've got projects active in development in all the other RTOs.

So in our experience in navigating the interconnection process for the battery has really informed our experience with the wind and solar side, which, as Mr. Gosselin explained, well, several panels. There are issues to deal with in terms of navigating that process, the timeliness and accuracy of studies, and the delay, and all that good stuff.

As we think about developing battery storage as a large generation owner, we first wanted to co-locate our batteries with the existing generation projects to figure out where is that extra unused capacity, or frankly even land rights, where can we go and plop on an outset? And as a highly-controllable device from a battery's perspective, we can control anything. We can use the excess interconnection rights, we can oversize the project and just never exceed our interconnection rights. But as we've gone through the interconnection process, typically the way the RTO could consider our project is as an incremental addition. So we get studies based on the total injection.

And what we would like to see for co-located projects is to really focus on what it is that the customer is requesting on the actual injection rights. And so that's the main path that we have today and we look forward to discussing all the other issues with you.

MR. FERNANDES: Good afternoon. Chairman Bay and Commissioner LaFleur, thanks for joining us. And thanks to Staff for the invitation to speak and for sticking around late on a Friday.

John Fernandes, policy director for RES Americas.

Within RES's of 10 gigawatts of global energy projects, we have about 100 megawatts of storage that's in operation or under construction in four different countries.

When I think about the strides that we made within energy storage, especially over the past couple of years, I think a lot of that has been predicated upon the speed and accuracy of a storage plan. And I think one thing we have ignored is the speed and accuracy of the control platforms that sit behind the storage plan. And it's those control platforms that set the parameters within which storage will charge and discharge, fully automated. And a lot of times we're frequently developing plants to operate that charge and discharge around net zero, not at a full discharge and not at a full charge.

So I think as we consider that a little bit more moving forward, especially inform system operators, RTOs, and coming utilities, really on what is that storage project going to be doing and what are the real interconnection needs for that plan? So I look forward to discussing that at little bit more today.

MR. GABBARD: Good afternoon. I'm going to reintroduce myself.

My name is Dave Gabbard, I'm director of electric generation and interconnection for PG&E. I'm responsible for inter-connectional traditional renewable and energy storage generation to PG&E transmission and distribution system.

PG&E is in partnership with California ISO. The stakeholders have put a significant amount of effort into looking at the interconnection process for storage generation to PG&E's wholesale distribution tariff and California ISO interconnection process. To date, PG&E has over 1,400 megawatts and 2,800 megawatts of active storage under the CAISO GIDAP and PG&E WDT processes, respectively. That's actually a number before our cluster 9, which has just closed, so that number has increased.

PG&E has progressed stand-alone and renewable-paired storage generators through the current interconnection study process. Under the direction of the California ISO, PG&E has also successfully studied the addition of energy storage to existing generation through an accelerated material modification process.

CAISO-driven collaboration across PPO's and storage stakeholders was fundamental in enhancing the interconnection process to evaluate the impacts of both the generation and negative generation aspects of the energy storage generators. PG&E agrees that the California ISO interconnection process is sufficient and safely and reliably interconnect to energy storage through PG&E interconnection systems. However, PG&E

believes additional work is needed to establish a process in evaluating the aggregated distribution level storage participating in CAISO's market.

PG&E is concerned that existing distributing interconnection processes may not fully evaluate whether any safety or reliability issues arise when a significant number of DER's, Distributed Energy Resources, responding in an aggregate manner to CAISO market signals and dispatch instructions. PG&E believes that the distribution of energy resource aggregator should be required to complete an interconnection study process before operating as an aggregation of distributed resources in the CAISO market.

Thank you.

MR. McBRIDE: Good afternoon. Alan McBride again with ISO New England.

I want to thank again the Commission for the opportunity to speak today. My comments are focused on the interconnection aspects of storage.

ISO New England is currently processing interconnection requests for the addition of storage devices in New England. These requests include the additional storage to existing generation facilities and the inclusion of storage devices among other types of generation of new generation facilities.

While the ISO believes that the existing interconnection procedures are adequate to manage these interconnections will continue to moderate stakeholders and take up discussions if it appears that enhancements may be needed.

The ISO would also like to note that most historic performance on the technology, the efficient processing of these interconnection requests is dependent on provision of a appropriately robust design. The equipment needed to meet the established performance requirements which our power factor ride-through and frequency response and power system models need to perform well and network study analysis. After the interconnection process is complete, the ultimate aspect of participation metering telemetry, et cetera, for a storage facility, will depend on the markets in which the resource has chosen to participate.

Thank you.

MR. RUTTY: Good afternoon. Steve Rutty from California ISO. I'm the director of grid assets, oversee the generation of interconnection process there.

And storage has become front and center at the ISO over the last couple of years. We have held at least four stakeholder efforts to discuss interconnection efforts, market efforts, and operation, both operational issues that go along with storage. Our queue is heating up pretty heavily. We have currently cluster 7 through 9, 77 projects with 8,700 megawatts of storage that are trying to interconnect, 34 of these are hybrid units, a couple that are flywheel.

So short opening statement. We're heavily into it, we know we have -- I am trying to remember who said it down there, we are early on the learning curve. So I'm sure we'll be making changes as we go forward. But currently, as Dave said with PG&E, our processes are allowing a very competitive market from the storage area.

MR. HERBERT: Great. Thanks a lot guys.

So the first topic we had teed up for discussion is whether the existing small and large pro forma interconnection agreements and procedures are sufficient to accommodate the interconnection of electric storage resources? So the question is, have you had any difficulties using the existing pro forma agreements or pro forma procedures for large or small generators in your region for the transmission providers or in any region for the developers when interconnecting electric storage resources? And if so, can you please explain those difficulties? And we're just go down the line from my left.

MR. EGAN: So for large generation-sized battery interconnections, no problems at all. Small generation, they have a propensity to come in under our very small gen, less than 10 kW inverter base and under 5 megawatt inverter base. The issues there, though, pure distribution, the interconnection process is not jurisdictional. So that's the only rub we have there. But we typically coordinate with our transmission owners to work through the state process and establish if they're trying to participate in the PJM market, we get them at wholesale market participation agreement so that they're able to do that upon completion of the interconnection process through the state's interconnection process.

MR. EMNETT: Mason Emnett with NextEra.

So our four projects that we're operating are within PJM, and I'd say PJM has been great and the TO's we have interconnected with have been great. But we're learning our way through the process. We've co-located our projects, so issues that we found are -- as PJM has over time kind of maybe improved upon the way or learned its way through the studying process, we see slight differences in system impact study approaches with respect to modeling, injection, as Dave said, there's a modeling of withdrawal that makes sense to us particularly in a weak area of the system, so those studies make sense. But the modeling of thermal violations associated with new injection, in some instances we've been modeled as if the battery is just a complete injection above the interconnection that the customer had, even though we were proposing not to increase that amount. In later system impact studies, it appears that's not the case, but we're not entirely sure.

So we'd like just to go forward not only in PJM but in other RTO's, just more clarity, and this kind of gets into the later issue in topic 3, but it's one that's important to us.

The mechanics, in terms of the mechanics, yes, there are kind of practical issues in working through the interconnection application and the agreement, there are some provisions that don't apply, there are questions that -- don't aren't really relevant, and there the most part we've been able to work through that. There is a little bit of a risk from the developer perspective of if you're not answering a question correctly that can lead to consequences in the interconnection process.

So we've worked with the PJM rep to say, "Is this how you're going to interpret my question with respect so a storage device" -- and they say to you "We were all good" and we get it in an e-mail and we're fine. So that hasn't been a significant issue for us. It's really more, conceptually, what is the project doing when is comes on line? How does PJM model it? And then make sure that reliability is protected.

MR. FERNANDES: Thank you. John Fernandes from RES Americas.

I would agree with Mason, the RTO ISO transmission owners, distribution owners, they've been very willing and very collaborative to work with we, the developers when it comes to interconnecting storage resources. There's been a lot of questions in both directions, a lot of studies, but that's okay, I don't think holistically there's anything wrong with the current process.

I actually want to go back to something that came up this morning. We have a generator interconnection process for supply resources; and then we have a transmission planning process for transmission infrastructure. You hear it all the time now, "We're developing storage and we're trying to stack services." And that's actually the primary business model for RES right now. We are building facilities to serve as the infrastructure for incumbent utilities. Whether it's with an RTO, ISO, or even with utilities, that challenge of, "Well, these guys over here do the wires and these guys over here do the supply," that does not lead to a smooth process for interconnecting a storage plan that's going to do both. And so I think there needs to be a more direct way to combine those conversations so we're not having it two times with similar folks.

MR. GABBARD: Dave Gabbard, PG&E again. With energy storage being -- having such diversity in technology, and like was said before being early on that learning curve, there's definitely challenges; we've encountered a handful today. As Steve mentioned, we have worked collaboratively across stakeholders to work kind of through some of those challenges, and we are effectively progressing storage generation through our interconnection process using the existing pro forma contracts. I think we're going to continue to see challenges, but the collaboration that exists in the community, stakeholder community is going to allow us to address those challenges as they arise.

MR. McBRIDE: Alan McBride from ISO New England. I would agree that the existing small and large pro forma procedures are adequate, but I think to the learning curve I think, as I think we've heard just now, that the storage development community is coming to understand what is required by the LGIP and the SGIP. We've heard examples of proposals coming forward, as we've explained with there's a power factor requirement, ride through requirements, there's a frequency response requirements. And we found ourselves with models that actually capture none of the above. And we talked about modeling this morning. We've taken some pains and we've had the recently approved interconnection improvements to very clearly lay out what are the data requirements coming in to the process for modeling. And we expect that that will help communicate to folks that how to get into projects is having models that can hit the ground running, and that's a part of what's associated with the performance standards.

MR. RUTTY: I'm not sure I could add any more than what my fellow panelists had said. Like Dave mentioned, we did meet with our stakeholders including a lot of storage interests, to really review what our interconnection process looked like, what our pro forma documents were. And it was pretty much consensus that our current process will accommodate storage. And, again, we're going to continue to watch it, we're very early, cluster 7 has just finished its phase-2 studies, we'll be moving to the LGIA phase very shortly. So stay tuned.

MR. HERBERT: Great. Thanks guys.

Encouragingly, there's a pretty high level of satisfaction it sounds like. I'll ask the next question anyway's, so it might be a quick one. But do you have any sort of suggestions for best practices, potential improvements to the pro forma interconnection agreements and procedures and how to accommodate storage? I know Mason, you said with PJM there are some non-applicable provisions provided they meet a data requirement for example.

Has there been anything that's caused enough heartburn do you think justify improvements.

MR. EGAN: Mason brought up a good point. So when you have an ISA and you have, let's say, 100 megawatts of wind and you haven't built it all up, you have 80 megawatts built you have 20 megawatts left that you want to build up, the problem with the interconnection service agreement, the way you would make a change is through -- in ours is appendix 2, section 3, which is material change to the project. While it's still inverter-based, we do do a vulnerability study on the wind. So the way we're looking at it is if you haven't built out the full hundred you, would need to come back to the queue for the this performance since we haven't completed the study. If it's not transparent when you use what we call the "necessary study" -- I think that's what's it's actually referred to in lower case -- PJM will perform a necessary study, it's not public, it's not very transparent until after you would correct the ISA. So I probably should have mentioned that the first time when we were talking about are there issues with agreements, that is one issue of the ISA right now, try to change technology that doesn't really allow for that. I think the way we're handling it is appropriate, because we do get the appropriate study in place to ensure it's adequate.

And as far as -- he also mentioned the increase, that comes to -- as Mr. Fernandes said, the technology in how you're putting the output out on the system, you need to be clear on what your output could be to the system, worst-case. So while the machine can be set to zero, they can also be set to some higher value in the inverter capability. So as the transmission provider, I have to make sure reliability of the system is the worse case. Unless we're blocking the box that allows that control so that you can't deviate from that, we would have to study the worse case.

MR. EMNETT: Mason for NextEra.

"Satisfaction" is a strong word in the interconnection process.

(Laughter.)

One of our projects, a 10-megawatt project involving partial use to sustained rights took two years. So I can't say we're satisfied with that, but we get it. We get that people are working hard on issues and some are them are contractual and some of them are study-related, and we wish they didn't happen.

In terms of kind of things to improve, yes, that ability to take full advantage of effectively what we've already contracted for, and so the studies that PJM would need to perform, part of that I believe would also load deliverability and the remaining studies relate to the type of injection rights we're seeking, whether it's energy-only or capacity. And so more -- it's not entirely apparent how going in we could define what it is we as interconnection customer are seeking as effectively a programmable device the conditions which we are willing to accept in order to avoid any problems on the PJM system. That type of -- so NextEra also, our major subsidiary is Florida Power and Light, a vertically integrated utility integrated utility, as we are thinking about integrating batteries on that system, that's the internal conversation we can have. This is what that device can do; how can we operate it; how might we want to optimize it. Well, that type of conversation doesn't fit within the PJM process because that's not the way the interconnection process is designed, which is fine. We'll accept that process as it is. But let's figure out a way to effectively, from our perspective, maximize the assets that are already in the ground because most of the batteries that we're developing at this point are in the 30-megawatt range. There are developers that are looking at much bigger, but we're just looking at little incremental additions to the system, and it seems like that could be easier.

MR. FERNANDES: So I think we've touched upon a real key challenge, not only do we know how to improve upon this. Entities that are responsible for reliability have to plan for worst case scenario; that's what's they've been charged with, I'm an ex-utility guy, I completely get it. At the same time developers, we're interconnecting a distribution to provide services to the balancing authority. When the distribution utility looked at the full charge discharge cycle of the capabilities of the storage plan, it resulted in voltage flicker-down on their system, and we were handed a $2 million bill for system upgrades. We were able to show them, we wrote a control algorithm, and we were able to show them that you could slow down the responsiveness of the battery to still provide the service that the balancing authority needed but to completely mitigate the voltage flicker farther down on distribution. And the distribution utility accepted it and didn't require one bit of upgrades. And so that's -- I certainly don't think that the distribution utility's falling short of their reliability obligations. They recognized and accepted the fact that this is a controllable resource, that a mathematical algorithm would prevent that plan from doing something where, technically incapable on paper, it was capable of going to the full charge and full discharge instantaneously, but we prevented that from happening. And I don't exactly know how to bridge that gap between those responsible for reliability and those of us that are designing these systems.

MR. GABBARD: Just quickly that I think both sides of that spectrum have been touched on, I think we really need to highlight that it's a balance. The biggest benefit of energy storage is also one of the biggest challenges is disruptibility and opportunities to leverage. That flexibility to maintain the safety and reliability of the grid, we have found opportunities to leverage control systems and other control mechanisms to maintain that safety and allow interconnection under material modification process, for example. But we've also had instances where developers want the flexibility to be able to stack those revenue streams and be able to perform in whatever potential future market that could exist at some point and so we need to make sure that we balance both sides of that spectrum and maintain that safety reliability that we require on our grid.

MR. McBRIDE: The use of existing interconnection capability and this may be something that the Commission would think more about, maybe take an example of, say, an existing hundred-megawatts generator and a new proposed hundred-megawatt storage facility. If the proposal would be to reduce that existing from 100 to 80 and then replace the top 20 with the storage device, that is certainly something that could be studied. It would avoid the thermal analysis, but we still would need to study the performance, voltage performance and things like that, to ensure there was no degradation. That's the study side.

I think there's also the interconnection service and interconnection rights question, what has actually occurred? Is it essentially a retirement of rights from that first unit from 100 down to 80, call it a permanent right? And for us in New England, that brings up capacity market questions and the capacity piece probably has to go through the capacity market and dealt with in some way. It could be dealt with maybe as a re-powering, so it's a partial re-powering of the facility where it was presented and operated before and in a different way afterwards.

So I think there are different options and we may already have all the tools for that particular proposal that we need, but it may be worth thinking through the interconnection rights piece of it to make sure what's actually achieved at the end of an endeavor like that.

MR. RUTTY: Again, going last, I don't know if I have a lot to add to what my fellow colleagues have said.

(Laughter.)

It's just the process needs to be very flexible. Developers make changes all the time. They may come in with a solar plant and then halfway through may want to take away part of the solar and add some battery storage. The battery is a little bit different than solar, so there's level of deliverability, that level might go down. But it's something we would work with them on. We allow all kinds of changes and modifications through the process, as long as it doesn't negatively impact the other interconnection customers that are there.

So that's the key that we look at, we make sure when someone comes in with a change that it doesn't negatively impact projects to put them in jeopardy. But there are a lot of opportunities to learn and meet with these developers want to put in. So it's a very creative market right now. It's a learning curve, lots to look forward to.

MR. HERBERT: Great. Thanks again.

We've largely segued to the next topic already, that is the modeling of electric storage resources. John, you gave a nice example. Alan, you talked about how ISO New England does it. Maybe you can move through those a little bit quicker. But for developers and potentially PG&E, you have any, I guess, additional experiences with the way your storage device has been modeled, either sort of unnecessarily delayed the interconnection process or did not accurately account for the resource operational characteristics?

And if so, would you recommend any improvements or best practices to have that done? That one's geared at the developers.

We have a follow-up question for transmission providers.

MR. FERNANDES: So John Fernandes from RES.

I think one of the real challenges when it comes to the modeling of storage is the only way -- that's been shown to me, anyway -- for system operators is to model the charging of a storage resource that's been treated as a load. The charging of a storage resource is anything but load mostly from a control perspective. So I think -- and maybe that's where we the developers can come together with the system operator and start to share some modeling processes, how exactly do you show the controllability of the charging of a storage asset, but also keeping in mind that frequently when we are charging a storage plant, we are doing so under the instruction of the system operator because that's part of the service we're providing. And that is rarely reflected in a load construct really unless you're talking about load curtailment, some type of demand response-type idea.

MR. EMNETT: Mason Emnett from NextEra.

Not much to add, but there was a link obviously in the conversation earlier today about when wind and solar is modeled, capacity factors. It matters in the RTO's analysis what the assumptions are in the operation of the resource. And as John and Dave acknowledged earlier, the way that PJM would study is maximum charge at the worse time and maximum output at the worse time. And that's not the way the asset is going to operate, we all know that. So then how do we get to a place where you would have some reasonable function or control around the way that the asset's going to operate.

MR. HERBERT: Dave, do you have anything on modeling? I know you're kind of the middleman between the developers and the operators.

What's PG&E's perspective?

MR. GABBARD: I don't have anything to add from an engineering standpoint. But I do want to add to what John referenced about the differences between the charging of an energy storage device and load. If you noticed in my opening comments, I deliberately called out negative generation. I think that's been one of the biggest successes in the California ISO process, to really look at how do we model and how do we interconnect energy storage. The fact that energy is intended to operate in a way that helps the grid is something that we need to take into consideration. And understanding how we can leverage the existing generator processes to evaluate the gen and negative gen is important, and it helps clarify some jurisdictional issues that also come up around energy storage and allows us to effectively use these as they stand.

MR. HERBERT: Great. Thanks.

So all of questions for the transmission providers, Dave kind of described us for California already, but you briefly described a methodology for modeling electric storage resources during the interconnection process. And specifically with respect to how it is modeled as generation, load, or both, and whether it does accurately account for the generally fast and controllable nature of these type of resources?

Dave, if you want to start?

MR. EGAN: That's a tough question, because it depends on how they're using the device. That's the rub. I think, as we learned, it requires communication with the customer and how they're anticipating using the device so we model it properly. I don't know if that covers the question. It's very difficult to have a one-size-fits-all for them to operate on the system.

MR. HERBERT: Okay, got it.

MR. McBRIDE: So in New England when it's generating, we pretty much model it essentially the same as any generation base on the technology. We'll be doing the appropriate reviews that we would do for similar type of technology, especially for inverter-based injections. The study as a load is an interesting one, at least on the transmission system in

New England. We have had storage in New England for a long time, and other reasons -- we have pumped storage. We have been trying the market mechanisms further up the road. So we have, for example, an asset-related demand, which is not load but it's the ability to buy from the transmission system and the pumped storage devices use that today when they're pumping, and then they pay the locational marginal price, et cetera.

So when we're studying a storage device we'll be doing with that in mind, so we're not going to be studying it as firm load or as network load. So a new network load, let's say 20 megawatts, would be studied under a set of conditions, it would probably be more conservative than the asset-related demand, storage-type load. But that network load is going to be aimed at transmission service, it's going to be paying for the storage transmission service. So in turn, it has a higher level of transmission service.

So the storage device, when it's acting as the load, we will have ensured there's no adverse impacts when it's essentially opportunistically taking power off the system to charge, and there could be upgrades to make sure there's no adverse impact. But other than that, it is a different concept from network load so we're studying it in accordance with the service it's going to have going forward.

MR. RUTTY: Very similar to ISO New England. We look at the charging aspect, as Dave mentioned, the negative generation, and the reliability studies we look at it to make sure it doesn't cause any issues and that our congestion management or the market signals can make it work. We don't identify upgrades based on charging as long as the unit is dispatchable, is responding to market signals, and is curtailable if that's needed. Similar to them, when it's acting as a generator it's studied just like any other generator we have in our queue.

MR. GABBARD: Real quick, one point on that just to clarify. When we are studying the negative generation or charging characteristics of the storage, we will look for upgrades required in order to accommodate firm load and we will communicate those if identified in the study report, but they're there for informational purposes only. So we will not move forward with build out of an infrastructure for a firm road because we understand that the market signals are intended to account for that, any potential congestion.

MR. LUONG: I guess just I had a follow-up question. John mentioned earlier that storage is somewhere between generation interconnection and transmission process, are you trying to say that one of the ways to connect it is the power piece of equipment, that you should look at storage and the transmission piece?

MR. FERNANDES: So we are definitely developing storage. Probably right now it's more distribution, I think most of your incumbent utilities are trying to take small bites of this. So we're looking for more infrastructure-upgrade referral-type process, but we are also looking at storage as transmission as non-transmission alternatives possibly to be submitted into ISO planning processes. I don't know that the challenge that I brought up earlier specifically related to the little piece of interconnection. But I think there's something, and maybe this is for the separate market participation docket, I don't want to get too out of scope for today, but there is an issue when we are developing storage plans that are being built to offer multiple services. And one half of these services is something related to infrastructure, whether it's congestion mitigation, reliability, voltage control, power quality, whatever it may be, and then perhaps we're collecting supplemental revenues from an ancillary services from an energy market. Those are not the same groups of people that we're talking to when we're trying to plan the interconnection and operation of that facility and when we're trying to -- on the infrastructure side, typically that's going into infrastructure rates and on the supply side that's going into the market to collect revenues. And there are different groups of people, they're different timelines, they're different studies altogether. And that is holding up the process a little bit.

So I don't know if I answered your question. Okay.

MR. RUTTY: Steve from the ISO.

That's the exact question we've been trying to ask, "Well, can it be a transmission asset?" And the ISO has to be very cautious that it doesn't get into operating an asset where it can actually change the market. And so if we did put it in as a transmission asset, it would have a very limited use and pretty much limit what the storage system could do for us if it was a market participant. So there's that conflict we've been dealing with.

MR. FERNANDES: And that's an excellent point and it's absolutely correct. And I would not go out to the market, broadly speaking, and develop a storage plant that has an operational obligation to the system operator. I'm not going to put a storage plant in rates in transmission or distribution and then go to, say, a capacity market and try to clear that option and take on a capacity obligation at the same time. There's going to be a primary driver for any storage plant that has stacked services, and that primary driver is always top of the list. And it might not necessarily be what that storage plan is dispatched for the most hours per year, but it always get the priority. So when we write our algorithms, that's what's at the top of the stack. Meeting that utility obligation or on the other hand a capacity obligation, there are markets that offer tremendous flexibility day-ahead and real-time, even inter-hourly, to come in out of that market and just begin to collect supplemental revenues, these are not the economics that are driving the overall cost recovery system but they're certainly contributing.

MR. HERBERT: All right. Let's move on to the next topic.

Next one was the interconnection of combined storage and generation facilities. We had a number of kind of subtopics identified here, interconnection service, combined facilities, operational understanding, telemetry and metering for those facilities, and the appropriate process for adding storage to existing facilities. So we'll start at the top of that list. We've heard sort of mixed opinions, I guess is one way to say it, regarding the appropriate level of interconnection service for these types of facilities, whether it should be sort of the cumulative rate of capacity of all of the assets behind the point of interconnection or whether it could be somewhat limited level of interconnection service based on how the developer actually intends to operate the device.

So we'd just like to, I guess, hear from all of the perspectives at the table, what you view as sort of the appropriate level of the facilities to be.

MR. EGAN: Dave Egan, PJM.

So the general history of where we've seen these, typically some form of renewable with the battery storage, and the issue there that drives up cost is having the meter separately. So in order to get the renewable energy credits, the renewable resource has to be entered separately. That's really the biggest issue I see. As far as everything else, it's pretty straightforward as far as that studies.

MR. EMNETT: Mason Emnett for NextEra.

I think we would agree in terms of straightforward as to the studies, we understand how the studies is being performed and what is being done. Our ask would be what is being studied actually reflects the injection that we are requesting. And so as an owner of large asynchronous resources within the system, which are highly controllable and we're attaching a battery that is highly controllable, it's not immediately apparent to us why we could not attach a battery to an existing asset, say a wind asset, that if we've got excess interconnection rights that we are not using, then transfer those over. Could be transferred over depending on our financing legal structure, you might transfer over within the existing entity, but that's kind of in the weeds. But there should be an optimization.

And then it also seems to us that you shouldn't necessarily be limited in terms of installed capacity to your interconnection rights with controllable devices. You should be able to include more on the customer side of the control down and never exceed the injection rights that you have already agreed to that, that's already been studied. Now, there wouldn't need to be studies of withdrawals, there wouldn't need to be stability studies. But the thermal studies of the injections it would seem have mostly been done. And if we can kind of find agreement on that, then one of the more complicated issues in the interconnection process, as you've heard all day long, is the linking of interconnection requests through the study process and the queues, and the dropouts causes the delay. If you could take one element of that and put it aside for these type of projects, because they're going to control in on them. And that generally has not been something that has been well-received from the RTO perspective. So if we could find comfort around that.

There are a couple of examples we could point to where the RTO's have accepted interconnection agreements for install capacity and in excess of the injection rates and the maximum facility output. And there is contractual language in the ISA saying "I understand I will never exceed this number, I have more installed but I will never exceed this number." And we understand that, we can handle that. And that would be our ask.

MR. QUINN: I guess this question is really if you had a red button that you're not controlling, we have a red button that says "if you exceed, we'll control," and then would you be comfortable with them having a red button?

(Laughter.)

MR. EGAN: I would say what we want is they would install a power flow relay that would limit the output, the problem you have is if you have the capability and you can exceed the thermal capabilities we have studied you could cause damage. I would prefer to see, if you're going to say I've got 100 megawatts wind farm and I'm putting my 20-megawatt battery there but I'm going to limit it to 100, then put something there to ensure that the system is never in jeopardy.

MR. EMNETT: And we would be fine with accepting the limitations. I think the red button is there, it's in the control room at PJM. We can be curtailed and the operators can -- they monitor us, they understand what our output is and they would call us if we were exceeding. Now, would it actually be reasonable for the operators to note for every resource the amount that they are and are going to track it? MISO has cracked the nut with net zero interconnection service, there are reporting obligations on behalf of a customer who has installed more capactiy on its side of the interconnection than it actually has interconnection rights to. Pro forma agreements which govern the relationship between the two entities, if they're separate entities on the EOI side, as well as the relationship between the monitoring, the TO, and MISO. And so it's all doable, it's just are we going to do it?

MR. QUINN: Do you have a comment?

MR. McBRIDE: Yeah. I was just thinking to myself I think all the ISOs, would want the red button regardless, and that should be in place. I think everything that Mason talked about is doable and I guess I feel like a little bit I might have jumped ahead in my earlier response to this topic. The key would be very concerned about a situation where facilities interconnected that is physically capable of injecting more than the rights that are associated with it. So there will need to be appropriate protections and assurances for dealing with that.

But along with that, I think just to reiterate the earlier comments, just to make sure the resulting service and upgrading rights and descriptions are very clear and implementable on all sides.

MR. FERNANDES: I guess maybe I had my own follow-up question. So for the system operators, I understand the assurances you got as far as we'll give you the red button to put into your control room. As far as again going back to the control platforms that sit, just loosely speaking here, they sit between the actual storage plant and then the SCADA system, is that something different than the red button? Is it the same level of assurance as the red button what I've shown you a control algorithm that technically prevents that whatever is behind that point of interconnection from injecting beyond X or withdrawing?

MR. EGAN: My comment is that would be you'll have to show me that failsafe. In other words, it can't be overridden by you, since you're in control of it, you're injecting on my system. That's why where said if you could padlock it and it could never break, I think I could trust it, otherwise, I think I'd want something.

(Laughter.)

MR. HERBERT: Anyone else?

Dave or Steve. Either.

MR. RUTTY: I agree with them. I agree with what's been said. California ISO does require that the flow is limited to that maximum amount, whether it's by protection scheme or a device, or other, as proven to be failsafe we're not going to put the grid at risk.

MR. HERBERT: We'll jump to the next question. This one is for the RTO's and maybe PG&E as well.

What are your primary operational concerns of these combined storage and generation facilities?

Dave, I know you mentioned earlier modeling discussion, you don't necessarily know how to model them, or maybe you do.

MR. EGAN: I think we know how to model them. It's just if you're going to set it at zero and never inject a lot of energy, I think that's what you're getting at with that. The problem is if he's controlling that, it could inject a lot of energy, so it's really a function of what you're installing, and I would want to make sure my system could handle -- suppose somebody one day went in and messed up the controls and put power out. I need the study so my system is not damaged, that's really the issue. How do we get past that? I think it's just a communication, talking to each other, so this is all new stuff, so.

MR. McBRIDE: If your question was in terms of modeling the proposal and identifying scoping out the study? I think we can do that.

Was that what you were asking.

MR. HERBERT: Just generally whether you have kind of operational concerns with these combined facilities.

MR. McBRIDE: I would say, other than the stuff we've talked about, I think we can study a proposal and we can identify the appropriate interconnection. You asked about very quick ramping, for example, if that was something that needed to be studied, and we have not yet -- to this point identified a system impact study issue that would be associated with that, it's just an attribute of the system that will be there when it's operating. So we don't have a concern for that particular aspect, for example from a system impact study perspective.

MR. RUTTY: Yeah. On the same line, we're very pro having this type of facility come in. And it really helps us with the operation, especially getting on the ramps for the peaks and extending the life/the output of a solar plant or a wind plant, being able to take over when the clouds come over, I mean, it's definitely a very huge benefit to us, so we're looking for any way to accommodate and bring these type of facilities on line.

MR. GABBARD: I just want to emphasize that as a PTO, we have an interesting position where we're balancing multiple assets on the grid, both safety and reliability and affordability for our customers. And so most of you were here earlier today and we clarified that in the California ISO service territory network upgrades that are triggered by generation are ultimately funded by ratepaying customers. So we are always looking for opportunities to minimize that financial impact on our customers, we always look for these opportunities to avoid overbuild of our system. But at the same time, we want to make sure whatever assurances we're relying on are sufficient to maintain that safety and reliability. So not only do we have that balance and make sure we are good on both fronts, that's just the predicament that we're in.

MR. HERBERT: Okay, let's go ahead and jump to the next topic. The next one was the potential processes to facilitate the interconnection of electric storage resources. I don't think it's any secret that every developer would like to have their asset on the grid as quickly as possible. The Commission has in the past sort of acknowledged differences in technologies. We have a fast-track process for small generators.

We have a 10-kilowatt inverter process for small generators, there are the network provisions that you mentioned, Mason.

We have provisional agreements. A lot of these were developed both out of, I guess, acknowledging the technology differences and also sort of the need to bring these resources on line faster. So I guess how could -- if we were to decide that that need did exist, how could the Commission justify sort of facilitating the interconnection of electric storage resources? And also, if we did, what would be the best means to bring those resources on line faster? We can go ahead.

MR. EGAN: I'll start with the last part of that, because the first part I am not sure I can even answer. The last part about moving faster, we have an issue, I brought it up in the second conference discussion earlier today. At PJM, the small gen several years back requested that anything under $5 million be allocated within the group. So the problem with that is it actually clustered together everybody in the queue. We have to wait for a queue so we can determine who would get cost allocation if it gets pushed -- if a facility gets pushed over a hundred percent, they will all share in it. So we can't move anybody fast. And that's a tradeoff between seed and cost share. So, to me, that's the biggest issue right now in our footprint would be the under $5 million cost allocation rule. And coupled with that is our alternative queue study process that says if anybody is sharing in a facility overload, we have to wait for the queue to close. So both of those provisions that were added, I think were around three to five years ago in our tariff, are obstacles, very fast in interconnection small generation.

Did you want to clarify your first part of that better.

MR. HERBERT: I guess it's just, if there was an inclination to do this, I mean, we've heard that these are, for example, fast controllable devices, operational requirements in the grid are changing.

From an operator's perspective, could PJM sort of philosophically justify bringing these resources on line quicker or operationally? What would the requirement be?

MR. EGAN: I'll pass on that. That will be in our comments.

(Laughter.)

MR. EMNETT: Mason Emnett for NextEra Energy.

Not having to operate, at least that system, that's kind of where we would come from the developer of storage within a RTO market, is within a region that is big and complicated and involving lots of effectively interconnecting resources. Moving through the interconnection process because of the way the studies were performed, a way to distinguish between relatively small -- you could do size requirements, you could do stability requirements, a shifting of risk between interconnection customer and coming along the battery developer, and saying, "I will move more quickly through the process but I will do that at my risk. If I sign an interim ISA now and go ahead and get faster service, then I'm subject to the outcome of whatever the studies may be at a later point in time. And I understand that and I accept that that's a possibility." I think you would justify that with essentially that sharing of risk and being able to control around whatever the issues or constraints might be in the interim or the concerns, that would have to be managed the parallel study process that would have to be managed within the RTO, and that wouldn't be easy I imagine. But if it would be a way to pull some resources out of the queue, and might have other benefits just in terms of trying to clear out some of the term that occurs.

Because another point that was made earlier in the day in changing technology -- and I think somebody referenced it on this panel -- storage developers have that same issue. By the time you get through two-year process, the technology has changed, it just has. So what you thought you could order a couple years ago, you can't order anymore. So you got to go through the process of just making changes. Is that material or not? Is that going to go? It's a lot of the things you find applied to a different technology.

MR. FERNANDES: That last point was a real good one. John Fernandes from RES.

Unfortunately, haven't done enough of these within one market or with one transmission owner where I can point to a spot within the interconnection process, a contractual agreement, the modeling, our control algorithms. But I think hopefully we can start to identify somewhere in those operating parameters where we show this is not every system at max gen and especially max load at the worse possible times. I think that should be able to advance a storage interconnection farther down the road maybe through a faster-track process. I really think it's going to come down to the operator's trust in the control algorithms and what we as the developer, why are we building that plant? What are the contractual obligations we have?

MR. GABBARD: So over the last 10 years, we've done a lot of work in ways to look at the acceleration process. We have a strategy and facility process, we have the material modification process to modify an existing generator. But I want to caution the Commission. We are talking about large-scale generators. We have a generator interconnection process for a reason, to evaluate the impacts on the grid and maintain safety and reliability. While we're going to continue to partner with stakeholders to identify ways we can tweak those existing fast-track processes and other processes to accelerate interconnection, we want to maintain that safety and reliability.

And I want to clarify a couple of things that were called out earlier today. The folks referenced the long study process or the long interconnection process. My comrade earlier from California ISO referenced the two-year study process that we have in the state of California. But I want do clarify that the actual studies being performed by the PTO or the RTO are a matter of months. Through the study process and through the interconnection process are iterations of tasks that are on the PTO, RTO, and tasks that are on the interconnection customer. A large portion of timeline through the overall interconnection process are periods of time when we're waiting when the interconnection customer's working to get a PPA, financing for their project, and other aspects. It's a natural flow. And so understanding where there are things that are not working, we definitely need to come together as stakeholders and find ways to fix those. But some of the timeline is actually more effective, it's actually a more tortoise and hare situation where it's effectively moving through the process at a pace where we allow developers to effectively develop their projects, and ultimately reach our goal which is getting more generation on line whether renewable or otherwise.

MR. McBRIDE: To answer as the open access transmission provider in New England, I don't have a reason -- with respect to interconnection perspective or reliability perspective, a reason why these proposals would be treated differently than other proposed requested to interconnect to the grid.

MR. RUTTY: In consideration of time, Dave pretty much took every note that I had written down to answer that question. The only thing I can say is the material modification has proven very valuable to the ISO where we've been able to add storage to existing projects, ensuring that it didn't add a major impact to the grid or to other customers.

So being flexible in that environment is pretty important to us and how we accommodated a lot of changes to existing or near-existing plants. And the re-power process as well has allowed existing generation among others to re-power with batteries and other types of resources. So again, we have to look at it for reliability, we have to make sure it's a reasonable solution, so it's been fairly flexible for us.

MR. HERBERT: Commissioner LaFleur, do you have a question?

COMMISSIONER LaFLEUR: I wanted to ask a little bit of a philosophical question. I mean, when I used to run a distribution company, I would ask people if you lost the whole system and you had to start from scratch, what would you put up? Because I know it would look nothing like what's out there. Because if you don't know what an ideal is, you can't even make incremental progress. So the situation right now is, just the reality, is storage is a product in limited quantities that being -- we're trying effectively to graft on to a system that was built for transmission, distribution and generation. So in the time that we had the critical mass of storage and you were building a storage-centric to compensate it or whatever, would there be a parallel set of a grievance to what we have now, I mean, what would the future look like, if anyone has any thoughts, when storage is really big? Would it be like generation and we would be like a another sort flavor of generation that we would just pay that way, or is there some way of thinking about this that we're even missing in the way we think about paying it? Because I think every time we think of storage we're trying to fit it in another peg. Everyone doesn't have to answer, but we have all these experts here, if anyone has any insights I would welcome it. Because my mind doesn't go to where that is, it just goes to where we are now.

(Laughter.)

MR. EMNETT: Mason Emnett from NextEra.

It's a timely question. Yesterday, about 100 people from our company were together and we spent six hours together on storage, as a where-have-we-been-and-where-are-we going conversation. And that's not an easy question to answer. There really is no kind of current answer other than the way we've thought about it is. As an organization that has a large vertically integrated utility and an emergent side of this outside of Florida, we answer the question differently depending on which side of the house you're on. Right? And it is much easier, frankly, for the FPL side of the house to step back and think about how would I integrate this resource that does multiple things for me? And I have a rate base. I have a transmission rate base and I have a generation rate base. Allocation between those with respect to cost recovery, which then takes me into what's the function and what the benefits I'm getting out of it and can I demonstrate the value of that investment. Getting more value than I am for the investment itself for purposes of rate recovery.

When you move into the organized markets, it's extremely difficult to think about how you stack those functions and values in a market structure that is designed for generation. And it's designed for a generation in a way that makes sense with the physics and the operation of the system, but then a resource that steps across all those boundaries is tough. And I think that's the question that, frankly, we all need to answer and we'll need to answer it probably in the next three to five years.

COMMISSIONER LaFLEUR: Because we're making decisions now that are putting us in a path to where we might be when storage is bigger.

Do you know what I mean?

MR. EMNETT: And that is the way that we are thinking as to storage. Right now we're operating projects provide frequency regulation. And that is nothing of what these resources can do, but it is the product that is compensated and it justifies the investment. And we're learning, we're learning from the operation of those assets from going through the interconnection process and figuring out ways to manage it. And then we're looking forward to, what are the additional things we can do? We haven't gotten there yet, but hopefully we will and then we'll start to stack the things out and hopefully get there.

MR. FERNANDES: So I'll use Mason's analogy of what we're doing on the corporate side. Our wind guys don't do storage. Our solar guys don't do storage, our transmission guys don't do storage. Our storage guys do storage. We have a dedicated global storage team. And when I said I was taking Mason's idea, I believe he brought it up in a conversation that a storage contingency came here to the Commission years ago when demand response first started taking off. We tried to put it into these existing constructs and that was an absolutely horrible fit. And this Commission finally said: "Create rules for the demand response." And I am not trying to add to the tariff books, someone is going to stab me with their pen, I know.

(Laughter.)

It adds more paperwork, more operational complexity, more market products and everything else. But storage is very much its own asset class that touches just about every other asset class that hits the grid. So I think that really begs the justification for let's stop talking about storage as generation, as a negative gen, I get it but those are still dangerous semantics. Storage to storage, and I think it would be really want to be able to accommodate storage at a large scale five or ten years from now, those rules need to start going into place now.

MR. McBRIDE: I was just going to quickly offer because my own boss talks about it this way a lot. We have had storage in New England markets since the beginning.

COMMISSIONER LaFLEUR: Pump storage.

MR. McBRIDE: We have pump storage. And it's almost 2,000 megawatts, which is relatively large for our system. What I understand is that that storage was originally installed to capture essentially what we now call "energy price arbitrage" where it would pump during the night when prices were low and generate during the day when prices were high. And it still can do that, but now instead, for the most part, it participates more in reserves and regulation markets. So that evolved by itself, and there's been some adjustments in our markets to deal with that. So it could be that the technology will come forward and the technology will tell us how it wants to competitively participate.

COMMISSIONER LaFLEUR: Well, thank you. I'll let you get back to interconnection. It just seems like we keep going around this loop.

Thank you.

MR. HERBERT: If anyone else have anything? I think in the interest of time and with respect to everybody's weekend plans, maybe we'll just call it right here. We're already a little bit over. So thank you again for coming. I think this has been a very interesting conversation. I think it's the beginning of a very interesting conversation. We do have a couple of closing remarks from Adam, so don't get up just yet. But thanks again.

MR. PAN: I'll be brief. It's been a very interesting and informative technical conference we've had today. We thank everyone for attending. We thank all of our panelists who came out and participated today, especially for you who traveled from somewhere to get here.

In terms of next steps, to better organize issues that are being considered, Staff is looking to put out a targeted request for comments sometime soon. To the extent that includes questions, we ask that you respond to the specific questions. And please continue to monitor the docket and look out for that.

Thank you.

(Whereupon the technical conference is concluded at 4:54 p.m.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding:

REVIEW OF GENERATOR INTERCONNECTION AGREEMENTS AND PROCEDURES

AMERICAN WIND ENERGY ASSOCIATION

Docket No.: RM16-12-000

Place: Washington, DC

Date: Friday, May 13, 2016

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

Official Reporter

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