BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of: :

TECHNICAL CONFERENCE ON :

THIRD-PARTY PROVISION OF : AD14-7-000

REACTIVE SUPPLY AND VOLTAGE :

CONTROL AND REGULATION AND :

FREQUENCY RESPONSE SERVICES :

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Federal Energy Regulatory Commission

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The technical conference in the above-entitled matter was convened at 9:03 a.m., pursuant to Commission notice.

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P R O C E E D I N G S

(9:06 a.m.)

MR. AMERKHAIL: Good morning, and welcome to the Commission Staff's Workshop on The Provision of Reactive Supply Regulation and Frequency Response Services.

My name is Rahim Amerkhail from the Commission's Office of Energy Policy and Innovation. Seated with me are Mary Cain and Bob Snow from the same office. Greg Basheda, from the Office of Energy Market Regulation. Jason Feurstein from the Office of Electric Reliability. And Lina Naik and Chris Kempley from the Office of General Counsel. Oh, and also Arnie Quinn from the Policy Office.

This Workshop was initiated as a result of several overlapping trends in the industry. Chief among them are the entry of new types of resources into the market and the ongoing restructuring of the industry into disaggregated, competitive, and regulated components.

Ancillary services like frequency responsive reserves were once abundant in all parts of our country. In many areas of the country today, frequency responsive reserves are abundant no longer. This may be due in part to unintended consequences associated with the ongoing restructuring of the industry, but should not be viewed as evidence that restructuring has been a mistake.

The introduction of competition into electricity

markets has yielded tremendous benefits to consumers and the Nation, but inevitably changes on this scale will require further tuning adjustments, and finding new ways to support the needed levels of frequency responsive reserves certainly falls into that category.

Reactive supply and regulation, meanwhile, are services that have long been available in certain forms but new technologies may now make them available in new useful forms. Further, changes in the composition of the generation fleet may mean that the traditional sources of reactive power will not necessarily be sufficient to meet the grid's needs moving forward.

Ensuring that our Nation can continue to access the appropriate amounts of the ancillary services that it needs at reasonable cost, particularly in a time of great change like this one, depends in large part on the appropriate maintenance of and adjustment to relevant regulatory structures.

That, simply put, is the goal of this workshop--though it should be emphasized that this is a preliminary effort and we have no definite idea yet of where, if anywhere, this might lead.

In addition, this workshop serves to address the Commission's direction to staff to follow up on certain issues raised in comments to the Notice of Proposed

Rulemaking that became Order No. 784.

As such, we hope to learn whether the Commission's existing market power screens can be used to establish lack of market power for the ancillary services that are the subject of this conference.

As to the format of the panels, they will be roundtables with no opening presentations; just facilitated discussion of the issues raised in the Supplemental Notice and Agenda.

We are lucky to have on our panel some very distinguished experts from the industry and a National Lab who will be introduced at the beginning of reach panel. My colleague, Mary Cain, will now convene and facilitate our first panel to discuss issues related to reactive supply. Thank you.

MS. CAIN: Good morning, and thanks, Rahim.

Reactive supply and voltage control service, also known as Schedule 2 of the Open Access Transmission Tariff, is a critical service for reliably operating the transmission system.

This morning we would like to discuss whether resources that provide reactive supply and voltage control service should be paid; what their obligations are; and whether the obligations depend on whether the resource is compensated; and how to account for nongeneration resources

that provide this service.

Today most large generators are required to provide reactive power as a condition of interconnection, and reactive supply is mostly sold under cost-based rates either by transmission providers under Schedule 2 of the Open Access Transmission Tariffs, or by other entities under bilateral agreements using the cost-of-service methodology commonly referred to as the AEP Methodology for American Electric Power.

In Order No. 784, the Commission recently began permitting the third-party market-based sales of this service to public utility transmission providers at rates not to exceed the buy-in public utility transmission providers' Open Access Transmission Tariff rate for the same service, or at rates that result from a competitive solicitation meeting certain minimum requirements.

This morning we would like to develop a better understanding of how reactive power rates are determined, and to understand the differences among regions. FERC Staff released a paper earlier this month providing background on some of these issues that is available on the Commission's website through E-Library or the Calendar Entry for this workshop.

Thank you to our panelists for joining us this morning. I will introduce our panelists starting with Doug

Hils, on my left, who is the Director of Midwest System Operations for Duke Energy, and he is representing the Edison Electric Institute as well this morning.

Ryan Hanley is Director of Grid Engineering Solutions from SolarCity. Dmitry Kosterev, Electrical Engineer from Bonneville Power Administration. Stu Bresler, Vice President of Market Operations for PJM Interconnection, L.L.C. Michael Jacobs, Senior Energy Analyst, Union of Concerned Scientists. Vladimir Chandliev, from First Solar. And James Ginnetti, Senior Vice President of External Affairs and Markets for EquiPower Resources Corporation.

Our discussion this morning will begin with whether resources that provide reactive power and voltage control service should be paid; how they should be paid; and then reasons not to separately pay for reactive power and voltage control service; and also what obligations resources have or should have to provide reactive power and voltage control service.

To begin I'd like to ask each panelist to provide your thoughts on whether resources that provide reactive power and voltage control service should be paid.

Do we have a volunteer to go first, or we can start with Doug Hils and move from left to right. Doug?

MR. HILS: I can start, yes. Thank you for the

opportunity to participate at this workshop.

I am responding on behalf of the EEI members, those that are in the non-RTO/ISO regions. So my comments will be fairly limited to that. And to the extent I am making a comment on behalf of Duke Energy, I will clarify that as well.

I guess, as EEI indicated in its comments in response to the NOPR on RM-1124, reactive is generally an embedded service capability that's provided by a resource otherwise developed or procured by a transmission provider in a bilateral market pursuant to its resource plan process or other existing agreements.

In some cases, though, transmission providers provide the service for no additional charge when providing service to their customers under their OATT, I guess making the need or desire for this ancillary service to be provided by a third party somewhat unlikely. While in other cases there may be cost-based recoveries through the Tariff, it's important to note I guess, as EEI would point out, that this is a regional issue and to that extent there may be changed circumstances that vary by region, and encourage the region to be open to solutions that are regional specific.

MS. CAIN: Thank you, Doug. Ryan Hanley?

MR. HANLEY: Good morning. I would like to echo Doug's appreciation. Thank you for hosting this workshop.

I'm excited to be here. I'm representing SolarCity, and SolarCity has an invested interest both in this panel and in modernizing the grid. We are excited to talk about utilizing new resources that can be leveraged by our ISO partners and our utility partners to open up some value on the grid.

And reactive power we believe is one of those key opportunities. As you mentioned, it's a critical service that definitely needs to be provided for transmission distribution. We do think that there are new ways to provide reactive power that can leverage new assets on the grid.

And particularly on the distribution circuits, as we've discussed in the--or as was discussed in the working paper from the Staff, reactive power doesn't travel well so it has locational benefits. By all means, with all these new inverter-based systems that are coming onto the grid, particularly behind-the-meter solar and storage, it's a new resource that we think could be leveraged to decrease societal costs in general, and we're looking forward to going down that road today and talking about how they can be leveraged. Thank you.

MS. CAIN: Thanks, Ryan. Dmitry?

MR. KOSTEREV: Good morning, and again thank you for the opportunity now to participate in this conference,

and thank you for preparing a very good paper which describes all the issues related to the reactive power markets and purchases. That was very instructive and informative to direct this discussion.

So I am an electrical engineer, so I'm not a marketing person, so I'll try to restrict my comments, you know, to technical issues related to the procurement of reactive power. So I'll stay with that. Thank you.

MS. CAIN: Thank you. Stu?

MR. BRESLER: Thank you, Mary, and good morning everyone. As the other panelists have said, it is a pleasure to be with you this morning.

Certainly from PJM's perspective, to the extent that a resource provides a needed service to the grid that resource should be compensated for the provision of that service, especially to the extent that there are costs involved for that resource in providing that service.

Reactive, as has been mentioned, is a needed service on the part of the transmission provider in order to maintain system reliability. Also as has been mentioned, it doesn't travel all that well. It is indeed a very locational service.

So as you are probably aware, in the PJM region the costs that resources need to invest in order to have the capability of providing reactive service are compensated

through Schedule 2 of the Tariff, through cost-based revenue recovery. We aggregate all those costs on a zonal basis when they are charged to the PJM Tariff on an aggregated zonal rate.

To the extent, though, that resources that are providing reactive power to the grid are requested by interconnection dispatchers to adjust their active power output in order to provide more reactive service to the grid, there is additional compensation for lost-opportunity costs in order to reduce that active power provision or to provide more reactive.

Additionally, to the extent that we need to actually operate resources that would not otherwise be operated so that they can provide reactive power, there is a make-whole mechanism through the PJM Tariff that allows resources to be compensated for again the costs of that operation in order to provide that reactive power.

So there is active power compensation that's associated with the real-time provision of reactive power beyond the longer term cost-based revenue recovery that occurs through Schedule 2.

And that's the way things operate currently in PJM, but I have a feeling the discussion is going to go beyond that into what's possible. So I'll stop right there for now.

MS. CAIN: Thank you, Stu. Michael Jacobs.

MR. JACOBS: Good morning. Thanks to the Staff for putting this together and the Commission for sponsoring all of this. I appreciate the invitation to be here.

The Union of Concerned Scientists is interested in the new entrants into the electricity market and into the calculations of reliability, as well as economics.

We have been seeing proposals for both DC transmission and distributed generation, small generation under 10 megawatts, both of which face a variety of obstacles. And the recognition of the reactive power capability seems to be a value available if allowed to participate.

So our view is that, while this is a needed service and the fixed costs from any kind of inverter-based technologies may be very low, operating costs may vary, but the existing rules have--or existing practices, rather, have not changed to keep up with the technology, and we also have the reforms of 1547, the IEEE Rule regarding generation under 10 MVA, 10 megawatts effectively, that are now changed to allow participation of reactive power.

So our recommendation is that compensation be allowed for any reactive power source, and that be a signal that this inverter-based technologies be recognized and valued so they can enter the market and participate as well.

Thank you.

MS. CAIN: Thank you, Mike. Vladimir.

MR. CHANDLIEV: Good morning, and thank you for this great opportunity. So I believe all generation resources should be rewarded for reactive power capability through some market mechanism, and it should be based on technologies or size of locational generators.

Thank you.

MS. CAIN: Thank you. James?

MR. GINNETTI: Yes, good morning. And thank you for the invitation. I am in violent agreement with many of the people who have already spoken.

First of all, I'm here on behalf of my company, EquiPower Resources. We own about 8,000 megawatts of primarily natural gas-fired and some coal resources in New England, New York, and PJM.

We are members of EPSA, as well as of P-3, IPNI, and NEPCA, and although I'm not speaking on their behalfs but rather on our company. And in the interest of full disclosure, I come at this from a little bit of an operations perspective.

A long time ago I was in charge of operations at ISO-New England before it became ISO-New England. So I know the value of resources that provide ancillary services. And so some of my comments may seem like I'm talking from Stu's

voice as opposed to my own as a generator. But we certainly are in favor of things that generators like ours, and others, should be paid for the services that they provide.

These are critical services. They're not free. They require capital. They can require lost-opportunity costs if in fact they have to be backed down from providing real power to provide reactive power. And we are in favor of competition.

So if there's a way to introduce some market mechanism to decide which resource should be providing the supply, we are in favor of that. On this particular one, that may be a bit of a challenge. As people have already said, the VARS don't travel very far. There may not be a lot of alternatives in a given local area. So you may have to use some other non-market-based. But clearly there should be some compensation mechanism provided for those who provide this valuable service.

Thank you.

MS. CAIN: Thank you, Jim.

Next I'd like to talk a little bit about cost-based rates and your experience with developing cost-based rates for reactive power both from the transmission provider, are the rates--is the process workable? Are the rates that we're ending up with, the cost-based rates, reasonable? But also from the generators' perspective, are

the rates ending up in a reasonable place? And for the non-generation technologies, do we even have a process to calculate the cost-based rates?

Does anyone want to go first?

(No response.)

MS. CAIN: Well, we can start at the other end this time, then.

(Laughter.)

MR. GINNETTI: Okay, thank you.

Well first of all, the different ways that people are compensated for reactive, they all have their strengths and weaknesses. And let's mention the AEP methodology. We think that's a very good methodology, cost-based, and unfortunately that can be quite a challenge to work through and come down here and get it approved by FERC, and so on.

So although that may be, let's say the right answer, it's administratively difficult to get that working. If you go to the ISOs in New England or New York and they don't--they have more of a tariff rate. They have kind of a one-size-fits-all. They have--in many ways what can be considered a black box settlement that picks how many dollars per mVAR per year do you get paid for either leading or lagging capability.

And then any unit--for example in New England, that goes and demonstrates those capabilities will get paid.

So that has the ease of some administrative--the administrative ease of that system, but again the one-size-fits-all may not be the right number for any one, or any generator providing the service and may be too high for some, and too low for others.

So, you know, in the ideal world we would be able to meld those two systems together. There was--and I forget which of the documents that staff provided that I read, but someone suggested that FERC has a long history of these costs based upon, you know, this type of generator in this year came in and we approved this rate. You know, there may be--I thought that was an intriguing concept to maybe use some of that data to construct some historical data for different types of generators. So maybe it wouldn't be a one-size-fits-all, maybe it's a five-sizes-fits-all. And then you may be able to then apply something like NISO, or ISO-New England. And if you have a generator that fits into this slot and you demonstrate your reactive capability, you get paid this amount of money each year.

So there may be some--I thought that was an intriguing concept, and I think that may work, and hopefully combine the two systems to get the best of both.

MS. CAIN: Thank you, James. Vladimir?

MR. CHANDLIEV: Yes. As First Solar we didn't have an opportunity to participate in markets, as Jim

described. Most of our projects are in the Western Interconnection, Arizona and California. So a local utility asks us to provide voltage schedule or control, and it's done so far on good faith practice. So at this point we wouldn't have opportunity to participate as Jim described because CAISO, as you know, or Arizona Utility or Utility Nevada don't have this rates for reactive power provisions.

MS. CAIN: Okay. Mike.

MR. JACOBS: From my experience in the private sector in development of new entrants, both in the Eastern markets and in Hawaii, we found that the developer at best would be able to pay attention to a posted tariff.

In a sense, the sort of time, attention, and administrative costs to go through any kind of cost-based or market-based calculations would be overwhelming to the new entrant. And so having a posted target made the whole calculation and whole negotiation to be much clearer.

This is also, it seems again from a new-entrant's perspective, that the requirements and the expected operations are a black box. So the obligations are hard to calculate.

MS. CAIN: Thanks. Stu?

MR. BRESLER: Thanks, Mary.

From PJM's perspective, we typically do not get into the middle of the generators cost-based filings with

FERC and FERC's approval thereof. It is more of an interaction directly between the generation owner and the FERC as far as getting their rates approved that PJM then incorporates in the tariff and allocates the costs out as necessary.

However, looking at it a little bit from a market participant's perspective who is paying those rates, because I notice that the question specifically mentioned transparency, I do get the feeling sometimes that there may be some concern about the transparency of the zonal rates and what went into those zonal rates.

So I can certainly see that from some perspectives there may be an attractiveness to something that's much more standardized, as a couple of the first panelists have suggested may occur other places.

On the other hand, I don't think this has been a significant concern for any of our market participants because, quite frankly, the costs are pretty low, especially in proportion to the rest of the wholesale power costs. You're talking on the order of, you know, less than a tenth of a percent probably of total wholesale power costs.

So again there hasn't been a whole lot of concern with respect to the specifics of what goes into those rates because it's not a big part of what they pay. So I can kind of see competing sides there.

Whereas, from a simplicity standpoint it certainly would be beneficial I think from the generators' perspectives to have something that's much more standardized and not have the administrative complexities associated with a full-blown cost of service proceeding.

On the other hand, that tends to raise some concern from a market participant's perspective of do you tend to either over- or under-compensate if you try to go to something standardized.

So I can see sort of, you know, pluses and minuses there, as well.

MS. CAIN: Thank you, Stu. Rahim.

MR. AMERKHAIL: First let me recognize that Commissioner Moeller has arrived. So it's not just staff anymore.

I just wanted to follow up on one thing on the posted-rate idea, since it's come up several times now. In Order No. 784, as Mary mentioned, third parties can now sell reactive power, among other things. This is less relevant in organized markets, but they can sell to the public utility transmission provider at its--basically at its own Schedule 2 rate for reactive supply. And there's another option, but just relevant to that option, does that help a developer like First Solar, or SolarCity, or even EquiPower, in any way?

Let's start with SolarCity.

MR. HANLEY: Absolutely. If our first goal here is to open up the market and allow some competition, we will take any opportunity to participate.

We do think that the cost-based approaches have worked well. The AEP methodology seems to have worked well. It seems to, looking forward, maybe have some antiquated components particularly since generators now, if you include inverter-based generators, have a very different cost structure and that cost basis may not incentivize the action which we want, which is the most economic deployment of resources. If inverter-based are cheaper, they should potentially be rewarded for that.

So by all means, if you move away from cost-based and you get something closer to paying the cost of service on the utility itself, or people have mentioned a tariff, those are certainly closer to an open market, which SolarCity would advocate and we think it encourages competition.

And I know we're getting into questions later about the market itself, and we don't necessarily think that is the right solution particularly for reactive power as well, since there may be some challenges locally in particular of not having enough participants to have a well-functioning market, on top of some of the onerous

applications that people have referenced before.

But by all means, a mechanism such as you discussed is I think a step forward from where we are, and by all means I think it is the right direction.

MR. CHANDLIEV: Yes, I support the previous speaker. And I want to mention two comments. I think it's great to have a standard mechanism across the country for this compensation.

MR. AMERKHAIL: Mr. Ginnetti?

MR. GINNETTI: Yes. Certainly, as I said at the beginning, we do have one plant in a non-organized market, and certainly having the opportunity to sell any products, reactive included, into another system, a transmission operator system, would certainly be something we would be interested in.

MR. AMERKHAIL: Thank you.

MS. CAIN: Thanks, Rahim.

I think we still need to hear from Dmitry Kosterev and Doug Hils on cost-based rates. Let's start with Dmitry.

MR. KOSTEREV: Thank you. So we, again we're following the FERC LGA 2003 Order in which we don't compensate generators that operate in the .95 R Factor band. So I'm not that familiar with the cost-based stuff, but if I may offer some technical opinion.

So if you look at the synchronous generator itself, it needs an exciter to operate. It can't operate without exciter. And certainly exciter needs a voltage regulator, and not for the necessarily purposes of providing reactive power but to maintain stability of the unit. So you need to have been able to withstand the disturbances on the system. Recently approved PRC 24 standard requires disturbance ride through which includes voltage fluctuation, which actually requires pretty high performance excitation system to be able to ride through those types of events.

So I guess the question of where to draw the line. And then it seems like it's pretty reasonable to, also to ask generator to supply, self-supply reactive losses from the terminal so the generator to the point of interconnection. If you're looking at the step-up transformers, they are 15, 20 percent impedance in some cases, so we have a 15- 20 percent of reactive power losses just from the terminals of the machine to the point of interconnection.

And the way to measure reactive power, you know, to recover cost-based at the terminals of the generator, or the point of interconnection. That's another thing you need to consider. Right now in the AEP methodology it's done at the terminals of the machine. Well if you look at trying to bring, you know, wind and solar generation at the same pace,

well maybe we need to consider looking at the point of interconnection, which is the high side of the transformer.

So this, I guess the question is where to draw the line? I mean, what's the responsibility of the generator? What's the responsibility--what's the service, you know, they provide to the system? And certainly if you're trying to redispatch generation down, you know, to provide the reactive support, that means to be compensated. If you bring in generation on line and you're ordering it to provide reactive, it needs to be compensated. But it seems like, you know, operating a .9 power factor, that seems like a reasonable thing to do, expect generator to provide without payment.

MS. CAIN: Thank you. And, Doug?

MR. HILS: Overall I guess the EEI, non-RTO/ISO members fairly, I guess, are open to alternative payment methodology, but the AEP methodology is widely supported. And addressing that on a case-by-case basis, I guess EEI doesn't support development of a generic rate for provision of reactive power services. It could be one where there could be shortfalls. When you develop a generic rate, as pointed out before, you may be under- or over-compensating for the service by doing something on a generic rate standpoint.

MS. CAIN: Thank you, Doug. Does anyone else.

Yes?

MR. SNOW: Just a follow-on, Dmitry. You kind of--when we talk about power systems, we really talk about it from a generator to the load and everything in between. But in Stu's part of the world, he is basically talking about the bulk power system, and there's some interface between where his operation ends and the rest of the system occurs.

You talked about generators having some reasonable--by words, not yours--power factor. Could you discuss a little bit from your engineering point of view what's reasonable for the load to provide a power factor or VAR requirements on the transmission system? And who should be responsible for getting that interface within reason, whatever "reason" might be?

MR. KOSTEREV: On the low side of things there is a power factor requirement on the load, and if you would be exceeding that requirement they would pay a penalty. Is this what you're asking?

MR. SNOW: Expand a little bit on that?

MR. KOSTEREV: So the load at the point of delivery is supposed to keep a power factor within a certain range. And they do it by, for example, by putting shunt capacitors on the distribution system to maintain the power factor.

So it should be--I think the load-serving entity would be penalized if they don't keep the power factor within acceptable ranges.

MR. SNOW: Stu, you look like you want to say something.

MR. BRESLER: I have to watch that look, then.

(Laughter.)

MR. BRESLER: But, no, since you asked, you mentioned, Bob, the interface between the bulk power grid where PJM's responsibilities primarily lie, and then everything else, right? Which on one side is the distribution load where load is being added to the system.

And I think it's important for that coordination to occur in the planning process so that the transmission planning folks and the distribution planning folks understand what each other is doing. Because from the transmission planning side, we will plan transmission upgrades in order to maintain acceptable power factor with respect to the load. So, you know, series devices and those sorts of things in order to maintain acceptable power factor.

From the standpoint of on the resource side--and we'll probably get into this a little bit when we start talking about the potential for any kind of a market-based product--we never really determined a requirement from the

standpoint of how much reactive do we need. Whatever is there gets compensated at whatever cost-based compensation is approved and then allocated out to Schedule 2 of the tariff.

There are minimum requirements as part of the interconnection process, which I think was mentioned earlier this morning as well, but we've never sort of determined a requirement against which market participants would bid to provide more reactive from a resource standpoint because we have some sort of requirement for system reactive that we need to maintain. I don't know if that helps you, Bob, or not.

MR. SNOW: I think that describes what I'll call the steady state dispatic reactive. Dmitry identified some dynamic aspects also, and Dmitry has spent a lot of his career on some voltage-induced delayed recovery aspects.

Where is there a market for dynamic to address issues that can be impacted both from a voltage point and a stability point?

MR. KOSTEREV: So I mean, Bob, you're referring to the phenomena called fault-induced delayed voltage recovery when faults on the transmission system can result in stalling of the residential single-phased air conditioners. And when the air conditioners stall, it draws a large amount of reactive power and potentially can put the

voltage stability at risk.

So the reactive requirements for this type of phenomena will be determined through the transmission planning process, and whatever the right solution will be identified and built to mitigate the problem.

MR. SNOW: So the fellow to my left, your right, would be very interested in providing some dynamic? Is that a market that's involved?

MR. KOSTEREV: That's certainly--he may answer for himself--but certainly that's one of the solution options to actually mitigate the problem at the distribution side, and that's probably very effective.

MR. HANLEY: Yes.

(Laughter.)

MR. HANLEY: To elaborate, we think that reactive power at its core may not look a lot different from real power, in that you could, if you had base supply of volume, or the reactive power itself that sort of mimics in many ways the energy markets, you have the availability to mimic the RA capacity markets.

And then to your point, getting into dynamic reaction, dynamic providing of VARs, by all means it starts to look like an ancillary service that some resources are better suited to provide than others. And we think all three of those are potentially services, and inverter-based

technologies, you're right, we think that we can do the dynamic ones pretty well.

MR. KOSTEREV: And I think a lot of the difference is just with the real power markets is, again, VARs don't travel well. So there's an issue of deliverability of the VARs from the source to the--where the demand is. Those actually, IEEE people from Iowa State are looking at the reactive reserves and the definition of reactive reserves. Professor Ajarapo prepared the paper. And actually looking at Q-max of the generator is not necessarily an appropriate definition of the reserves of the unit, because you have to deliver those reserves to where they're needed.

And we certainly saw this in one of the examples in '98. I was doing studies, and we saw that. We were running the cubic analysis on the system, and we're not getting the full reactive capability out of the generators. We're actually getting very little support.

And it turned out to be that those generators had a reactive current compensation. So you have a 15 percent impedance of the transformer, and then you have to loop--actually, to loop 15 percent back inside the generator. So by the time the voltage gets to collapse point, it's delayed, you know, not providing much support for the contingency.

So one of the things we did, it's the same watt of mega VARs, but changing the regulation point of the generator, like putting in line-drop compensation. We didn't change the amount of mega-VARs, but we changed how they were delivered to the system, able to get about 300 mega-VAR capacity on the system.

MR. SNOW: Any other comments from the panel?

(No response.)

MS. CAIN: Thanks. Several of you have mentioned providing reactive power from distributed resources, or resources located on the distribution grid. And that's one of our questions.

To a transmission operator, does the reactive power look different if it comes from the distribution system than if it comes from a generator at the same location? So when we talk about reactive power doesn't travel well, do we only mean over distance? Or do we also mean over voltage levels?

Stu?

MR. BRESLER: Thanks, Mary. Certainly I think what happens at the distribution level affects what goes on at the transmission level. So I don't think it's exactly the same, when we talk about they don't travel well, from the standpoint of location on the grid versus distribution to transmission. I think distribution definitely affects

what happens on the transmission system.

I think when we think of opportunities at the distribution level versus transmission, I think we're only thinking really of the relative size of the resources, and therefore the level of impact they would have.

So, you know, when we identify a need for reactive support at the transmission level, typically it's a need for a lot of it. And certainly that could be a market sort of based opportunity for sources of reactive.

When we put sort of almost through our transmission planning process, say we have an issue that needs to be resolved, we take the proposals for how to resolve that issue, certainly that's an opportunity for potential sources of that need to compete to provide it with the most cost-effective project that provides, you know, that satisfies the need.

But we were just--I think when we say that there are a lot of opportunities at the distribution level versus transmission, it's because a lot of these resources are smaller distributed type resources that would be able to provide more of that distribution support than significant transmission support that would travel well on the transmission system itself.

MS. CAIN: Thanks. Anyone else?

MR. JACOBS: If I could, I think to do some of

the things that Stu was describing--for example, there'd be modeling obligations. You know, the visibility of the devices, their capabilities all have to present or enter into the utility industry models and then be exercised.

And the initial threshold for all of this would be the first sort of recognition and inclusion of those kinds of assets in the listed capabilities.

MS. CAIN: Dmitry?

MR. KOSTEREV: Yes, I just want to second what Michael mentioned and the need for good models. From the transmission operations and the planning perspective, we like certainty. And we need to do system studies ahead of time--sometimes seasonal day-ahead, week-ahead studies, hour-ahead. And to do those studies, we need to have good representation of the equipment and its capabilities and dynamic response.

MR. AMERKHAIL: So, Mike, you mentioned that the capabilities of the assets must be rendered into the models that PJM uses. What does it take to do that? Do they need to be--do they need to have revenue quality metering, that sort of thing, that they won't like?

MR. JACOBS: The modeling inputs aren't so much from some metering level instrumentation; they're more inputs. I mean, it's almost like a spec sheet kind of entrants into the modeling, as an input into the modeling.

So in the narrowest sense, an inventory of the capabilities I would think actually would come from the distribution company and would be provided to PJM. But something of a substation-by-substation, here's the capability that exists with a confidence level, some range of expected performance, which we have to do with all the modeling. So it's a balance between, you know, deterministic and probability of what's really going on.

But in that sense it doesn't require anything beyond sort of registration of what kind of assets are there.

MR. AMERKHAIL: Okay. Thank you.

And on another topic, so, Stu, you mentioned that you're totally open to having distributed resources provide these services if enough of them can be aggregated, I gather. So just mechanically, does that mean you would include the costs of an aggregated project like that in the Schedule 2 rate that you then recover from market participants?

MR. BRESLER: Yes. I think that's one possibility. Certainly I don't think there's anything that prohibits that type of aggregation with respect to cost-based recovery.

The other possibility I was suggesting is rate recovery through transmission rates as opposed to through

Schedule 2 reactive cost recovery. So in response to a need identified by the transmission provider, and then a solicitation for proposals to satisfy that need from the standpoint of transmission upgrades, it could be recovered through a transmission rate in addition to, like I said, or as an alternative to, let's put it that way, a Schedule 2 cost-based reactive rate.

MR. AMERKHAIL: Okay. And the Commission looked at that way back in Order 888 and has recognized that some types of assets are transmission reactive power assets. Are you--would you have to recognize new types of reactive power assets? I mean, would you take something like a SolarCity inverter on the distribution grid, or an aggregated amount of them, and view it as a transmission asset?

MR. BRESLER: I think it might be a possibility.

MR. AMERKHAIL: Okay. Thank you.

MR. CHANDLIEV: I would like to make a couple of comments, if I may.

MS. CAIN: Vladimir and then Doug.

MR. CHANDLIEV: To Dmitry's comments about power factor controlled by loads, distribution system, usually it's supply for large customer, a bunch of residential--of course they can't control power factor, you know.

And second comment about modeling, detailed modeling, talking about load flow or dynamics model, just

normal utility using for study or independent system actuators, it's already complex enough. So I don't know if even they can handle that granularity if you go to distribution level. I don't know if it's really possible to do that or not.

MS. CAIN: Thanks. Doug?

MR. HILS: Thanks. I'm clearly speaking on behalf of Duke Energy and not EEI. I guess my question, I'm not familiar with--and some of the gentleman from New England, I'm much more on the operations side. I've always been control/BA in operations.

So my question I guess would be has anyone looked at, to the extent that you are looking at resources that are distributed in that manner, and especially for provision of reactive, what would it take, or does it take additional capability of the distribution provider to be able to have that feedback?

How would you get cost recovery of that? Does that start to step into some of the things that the states would have an interest in? You know, that as well. So I guess our emphasis would be, you know, down the line of what would it require? What would it take? Because it's really all those costs that should be considered to be able to ensure that we can really use that at the transmission level. Thanks.

MS. CAIN: Comments on that? Mike?

MR. JACOBS: Well this is a marathon, not a sprint. We start--my experience starts with including the terminals of the cross town cable, of the DC transmission line. And it simply wasn't in the tariff at the time that such an asset could receive compensation.

It wasn't a great leap to change that. The question of whether this should be in one jurisdiction or another, I think the question first starts, is it something that's competitively procured? Is it, you know, a market item or not?

So I wouldn't expect to resolve these things in a morning.

MS. CAIN: Ryan?

MR. HANLEY: I'll allow for some positive experience that SolarCity has had with a mechanism that seems to work for us and the receiver of our services. We participate in a couple local capacity requirement RFOs. As you mentioned, competitive solicitation where we offer our service regardless of the cost to us.

And then the technology from there is rather simple. We have had some robust discussions with our partners on how to provide two-way communication. So in that capacity it's actually a little bit different than some of the demand response markets where you have to use

statistics to understand what your response is.

It's pretty easy to provide the two-way confirmation, to say that you actually got the benefit of the resource that you wanted to call, which is pretty important obviously in the transmission, in the operations world. We have had some good success with that, to have those competitive solicitations.

MS. CAIN: Thank you. Any other comments on that?

(No response.)

MS. CAIN: Okay. I think next, we've had a lot of people bring up the idea of a reactive power market. So we would like to discuss first, are there ways that we could do competitive solicitation for reactive power instead of or in addition to some of the cost-based rates?

And after we discuss that, then we can get to other types of markets. So let's start with competitive solicitations. Do any of you have experience with doing some competitive solicitations for reactive power? Or do you have ideas of things we should be looking at in order to implement competitive solicitations? Ryan?

MR. HANLEY: Maybe I'll just add on to my last comment with slightly a bit more detail.

It was great for a LCR, a Local Capacity Requirements, great for us because we believe with reactive

power, as was mentioned before, there's a local capability to this that is important. It travels locally. It doesn't travel far.

So in the current mechanisms that the ISOs have to identify local areas, this is a great resource to really go right after that. And in that regard, we are getting a tariff for what we're providing locally. And we're not even assuming that we're going to provide services to the broader VOC network, which I think in some regards might be--there's a bit of fairness for that, for reactive power for sure.

MS. CAIN: Anyone else?

(No response.)

MR. AMERKHAIL: Ryan, I'm just curious. I mean, we mentioned the possibility of competitive solicitations in Order 784, so if you can speak about more of the details of the solicitation that you--I mean, was this carried out by a load-serving entity, an RTO?

MR. HANLEY: Yes. It was part of the--an ISO's LCR, and then it was administered by a load-serving entity. So one of the IEUs facilitated it. So within the long-term planning process at the ISO level, they identified an area that required some additional capacity support. And so we were not providing reactive power, since there wasn't a market for this where we were working, but nonetheless we were providing some real power and benefits that were around

capacity and energy delivery.

We also had some ancillary services that were part of it. But by all means, per my comment earlier, I think reactive and real power markets by all means are different, but there are some similarities with how we would address those. Being able to aggregate our resources and with our two-way confirmation there should be no reason that we can't go after reactive power needs in one area if it's identified for us either through the long-term planning process, or some other mechanism.

MR. AMERKHAIL: Thank you.

MS. CAIN: Stu mentioned earlier that PJM doesn't really identify a need for reactive power necessarily, but when you do cost-based rates you pay all the generators. Do any of you want to comment further on how we could identify the need, if we were to do a competitive solicitation? It seems like one thing you need to do in order to do a solicitation is identify a need that you're soliciting for.

Doug?

MR. HILS: I think from the perspective of the EEI members that are outside of the RTOs and the ISOs, it's up to the individual systems to determine, you know, where their needs are.

Many times the generators are already--well I think even your staff had noted, in some cases it's cited as

good utility practice to operate within the power factor range. So on a case-by-case basis, you may see cost-based, I guess, provisions being noted by individual members to go ahead and pursue a rate through FERC on that.

I guess overall the solicitation side, though, I'm not quite sure--and I think the staff even noted in its paper--there's different approaches to how you would look at that. There's one thing for having the capability and another thing for how you would compensate for it as it's used. And to the extent you're driving other resources--or driving the resources to provide more than perhaps what you have.

So I'm not quite sure how a solicitation process, to the extent it was used, if a system did determine that it needed that service, I think in the solicitation process it would have to define all those different parameters to make it useful. It's not I'll provide it for X amount of dollars because where you need it and how often you need it and all those things vary widely, whether you're in an RTO or not I guess.

But so the solicitation process, I guess to the extent that a system desires to, you know, actually determines a need and decides that they need to go after that, there are different options. I don't think any of the members want to be told you can only use this one way of

doing it. Thanks.

MS. CAIN: James?

MR. GINNETTI: Just one comment. As I said earlier, I think because of the limitations on moving VARs around the system, a competitive market may be challenging.

One of the concerns I would have--and I just thought of it as I was listening to the last speaker--if you had it selective where only a subset of the generators provided reactive control, you would likely get to where the ISO was, my guess is, favoring one over the other. Because if he commits unit A for energy, he gets reactive control on that same generator. And if the generator next door didn't participate, you know, how would the ISO handle that situation?

You would want to keep it out of the energy dispatch, but in the back of their minds my guess is the operators would rather have the unit that could provide reactive--that was willing to provide reactive, in addition to its energy.

So I think you would have some of those complexities. I think the system now--and I think because you'd have only pockets of where you could have a real competitive market, whether some sub-area where there were multiple units that could bid--you might run into some

complications. Whereas, in New England, like I said earlier, you know, essentially everybody who can demonstrate their VAR capability gets paid. So when the ISO commits those units, they really get both their energy and capacity as long as--in addition to their VAR capability.

So I think if you get to that competitive solicitation on a macro scale, it may prevent some other--it may present some other challenges.

You know, I certainly agree with earlier comments that on the distribution level that may be fine. And you may actually have under the distribution company tariff some competition. But to get it up on the bulk power system level, it may present some other challenges to do that.

MS. CAIN: Thanks. Anyone else?

(No response.)

MS. CAIN: To wrap up talking about markets, what would be some of the things that would be needed, or what would be some of the impediments why we shouldn't go that route to have a competitive market for reactive power similar to what we have for real power? Stu?

MR. BRESLER: I think you're probably going to talk about one of them this afternoon. And that is, as I think we've all agreed a couple of times now, reactive power is extremely locational in its need in its provision. It doesn't travel well.

And so, you know, if you're going to have some sort of, you know, market-based product for it, it I think becomes quickly very so locational that what you wind up with is, you know, cost-based pay-as-bid type scheme because, like I said, it gets to locational in nature and then market-power mitigation kicks in and everything becomes cost-based anyway.

I think the most likely place, you know, as we've said already, and I hate to be repetitive, is in the transmission planning process.

And one thing I thought I'd throw in that might be interesting is, I think when we all think of reactive power provisions sometimes we think mostly of injecting VARs for the purposes of voltage support.

One of the issues we're seeing on PJM's system, given the changing fuel mix and retirements in some areas of PJM and new generation added in others, is we see a lot of high voltage conditions on the transmission system where we're actually planning through our transmission planning process the addition of static VAR compensators for the purposes of absorbing VARs during lighter load conditions when the voltages are actually too high.

We actually have conditions on the system in some locations where we operate generation--call generation on for the purposes of absorbing VARs because of high voltage

conditions during light load situations.

So I think that might be something else for us to think about as far as alternative potential resources that we might be able to identify, again most likely as part of the transmission planning process, that could be alternative sources that could provide that type of voltage control.

MS. CAIN: Thanks, Stu. Anyone else? Yes, Doug.

MR. HILS: I think in general just the--again, I think it's just a matter of whether there's a need. I was asked last week in a discussion with the Electricity Committee for NARUC, they asked me why are we talking about reactive? And actually in our discussion with the EEI members we really were not seeing the driving need outside of the markets.

You know, to the extent that we're capable of managing--meeting the new requirements in fact that are in the PRC NERC standards, and to the extent that we're able to do that, we're not seeing a driving need to go out and look for, you know, are there additional resources?

So I guess driving for a market, locational regional differences definitely exist there, but right now we're really not seeing the driving need to look for additional reactive capability.

Now as you have, over the years--and like I said, this is a marathon not a spring--over the years as we see

some generation retirements and things like that, you may start to see some of the need for looking into reactive capability. But like I said, it's more on a case by case basis of what you will probably find outside of the RTOs.

Thank you.

MS. CAIN: Thanks, Doug. Ryan?

MR. HANLEY: Yes, I'll certainly agree it seems like every situation is probably different. A couple we've seen is that, to highlight the difference between sort of static reactive power and then dynamic reactive power, we are seeing a lot of need recently for that dynamic reactive power. And I think utilities and the ISOs have a lot of tools in their tool kit right now to handle the static, and in many ways their grids are set up to manage reactive power flow at that level.

Yet we've seen some installations of new inverter-based technologies, moratoriums going on in those installations because there is such a need to manage the dynamic reactive power. So we're seeing an impact, a real impact and a real need, and there are some resources out there that if you could compensate for the service they can provide--for example, reactive power--they can both provide a service in situations and also help the economics of those resources themselves to be more competitive in the marketplace.

MS. CAIN: Thanks. Dmitry?

MR. KOSTEREV: I just want to say that it's true that the need for the dynamic reactive power is becoming greater and greater in the latest years. One of the phenomenas we described, air conditioners stalling, which requires dynamic voltage support.

Another phenomena is degradation of variable generation in the system, when you have sudden changes in the flows and you have to plan for and operate for dynamic transfers. So how do you enable, you know, the transfers across the regions while supporting voltages at the same time within acceptable levels and maintaining appropriate reactive margins for contingencies? So that is certainly an important issue.

And how do you value the reactive power? That's another question. When you compare against conventional solutions like SVCs, and so we actually try to do some study, you know, when--we didn't go very far, so we don't have any conclusions--but when we were integrating a large amount of wind generation the question was what's the best way to do it? You know, to have a static VAR compensator compensating for wind hub consisting of maybe 10 generators--I mean, 10 plants, 1,000 megawatt capacity versus each of the generators providing its capability.

We ended up, you know, with the generators

providing their own reactive support source supply, but we didn't go very far with the study. But that was at least an attempt in our mind, you know, to quantify the value of reactive.

MS. CAIN: Anyone else? Vladimir?

MR. CHANDLIEV: I just want to mention solar PV project, very competitive as far as dynamic reactive control. It's reacting much faster than conventional generation. And also it's variable generation, what we call, it can produce reactive power independently, what it's doing as far as reactive power goes.

And I also want to mention, everybody's talking about market and we've been talking about system intact conditions, but around many situations when something critical happens on the system and we'll be calling operators to inject or observe VARs, and we've done this very fast. So thank you.

MS. CAIN: Thanks. For Ryan and Vladimir, do any of your resources currently provide dynamic reactive power? Or do you have that capability turned on?

MR. CHANDLIEV: Most of them. We depend on location. Some transmission owners asking us to (unintelligible) power factor. Some have given us voltage schedule, depending on season or time of the day.

MR. HANLEY: And, agreed. All of our inverters

have that capability in the ground now, and we're basically biding our time for some of the working groups to finish the smart inverter requirements so that we can turn those on. But we're certainly expecting that to hit the marketplace.

MS. CAIN: Thank you. A few people have mentioned--and our staff report talked a little bit about this--that some regions do pay for reactive power through cost-based rates, and other regions don't pay for reactive power. And I want to discuss that a little bit, a little of the history, if any of you know it, of why some regions have decided to pay over the years, and why some regions have decided not.

Is it just because there's not a need? Or are there other factors contributing to that?

MR. HILS: I'm not sure.

(Laughter.)

MR. HILS: I know for the regions outside of the United States, you have the thought of when a generator interconnects you have the idea of meeting a certain power factor and stay within a certain range, and that be the expected, you know, capability.

To the extent that you need to do other things other than that, I guess some systems may have pursued cost-based rates from the standpoint of doing more than that. But for a lot of systems it is back to just the fact that

it's seen as an undergrid utility practice operating within that range. And, you know, and then of course the obligation and the GOP's interaction with the transmission operator, basically staying within its voltage schedule.

MS. CAIN: Stu?

MR. BRESLER: Yes, I think from PJM's standpoint, including Schedule 2 as part of the PJM Tariff was a reflection of the sort of overall unbundling, if you will, when we designed the markets following 888-889 deregulation in general.

The assumption was that generators would largely no longer be operating under, you know, cost recovery rates with the state commissions but rather would be looking to the wholesale tariffs to ensure complete recovery of all their costs. And so this was another component that needed to be separately accounted for because it wasn't in the real power energy payments or capacity payments or any of the other components.

So I think that's why the organized markets, at least from PJM's standpoint, went that way. I have a much harder time speaking for other areas that may not have gone that way.

MS. CAIN: Thank you. Any other comments on that?

(No response.)

MS. CAIN: The other thing we wanted to talk about is whether the obligations of generators, whether they're paid or not paid, so there's the interconnection agreement that put some obligation on generators, but what other places do generators get obligations to provide dynamic reactive power, or to come online only to provide reactive power to be dispatched off of their economics for reactive power?

Stu, go ahead.

MR. BRESLER: Yeah. I kind of I think started out with this in my initial comments to the first question, but from PJM's standpoint we do have the ability to dispatch resources, active power output such that we can get the reactive power provided that we need, either injection or withdrawal of reactive power.

So we can either dispatch a unit's active power output down or to maximize reactive power output when it's necessary to support a voltage. We can bring units on, either to provide reactive power and support voltage, or to absorb reactive power in order to regulate voltage within acceptable limits.

The PJM Operating Agreement, as part of the Tariff, provides compensation to units for following those operator directions in order to provide the reactive power that is necessary.

MS. CAIN: And one follow up, Stu. Does that apply to all generators, whether they have a Schedule 2 rate or not?

MR. BRESLER: Yes, Mary, it does.

MS. CAIN: Jim?

MR. GINNETTI: Mary, I guess what I'd say is this: If you look at the revenue streams available to competitive generators, in some of the markets you have a capacity market, and to the degree that every resource that gets a capacity payment has the same obligation, then I think that's fine. Then you could say, you know, as a utility practice you need to provide this.

I think the deviation comes from, you know, of late we have a lot of resources that get a capacity payment, the same capacity payment, and they don't all have the same obligations. So in my view it's not fair to be paying resource A who does not have to provide reactive or frequency response or something else the same capacity payment that my generator gets paid but I have all of those obligations and costs.

So I think--and I think maybe this got to your question a little earlier--some of the evolution in some of the organized markets of why did they start paying for reactive supply, I think they may have realized that there were some resources that didn't have that obligation but

were getting the same capacity payment.

So I think you need to break those--again, we're very much in favor of comparability. Everybody who gets the same payment should have the same obligations. So to the degree that's not the case, that's when I think you need to have a supplemental revenue stream to pay us, and others who provide that other service, that not everybody who gets a capacity payment has to provide.

MS. CAIN: Thank you. Anyone else? Yes.

MR. AMERKHAIL: So, Vladimir, you mentioned that inverter-based generation can supply reactive power supply, or absorb, without impacting the amount of real power it provides? Is that right?

MR. CHANDLIEV: That's correct.

MR. AMERKHAIL: And earlier Stu had mentioned that in general their system pays you for the capability, and then if you're actually dispatched it means, at least if you're a conventional generator, you're giving up some amount, at least possibly you're giving up some amount of real power sales and so you get a lost-opportunity cost.

And I assume you don't have too many solar facilities in your market, but if you did what happens to the opportunity cost if there isn't one? Or are there different opportunity costs?

MR. BRESLER: Well I guess if there's no need to

reduce active power output in order to provide the reactive power that's necessary, there wouldn't be a lost-opportunity cost to pay. So it would sort of be, you know, whatever fixed cost recovery is in place is sufficient to cover the total cost of providing that reactive.

MR. AMERKHAIL: And could I look at that as a competitive advantage that you might dispatch that type of resource more?

MR. BRESLER: To the extent that type of resource is dispatchable. But certainly I would think that it would have an advantage as far as being able to provide the reactive much more freely than a resource that would need to adjust its active power output in order to otherwise provide it, yes.

MR. AMERKHAIL: Vladimir?

MR. CHANDLIEV: I just want to make one caveat about the active power loss. The project should be designed correctly. There should be oversight. I just want to make a caveat, you know.

MR. AMERKHAIL: Michael.

MR. JACOBS: And I've had experience with storage assets where there's an ongoing operating cost. In fact, this was true actually with the DC inverter crosstown cable as well. To keep the unit energized, there is losses. So to be ready to provide reactive power, there is operating

costs. It wasn't necessarily energy costs that were not bid into the market, though.

MR. AMERKHAIL: And, Stu, is your system capable of capturing any of that?

MR. BRESLER: At this point I would say I don't think there is a tariff provision to capture that particular component, no.

MR. AMERKHAIL: Probably because there's no demand yet, or?

MR. BRESLER: Or we have not had a participant that's requested us to look into adding that particular component. But we are looking at these types of things in our stakeholder process. So I would imagine, should that come up, we will need to look into that, yeah.

MR. AMERKHAIL: Okay, thank you. Does anyone else have thoughts on this?

MR. CHANDLIEV: I just, in this case I would like to just focus, looking at solar as a big statcom sitting there, and they can utilize the capability any time.

MR. AMERKHAIL: Your projects are mostly utility scale?

MR. CHANDLIEV: Yes, utility scale. We just develop a control system, just can utilize inverter capabilities and provide reactive support dynamically any time.

MR. AMERKHAIL: Thank you.

MR. CHANDLIEV: And that's also true for the wind power plants. You know, the Type 4 technology can operate as a statcom with no wind generation on the lines.

MR. AMERKHAIL: Thank you. That's helpful.

One other thing, and this will be the most difficult, probably, we talked earlier about adding more types of reactive resources to the transmission access charge. And I guess the difficulty from FERC's perspective often is where do you draw the line? A conventional generator with say a hydro resource with reactive capability would provide dynamic, I believe, pretty high quality dynamic reactive capability the same as I guess a statcom, if that's the right term, or some other new resources.

Is there any reason why they shouldn't have part of--if you allow a new resource into the transmission rate, is there any reason you shouldn't allow some of the old resource to recover at least some of their cost that way as well? And is it a slippery slope?

MR. BRESLER: You're looking right at me, so I'll take a shot, I guess.

(Laughter.)

MR. BRESLER: I think, as Michael said earlier, I would agree with this. This is a marathon not a spring. So none of these issues are all that easy, and some are going

to take longer to solve than others.

But I guess from my perspective, I think as long as--as long as we're careful that there isn't double recover, if you will, right, where they're recovering a certain amount of costs as a transmission asset because they're providing a transmission service, and then turning around and also recovering that someplace else, that same cost, twice, I guess from my own perspective I don't know why we couldn't allow some sort of cost recovery as a transmission asset if it's providing a transmission-related service.

Like I said, I don't know if that's easy to make sure that we can ensure that that doesn't occur, but certainly conceptually I think it could be done.

MR. HILS: I think from EEI's perspective, you may already have a case where some generators, and similarly to what Stu had mentioned, some generators may be recovering their costs associated with providing reactive through bundled rates and other generators are not.

But based on the business models, not all generators are similarly situated. You could have existing agreements that prohibit certain resources from recovering costs associated with reactive. So you may have that, as well.

EEI believes that any generator has the

opportunity to submit cost-based reactive power tariffs at the FERC at any time, barring responsibilities or anything that's prohibiting them from doing it through other agreements.

MR. AMERKHAIL: Thank you.

MR. HILS: Sure.

MS. CAIN: We did have a question on the agenda about bundled rates. So thank you, Doug, for bringing that up.

In some cases over the years there have been generators that are not paid for reactive power, that claim that it's not comparable because some generators have bundled rates, and independent generators do not. Yet they're both under the same transmission provider that doesn't provide anyone for reactive power.

Is there anything the Commission should do to reconcile that when we look at reactive power rates?

Doug?

MR. HILS: Since I started it--

(Laughter.)

MR. HILS: --I guess from the ISO, non-RTO members, EEI, there are those who don't really believe there's anything that needs to be reconciled. The structures that are in place, and the capability for generators to still submit cost-based tariff to the FERC for

approval, I think all of those capabilities are, to the extent that you have a generator wanting to do that. But as I mentioned earlier, we really weren't seeing the driver for us to change essentially what we have in place in a lot of areas, and also to the extent that you may also have contractual requirements that say that you don't get recovery for those types of services.

Thanks.

MS. CAIN: James.

MR. GINNETTI: I guess I would just put a plug in that, you know, comparability should be the key. And generators who provide the same services as some other providers, whether they're rate-based or not, should be compensated for providing the same service.

So I think the Commission needs to be the policeman in that kind of situation to make sure that resources, whether they're rate-based or competitive, are getting paid the same for the same services.

MS. CAIN: Anyone else on that? Stu?

MR. BRESLER: I have to say, our issue really is about discrimination. So this gets to the heart of it.

MS. CAIN: Thanks. And then, just going back to cost-based rates and transparency, is there anything you think the Commission should be doing to help with transparency when a generator files the AEP method for

where that information comes from, or how the rates are published?

James?

MR. GINNETTI: Yes, I guess I've thought--I mean, clearly you have some sensitivity of releasing confidential information. So clearly the Commission would have to make sure that that's not done.

But if it could somehow disguise, you know, the source of the data--as I mentioned earlier, in one of your documents you talked about a huge database of historical cost information. That by itself could be very helpful to people who either were doing to come into the Commission for the AEP method, or perhaps in the discussion some of the ISOs and RTOs have as to what their reactive rate should be set at.

MS. CAIN: Thank you. Anyone else? Stu?

MR. BRESLER: Mary, this is Stu. I just, I guess all I would say is that, you know, Schedule 2 reactive rates in some form are really kind of an Uplift cost, right, from PJM's standpoint, because they're allocated out to all load in a given zone.

We have other areas where Uplift costs are significant. So transparency is a real concern for market participants because they need to understand where those costs are coming from, because they need to be able to

anticipate them going forward as best they can.

Reactive, to this point, hasn't risen to that level because, Like I said earlier, it's a relatively small cost and it's also relatively static over time. So they're relatively easy to project into the future what that, again relatively small, cost is going to be.

So again, I think as I said earlier, from at least my vantagepoint, from what I hear from our market participants, at least in this area transparency hasn't been a real concern.

MS. CAIN: Thanks. And then for Vladimir, Mike, and Ryan, have any of you looked at how you would develop a cost-based rate for storage for solar, since the AEP method that we usually use is very focused on synchronous generators?

MR. CHANDLIEV: We didn't look.

MS. CAIN: Okay.

MR. CHANDLIEV: Not yet, at least.

MR. JACOBS: The sort of simple demarcation is the inverter is different from what's behind it, the DC generator.

MR. HANLEY: We agree. The system providing the power should be relevant and it should be the inverter itself. But like all the comments earlier, I think cost-based doesn't necessarily put--as comparable as some other

mechanisms could be.

MS. CAIN: Thanks. Does anyone else on staff have questions?

(No response.)

MS. CAIN: All right. Any other comments from the panel?

MR. HILS: Thanks, Mary. I just wanted to comment, I guess from our comments it's not a matter, in my mind, it's not a matter of discrimination; it's a matter of ensuring that we're not creating a need where a need doesn't exist. And I think that's more a fact of what we're looking at. And so that's why we're cautious in saying, yes, open things up. It is locational. All the concerns that come about of it being regional, and what kind of cost would you incur if you were to try to expand that. You know, ultimately we're looking at serving customers and, you know, keeping their costs reasonable.

Thanks.

MS. CAIN: Thank you. Any other last comments? Yes.

MR. HANLEY: I want to add, one topic we didn't quite get to, in the spirit of having as many resources participate as possible, there are some markets, behind-the-meter resources that cannot participate in wholesale, and we think there are some technology approaches that can solve

that. We mentioned aggregated resources a couple of times, and an aggregated resource looks a lot like a resource that is intertied into the distribution or transmission grid.

So having that avenue to--for providers to have the burden of making it easy and making it look like a real asset, if they are willing to take that burden, we think that they should be able to participate in these markets as well.

MS. CAIN: Thanks. Anyone else?

(No response.)

MS. CAIN: With that, I'll turn it over to Rahim.

MR. AMERKHAIL: We will just have about a 10-minute break between panels. So let's convene back here at 10:35, please. Thank you.

(Whereupon, a recess is taken.)

MR. AMERKHAIL: Okay, I think we're going to start in a few minutes, so if people could start moving toward their seats, please. Thank you.

(Pause.)

MR. SNOW: I would like to add my welcome to all of the panelists and the people in the audience, as well as those on the Web.

Earlier this morning the Reactive was an interesting and lively activity. I hope to continue that preference. Let me just kind of preface this by saying this

is a--my comments, not that of the Commission; I don't speak for anyone here--sometimes I don't even speak for myself, for that matter, but...

(Laughter.)

MR. SNOW: During the Commission meeting that announced this workshop, Acting Chairman LaFleur asked how Order 794--that's the Reliability Standard--fits in with Order No. 784, Power Screens. The proceeding is specifically how frequency response will be considered at the workshop.

Staff responded that 794, the approved Reliability Standard for BAL-3, Frequency Response and Frequency Bias Setting, identifies annual median frequency response obligations for all Balancing Authorities or Frequency Response Sharing Groups.

The Commission-approved standard defines what performance is required. There's a graphic behind me, the cheat sheet behind me kind of shows the top part of what is required. You have an event through an imbalance on the system. The classic shape of the frequency over time, time in terms of seconds so we're much faster than regulation. While the bottom identifies--but our discussion here is on how that performance may be achieved, or how resource responses would be measured.

Today our discussion should address how Balancing

Authorities would procure, measure, and if appropriate price their share of the annual median performance requirements.

Discussion of the magnitudes of the response, or the process on how you get there, or the inputs of that response that have been approved by the Commission are beyond the scope of this workshop. We're just discussing the how, not the what.

The electric industry once routinely operated its resources with certain governor settings. Many of those resources had responsive turbine generators with relatively fast response--not sliding pressure boilers but real drum boilers. And they routinely dispatched these units below maximum output to leave headroom for a response so as to provide useful levels of primary response from a large percentage of the synchronous generators, without providing a separate unbundled payment for such operation.

The interconnection-wide physical performance that we will be discussing requires the injection or withdrawal of power equal to the magnitude of the imbalance, within a very short time after that large imbalance. Small imbalances which result in the interconnection frequency changes within the deadband of most of the resources also requires some power changes but this is mostly provided by the inherent frequency response of some types of demand.

In all cases, sources of power to make up the

imbalance can be conventional generation, some types of renewable generation, frequency-activated demand response such as our friends from ERCOT will tell us about, and the inherent response of some types of loads or newer technologies such as storage.

However, with typical conventional resource droop settings, the typical way that units are provided, it takes a relatively large amount of synchronized headroom to provide required power.

We would like to explore whether a Just and Reasonable approach would be to procure at least some of the response from market-based sellers using less expensive or more efficient approaches, which is the general focus of Order No. 784.

To that end, the question in the workshop notice and agenda are intended to start our discussion, but certainly not limit our discussion, including exploring types of resources that are available and the technical capability of meeting the performance requirement; and, whether there are regulatory or market barriers preventing Balancing Authorities or the Frequency Response Sharing Groups from utilizing the most effective mix of resources to obtain frequency responsive services.

Thank you to the panelists, and let me kind of introduce you. We have some of our same faces as before,

but we've added--let me see, starting from my left, Sandip Sharma, a Supervisor, Electric Reliability Council of Texas; Erik Ela, a Senior Engineer, National Renewable Energy Laboratory--

MR. AMERKHAIL: For the camera, you should--

MR. SNOW: Sorry. Doug Hils, Director, Midwest System Operations, Duke Energy; Ryan Hanley, Director of Grid Engineering Solutions at SolarCity; Dmitry Kosterev from BPA; Stu Bresler from PJM; Erik Ela, Senior Engineer, National Energy Research Laboratory; and my eyes--Clyde Loutan, Senior Advisor Renewable Energy Integration, Cal ISO; and Jim Ginnetti, again EquiPower.

Starting our discussion, I would like to begin our discussion this morning by asking whether, in light of changing circumstances, there should now be payment for an appropriate performance for providing frequency response services? Or should some level of performance be more strongly required in interconnection agreements?

Do you want to start off, please?

MR. SHARMA: Sure. Thank you for organizing this workshop and inviting me. From ERCOT's perspective, frequency response is our interconnection requirement and currently we are in a process of reviewing the ancillary service for future, and primary frequency response was one of the service we identified. And we do see a value in, in

paying for even phased response, but trying to pay for a frequency response that's responding for every small deviation gets really complicated.

So from ERCOT's perspective, if you are--if you are--if the primary frequency response you're designing is based on even-phased, then it becomes very clear with a two-second and four-second type of data. But if it's--if you are trying to pay for, you know, a primary frequency response for all instances, then it becomes really complicated.

MR. SNOW: Could you expand a little bit on that, on what you mean by "every little event" versus the major events?

MR. SHARMA: So one example is right behind, you know, in the graph, that's an event, right? So it's very clear, it's very easy and very--it's very easy to see governor response for a event, for frequency event, when there is a big deviation. But if we are focusing on a small deviation, then we are talking about a very fraction of a megawatt that might look like a noise in a system.

MR. SNOW: Okay. Thank you. Doug?

MR. HILS: Thanks again. I guess from a perspective of a frequency response, right now BAL-003 is a requirement on the Balancing Authorities to be able to meet the level of frequency response. And I guess there was a--

back in the discussions about BAL-003 it was around, okay, do you require generators? And all generators are doing it? Or is it something that you keep at the BA level?

And really similar to BAL-001, which is more tied to the regulation, and BAL-002 more tied to contingency reserves and such, BAL-003 now brings in that requirement at the BA level. And the requirements within each BA are going to be different. You know, every Balancing Authority has a different resource mix. Some may be already very, very capable of meeting the standard once implemented with no need to look any further, and others may be looking at it to say, yeah, maybe we ought to look at enhancing capability, looking at alternative resources out there. But I guess overall, on behalf of the EEI ISO/non-ISO/RTO members, it's more a matter of it really ought to be looked at on a case-by-case basis. We shouldn't be pushing for a market-based approach to something where in many cases it's not needed.

The Balancing Authorities today can be looking at different alternatives. For example, when you're looking at frequency response and leaving some margin, well to the extent that that margin is already on a generator that's there for contingency reserves and it's also frequency responsive, those are some additional things that we are looking at. Well, you're not duplicating the cost for those types of things.

So I guess it's more a case of where I think it is on a case-by-case basis where you may see some systems requests for certain approval down the line, but at this point it's more a matter of looking at how we're going to be impacted over the net few years, and looking at it from that perspective.

Because as a standard is designed and looking at the response to the interconnection, at least--and I'm speaking to the interconnections that I'm most familiar with, Eastern Interconnection, and I believe the WCC as well--you have the capability to meet those standards in most cases across the board and just sustaining that. NBA is looking at the long-term, maybe looking at some alternative solutions there.

MR. SNOW: Just to follow up on that, the--granted each mix of generation has its own capability, hydro units with large heads are certain capable of doing lots of things. Certain types of boilers, you mentioned the EPA rules, the smaller coal units that were really just drum boilers, had lots of capability of doing that. But there's a cost associated with that.

Could you describe, or talk about how, if one just met the requirements as opposed to having excess, would there be a cost savings? Is there a way of pricing this so that the net energy, the net cost of the system, lowers?

MR. HILS: I say overall, from the perspective of the cost, as you mentioned, some of the resources out there, those with governors, for example, are based upon the standard being adopted, are looking at their current settings, are assessing what they're capable of doing.

We're aware of, like the Midwest ISO, for example, or Mid-Continent ISO, looking at working with its generators to look at the response, and actually are providing feedback to the generators on what they're seeing for certain events.

So we're already seeing some things based upon the NERC standard being developed of resources looking at their capability. You know, what are they capable of doing? I really can't say if--and this is speaking as Duke Energy--I'm not sure what MISO's final intent is, as to whether they're going to structure something toward compensating for frequency response because there's different opportunities there.

You could structure something for compensating for response, or you could be looking at compensating for other types of resources where you want not necessarily frequency response but you may be able to offset your costs of carrying frequency responsive reserves by having load triggers, I guess similar to ALARs in ERCOT of actually setting some thresholds. Like I said, not frequency

response necessarily but aiding in meeting the frequency response standards.

So I'm sure there's a lot of those different types of things being looked at to minimize the cost of providing that additional service.

MR. SNOW: Ryan?

MR. HANLEY: Thank you again for letting me participate in this workshop. SolarCity does recognize and does believe that there is, as you mentioned, there's a headroom and therefore there's an opportunity cost for frequency response.

And to your questions, they are, right now the way it stands, being bundled into the payments that these generators receive. It's not necessarily being dispatched the most economic way possible. There is a service there that can be quantified and can be provided by other resources.

And even though we don't think the service should be discriminated by technology, it is technology differences in our conventional generators that is opening it up for a new opportunity to say that there are more economic ways to go after frequency response.

We think the demand is there. We think the potential in the future for these events will increase and be more frequent, as well as the absolute size of events has

the potential to be larger. So the need for frequency response we think is going to increase.

And as far as the market itself, we believe that there are enough players out there in the market to provide this resource to make it a true market. With all the inverter-based technologies obviously that are coming online, some are particularly well suited for this type of fast autonomous response--batteries in particular come to mind of things that are basically made for this sort of thing.

And with them going into the ground, we think there are few technical barriers to opening them up to participate in these markets, both from integrating into the ISO or the system operator, as well as on the owner of those assets to make upgrades to their systems to be able to participate.

MR. SNOW: Are there any regulatory barriers that you'd like to identify?

MR. HANLEY: There is. A couple. There's one in particular, obviously. Unlike frequency--sorry, unlike reactive power, which we discussed previously, frequency response can be delivered across the grid. And so the capability of a resource on the opposite side of the grid to provide services on the other increase.

And so distributed generation behind the meter,

particularly inverter-based storage devices, should be able to be allowed to participate in these markets. They are an untapped resource that we think benefits the end customer as well as the utilities to be able to use the lowest-cost dispatch for these services that they require.

MR. SNOW: Can you see any of the IEEE standards that currently are required to be a barrier to your providing this service, considering the range of frequency might be quite significant?

(Commissioner Moeller leaves the meeting.)

MR. HANLEY: There are likely some resources that are inverter based that will be less suited, so--however, the IEEE standards as it relates to storage specifically don't seem to be a barrier.

There may be a challenge for some inverter-based with solar behind it to respond to the full range, but nonetheless I think there's plenty of resources that will be on the grid that could provide that service. It's less of an IE requirement and more of just logistics. There's also the challenge of working through the communications and allowing these resources to participate.

So I know that PJM has done a bit of work, and maybe Stu can take this later, but a bit of work on allowing a different type of metering and telemetry of behind-the-meter resources to participate in the frequency regulation

market that are not the, you know, the revenue-grade meters that they have on other generators.

As long as you can get the accuracy you need out of these devices to participate, or to have the compensation at the end, I don't think there's any downside to reducing some of the costs of metering and telemetry on these devices. So if you can reduce the costs of metering and telemetry for some of these devices, it makes it easier to get more resources to participate and less of a regulatory issue and more of a practical one that we think would open up the market even more.

MR. SNOW: Dmitry?

MR. KOSTEREV: Again, thank you for inviting me to participate in this panel. I think, yes, you know, the frequency response should be paid for because it has a one-to-one correspondence with the megawatt production of a generator.

The chief frequency response you have to back off generator to create enough headroom, so in case of a frequency deviation the generator will have enough capacity to pick up--increase its output.

So as you know, I favor the UK model in which you require the--each generator is required to have capability to have response. And then, based on the operating conditions on the selected generators, provide the response

and get compensated for that.

MR. SNOW: Stu?

MR. BRESLER: Good morning. Thanks again for organizing this panel and for having me participate. Certainly PJM understands the driver for the discussion that we're having this morning, and the observed, if you will, decrease in potential frequency responsiveness of resources in the interconnections.

Certainly we also believe that, to the extent resources are providing a needed service to the grid, to a transmission provider and are expending a cost in order to provide that service, there should be compensation for providing that service that has been deemed necessary for the grid.

I think somewhat recently--it's hard to believe it's been a year-and-a-half now at least--in response to FERC Order No. 755, PJM has made some fairly significant market design changes with respect to our regulation product that is provided in PJM.

One of the major changes was to add a second regulation signal, a fast signal, to our regulation product. So in addition to the traditional regulation signal that responds in five minutes typically, there is now an additional signal resources can qualify to follow which does respond much more quickly than that.

In addition, the market design change result in not just paying for the capability to be able to respond to either one of those signals, but for actual movement in response to those signals. So we'll pay for performance incentive as well.

One of the major goals of those market design changes was to provide the incentive for alternative resources to continue their penetration into the regulation market. And as a result, we have seen the penetration of additional resources such as storage, significant battery installations that are providing regulation in PJM. Demand response as well, providing regulation in PJM. In addition, some generation types have actually qualified to provide that fast regulation as well.

So we do see that there are some resources in PJM that are contributing to our ability to meet changes in the frequency on the system, and assist in our meeting of that BAL-003 standard that Doug discussed a minute ago. And so we need to really I think continue to work to establish whether there is a need to provide additional compensation for more resources to provide more of that frequency responsiveness than we would otherwise have on the system going forward if we see that the continuing decrease could occur and negatively impact our ability to meet that standard.

So with that, I think we'll get into potential, some of those potential mechanisms as we go forward today.

MR. SNOW: Stu, you mentioned the secondary regulation five-minute typical number.

MR. BRESLER: Um-hmm.

MR. SNOW: What's your faster cycle time?

MR. BRESLER: The faster signal actually--let me give you a little bit of background; I don't want to take too long--but when we first had a storage resource that was participating in our regulation market, what we learned very quickly is that that resource could follow the signal much, much more quickly than we could even update it. Meaning, every two to four second update to that signal, the resource followed it within, you know, milliseconds, if you will.

And so that's why we sort of separated the two signals out. So the traditional signal is more following, or reflecting the tie-line error that's part of the Control Area calculation. The second signal, the faster signal, is actually developed based on the frequency component of the Area Control Error. So it moves much more quickly than that traditional signal does.

MR. SNOW: In primary response we were kind of chatting about automatic and autonomous response from each of the resources in a seconds-kind of timeframe. Are you indicating your regulation can get--or you're trying to

regulate at that level?

MR. BRESLER: It does provide response within seconds, yes. That secondary signal. That is the minority of the resources we have following regulation right now, and so we do expect that we will see increased penetration there, given again the pay-for-performance changes. But we do have some resources that are responding that quickly, yes.

MR. SNOW: Thank you. Erik?

MR. ELA: So I'd like to thank the FERC staff for putting this conference together and echo some of the other panelists in inviting me to participate.

So NREL does conduct research on integrating renewable resources and other emerging technologies on the bulk power system, and that's part of why I'm here.

So I guess what I would like to say is that primary frequency response is very similar to the other ancillary services that do have dynamic markets today, but it is also separate from those other services.

So it requires capacity headroom, as we've discussed, that competes with the energy market as well as the other ancillary service markets. There's a cost to doing that. But it is also quite different in that it is an autonomous response responding to frequency, not to Area Control Error, and so it is a separate service.

So I do think that with the new BAL-003 it does seem like a logical next step to try and for at least--I should say that my expertise is with the ISO/RTO restructured regions--with the new BAL-003, it could be a logical step in order to make sure that the individual resources that meet the Balancing Area requirement have some sort of incentive to do so. You know, and that may be first eliminating any disincentive to do so, which there may be presently.

And then, understanding what types of incentives need to be implemented in order to get that response from the individual resources to meet the Balancing Area requirement.

MR. SNOW: Thank you. Clyde?

MR. LOUTAN: First I'd like to say thank you for inviting the California ISO to participate today.

From a technical perspective, there's no question that frequency response is required to maintain reliability on the grid. Each system is a little different.

In the Western Interconnection today, frequency response is a requirement for any resource participating in spinning reserve, our regulation. So we acquire frequency response today based on the resources that are bid into the market and accepted for providing spinning reserve.

We went one step further a few years back. We

are allowing loads to participate in spinning reserve. One of the requirements is, we try to mimic frequency response, inertia response. So whatever megawatts are bid into the market, 10 percent are DR requirement needs to be achievable within 8 seconds.

So that would follow the inertia response to help RS frequency and also stabilize the system following a disturbance. So both traditional resources and loads can participate in spinning reserve today, which we think would give us a majority of the frequency response requirement we need.

The other thing we're going to be looking at is do we need to spread this spinning reserve requirement among more units? Again, each system as I said is quite different. In our system, our minimum load during weekends used to be around 20-, 25,000 megawatts. A couple of weeks ago, two Saturdays ago, it was 23,000 megawatts. We had 8,000 megawatts of wind and solar simultaneously in the system. It was the second time in my career I have seen net load drop below 15,000. That creates a problem for us in that we have over 10,000 megawatts of nondispatchable generation on the system.

You know, when you look at the nuclear, the biomass, biogas, geothermal resources we have that's not dispatchable, it's over 10,000. So now when you look at

this from a dispatchable perspective, you have less than 5,000 megawatts you could really dispatch.

So the point here is we believe that variable energy resources should be able to provide some of this frequency response reserve. This would help mitigate negative prices in overgen situation. So again going back to last Saturday, for almost 43 percent of the day we saw prices at zero negative.

We did have to curtail wind generation during that timeframe. We think with our variable resources providing frequency responsive reserve, it's going to create additional problems for us.

MR. SNOW: I wonder if you could say a little bit more about--you're kind of talking about we need frequency response all the time, 24/7, and you're identifying there are operating modes, a beautiful weekend, very light loads, great wind, and so that inherently you may have more than enough at certain times, just enough--you know, Goldilocks, at some other times, and too little. So it sounds like a Goldilocks situation--too much, just right, too little.

What are some of the proposals on how do you get the right amount all the time?

MR. LOUTAN: Well this is going to be part of our analysis, you know, right now. And again, you know, in BAL-003, now you've got to respond to any disturbance

anywhere greater than 500 megawatts, regardless of where that disturbance occurs, right? Which makes it, as I said, a little more challenging.

So there are times that you have a lot of unloaded capacity. You have the frequency response that you need. But again, during weekends, or holidays when you have a lot of renewables on the system, and you've got to back off your conventional resources, it's something we need to look at in terms of can loads, plus your conventional resources online, can they provide the frequency response obligation? Or do we need to look at getting a portion of that from variable energy resources?

MR. SNOW: Jim?

MR. GINNETTI: Yes. Good morning. Thank you again for having me here.

As I mentioned at the beginning of the first panel, a little over 20 years ago I was responsible for operations at what became ISO-New England. And the data point I remember back then was a 1,000 megawatt loss of generation on the Eastern Interconnection had the frequency dip about 18 millihertz. I've been told now it's about double that.

And this is an obvious solution to me, is that when people got generation unbundled, generators who were competitive like ours no longer had any financial incentive

to continue to provide this. Many new generators might not have installed the equipment available. On some combined-cycle gas turbines it's an add-on package that owners might have decided not to invest in. It's not cheap.

There is an hourly--as others have said, you have to leave some headroom so that you can increase your generation quickly if you have a disturbance and the frequency dips. And that has a cost with it.

I did talk to ISO-New England before coming here today. They tell me many of the steam units have boiler controls that squelch out generator response, or governor response, because they're aiming to get more economical operation rather than supporting the interconnection. So to me, this is a perfect solution--or a perfect instance where you would institute a market.

Unlike reactive, each Balancing Area has a requirement. They can figure out about how much governor response capability they need. It is transferrable across, for example, New England, New York, and I guess there's even PJM. So it's a perfect situation where you could institute a market where people could compete and offer in to provide certain amounts of governor response to solve this problem.

So that would be our recommendation. As I talked earlier, you know, some may think that, well, you're already

getting a capacity payment. You should provide this for free. And as I mentioned, we are in favor of comparability. If not all resources that get a capacity payment in one of the organized markets, if not all of those resources have to provide this service, then none of them should have to pay or provide it for what they get paid in capacity and it should be spiked out as a separate revenue stream to those units that provide it.

And if you have a market, you can provide it at the lowest possible cost. So that would be our recommendation.

MR. SNOW: As a follow up, I think you made the point that having a governor setting is necessary but not sufficient; that the boiler, the prime mover of the energy source, needs to be responsive enough to push more power out in a fairly short period of time, a seconds timeframe.

So your discussion of a sliding pressure boiler, or boiler controls that are set to optimize no matter what they're told otherwise, doesn't meet the requirements. So governor setting seems to be insufficient. And since we want to be technology neutral as far as what--you know, because it's the addition or subtraction depending on what kind of event you have, of power that's needed, what would your comment be on how to measure that more generically?

MR. GINNETTI: Well certainly we are in favor of

competition. It should be, you know, technology independent; anyone who can provide this, whether it's load or resources, should be able to offer in.

I think it--and I haven't thought through exactly how to do that, but clearly it's the entire package. If we're talking about a steam boiler, it's where is the unit loaded to start with? If it's already at its max, it's not going any higher, right? So you have to provide some headroom.

You obviously have to have your governor set so that it would respond, and then you want the boiler controls to not squelch out the response that it just got. What ISO-New England has told me, and they have surveyed many of their units including some of ours, and you can plot that many of these units respond, and then all of a sudden they stopped responding. And instead of frequency being restored to whatever it should be, it stays low for a long, long period of time.

So I think it's a very comprehensive review, but I think if you lay out what is required, and then you let all resources and/or load offer into that, that it can be done on a fair and a competitive basis, and it would solve each of the Balancing Authorities needs to provide their frequency bias setting in a most economical way.

MR. AMERKHAIL: So, Jim, it sounds like you're

thinking of a new governor response market. What I heard some of the others--I think Clyde mentioned this, possibly Sandip--is at least possible to conceive that the spinning reserve markets that already exist, if the qualifications at least were tight enough, could cover frequency response as well. Are you opposed to that?

MR. GINNETTI: I think that would have to be looked at on a per-RTO basis. My initial concern may be, you may not have enough spinning reserve on the system to get adequate governor response for what you need.

So I think an RTO, if that works for California and they can get their adequate frequency response that way, then that would be fine. But again, I think you need to have the open competition so that people can bid in and compete for that revenue stream, whether it's, you know, inside the spinning reserve payment or it's some other revenue stream.

MR. AMERKHAIL: Thank you. Doug?

MR. HILS: I'd like to just comment that, in a prior company of Duke Energy I worked for Synergy, and we were within the ECAR region, which ended up becoming part of RFC, but the old ECAR requirement, while it was spinning reserve, was frequency responsive reserve. That was the definition. It was synchronized capacity frequency response, all those attributes, but I think as an industry

we sort of did it to ourselves as far as where we ended up there. Because as that frequency responsive piece was challenged by other participants wanting to get into that market of providing that, why does it have to be frequency responsive in the Eastern Interconnection, it's so robust, you define why we need frequency response.

I mean, as an industry we ended up where those provisions, and different regional requirements, that frequency responsive piece was taken out of what it meant to have spinning. And truly with each system it's probably different ways of managing it, and that way it sounds like for the ones that--and the ones that you would think of first, you know, the Hydro Quebecs, the UK, ERCOT, have to look at things a lot more closely sooner than perhaps Eastern Interconnection just because of how I guess how robust the interconnection is.

For the sample frequency deviation then it goes down to 59.9 in WCC, it goes down to 59.95 in the Eastern Interconnection. But back on the subject of frequency response, there are definitely different ways of being able to provide it.

I guess from our perspective--and this is the perspective of the non-RTO/ISO members, it's more as this is a BA requirement. We're seeing frequency response as a new requirement out there, but it's not new to us. We already

calculate what our response is on our system every year.

We look at those measures. And as we looked at what that measure was going to be as applied to us in that manner, many systems will be meeting that standard without making any changes at all. But when you're able to look at the Eastern Interconnection and what the response has been, and we commented over a year ago about this, is that right now we're seeing response sort of at a plateau. We don't see it declining. You definitely see something that looks like a step change that probably accompanies other things that happened on the interconnection.

Right around 2005 you had the expansion of the PJM system. You had a Contingency Reserve Sharing Group that formed, larger than any other reserve sharing group, that reduced contingency reserves by 40 percent.

So a lot of other things on the system affect that frequency response besides just, well, what people are doing and what their generator or governor is. But the fact is, now that we have a standard there, there's generators who are looking at those things. They don't know if in the future are they going to be paid for this as an additional service, or is it already part of the capacity payment they're getting on the things. But there's time to take a look at that to figure out, you know, where are we headed with that.

Because as an industry, and where ERCOT already is, defining what is the acceptable deadpan? How far do you want that deviation to go for your resource? How long do you want that resource to be sustained?

They're all different things that, to the extent you lock that in, you may be excluding other resources that are capable of participating but just maybe not to that level. So I guess we're looking at more that this is something that we can be looking at. To the extent we're already compliant, we're not seeing the burning need to go out and try to find additional. But at the same time, there is the need, if you are pushing toward a product that can be done and I guess utilized outside of a market, that you want to go ahead and really define, okay, what is that? For the markets, I'm not sure if the MISO version of frequency response would look like the PJM version of frequency response, and whether that would look like the ISO-New England version of frequency response.

But if you make it a product that they're trying to do a one-size-fits-all, I think you're going to be losing the opportunities of other resources that could help and provide the response to meet the specific needs of the BA that kind of hands to what qualifies for that may be a detriment to us.

MR. AMERKHAIL: Erik?

MR. ELA: I just wanted to comment on the concept of having--the spinning reserve market have frequency response requirements within it.

There was some research, a paper written on this back in 2007, that kind of looked at what the differences might be. We kind of looked, you know, kind of expanded on that, sort of seeing what types of benefits you can get from implementing this within the spinning reserve market, or maybe even within the regulating reserve markets, since those are the same schedule.

And, you know, one of the clear advantages was simplicity, relatively speaking, in that to add a new market is a very complicated process both with software and regulatory. But we also saw--and this could probably work very well in the near future, since we already know we have a lot of this response today without any markets.

So ensuring that the resources that are getting paid for the spinning reserve market are also frequency responsive, you probably have no issue meeting the BAL-003 requirement.

That being said, in more of the long term BAL-003 is, you know, in different units than spinning reserve. So spinning reserve is looking at megawatts, 10-minute response; and primary frequency response really requires megawatts per .1 hertz, you know, in seconds. And there's a

lot of other differences, including the locational aspects.

So spinning reserve typically requires locational requirements where primary frequency response may not have as stringent of locational requirements. And you may also have resources that can provide very good spinning reserve, while they're not frequency responsive. So there are some complications.

I think that, you know, I think that in the near term that would be a good solution, a simple solution. And I think kind of looking further out, you know, as you have more technologies that wouldn't inherently have frequency response capabilities, that just a changing generation mix and how the system is evolving, that in the long term that may not be the best solution.

MR. SNOW: Just to follow up on that, in one of your sister labs, Lawrence Berkeley, did some work four or five years ago, and they were tracking--one of the interesting parameters they were tracking were the percentage of generation resources, I should say, that were responsive, and what minimum numbers they were kind of looking at to get the system to work; that the nadir did not go below UFLS set, Under Frequency Load Shedding settings.

They were looking at like 30 percent of the units. That seems like a really high spinning reserve, synchronized spinning reserve number. Could you comment on

that?

MR. ELA: This is the KT--

MR. SNOW: Jondrill's value, yes--

MR. ELA: Yeah. So, and I know a bit about that study. I guess I'm unsure of what to comment on it, or just--

MR. SNOW: I think what John was showing, Lawrence Berkeley, John being the principal investigator on that portion of it, were showing that to get the speed of response--your comment a moment ago was that you need X number of megawatts, not in 10 minutes but, you know, more like in seconds' time frame, which is kind of the bottom slide here, which is what those things are trying to show, but to do that you need like 30 percent of the units, each one providing a little bit. And I've never heard of a spinning reserve--synchronized spinning reserve requirement being anywhere near that, you know, maybe like a sixth of that kind of number. I just want to understand, you know, how something that's so much smaller than what seems to be the minimum requirement could handle the issue.

MR. ELA: Yeah, and actually I thought that that parameter was the percentage of online units that had enabled governors, not the percentage that had headroom.

MR. SNOW: There were a couple of variations. They were the percentage of generators' resources that

responded. Obviously if they're responding they had to have a governor service, and they had to have a prime mover behind it that could provide the energy, and they had headroom, yes. There are kind of three things that need to be there that are necessary to get the response.

It's an unfair question, apparently, at this point in time, so let's put that on the parking lot then.

Clyde, you seem to be wanting to flip that switch. Go ahead.

MR. LOUTAN: We also looked at that, and I'm familiar with this KT concept. And you're right, it's about 30 percent of the resources online that typically would respond.

But when you think about, like the West for instance, it depends on the size of the Balancing Authority. So when we carry spinning reserve, we do not carry spinning reserve based on the most severe available contingency. We carry reserve based on load and generation.

So our spinning requirement is almost twice as the most severe signal contingency we have on the system at times, and sometimes it's even higher. The charge we see really is offpeak, being able to meet the frequency responsive obligation and having the headroom.

Through a peak, you have a lot of resources online. You have headroom. You have the inertia on the

system. And being able to meet that, an obligation we don't think, you know, it's really a problem.

Offpeak, especially if you have a good hydro year, you have a lot of renewables on the system and you do not have headroom, now headroom is a couple of things. It's beyond--it's your spin plus your available unloaded capacity on the resources. So you can have a lot of headroom on the unit in addition to just your spinning requirement.

And when you think about a unit and governor control, it responds based on your frequency dip, right? So typically in the West, you know, governors are around 5 percent droop, which means you've now frequency drops to let's say, by 3 hertz, that unit needs to go from zero, or from minimum load to full load based on the frequency dip. So just based on the definition, you should have the frequency response capability, you know, with the units synchronized to the grid.

I think what we need to go back and look at is why some of this resource is not responding. You know, look at the way we dispatch resources. One of the points that James just brought up here was, in addition to the units not responding, is like setpoint control, something we need to look at because they would respond and then go back on setpoint.

So there are a lot of things, you know, we think

we need to look at closely to see why the resource is not responding today. Because almost I think everything, I'm not 100 percent sure, greater than 20 megawatts, or 75 megawatts in an aggregate, need to have governors that's well tuned and synchronized to the system.

So technically we should have the frequency response that we need. We just need to figure out why we're not getting it.

MR. SNOW: Dmitry, you've been very patient. Thank you.

MR. KOSTEREV: Thank you, Bob. So speaking for the West, so we, today based on the historic data, we keep a pretty good baseline of the frequency response in the West over the last decade or so.

So typically we provide about 12- to 1600 megawatts tenths of a hertz response in the West interconnection. According to the BAL-003 standard, our new requirement will be around 1,000 megawatts or somewhere there. So today we have about 30 percent of units actually responding to frequency, and it looks like that now we can even go a little bit lower. But if we get 30 percent of units providing spinning reserve, and you think of it that each unit would carry maybe 10 percent headroom, so that responds to about 3 percent of the headroom capacity interconnectionwide, which is sufficient to cover for the

largest contingency, which is a two-unit outage at Palo Verde. So that kind of numbers kind of work that way.

MR. SNOW: Questions?

MR. AMERKHAIL: So, Stu, you mentioned that the Order 755 changes you've made have resulted in more fast resources. And I thought I heard you say as a result of all the fast response you're getting, although centrally dispatched, you might not see as much need for frequency responsive reserves as you would otherwise? Is that right?

MR. BRESLER: Well, technically before our 755 implementation we had no fast resources, really. We had sort of gradually developed this faster signal that was responsive to, or really it's also a pass through of the frequency changes that contribute to the ACE calculation, right? And with 755 we actually have a pay-for-performance in place now. So those following that fast signal and moving around a lot following that fast signal can actually get compensated commensurately with the movement they're providing.

And since we've implemented 755, we have seen additional penetration of resources that are providing that fast regulation.

So I think, again, to the extent that we determine we need to ensure that we have additional resources to have all those three components Bob just talked

about, right, the governor turned on, if you will, enabled; the other controls that are not squelching what the governor would otherwise be doing; and then also from a compensation, at least in a real-time, if you will, compensation perspective, maintaining headroom that will allow that movement, right, to the extent that we determine we need additional resources beyond what we have following the combination of regulation signals, then the question becomes how does one structure that compensation and what does it look like?

Because I would imagine there's multiple components to it. There's probably some fixed component to it, to have the equipment actually installed and available, right? But then there's also a variable component that's associated with maintaining the necessary headroom, right? So I think the question becomes how do you restructure additional payments? But first you've got to determine do you have a need to actually assign and commit, right? Because resources are taking a risk when they commit, because there must be some sort of performance measurement, right, that goes along with compensation to units that are providing an additional service, right?

MR. AMERKHAIL: Absolutely.

MR. BRESLER: And there's a risk of not providing that they may, you know, either not get the revenue that

they're investing in providing the capability to receive, or in some cases maybe even a penalty for not providing it because it is a reliability service.

So, you know, that all needs to be I think thought through very carefully as to how that would work.

MR. AMERKHAIL: Absolutely. But the part of it I wanted to focus on was where you decide how much, in addition to what you already have, you might need. And I guess--and I'm not on the reliability side of the Commission, but my understanding of the BAL standard is it's a performance standard.

And I guess my question is: One thing I thought was important about the frequency response--and Bob mentioned this--is it's autonomous. It's not dispatched. And I guess I'm wondering if you can meet the performance standard, just hypothetically, with completely dispatched resources, including fast frequency response? Wouldn't you still want some resources that don't need to be dispatched to respond to frequency in case the communication system goes down?

MR. BRESLER: Potentially. And I think, like I said, the rub is in establishing what is the need, and how much do you need to have? Because once you do that, then you can design how you would compensate for that.

But I don't think--on the one side, do you need

some? Maybe. Maybe we'll figure out that we actually do need every single resource; that every single resource that actually says okay I'll do this gets compensated? Probably not. That's not probably an efficient mechanism for compensating these resources, either, right?

So there's got to be something in between. And to me, step one is establishing what do you need so that then you can determine, okay, exactly how am I going to compensate the resources that are actually incurring cost in order to provide a service that, yes, we can say that we need. That's kind of where I was headed with this.

MR. AMERKHAIL: Okay. Thank you. First Doug, and then Ryan.

MR. HILS: No, I'm all right.

MR. AMERKHAIL: Oh, all right. Ryan?

MR. HANLEY: Okay, thank you. Within the spinning reserve market, to James's point before about having everybody that is part of that market being utilized at the same rates so that they're not getting paid for a capacity payment that they're actually not using, there is a risk.

Our one consideration is if you have response being embedded into the spinning reserve market is that some resources are going to have fast response capability and will be called for those autonomous responses very quickly,

and then you'll have another percentage that is not called but the compensation could potentially be the same, at least on the availability charge.

So that's one thing to consider: Are you actually compensating the ones that are fast responding enough?

Specifically with that compensation of fast responding, there's maybe another component about mileage. So not only do you--are you available to return it, but can you follow the signal subseconds along the way up to the setpoint that you're given from the dispatchable entity. That's another capability that there's potentially some compensation. Some technologies would do that better than other, following the signal up and down all the way to the endpoint.

And then the last maybe consideration on combining spinning reserve and the frequency response is: Are those markets the same size? Do you need the same amount of resources in spinning reserve as you do in frequency response?

If you don't, if frequency response is much lower, then you're paying a large number of generators for resources for spinning reserve and they're also getting paid for frequency response when they probably aren't even needed to provide that resource.

Not that--to Erik's point, simplification is maybe a great asset early on in these markets, so I see the value of potentially combining them together, but long term there may be some considerations where they're not the same market.

MR. AMERKHAIL: Sandip?

MR. SHARMA: One comment. I think there will be a danger of over-estimating your frequency response if you lump frequency response and spinning together. Because not all spinning will be frequency responsive. Frequency response will always be, you know, directly related to how much--directly related to the magnitude of frequency deviation.

So maybe carrying 100 megawatts of spinning, but you're not supposed to count all 100 megawatts as frequency responsive. It would be a very small amount. So it needs to be not carried just by one generator, it needs to be carried by a lot of generators and not all spinning will be frequency responsive.

MR. AMERKHAIL: And you mentioned earlier that currently there's a requirement. Does that do that? That requirement is on all generators, but it's very small?

MR. SHARMA: Right, so the one requirement that we have in ERCOT currently is every generator, it cannot contribute more than 20 percent. So 20 percent sets the

limit. And the way the 20 percent is derived is it's based on our under-frequency load set at 59.3 hertz, and for 1 percent change in frequency, with 5 percent droop setting, all of that spinning reserve has to be deployed as governor response. That's how the 20 percent is derived.

MR. AMERKHAIL: Thank you. Back to you, Bob.

MR. SNOW: I wonder if I could just follow up a little more. Can you describe the system you have in place that measures what each individual--well the units that should be responsive, how you determine what their, I'm going to use the term, boggy level should be? And what report card do you have back on whether they meet either requirements or not?

And after you describe that, describe what market-based systems, or what other types of resources that you pay on almost an hourly kind of basis to basically put this whole system together for both the peak load days and the minimum load days with lots of renewables online?

MR. SHARMA: So right now, on an average we have around 6 to 7 measurable events every month in ERCOT. When I say "measurable events" it's because of a large loss of generator in realtime. And every month we have a group that works on these events, and so we are looking at every individual generator's performance against the 5 percent droop requirement. And we are looking at every individual

generator and seeing, looking at whether they are meeting the 70 percent requirement or not.

The requirement today is they have to meet the 70 percent requirement within 16 seconds, and then sustain that requirement for an additional 30 seconds. That's the requirement in ERCOT, and we use 2 second pi data to come up with that evaluation. I think that answers the first question?

MR. SNOW: To avoid some of the plant information, pi data that's at the location that's used as the reference source, not the telemetry data?

MR. SHARMA: The data that is used is the data that we get from the plant. It comes to us from the plant. It comes to the BA from the plant.

MR. SNOW: And that's the plant requirements. What's in addition to that, including your load responsive.

MR. SHARMA: Right. So that's under individual plant. Now we also procure--so what we do is, we procure 2800 megawatts of frequency responsive reserve for all hours. Out of that, 50 percent can come from load resources.

Now these load resources, they have to be triggered by under-frequency relay set, under-frequency relay set at 59.7 hertz. So any time frequency hit 59.7 hertz for more than 20 cycles, they have to respond--they

have to trip the load and provide that response.

So especially with the low load, high wind condition, we see, you know, this type of fast response very helpful for reliability.

MR. SNOW: 1400 megawatts is no small amount of demand response. Can you describe what--who is selling you that amount of response? And what's their performance been?

MR. SHARMA: So mostly it's coming from large industrial load, and their performance? Well the problem is it's hard to measure the performance on every event because not all loads are tripping on every event. Because what they have done is, they have set up the--I mean, they have set up loads that they are setting at different frequency range, so one of the load, if it's set at 59.71, then it kind of stops frequency from going below 59.71, so we're not getting all 1400 megawatts of response on every event.

But whenever we have an event, we're getting almost 90 to 95 percent of the response based on the setting. So on January 18th, we had a large nuclear trip early in the morning, Saturday morning, and it took us, you know, I think less than a minute to recover from that event. And our frequency was fully covered. We lost close to 1300 megawatts, and it took us less than a minute to, you know, fully recover.

MR. SNOW: So 90, 95 percent of the load. The 70 percent performance number for the other conventional resources and the wind resources, is it that difficult for these units to make it, that less than 90 percent are making? What percentages are making it?

MR. SHARMA: Well generally it depends on unit to unit. I mean, a very well-tuned unit, a well-maintained, well-tuned unit--and there are certain companies that do that very well--you know, the rolling average will be close to 100 percent, or even 90 percent.

But 70 percent is the minimum requirement. And most generators, they exceed that requirement.

MR. SNOW: So if we're looking at most units make the 70 percent independent of the type of unit that they might be?

MR. SHARMA: Yes.

MR. SNOW: So the 70 percent number is, it's unusual for a unit not to have that level of performance? They might do better, you know, some are better than others.

MR. SHARMA: Right. And so with the new BAL-001 standard actually that 70 percent is bumped to 75 percent. BAL-001 is the regional standard for ERCOT.

MR. SNOW: Does anyone want to add any additional things?

MR. LOUTAN: I just wanted to clarify one thing.

One the spinning reserve requirement, as I said, it needs to be frequency responsive, but we do not count or rely on 100 percent of our spinning reserve. Typically you rely on about 8 to 10 percent of that total requirement.

So if you have 3,000 megawatts of spinning reserve, on the high side you count or rely on about 300 megawatts as what you can get to reach that point B, or your settling frequency. So we do not really rely on the total 3,000 megawatts, you know, as what you can get through point B.

MR. SNOW: Before you were sort of chatting about droop settings, the 3 percent. Could you walk me through if you started with 3,000 megawatts of headroom, how--and you had a frequency change, what kind of change would you need to get to activate 300 megawatts with a 5 percent droop? I mean, do you need all of it available to get that 300 megawatts?

MR. SHARMA: Well it depends on the change in frequency. So as Dmitry had mentioned, when we say, based on historical data, when we see a dip of .1 hertz, typically we see anywhere from 1200 or 1600 megawatts. The frequency response obligation for the West is going to be 949 megawatts for one-tenth.

So we think we have some margin to play with right now. So going back, when I had said the frequency

response is embedded in spin, as a requirement for spin, let's assume you have 3000 megawatts of spinning reserve. You do not expect to get 3000 megawatts in 30 seconds. We would expect to get, based on spin, you'd expect to get, let's say you do lose 3000 megawatts of generation, you would expect to get 3000 megawatts of that reserve replaced in 10 minutes.

But the bigger problem here for the frequency response obligation is being able to arrest our frequency within 8 to 10 seconds, and being able to stabilize your system within that point B, which could be 20 to 30 seconds. So realistically you would expect to get anywhere from about, you know, 8 percent to 10 percent of that headroom that's available if it's frequency responsive.

MR. SNOW: Doug?

MR. HILS: Bob, I think it was pointed out a little bit, but I think more to the point on the spinning as well is that 10 megawatts of spinning on a resource that's 100 megawatts, what you would get in frequency response would be quite different than 10 megawatts of spinning that you would get from a 1000 megawatt resource because of the droop, and those things, as well.

So I think that's why the general number that Clyde used is one that's recognized, in that different resources will provide a different amount of response. From

Duke Energy's standpoint, you know, the types of things we're looking at is something in realtime to know not only the droop or other response of the resources on our system, but estimate from where they're loaded, what we can get out of them, for how big of a deviation can we use them, all those things are factors.

And when you start looking at some of the other resources that are similar to load, that's where you can make that economic decision as well. And that's, I guess in looking at do you really carry so much in online resources and frequency responsive resources to meet any possible deviation? Or do you look at what's the most probable of deviations based on some logic there, and then have another type of service such as a load service or something to hit at just those significant events?

And so those are some of the other things that enter into, you know, I guess what each BA is going to be looking at for what it needs in meeting the frequency response standard. And to the extent that some have resources that are committed for spinning reserves that provide frequency response, to the extent that that's minimizing how much additional is necessary, each BA will be able to look at it that way.

To the extent that the BA is starting to make decisions based on frequency response, that's where you

actually then look at, okay, now let's look at the economics of frequency response. Because to the extent that you're committing resources in a manner to meet the NERC standards, and by doing so you're actually still meeting and in some cases plenty capable of meeting BAL-003 as well, you may not be making economic decisions only to look at frequency response, but looking at how you're committing to meeting the other requirements as well.

Thanks.

MR. SNOW: That kind of brings us to the discussion of co-optimization of energy, ancillary services, and to some extent when you get to shortage pricing. Any thoughts on how one would do that?

The eyebrows have it. Stu?

MR. BRESLER: So how one would do a co-optimization? How one would do a co-optimization like you described?

MR. SNOW: What I'm saying is, if you--right now you want to optimize energy, the most expensive portion of the bill, with other ancillary services. As Doug was saying, there's kind of a--they step on each other. If you have one, you may have some part of another. You have certain spinning reserve requirements. You automatically get some amount of other item.

So how do you then, from a planning point of

view, from an operational planning point of view, not transmission planning, how do you optimize all these so you come to the lowest cost? You meet all your requirements, but you come to the lowest cost?

MR. BRESLER: So it sounds, Bob, like what your question is: Is this a resource that is providing regulation, for example, can also provide some sync reserve, or vice versa, right? And speaking purely from the PJM perspective, we do co-optimize all those services in our Real-Time Dispatch.

When it comes to whether or not a resource--oh, and by the way, we do that based on the product substitution cost, right? So a resource that could provide any one of the three products provides the one that it does so if you're the most efficient product substitution cost with respect to the other services, right? And then we set clearing prices for all three of them, energy regulation and reserves, every five minutes.

So it really is, when it comes down to the co-optimization anyway, it really is sort of a one or the other type of decision. However, we do allow resources that are assigned one particular service, like regulation for example, to also be credited for providing sync reserves during a sync reserve event, if it responds with more than its assigned amount of regulation for the amount of time

that it's required to respond and continues to follow the regulation signal as the system recovers.

So I think for us anyway it comes down to an estimate based on historical experience as to how many of your resources can actually do that, can actually respond quickly enough to exceed the requirement with one service in order to provide another to make sure that you're not assigning too much. In other words, that your requirements reflect the balance, and reflect the fact that some resources will actually respond with enough that you don't need to carry as much as you otherwise would of the other.

That's how we handle it, anyways, as far as how we do our co-optimization.

MR. SNOW: Clyde? You know I'm going to go to the next ISO, right?

(Laughter.)

MR. LOUTAN: So one of the things we decided to do is to look at, assuming you need to meet this frequency response obligation, what's the minimum amount of headroom you need to have on governor-responsive resources?

So we did this study, and actually we're revisiting this study as I speak. So you look at if you have to meet 100 percent of this requirement from conventional resources, what's the minimum headroom you need to have? So you do a lot of scenarios based on wind and

solar on the system, and play around with this KT that we talked about earlier. It will give you an indication, you know, as to a bookend--be it you need 2500 megawatts, or 3000 megawatts of headroom on governor-responsive units.

Then you can walk back from there. So you know in the planning arena if let's say you need to have as a minimum X amount of megawatts, then if you get loads let's say in real-time, if you get 500 megawatts of load you know that you can subtract 500 from that. Let's say you start off with 3000 megawatts of headroom that you needed.

And now you could get 500 megawatts of substitute. Now you really need 2500 megawatts of conventional resources. And then--you can play around with the numbers and say, you know, if you can get 1000 megawatts of wind and solar resources to provide some of that, then you only need 1500 more from conventional resources.

So this is the kind of study we try to do, but you do this in the planning arena, and you do many, many simulations with a lot of different operating conditions to identify what's the minimum headroom you need. And as I said, as a bookend, what do you need on conventional resources? And then you can move and say, you know, if I get X amount from nonconventional resources, you know, you can back that off from your conventional resources and that's how you can do that optimization.

So in your real-time optimization, now let's say you need 3000 megawatts. There's different ways you can do it. One, when you do the co-optimization with energy, you can say, well, my headroom or my spin requirement should be 3000. That's one way. But there are many different ways you can do that optimization.

MR. SNOW: Erik, do you want to get into the conversation?

MR. ELA: Sure. Just on the co-optimization piece, obviously doing it the same way as the other ancillary services would be the way to go. I did have kind of, sort of a caveat to that that I think is kind of interesting.

We've been talking a lot about how the spinning reserve market and primary frequency response may be separate things. However, the current way, from my interpretation of the way the BAL-003 is written, is it's not actually adding any capacity requirement to a BA. What it's doing is saying that your response, you know, must be this responsive to this frequency deviation.

So in that way it's not necessarily, you know, if your capacity just has to be this much responsive, what it can actually do is make it so the binding constraint for the ancillary service market would either be with the spinning reserve market or the primary frequency response, but not

both.

So in some ways, having this separate market can actually reduce the spinning reserve market if you go through the pricing hierarchy that my capacity for primary frequency response is a higher priority. So I think that is something we should look at.

Obviously that's my interpretation of how BAL-003 is written today. I think there may be differences if you have an area that is part of a large interconnection versus something like ERCOT where it's its own interconnection, and so the events that trigger both primary frequency response and secondary spinning reserve would be--you know, could be different or could be the same. So that could be an important part of that.

So I think that could be another piece of how this all would be part of that market.

MR. SNOW: I'm getting the hook from my--assuming, I think we can agree that you need some level of response in the system. The standard defines the minimum. But it has some value. It doesn't come for free. It may come as part of another process.

From the data we're seeing, public data we're seeing is that there are some resources that absorb frequency response. They lower their output as the frequency drops in short periods of time.

Should there be a penalty for that?

Should those resources make the system, the Balancing Authority whole?

And we'll start from the left-hand side and work our way over.

MR. SHARMA: Well I'm probably thinking you are referring to the combined cycle, other CTs that lower their--

MR. SNOW: From what I'm gathering, there are many different varieties. Combined cycle might be one variety, but not exclusively. And I think I'm really kind of talking about performance. I don't care what the resource is, if it does that.

MR. SHARMA: I think any time a resource fails to meet minimum performance requirement of frequency response service, or a similar type of--or spinning reserve service, then I think, you know, that needs to feed back into, you know, how it's paid. So I think a pay-for-performance type, you know, might probably help. You know, if there is a pay-for-performance, there needs probably more incentivized to improve its performance.

MR. SNOW: I'm thinking of a unit that's not in that market, is not doing that, not being paid for its performance. It's not supposed to perform. It's not supposed to provide any response, but it absorbs it.

MR. SHARMA: Well I really don't have an example of such a unit, so I'll probably let somebody else go.

MR. SNOW: When everyone is doing 70--meeting 70 percent of the requirements or better, you don't have an outlier.

MR. SHARMA: Right.

MR. SNOW: Other interconnections are different. Doug?

MR. HILS: Bob, I really don't have an EEI position on this, but I guess for the areas that are outside of RTOs that I'm familiar with, it's really more the obligation of the supplier to provide. Or if you went the direction of a frequency response, it would be more providing a certain amount of response. And to the extent that the resources in that portfolio aren't meeting it and others are exceeding it, I think it gets down to the individual systems on how they're managing that with the resources in their footprint.

MR. SNOW: If I understood that, it's a portfolio kind of discussion as opposed to any single unit?

MR. HILS: Right. If it went the direction of whether frequency response was like in a market on a generator by generator specific basis, I'm sure the circumstances would probably be different.

MR. SNOW: Ryan?

MR. HANLEY: We would agree that it should be assessed based on its performance. If it drops, if it doesn't respond, I don't know that we have a position on whether there's actually a penalty or it loses its capability to meet the requirements. Yeah, I think we'll stop from recommending whether there's a penalty or not, but being assessed on performance one way or the other is by all means I think encouraging competition in this area.

MR. SNOW: Dmitry?

MR. KOSTEREV: I think Bonneville's option is if you have a resource which withdraws frequency response, it can purchase the response from somebody else in order to meet it. At least, you know, the minimum requirement, which would be maintained in the maintenance of megawatt hour for this frequency declines.

MR. BRESLER: Yeah, I think PJM certainly would be in favor of, you know, pay-for-performance type of constructs so that there is an incentive to provide the system with what it needs. I think we need to be careful though when we talk about penalties.

PJM has been very conscious of, where we can, staying away from penalty-type constructs. Aside from the cases where resources willingly take on a responsibility to provide a service, that is a near-term reliability service and then fail to provide it, there is a penalty that could

apply, which is really most of the time taking away the revenue that would have been earned if the resource had actually performed.

And the reason why we've tried to--or why I think it needs to be careful when you think about penalties is because it does increase the risk of resources, and therefore could have a suppressive effect on the willingness to invest and increase the overall cost to the system. So I think this may be a very small component of that, but one does I think need to be careful when we talk about penalties for nonperformance, if you will.

MR. ELA: In many of the--most of I believe the RTO markets, frequency is not part of the settlements' system currently. And I think, you know, talking with Sandip, they have something that is sort of built into the ERCOT market.

So in some ways they're getting penalized today for providing response that is supportive of frequency because it's off of the dispatch schedule. So in response to the question of penalizing for providing response, that's opposing that.

I think if you--obviously the RTOs have the frequency, you know, reading. So having something like that to see whether it is going against frequency I think would be a simple thing to do. You know, depending on if they

already have penalties as part of the market settlement rules, or sometimes there's, you know, price changing for ex poste pricing. So there's different ways of penalizing, but having the frequency there as part of the settlement system to see whether you're supporting it, in which case you should not get penalized, or opposing it, in which case maybe you should be penalized, or however that's done currently for not responding to what they should be responding to, I think can be put in place and potentially should.

MR. SNOW: I believe in the paper that you authored within the last year, you suggested the approach appeared to be biased. A setpoint would avoid both the penalties for producing, or in this case not producing? Is that what you're suggesting?

MR. ELA: Not necessarily. So I think what we-- we put a few options down. So the example that you're referring to is showing that, you know, a generator with a 5 percent droop curve that gets penalized if it has a 3 percent off-schedule penalty will automatically be penalized for a 90 millihertz frequency deviation. And then going forward with that.

The ways that we I think recommended solving this is just either eliminating the penalty if the frequency deviation is greater than what the typical deadband might

be. However, that would not get at keeping the penalty for those opposing the response.

And then the second option would actually be having, you know, what is your droop setting? What is your deadband? And keeping the frequency as part of the settlement system to say only those who respond positively to it will avoid any penalty for being uninstructed deviation.

MR. SNOW: Thank you. Clyde?

MR. LOUTAN: So the intent for this frequency response standard is to do really two things: To arrest frequency and stabilize your system at point B. So I think any resource that withdraws frequency response before point B should make arrangements, like Dmitry said, to acquire that response from somebody else.

Because this is your first line of defense on the system. And if you know that this resource is going to withdraw a response during that critical time that it takes to reach point B, we should have arrangements ahead of time to procure that from a resource that could provide it.

MR. SNOW: Jim?

MR. GINNETTI: I will quickly agree. I don't know the details as to why they're being counterproductive to arresting the frequency drop, but when you're incenting people to provide this thing that the system needs, and

someone is counterbalancing that, certainly a penalty of some sort seems to be appropriate.

MR. SNOW: Thank you. I'll open it up to anyone else. Any other comments, please? Doug?

MR. HILS: I think the subject of how you measure, and to the extent that you try to accommodate in a market environment, again this is me as Duke Energy speaking, within a market, to the extent you're looking at that resource and trying to make sure that they're getting the right signals so that you maybe aren't penalizing them for not meeting the dispatch schedule, to the extent they're supporting frequency with some measure, that brings the next question. Well, how long does that lenience, how long is that given?

Is it for only that one minute? What if frequency actually drops below and hangs at 59.7 for a few minutes? Is that still frequency response? Is it still recognized? Is that really what you want the generators to do? Or are they to respond for a certain amount of time, and then essentially let the market setpoints take over for where the unit is?

I don't think there's really general agreement on even those types of points with regard to frequency response. So to the extent that I have a generator--I use "generator," but really any resource, to the extent you can

define what you want them to do, is it a point to where I'll use the conventional generator with a governor, to the extent they design the governor, is it to go ahead and basically take my setpoint dispatch from the market and then add to that whatever that desired response is so it's always adding to that market dispatch? Or is it to go ahead and essentially after one minute go back to only what that market is telling it to do because ADC is kicking in and trying to do a more economic mix of what's meeting the system requirements.

But back to the example of frequency going down below and hanging at 59.97, at 59.97 where you're right outside some deadbands, does it stay there? Does it continue to provide response as long as its frequency setting there, or is there at some point where it's supposed to be doing something different?

Those are the types of things that have to be recognized as well if you try to have a mechanism that tries to penalize--incent and penalize for performance.

MR. AMERKHAIL: Okay, thank you to our second panel. We will take our lunch break. It is 12:15 now, so why don't we just say 1:15 to return with our closing panel of the day. Than you.

(Whereupon, at 12:13 p.m., the meeting was recessed, to reconvene at 1:15 p.m., this same day.)

AFTERNOON SESSION

(1:18 p.m.)

MR. AMERKHAIL: I think we will get started pretty soon here. Okay, good afternoon everyone and welcome back to our workshop.

Among other things, the morning panels discussed how if at all resources that provide reactive supply and frequency response services should be paid for providing those services.

I want to reemphasize, we discussed whether they should be paid, if they should be paid, what it should be. We have no end-state in mind yet. We are still--this is a very preliminary investigation. And in particular we are not necessarily saying that we will come out with any sort of market mechanism, at least for some of the services, but the fact remains that if you pay for such services one option would be a market-based mechanism of some type.

So that is what we will explore in this afternoon panel. Broadly speaking, the Commission approaches market-based sales with a two-pronged strategy to ensure that they result in Just and Reasonable results.

First, each seller is analyzed or screened to determine its potential ability to exercise market power for the product at issue before it is authorized to make such sales. And then of course we have an office dedicated to

the ongoing monitoring of markets. We're not going to talk about that process. This afternoon panel will focus exclusively on the first prong of the Commission's oversight of market-based sales: the upfront screening of potential to exercise market power.

And to aid us in understanding how the Commission administers this process, Greg Basheda, who is an expert from the Commission on this process, will now provide a brief overview of it with PowerPoint slides, hopefully, if we can get it up to help. Thank you.

(A PowerPoint presentation follows:)

MR. BASHEDA: Okay, thank you, Rahim.

Good afternoon. I will briefly go over the market-power analysis that we conduct to see whether a seller will be permitted to sell energy capacity and certain ancillary services at market-based rates.

I am going to focus pretty much just on the, what we call the horizontal market-power analysis and the screens because that's essentially the topic of our session this afternoon. So I won't be going into every aspect of our market-power analysis effects.

And that's the usual disclaimer that I'm speaking for myself, and this will be a descriptive presentation.

Okay, the principles behind our market-based rate screening analysis. Well, you know, sellers must

demonstrate to FERC that they lack the ability to exert horizontal and vertical market power.

If the seller makes these demonstrations, and based on that and other commitments and representations, we will grant sellers the authorization to sell energy capacity and, as of now, certain ancillary services at market-based rates.

And essentially this technique is similar, or really is derived from the antitrust techniques of defining both the relative geographic and product markets to examine the seller's posture or position relative to other sellers in the market.

A geographic market, how do we determine the relevant geographic market? Well, it's basically where the seller is physically located. And we look at the BAA, or market, if we're talking about RTO, where sellers are physically located.

Now if a seller owns transmission, owns or controls transmission, then the relevant market is not only the BAA where that seller is located, but it's also all the direct interconnects, what we call the first-tier markets that are first-tier to where the seller is physically located.

Now if a seller does not own transmission, then the geographic market is just the BAA where the seller

physically resides. So basically the way to think about it is, if it's a vertically integrated utility, essentially then the relevant market is that utility's BAA plus the first-tier, the direct interconnects. And if it's an IPP that doesn't own or is not affiliated with transmission, then the market will just be where the IPP is physically located.

And then when it comes to an RTO or ISO, it does not matter whether the seller, whether you own transmission or not. In that case, the relevant market is the RTO or the ISO, mainly because these are already large markets.

The last bullet is important here. In our analysis, we also look at imports into the study area. So whether we're just looking at the BAA itself where the seller is located, or also if we're looking at the first-tier interconnects to that BAA, in all cases the analysis can consider imports up to what we call the simultaneous transmission import limit--which is a fairly sophisticated engineering study that we ask applicants to provide and that we review here to just determine how much power can be reasonably imported into a study area.

All right. And then the product market we analyze is uncommitted capacity. Well, I'll start with capacity. Basically what we do is we total up how many megawatts does a particular seller have in the geographic

market, once we've determined the latter.

And it's a fairly simple analysis. We look at first all the capacity you own. We can look at nameplate or seasonal. Either measure can be used. We also then, you add to that long-term firm purchases. And then you subtract from that long-term firm sales, native load obligations, operating reserves, and planned outages for each season.

So in other words, for a vertically integrated utility they get to deduct their native load obligations. For any seller who has long-term firm sales commitments, you get to deduct those as well. And again, the same formula applies to all sellers.

Okay, well what exactly is the purpose of analyzing horizontal market power? Well, the idea is that if a seller is presumed to have horizontal market power, they could potentially manipulate prices by withholding their generation, known as physical withholding, or by bidding into the markets at very high prices, a price that's meant to be a price above the clearing price. And that's referred to as "economic withholding."

And so at FERC we use two what we call "indicative screens" to test for horizontal market power. The pivotal supplier screen and the wholesale market share screen. And again these screens are intended to be conservative in the sense that they are, as the term

implies, a screen. It's just to determine is there a possibility of a market power problem here? It's not meant to be a definitive analysis, but a screen that creates a presumption one way or the other.

Okay, next. All right, the other thing is I'll just walk through sort of conceptually how the screens work. If anyone is interested, if anyone wants to see an actual screen, I can point you to the FERC Regs, or you can come talk to me and I can point to some examples. But I'll just sort of walk conceptually through how the two screens work.

The one screen is what we call the "pivotal supplier screen." And the purpose of this screen is to determine on-peak, you know when demand is at its highest, does the seller's capacity need to be used to meet that demand? And so that's basically what we're looking at in the pivotal supplier screen.

So as the second bullet notes here, it measures the ability of a seller to exercise market power unilaterally, and the ability of the seller to dominate the market at peak periods. Because the idea is, even if you don't necessarily have a huge share in the market, if your generation is pivotal, if your supply is needed during peak demand, then you could still potentially unilaterally exercise market power.

So in this case the seller fails the screen if

the annual peak demand cannot be met without some contribution of supply by the seller or its affiliates.

Now the wholesale market share screen, conversely, this is looking more at how big a player are you in the market. And it's a seasonal analysis. We look at-- you know, we break the year into four seasons and we measure whether you have a dominant position based on your share of the uncommitted capacity in the market, compare the uncommitted capacity of the entire relevant market, and here the magic number is 20 percent.

If it turns out that in any season the seller has a market share of above 20 percent, then that creates a rebuttable presumption of market power.

All right, what happens if the seller passes both screens? Well, basically that's the test you have to pass to get MBR authority. So that creates, as I mentioned, a rebuttable presumption that a seller lacks market power. Now interveners are of course always permitted to present evidence to disprove the presumption--things like sales data and other evidence that might indicate the seller has a larger presence in the market than the screens indicate. But if no evidence is presented to rebut the presumption that the seller lacks market power, then the seller will obtain or retain its MBR authorization when you pass both screens.

Okay, what happens if the seller fails one or more screens? Well, then it is the opposite. There's a rebuttal presumption that the seller has market power. And FERC--now if it's a seller with existing MBR authority, then FERC will initiate an investigation, what we call a Section 206 investigation, or action, or basically we suspend the seller's market-based rate authority going forward and determines--as it mentions here, makes rates subject to refund.

Now if a seller fails the screens--and this is quite typical--they can present other evidence to show that they really don't have market power, they're not a dominant seller in the market.

The primary alternative evidence that sellers can present is what we call a "delivered-price test." I won't go into that here because that would be about easily another ten minutes of discussion, but delivered-price test is a much more sophisticated data-intensive test. It's also the test used in things like merger applications. But that's what sellers will often, and what they always have the option to present. If they fail one of the screens, they can come in with what we call a DPT analysis. And there's other things that the seller can--other evidence they can present. Historical sales data in some cases is what sellers file to say, hey, you know, we're really not a big

player in this market. Look at what we've done in the past in terms of sales.

And of course then the final option is a seller can just sort of concede and say, okay, we'll propose mitigation to eliminate market power concerns. A mitigation generally means not--selling at cost-based in any market where you fail the screens. And we see that. There's quite a few vertically integrated utilities that are mitigated in their home BAA because obviously they're big players in their own BAA, and in general what we see there is they just sell at cost-based rates in their own BAA.

Okay, and then finally, to conclude, if the seller--well, if the seller is ultimately found to have market power after what we refer to as a 206 investigation, or it does not rebut the presumption, as I mentioned if it's an initial MBR applicant, someone just seeking to get market-based rates for the first time, it is denied MBR authority in all geographic markets in which it has market power.

Now the seller, if it's an existing MBR applicant, it is denied authority to enter into any new arrangements to sell power going forward at market-based rates in all markets in which it has market power, though it can continue to sell at market-based rates under any prior long-term arrangements they've entered into.

And then refunds would only be due if FERC ultimately finds market power and the seller does not challenge the presumption.

And with that, I'll turn it back over to Rahim.

MR. AMERKHAIL: Thank you, Greg.

So what Greg has described is the Commission's long-standing approach to analyzing the potential to exercise market power primarily for sales of energy and capacity.

As he mentioned, there are essentially two main components. You define the product so that we can determine what proportion of resources are capable of supplying it. And you determine the appropriate geographic market over which such resources are physically able to compete.

In Order 784, the Commission determined that from a technical standpoint the range of resources capable of providing energy and capacity is essentially the same as the range of resources capable of supplying imbalance services and operating reserve services. And furthermore, with appropriate transmission scheduling provisions the same geographic market could apply to all of those services.

Accordingly, after Order 784 and with certainly other conditions met, we were able to find that the same market power screens that Greg just described that focus on uncommitted capacity, they can be used to test the potential

market power for sellers of energy capacity imbalance services and operating reserve services.

But we have not been able to make the same case with respect to reactive supply or regulation. And we did not even explore in Order 784 potential sales of frequency response as a separate service distinct from regulation, as we are doing today. And that will basically be what we are looking at this afternoon.

So for purposes of this workshop, and just broadly speaking, we view reactive supply service as the production or consumption of reactive power to maintain specified voltage levels. Regulation is produced from either manual or automated dispatch through automatic generation control from a centralized dispatch system, and usually in order to control area control error. And frequency response involves the autonomous reaction of an individual resource to change its output to rapidly dampen large changes in frequency generally through appropriate governor settings or similar equipment.

And the particular technical characteristics associated with each of these products may impact both the range of resources capable of supplying them, and the appropriate geographic markets over which we test entities to see what level of competition there is.

With our panelists we will discuss each of these

issues in turn, and I want to thank them for coming. In order, we have again Doug Hils, Director, Midwest System Operations for Duke Energy, and speaking on behalf of Edison Electric Institute. Thank you.

Dmitry Kosterev, an electrical engineering with Bonneville Power Administration. Thank you.

Nick Miller, Director of Energy Applications & Systems Engineering for GE Energy, manufacturer of many of these systems.

David Hunger, Vice President, Charles River Associates, who has performed many market power analyses.

Clyde Loutan, Senior Advisor on Renewable Energy Integration for the California ISO.

James Ginnetti, Senior Vice President External Affairs and Markets, EquiPower Resources Corp.

And Ryan Hanley, Director of Grid Engineering Solutions for SolarCity.

Thank you again. And I would like to begin the discussion with reactive supply. And I think it would probably make sense to start with the geographic market definition for this particular service.

I think this morning we heard many people agree that it's a highly local service, so probably--but we also discussed the potential for distributed resources to provide it. And as I look at the screens today, I think you might

interpret them to apply to resources on the transmission grid. And if you do that, then you might ask a question, which I will: Is it appropriate to actually expand the geographic market to include resources on the distribution grid?

And I think I will start with Doug on this one

MR. HILS: As far as what the EEI members that are outside of the ISO/RTOs, I guess in general due to the locational nature of reactive power, we really don't see a lot of opportunity or applicability for inter-Balancing Authority exchange even for the smaller systems.

Definitely when you get to the ISOs of course, even those have to be sub-regional. It's not across the whole ISO footprint. But the Balancing Authority areas are very small. Trading could be possible. It's difficult to envision a suitable market power screen for that based on an appropriated--appropriate geographic model there, market model.

EEI supports retention of FERC's current policy allowing market-based sales pursuant to a competitive solicitation, or when the sale is made under the transmission provider's existing OATT Schedule 2 rate.

But again back to the geographic, it is very limited there. Also to the extent of even extending just beyond Balancing Authority boundaries itself. Even to the

extent of including adjacent systems in such analysis.

MR. AMERKHAIL: Thank you.

MR. KOSTEREV: Again, I want to second the opinion of the reactive power is so local, you know, it's really difficult to envision the market for that.

MR. AMERKHAIL: Okay.

MR. MILLER: Since it's my first time speaking, thanks for inviting me. And just as a word of explanation or disclaimer, I wear two hats. So I'm a fairly senior researcher at GE in power system application type stuff. I'm not a markets guy, but I'll also speak to some extent for GE, which makes pretty much all of the stuff that's under consideration today.

The locational aspect has been brought up repeatedly today, and I fully agree with that. Also in the earlier panel I think somebody used the quote "five flavors," which I quite liked. Reactive compensation comes in different flavors. Sort of as a rule of truth, you don't throw stuff fast when you can do it slow; you don't do stuff dynamically when you can do it statically, because that's the most economic.

Consequently, not only is there a locational challenge to getting this market right. There is a "what are you buying?" And you don't want a Ferrari when a tractor will do the job.

Having said that, I'm a fan of market-type structures and my instinct is that this has to manifest itself in competitive procurement up front. It means mechanisms to get the least-cost provision with the investment in the capital. And I'll toss out a couple of things that I haven't heard this morning, quickly.

One that we see quite a bit is, for example, wind plants--Dmitry mentioned it--solar plants can provide reactive compensation when there's no wind or sun. They are not doing that in general because there's no mechanism for them to be compensated for that.

Another thing that's a big deal for probably everybody in this room is retirements of thermal generation that has historically provided all of these services we're talking about today. And, you know, in the interest of full disclaimers, one of the services that GE sells is turning those thermal plants into synchronous condensers, which tend to be in a good location with a nice dynamic capability. But the market mechanism to allow that change in function of those plants, unravelling the sunk costs of the plant and the additional capital cost to turn it into a condenser, even when everyone in the room can agree that it's a good thing for the grid at that spot, causes the wheels to fall off. Nobody can get around that.

And there's other variations on that theme. So

the point being, different flavors, new technologies, old technologies, you've got to get them all out on the table. Having all your reactive compensation come from the generators obsolete.

MR. AMERKHAIL: Thank you.

MR. HUNGER: Also thanks for having me here. It's nice to be back. It sounds like, given the local nature of reactive power, the product, if you were going to try to apply the market-based rate screens, you would probably have to start with eliminating imports. It sounds like imports aren't really feasible for providing the service, these services. Maybe that would be a place to start.

It sounds like there may also be--it may also be more local within the Balancing Authority area, or within the RTO. So you may have to go to a sub-market within the default geographic market. And that kind of raises the question:

Do you want to have different markets for different products?

One of the nice things about the Commission's market-based rates program is you kind of know where those sub-markets are, you know, the existing relevant markets, what the default markets are. It makes it easier for people on the outside when they're playing, whether they can do a

deal or whether they can get market-based rate authority.

So I don't know if you want to have--it sounds like the nature of the product might lend itself to, oh, we need to have smaller geographic markets. Maybe that's okay. But that would be one thing that you'd want to consider, how that would interact with the other products.

But, you know, I'm not an engineer, but listening to the engineers, they've made it pretty clear that this is a pretty localized service. So my sense is the screens, as is, as they are, would need to be modified if you were going to--if you could apply them.

MR. AMERKHAIL: Thank you, David. Clyde?

MR. LOUTAN: It's pretty clear, you know, from what we heard this morning, that reactive power cannot travel well and it is a localized problem.

So the need for intravene training, I don't really see that as a need currently, but I do see distributed resources playing a pivotal role in supplying reactive and reducing the support you need from the transmission.

MR. AMERKHAIL: Thank you. We're going to come back to that, definitely, in a moment. James?

MR. GINNETTI: Yeah, I would just echo what everyone else has said, and we said it this morning. It's such a local product, it's hard to see how you would even

envision a market with such, you know, so many fewer competitors than you would have in a normal market. So I still think this is probably not a market approach that we should take, and compensate those who provide it in some other way.

MR. AMERKHAIL: Thank you. Ryan?

MR. HANLEY: SolarCity agrees. This is local. And to your point that there are many locations that you'd have one or two players that would have over 50 percent of the market, that doesn't create a market.

That being said, we do think that there is needed support on the competitive procurement side of this, as we discussed this morning. In particular, it sounds like we're going to get into the definition of "transmission" and "distribution."

Although we're focused on both power support, I would argue that creating a market downstream of that is also important, or at least a competitive solicitation downstream is important because of the impact that reactive power at the distribution level has on transmission. So it's probably a question of jurisdiction, but by all means supporting that solicitation down the chain helps open up more resources to participate that do in turn help bulk power.

MR. AMERKHAIL: Thank you, Ryan, and everyone

else. Just to close the loop, what I think I hear is we definitely cannot use the default that's in the existing screens for geographic market for this particular product. And while it may be possible to define smaller markets as probably going to be very case specific and not likely to be much we could do on that front, but we have already done things on the Order 784 front with defining the types of competitive solicitations that we would find acceptable for these types of sales. So hopefully that will be enough.

Before we leave reactive power, though, I think we should cover the other side, which is talking about what types of resources can compete to provide it. Well, actually, I don't know, we're pretty far down on using the existing screens. Maybe we could--unless anyone has further questions on reactive, maybe we could jump to regulation at this point.

MS. CAIN: I have one, though.

MR. AMERKHAIL: Oh, please.

MS. CAIN: Several of you mentioned the importance of reactive power from generators on the distribution system, or resources connected at the distribution level. Would it be possible that there would be enough competition at any location if we considered all of the distributed resources in a localized market power screen?

(No response.)

MS. CAIN: Ryan?

MR. HANLEY: I think it's possible. I don't think we have the stance that it's necessarily required, or you need it for adequate competition. The risk there is that you get an aggregator, somebody like Solarcity, that even though we have a lot of distributed resources, as we aggregate that and put it in as one resource, that could be a potential size of the market.

But to reiterate, we absolutely think that having something competitive on the distribution side not only spreads competition but it does improve the support on the transmission side. So--and we think that there is a large need for support there.

MR. HUNGER: I agree that that seems to be a viable source of competition. I'm just not sure how you would shoehorn that into the screens. That would be a tricky one. You know, when you look at the uncommitted capacity of sellers, what's the market size, when they're on the other side of the meter usually they're, you know--is it on--does it affect what the load is, depending on what kind of a resource they are?

That would take some thinking to figure out how that would fit into the kind of pivotal supplier analysis to sort of calculate a market share. But, yeah, it seems like

they would be viable sources of competition. Maybe if you fail a screen, or you're not using a distributor you're just trying to sort of do a case-specific showing of why there might be a reasonable competition, it might fit in there. It's a tough one for the screens, I think.

MR. AMERKHAIL: Okay, so I think the way we've left this is that it's not impossible for someone to come in and make a case-by-case showing. That's the situation even before this workshop or Order 784, and it remains the situation. But we haven't really found a way beyond what we've already done in 784 to move forward on market-based sales of reactive power.

Doug?

MR. HILS: Yes, I was just thinking from our company's perspective, I think we would have to look at also what--when you're doing something in an aggregation across the full system, yet also knowing how local that is, I'm not sure really what it means to the distribution provider when it's down at that level. Because I know that they are also doing things. They have the distribution management system. They're managing things, as well for their local system.

So I think there's a whole lot that would have to be discussed there as far as how all those things work. If you have to enhance the system to allow that capability; if you have to actually manage the needs of the transmission

system with the needs of the distribution provider, to the extent you'd have resources providing a service for transmission but it is affecting the distribution system at the same time.

So I think there's a lot of those things that really need to be thought through. I haven't though through them, and so I think input from more of the distribution expertise into these types of discussions I think would be helpful as well.

MR. AMERKHAIL: Fair points. Thank you.

So let's move on to regulation, then. And I'll just ask: Can the same geographic market, the Balancing Area, essentially can that be used for testing market power for sellers of regulation? And again, "regulation" is a centrally dispatched service AGC-based.

Let's start from the other side this time.

MR. HANLEY: Yes, we would think that existing market screens work for regulation. We think it travels, and there's enough potential players, particularly if we are able to open up some of the additional resources on the distribution grid to participate. It only adds to the potential competitors and that helps support the market.

MR. GINNETTI: I would agree with that. Again, the regulation is based upon a Balancing Area's footprint. And certainly there's plenty of competitors in all of the

existing RTOs who can provide the service.

I'm sure they put some market screens on it now that I'm unaware of, but I would think you'd have plenty of competition and that should not be an issue. If we get into later as to whether you sell some across a boundary, I'm a little sorry Stu left because that I think adds complexity to the interchange accounting in spades. That makes a much bigger challenge to know what really is going across the boundary that's inadvertent energy, or is it your frequency bias help to your neighbor, or what it is.

So I think there's a lot of energy accounting across the boundary if you decide to try to sell this from one Balancing Area to another.

MR. LOUTAN: I think within a BA, there's a lot of competition providing regulation. When it comes to acquiring this regulation from outside the BA, a lot of things come into play. You know, you need to have dynamic transfer capability set in, you know, prior to doing this. The units need to be, you know, AGC responsive.

Again, you need to have transmission reservation to accommodate the maximum amount of import you expect, or reg up, let's say, you need to get from that resource.

MR. HUNGER: Yeah, I agree. I think it's much more promising to use the market-based rate screens for regulation services. A couple of things to think about:

It sounds like import--and there's a couple of ways you could go. You could say, well, there's enough--we're not going to look at imports but we will look at the entire Balancing Authority area. Or, perhaps--because the simultaneous import limitation study may not be the relevant study for who can provide frequency regulation from the outside.

(Electronic interference noises.)

So maybe it's--we start with the home--

MR. AMERKHAIL: Does anyone have a cellphone on, or something that might be interfering? Okay.

MR. HUNGER: It might be me. My ringer is off.

Or it sounds like resources that are pseudo-tied could be considered within the relevant geographic market, but would have to think a little bit about how to treat imports.

Also, remember the screens, when you look at the pivotal supplier screens that's based on--a big component of that is what is the load at the highest time of the year--also in the market share screens, and what is the relevant load to use? Is it the energy market load, typical load of the energy market? Or is it related to how much regulation service is needed?

I haven't really thought through that, but I think it would have to be thought through to figure out

whether you could--but the principles of the screens, it sounds like the principles of the screens could work here, and ideally you would be able to use--you know, it would be nice if you could use the screens as they are, but I think you might have to think through what the effect of imports would be. What's the right calculation for imports?

My limited engineering understanding is if they're pseudo-tied they might as well be in the control area. So those would be viable.

And then, you know, if you think--if you go back to Order No. 697 and A, and there's a little chart in the back where you calculate the market shares, and how you do the pivotal supplier test, there's a lot of lines in there for load. And we need to know what should the load be in this case. Maybe it's a percentage of regular load. I don't know. But it's promising.

MR. MILLER: I guess I tend to look at these problems in recent years through the filter of a future, a near future of extremely high levels of variable renewable generation. So we have Sandip in the room that hit 40 percent instantaneous penetration a couple of days ago. And some of these views of the world that we have now get very brittle at those very high levels of penetration.

So I guess two things. One is the complexity notwithstanding of making the circle bigger, and figuring

out ways to exchange regulation services with adjacent areas, or even farther away, yeah, all those statements of caution about how hard the bookkeeping is and keeping the reservations right are true.

But the economic and other societal consequences of deciding it's too hard to bother with I think are high, and I don't think we should go that way--at least not until we've proven that the problem is such a hard nut to crack that we can't. And I fully acknowledge that that's a tricky one.

The other one that I'll just toss out here, and maybe doesn't warrant too much more discussion, is that with variable renewables is a highly statistical phenomena with generation. And one of the things that happens constantly is that the system--you know, people like Clyde are bit by the outliers, the statistical outliers.

And one possible means of making the system economic is to actually have a tiered service of reserves so that there's a second-class, quite literally second-class reserve functions that are called on as the reserve of last resort, and have a different financial arrangement. And maybe that isn't done with a fully liquid market; it's done by some other bilateral. But the only point being, is that it's not clear to me that 100 percent of all regulating reserve functions need to fit inside this market structure

that you're talking about; that there's some room to come up with whatever supporting structures that will handle the outliers.

MR. KOSTEREV: Well thank you. BPA has about 5000 megawatt of renewable generation, primarily wind, integrated in its Balancing Authority. So this issue that Nick described, they're very relevant to us and how we are trying to regulate for the wind ramps, certainly.

And as Nick described, we want to make the footprint bigger. So using bigger, by using the dynamic transfers, the other Balancing Authorities, like ACE diversity interchange, you know, so we can share the regulation burden with other participants.

Some of the actions like, you know, customer-supplied regulation is also on the table. So I think, you know, I'm not a market person but certainly it seems like, you know, the footprint for the regulation services is in general large enough, or could be made even larger with all the things, you know, going on. So the screens, you know, that Greg described, you know, would apply to regulation market, it seems like.

MR. HILS: I guess, especially for the systems outside of the ISO/RTOs, I guess as we looked at it from a market screen perspective, to the extent that a resource already passes the market power screen for bulk power sales,

the capability to provide regulation, you're still using a transmission path, you're still using a certain amount of transmission capability, so to the extent that the transmission is there to be able to support bulk power sales, it really should be there also to be able to support a dynamic transfer of power that varies, rather than always be flat out at the full reservation.

So to the extent that an entity may pass all the market power screens from a bulk power sales standpoint, perhaps that is good enough for also being able to address the regulation from adjacent systems. And that way, being familiar with the NERC standards, we definitely from a Balancing Authority standpoint know well how to handle dynamic schedules and pseudo-ties, and how to implement them, and what's needed to properly account all the way down the line. There are definitely the hurdles of getting the telecommunications in place, having all the things in place to enable that capability, but we have to do it and we're required to do it in way where we're not impacting the reliability of the system.

And so from a Balancing standpoint, if I have another system where I have a generator wanting to provide regulation, or even provide a portion of the regulation to another BA area, whether it be done through a pseudo-tie or through a dynamic schedule, we know how to do it so that it

can be done I guess in a reliable manner and not impact others on the loss of a signal, or whatever the case may be.

There are some other things, when you talk about pseudo-ties, is that there's the idea that you're taking full ownership of the resource of a load when you do a pseudo-tie. It's not where you're just parsing out a single piece of a service versus dynamic schedules tend to be more where you're doing a specific service but it's still essentially within that host system. All the other things about it is within that host system.

At least from Duke Energy's perspective, under the LITT, we lean more forward when you're seeing a service that's very specific like that, it seems like dynamic schedules have been more the direction to go. But we also know that NERC has been working on also going down the line of having both pseudo-ties and dynamic schedules captured in a way to where it's very clear which ones are out there so that they can be easily reviewed to make sure that they're properly accounted for.

I would note one other thing. The Balancing Authority ACE limit under BAL-001-2 that's been submitted by NERC, that's a standard that's also taking us in a different direction, well, in a positive direction, in that we're going to have now two requirements, the CPS-1 and the BAL,

both written in a way so that it encourages support of the interconnection frequency.

BAL is replacing the CPS-2 requirement. That requirement required BAs to stay within BAL's plus or minus that CPS-2 limit, and to the extent that you had variable resources, or any kind of a swing in the ACE to where you were outside those bounds, you were having to take corrective action. Versus, now you have--which was contrary to CPS-1, which was encouraging to keep on doing what you're doing; you're helping frequency.

So now that we have CPS-1 and the proposed Balancing Authority ACE limit both sort of in lockstep, that when you see something on the system and it's in support of frequency you're not having to immediately try to turn that around, I think it will be helpful for all in the integration of additional resources and what's needed to be able to meet those requirements.

Thanks.

MR. AMERKHAIL: Thank you. I would like to follow up on something you said, Doug. So if a particular market-based seller passed the existing screens based on uncommitted capacity, and those screens didn't happen to need to consider imports, then I could see a case for saying, well, maybe regulation makes sense, too, at market-based rates.

One thing we identified in the 784 proceeding is that many people, or at least some people, only passed the screens if they consider imports in addition to competition within the home BA, Balancing Area. So I guess my question is: Would what you said earlier still apply in that case?

MR. HILS: Actually, it would. Actually I was speaking from the context of the existing market power screens in that way, of looking at the imports, looking at those things. To the extent that an entity is deemed to not have market power under that kind of a construct, the capability that instead of 100 megawatts transferring across an interface, now it's 100 megawatts that varies from 0 to 100 really shouldn't be a factor.

So I guess that's one thing to consider, is that if you're already qualified in one manner for that way, regulation perhaps should just fall under that.

MR. AMERKHAIL: So one thing we've assumed since the earlier proceeding is that you would have to have either dynamic scheduling or pseudo-tie arrangements because a resource in the neighboring Balancing Area responding to a regulation signal from a different Balancing Area would be viewed as deviating from its schedule unless there were something like that in place.

Are you saying that's not important?

MR. HILS: No. I think when you're talking

regulation service, it is important. I guess what I was indicating though is that from the standpoint of the implementation, whether it be as a dynamic schedule or pseudo-tie, I myself, I don't see that as a hurdle in the implementation because I mean we've been doing that for years, of implementing dynamic transfers.

MR. AMERKHAIL: Well it would definitely be helpful to file written comments after this workshop.

Let's see. Let's get into what it takes to provide regulation. Obviously something like Automatic Generation Control that responds to a central dispatch signal. From what I took away from someone's earlier comment--I think Jim said this, actually--sometimes this type of control equipment is a package, an optional equipment package you can add or choose not to add, depending on whether you see an economic advantage to it.

Right now if Greg were to perform an uncommitted capacity-based screen, he wouldn't be looking for particular types of equipment on all the resources that have uncommitted capacity. So what do we need to know to decide whether for regulation we can make the same assumption, that all of the uncommitted capacity is there?

Is it easy to add this equipment if it isn't already there? Do most resources have it? That sort of thing.

Does anyone want to jump on this one? Nick?

MR. MILLER: Well, I'll jump in. I'll put on my manufacturer and researcher hats simultaneously.

In particular, so let me answer that from the perspective of some of the nonconventional, nonsynchronous generation. And in particular we'll start with wind. But this is I think germane to solar and, frankly, some other resources.

The first thing is, many of these nonsynchronous resources are very asymmetric. So in simple terms, a wind plant can go down very easily and with essentially no opportunity cost until it's called on to do so. But a wind plant has a major opportunity cost to go up. That's true for other kinds of resources. It's a little bit inverted for loads.

Consequently, I am of the opinion, first of all, that up versus down reg markets are much more likely to be responded to economically than symmetric markets. I sat at a hearing in here a couple of years ago where at least a couple of the big guys were of the opinion that that was unnecessary.

So having said that, there is not a major hardware cost associated with providing that capability for example on wind plants and utility-scale solar plants. But it's a brains, communications, and so on a per-unit basis

the cost starts to become considerably more intimidating as you push it down to very fine levels of granularity.

So the cost to have AGC-capable dispatch on a 200 megawatt wind plant is probably in at least tolerable, if not in the noise range. The capability to have such dispatch capability on a 1 megawatt solar plant is probably pretty painful.

So a blanket answer to: Is it available? Is it economic? Isn't quite as easy as it might be. And I think you need to take that into account.

MR. AMERKHAIL: Could I just follow up on that? So if a merchant generator with a 200 megawatt or larger wind plant came in and wanted to make a market power showing for regulation, is there basically--or I guess anyone else--is there a rule-of-thumb we could just say cut off anything smaller than--don't consider anything smaller than 200 megawatts a competitor?

MR. MILLER: The short answer is, I'm not aware of one. I guess if you were to ask me that with my feet to the fire, I would say make it the cutoff for the LGIA, 20 megawatts.

And I might just, if I could talk just for a smidgen longer on the topic, there's one of the big utilities that's in a non-RTO, or in non-RTO parts of the U.S. that has a substantial wind portfolio. And they have

in the last year or so implemented a requirement that all wind plants with whom they enter into PPAs have AGC on their wind plants. It's a requirement. And they use it regularly.

So it is in a sense a demonstrated capability. Having said that, the market mechanism by which they keep that fair--that was one of Mike Jacobs' worries, right; this has got to be fair and accessible--is, they pay when they curtail the wind plant. That keeps them very honest. But the marginal cost of getting that service is lower than any other mechanism by which they might get there.

I've seen other systems in which the grid operator was reluctant to take advantage of either of those two directions, up and down, and the most perverse market outcome that I've observed in several places is wind being precurtailed so that thermal generation could be run, so that it had the capability to go down in case the wind picked up. Which that is a failure of some form that needs to be avoided in the market design.

MR. AMERKHAIL: Thank you. Doug?

MR. HILS: I was just going to say, as I mentioned BAL-001 under NERC, that pretty well from a Balancing Authority standpoint that pretty well defines what we need to be doing from a regulation and generation control standpoint.

To the extent you have systems there that are required to have at least 100 percent CPS-1 and they're sitting at 150, 160 percent, to the extent that you have, whether it be the CPS-2 or BAL, well within compliance there, that's sort of putting all the definition around do you have enough regulation or not?

So for the system--and very much as we spoke of this morning--to the extent that systems are already completely capable of meeting the existing NERC standards when it comes to CPS-1, the BAL, or CPS-2, there's not--I don't see that driving need to go out and procure additional capability. That's why we don't see a whole lot of dynamic schedules and things for that kind of a service because we don't see a lot of the need.

It's not near like what we see in the RTOs where all those services are procured. That's the way you get it there is those, you know, inside the markets. But for the non-RTO/ISO groups, to the extent that Balancing Authorities are well within compliance, there's not a big incentive there to go out and look at, well, can I get more? Because you don't need more.

MR. AMERKHAIL: Fair enough. Thank you. Jim?

MR. GINNETTI: Yeah, I just would like to comment. I think if you're looking at a market screen, market power screen, you shouldn't assume that every unit

has it. We are not in favor of, you know, mandates in the RTOs.

I'll give you an example. New England started its regulation market in late 2005. And at the time, I worked for a company who owned a very big unit that was an excellent regulator. And the first few months of that market, we made a very lot of money. But as soon as people started to see how much money was being made, they came charging in, which is what competition does, and now that market is very much smaller compared to what it used to be in terms of total revenues.

So I think what would happen is, if you surveyed to find out who had regulation capability, that might be your first test. And then recognize that, depending upon the prices that people see out of that market, you will likely get either more or less competitors depending upon what that price signal tells them to do.

MR. AMERKHAIL: Okay, thank you. I would just draw a distinction between testing people for market power to make the sales and actually forcing anyone to buy. From our perspective, the market does decide how much gets transacted because the demand side plays an important role on that.

So does anyone else have questions in this area? Actually, just to close the loop back to you, Nick, you

talked about how easy it would be for nontraditional resources to add the equipment, at least if they're of sufficient size. What about traditional merchant generators who maybe weren't set up that way to start with?

MR. MILLER: I think the answer to that's got to be: It depends. And certainly one of the things that makes Clyde crazy is he's got 10,000 megawatts of generation for which that sort of retrofit is pretty much out of the question.

So the new plants, the geothermal plants really don't want to be throttled back when they've got a little bit of room. Biomass plants that want to run flat, all these things that raise the floor make life progressively more difficult. And there's a big cost, either opportunity and/or equipment cost.

Having said that, you know, combined cycle plants depends on the vintage. You know, as I lecture around the world, I give my friends at HECO, Hawaii Electric, they went out and did an inventory of their ancient creaky thermal fleet--maybe I shouldn't say that publicly, but I think that's their words--and they searched for upgrades they could make to improve the ramp rate, improve the handshake with the system control, and they came back with a shopping list of improvements stacked, and they took it to their regulators and said we want to make this investment in the

system to improve its agility, and they were able to do, frankly, dramatic things.

So that's a long-winded way of saying that it depends, and you've got to go looking. There isn't a one-size-fits-all answer to that.

MR. AMERKHAIL: Thank you. That's helpful.

I guess the other thing you mentioned was resources like nuclear plants, what I think of traditional baseload, they run around the clock. I guess for purposes of market power screening, I wouldn't necessarily view them as having much uncommitted capacity anyway. So maybe that's not as big an issue that they may not have--they may not be considered, I guess, is my point, already in the uncommitted capacity figures.

What do you think, Greg?

MR. BASHEDA: Again our screens really don't distinguish between types of capacity. Perhaps that's something I could have pointed out. And of course we don't rule out any capacity based on its size. And also, when we do the deductions for native load, it's just the out straight deduction, what's your native load? In other words, we don't do any type of economic dispatch or that type of analysis because screens don't look at prices. It sounds strange, but it's true. We don't look at prices at all on the screens. So we really don't get into looking at

the composition of capacity.

MR. AMERKHAIL: Yes, but just as a matter of fact there probably isn't much uncommitted capacity from something like a nuclear plant?

MR. BASHEDA: Oh, I agree. I agree.

MR. AMERKHAIL: Bob.

MR. SNOW: Okay. You mentioned ACE diversity before, which are basically kind of averaging the ACE of a number of different entities. How should we be taking that into account in these market screens, since the diversity may not be maybe in the fourth tier in his approach?

MR. KOSTEREV: The question I guess, I'm not familiar with how the screens are done because, you know, I'm on the reliability side of the business.

MR. SNOW: Maybe you just want to start describing, when we say "ACE diversity" for those who are not speaking in code.

MR. KOSTEREV: Well ACE is "Area Control Error." It's typically calculated as a base on the boundary flows and also taking into account the frequency bias. And if you have several BAs, you know, they can--and your ACE is positive and other ACE is negative, you know, instead of each of you trying to bring your ACE to zero, you just share the ACE diversity among the BAs, you know. So that's a simple way of describing this.

MR. SNOW: From a--it looks like as if the two areas are one big Balancing Authority as far as the calculation of ACE, or the averaging of the ACE is concerned.

MR. KOSTEREV: There are certainly some restrictions, but if you--

MR. SNOW: --geographic area may very well, could dramatically change.

MR. KOSTEREV: That's correct, yeah.

MR. HILS: Let me add to that.

I guess the basis behind the ACE diversity interchange though is that it's not really in the form of discrete transactions that are sustained. It's really more of the inadvertent activity of individual Balancing Authorities to where in this instant in time I have a positive ACE and another BA may have a negative ACE. And so ACE diversity interchange recognizes that for that moment in time neither perhaps has to correct that ACE because, you know, they're offsetting each other.

So it's really as a means to reduce the regulation requirement for what they have to do from a resource control standpoint, but it's not done in a way to where it is a resource that any individual BA--and this is what I gather from other systems that have implemented it--it's not really seen as a resource capability of I have

these so many megawatts from this other BA and I can rely upon it even five minutes from now. It's very much a real-time sharing of the ACE in a way to where they're really just reducing their individual regulation requirements, but not in a way where one can be relying upon the other for any longer than the duration of seeing it instantaneously.

MR. AMERKHAIL: Okay, one other thing that we were supposed to look into. And, Doug, you had mentioned that the industry knows how to do dynamic scheduling, and pseudo-ties. It also seemed in earlier parts of our 784 proceeding that it would be useful to know how easy is it for, I don't know, for market participants to enter into an arrangement.

Are there any efforts to make something like the EEI standard contract, but make it for dynamic scheduling, or a pseudo-tie? Or is that just not even--is it not necessary?

MR. HILS: Actually, I can't answer that. I'm sorry.

MR. AMERKHAIL: Okay. Does anyone--okay. We'll see if any written comments come in.

Does anyone from the staff side have anything?

(No response.)

MR. AMERKHAIL: Okay, I think probably we can move on to frequency--

MR. MILLER: I have just one quick comment, coming back to the screens. It was said earlier, but I want to make sure that it didn't slip through the cracks.

If I understood the screens, they tend to be, as they currently exist, they are really kind of geared around the peak--you know, capacity peak load, that kind of condition under which you're worried about market strength at a condition of scarcity.

The condition of scarcity for reg and frequency response is in general going to be at light load. So I think that was said a couple of times, but that's clearly a critical element to the screen. You've got to be looking at the period of scarcity in the screen.

MR. BASHEDA: That's true. Again, the one screen in particular, the pivotal supply, yes, that's focused on peak demand. The other screen, not quite so much, but even there when we're looking at market shares in four seasons, but even there we're also basing it on average peak demand.

So not quite--the pivotal supply screen is the one that really focuses on the peak demand.

MR. AMERKHAIL: Well maybe just to summarize, then, we don't have the silver bullet yet to apply the existing market power screens to the service of regulation, but there are still other options. There are the two from Order 784. Third parties can sell to a public utility

transmission provider that is in the market at that provider's own rate, or at a rate that results from a competitive solicitation that meets certain requirements that are laid out in the rule.

So it seems we have at least some type of market-based mechanism out there for those areas and those transmission providers that do have a demand for regulation. We haven't been able to make it quite as easy as for the other ancillary services, but we'll keep looking.

Let's move on to frequency response, then. And again, this is different from regulation. This is autonomous response directly to changes in frequency, and I understand it requires a fair amount of rapidity. So it may be different for regulation in that way, as well.

We'll start the same way. Any changes needed to the default geographic market? Doug?

MR. HILS: Frequency response is going to be somewhat tricky from the standpoint of the implementation across multiple systems, but truly the provision of frequency response is to the interconnection. It's not to a geographic area. And I guess in certain cases, unless you end up with one region with a whole lot of it.

So it does lend itself that if a Balancing Authority needs some additional regulation, or actually frequency response, and they happen to be in Florida, they

could contract with somebody in Arkansas, or Wisconsin, or someplace else, because the provision, giving some megawatts, taking some megawatts back is what the interconnection is. It's not necessarily a bulk power transaction across multiple transmission paths like you tend to look at regulation, or any other kind of bulk power transaction.

So there are some things that we probably need to address from an implementation standpoint because, for example, Duke Energy Carolinas is a 20,000 megawatt system. Its frequency bias requirement is 200 megawatts right now. And so to the extent that--and its FRO is probably going to be 120.

So to the extent that we would decide that we want to go ahead and procure additional frequency response, it may be 10 megawatts, or some amount of megawatts. And so the question would be, are you going to get it from an adjacent system? Can you get it from a resource inside your system?

But once you start talking about dynamic scheduling or pseudo-ties, again the scale starts to come in from the standpoint of how much is it going to cost to implement that?

If I truly need to see that in real-time, that's one cost. If there's a way to not have to see it in real-

time and have it account for my BA area after the fact, that's another possibility. But we really have not gone down that path. We are looking at all those alternatives.

Bob, as you know, where we are with the frequency bias setting, to the extent that I had a resource in my footprint that was providing response for another system, could I actually recognize that on my system in real-time operations and after the fact allocate a piece of that response to another BA in the way we calculate our frequency response?

Those are questions we still need to look at from an implementation, because I could definitely say, yes, I can have this battery, or the solar, or this generator say I can get X amount of megawatts, and I can dynamically schedule that, see that on my system, but when we're looking at as small a megawatts as that may be, that may be where it starts to become cost prohibitive.

So from a market power--it's a resource that you could say really can get anywhere in the interconnection, but the cost of getting it maybe has to accommodate some other things on top of it like the dynamic scheduling, and how many megawatts are you really going to be implementing that for?

MR. SNOW: As a follow-up, the frequency response into your, into Duke Carolinas system, currently the

standards cover that under transmission reliability margin, TRM. It's kind of a line item there in a couple of different areas of those requirements.

So I'm a little confused about you using dynamic schedules, or pseudo-ties, when TRM is specifically identified as taking care of that issue. So I wouldn't have expected to double count it.

MR. HILS: No, I think this would be--I think the TRM, as you mentioned, Bob, may be more for what you're recognizing perhaps on your own system. But to the extent that if it is the Carolinas is getting a resource in South Dakota to provide a certain amount of frequency response, I think that would have to be acknowledged whether it be through a pseudo-tie or through a dynamic schedule so that that amount of response is actually seen in the other system while we figure out a way of accounting for it, you know, after the fact. But I'm not sure if we would decide, without accommodating it through something as a visible transaction rather than a TRM.

MR. SNOW: Without discussing or arguing that, I'm sure when we get to your colleague next to you, Dmitry Kosterev, provided some documents in a different docket concerning the COI, is his example. So I'll defer my questions to after he describes that activity.

But I think, if I understood you correctly, from

a market point of view, the geographic area point of view, it's kind of the interconnection you're talking about. If you're in the East, it's the East; the West, the West; ERCOT--ERCOT's by itself anyway. In reality, if we're talking about, you know DC ties between interconnections, if one wanted to--I'm not saying--one could fundamentally ship the frequency response from the East to the West, or ERCOT to both, or Quebec to--we don't regulate--forget that equation--all that, there's no, from whether you'd want to or not is another question, but could you? So the market screen would be the interconnection? Is that--

MR. HILS: (Nods in the affirmative.)

MR. SNOW: Thank you.

MR. AMERKHAIL: So we were going to ask about a dynamic or pseudo-tie issue. I had sort of assumed that, unlike regulation, which is dispatched, that frequency response might not require any type of dynamic schedule. You would pay someone in advance to respond to the frequency. They would do that autonomously when it reached whatever the agreed-upon limits were.

So I guess I just want to confirm. You believe even in that case you need a dynamic schedule, or a pseudo-tie, some type of special transmission scheduling arrangement?

MR. HILS: Again, if it's within the Balancing

Authority area, it is something that's happening I guess autonomously, it is happening within that system. But I guess I question to the extent that that Balancing Authority does not have enough within its Balancing Authority Area, the possible solutions would be to contract with another resource somewhere on the interconnection to be providing that response.

I'm not sure if that BA has to be seeing that response in real-time for what it's going to be doing for its own generation control, or whether it would go down the direction of that resource still being included in the bias of the host system where it resides, and it would be more of an after-the-fact acknowledgement of who that resource was responding to.

If it ends up that, no, when it's responding it's responding on behalf of this BA, and it needs to be in that Balancing Authority's real-time ACE in what it sees as far as flow in and out of its ties, then you would be looking at more of we're seeing it dynamically in real time so that that response would be seen no different than any other tie flow in the calculation of that BA area's required response.

So for the resources within the footprint, that's going to happen, no dynamics needed there. You will just need the information to acknowledge whether or not it was

provided.

But in the way that a Balancing Authority calculates its response, essentially they're looking at what is flowing in and out of its ties. That goes along with the most significant frequency deviations because it really looks like noise except for the largest of those deviations.

But if the Balancing Authority is held to demonstrating a certain response based upon that information, it's possible that if it's procuring a responsive resource elsewhere, that dynamically it may be needing to see that no different than another tie line or as if it is physically residing on its system in the way it calculates its compliance.

MR. AMERKHAIL: So for purposes of market power screening, it might just look exactly like regulation to us?

MR. HILS: Well from that perspective, I guess you're not necessarily having to have a transmission path--

MR. AMERKHAIL: Oh, okay.

MR. HILS: --to the extent that that's where we get into what transmission do you need. It's really not a transaction from point A to point B, but it's a transaction of that resource providing megawatts to the interconnection, wherever it's at. And either drawing megawatts in, or providing megawatts to fix the frequency. They're not fixing the BA's balance; it's fixing the frequency for the

estimated response.

MR. AMERKHAIL: Thank you.

MR. HILS: Sure.

MR. AMERKHAIL: That's helpful. Please, if anyone else wants to.

MR. KOSTEREV: I think Bob wants to put me on the spot. So the--

MR. SNOW: Just looking for your input.

MR. KOSTEREV: Okay. So Doug is right. The frequency response isn't a connection-wide phenomena because if you look at the disturbance in a system, maybe it's a different frequency in the first couple of seconds after a resource loss to the system that kind of moves around, you know, and propagates across the interconnection.

But maybe it's not in four or five seconds, you know, in the event, the frequency is pretty uniform across the entire interconnection to a large extent. So recognizing you have an intertie connection providing, and governors which are active, providing autonomous response to frequency, those implications could be implications for the system operating limits. Because the governor response in the system can increase transfers on the path which could be voltage stability limited.

So the megawatt flows increase because of the governor response. And as a result of that, you may have

voltage stability, or transient stability issues. So in specifically California's own BPA operate California-Oregon intertie, it's a 3800 megawatt transmission path between Pacific Northwest and California, and the system operating limits of the path are limited by the generation outages in Arizona. When you have a large contingency, a larger source loss, the generators respond across the system.

And that response in the West mostly comes from the Pacific Northwest, Canada, Northern California, and that tends to overload the tielines and cause voltage stability issues which limits the system operating limit.

So in that respect, we need to understand that there could be implications for the system operating limits. The governor response needs to be recognized. And if there are any sales to be made, we as engineers could do the system operating study months ahead, a season ahead, for visibility of these transactions, so we can model them correctly in the studies. So if there are any impacts on the system operating limits, we can reflect those impacts correctly in our studies.

So if there are any sales to be made, you know, I think it's--you know, probably need to enter in the agreement for the extended period of time so people could do the studies and we can plan and operate the system reliably.

MR. AMERKHAIL: Just to clarify, so you mean it

would never be sort of a short term? It wouldn't make sense, or it wouldn't be safe for there to be short-term transactions in frequency response? It should be some kind of long-term agreement?

MR. KOSTEREV: Well we prefer it to be a long-term agreement, particularly if it's sold across the tie, which is impacted by the--because SAL is impacted, you know, by the frequency response.

Certainly if you sell into another BA, which is like next to you and they just experienced generation loss which carried most of its frequency responsive reserves, I think those transactions could be made on a short-term, as long as you know there's no significant impacts on the system operating limits.

MR. SNOW: Dmitry, as I understand it, the binding constraint is really the very short timeframe when a design event occurs, and that the interface has not only the normal flow, the energy cell flow, but the responsive generation in your area for an event in a different part of the interconnection quite a--you know, thousands of miles away?

MR. KOSTEREV: Yes, that's correct.

MR. SNOW: The flow going through the California-Oregon interface, the issue being a voltage instability which it, an IROL, if I can, reliability limit, which if you

need to mitigate to limit the flows pre-event, 24/7 every day of the year kind of thing, to account for the time--because it happened so quickly there's no operator--I know you're good, but you're not that good--

(Laughter.)

MR. SNOW: --to respond to that. So when we're looking at selling, or sales between regions, looking for the interface limits, whatever the binding constraint might be--in your case it's voltage--would need to be accounted for in the simultaneous import limit for, I call it the transmission reliability margin before--I think we're parsing the same thing a couple of different ways via the standards--and while it's a very short timeframe, it is the binding constraint. Did I get that right?

MR. KOSTEREV: Yes, that's correct. And the timeframe you're looking anywhere from 30 seconds to like 3 minutes. That's when we see the highest pickup.

MR. SNOW: And now Nick will tell us how the variable--

MR. MILLER: I think Dmitry just put the other end of the bookend between the two, and I'll just chime in for some of our recent work looking at this question. One reading of BAL-003 is that each BA is responsible to do--to provide their FRO within their BA.

MR. SNOW: All right. Or the fellow--Doug was on

the team with the FU comment--

MR. MILLER: So well let him come back.

MR. SNOW: I don't know what the thing says.

MR. MILLER: Okay. In any case, the--I think Dmitry's counterpoint to the general statement that you should be able to swap frequency response obligations pretty much anywhere within an interconnection may be a little optimistic.

Having said that, the work we've done on the Eastern Interconnection and working with Clyde, whatever, suggests that these kinds of constraints that Dmitry is describing are absolutely legitimate but are--tend at least in our experience to be the exception on exchanging frequency response.

So the ability of a BA to go ahead and procure some fraction of their FRO because they're short should be at least so far based on work we've done, and some other experience, should be allowed. And the risk, the reliability risk that Dmitry correctly points out should also be evaluated and maybe guided, for example, by, you know, these guys have nomagrams for everything else, why not have nomagrams for figuring out whether or not they can provide all of Clyde's FRO or not.

Because, make no mistake about it, we're on a trajectory again in this renewables world of having the

possibility of incurring some significant cost, operating cost implications. If the interpretation of the rules comes back, Southern California Edison is obliged to meet their FRO 87/60, and may have to end up running generation out of merit solely to meet that because they don't have the ability to procure it from a neighboring BA, or another BA.

So we don't want the interpretation to be diametrically opposed to what Doug has said, but maybe it doesn't have to go all the way there.

MR. KOSTEREV: We're not opposed to the sales of FRO, but we need to be aware of the SL implications, and particularly for the operating engineers who do the day-ahead studies, or months-ahead, or seasonal studies, they need to account for these in their studies. That's really important.

MR. HUNGER: Yeah, I'm just listening to this and trying to figure out how the physical characteristics of this product or service would line up with the MBR screens. And this seems like a really challenging one.

On the one hand, if any generators located within the Balancing Authority Area can provide the service, that argues for this does fit in with the screens. It's hard to figure out who--and if anyone on the outside, outside the Control Area, can provide the service as well. And it's just for responding at the interchange, then it seems like

it's almost unconstrained and we're back to hub-and-spoke and no one would fail.

But, you know, if that's true then no one should fail. But I can't get a sense--it's hard to get a sense of what the relevant constraint on imports should be, if there is one, and the relevant geographic market I guess could still be the Balancing Authority Area even though it sounds like it's--but what's happening, the product it's serving is balancing between two Balancing Authority Areas.

But when I first started listening to this, I said, oh, this is not going to work. But as I listened to Doug and listened to you guys more, it sounds like, well, maybe this actually does fit in with the screens. But that's the question I'm asking.

Can any generator within the Balancing Authority Area provide this service? And what are the constraints on the generators outside--even the other resource as well, what are the constraints on the other resources on the outside from providing this service?

I'll ask these guys because they understand it.

MR. HILS: Well I guess BAL-003, there's a few mechanisms there that BAL-003 allows Balancing Authorities to form a Frequency Response Sharing Group, just as they formed Contingency Reserve Sharing Groups today, to where they jointly meet a contingency, and then after the fact

will calculate what their frequency response was as a group.

So there's one convenient mechanism there for just doing it when you're talking BAs that come to an agreement to say we'll share in this obligation; we'll write the rules of what we'll apply to ourselves for it.

But to the extent of--I don't believe the team working on BAL-003 ever envisioned that it's a requirement that has to be within a geographic area. Essentially a Balancing Authority Area is defined by its tielines and pseudo-ties. And so, you know, a meter boundary of a BA is really defined by those.

So you can have a generator 300 mile pseudo-tied. You can have those things, and they're all part of your BA Area by virtue of them being, you know, appearing like a tieline to that BA. So it's not limited to the transmission, physical transmission system that the BA may primarily reside on.

MR. KOSTEREV: If I may add, like David's question about the every generator can provide the service, and every synchronous machine has a governor. I mean, you don't want to stamp a machine which doesn't have a governor. It's a dangerous thing.

So conceptually, yes, you know, every machine can provide a governor, frequency response, assuming that they

have enough headroom. So they need to back off, forego the energy sales so they can respond to frequency. And Nick can talk about wind machines, too.

MR. MILLER: Wind machines do that fine. It's just that the opportunity cost is equal to the sales, as opposed to equal to the sales minus the variable cost of operation. So a thermal plant gets the revenue for providing the service, foregoing the energy sales but saving the fuel. A wind plant forgoes the sales and saves the fuel for zero savings. But otherwise the math is kind of the same.

MR. HUNGER: So if it's--the opportunity cost of providing--not providing energy is the relevant price, so that's good in that if you do fail the screens and go to the delivered-price test, that's based on the energy price, you know, and ten different seasonal load conditions. So that sounds like that price is meaningful to people making--deciding whether, or who can provide, who can economically provide frequency response service.

MR. AMERKHAIL: And just to follow up, you said that all synchronous machines have a governor. I'm given to understand, though, that frequency response is most valuable if it's really rapid. And I would assume some of those synchronous machines are slower than others.

If we were looking at all of the available

capacity on the system, do we need to care about how fast the resources are? Or do we really think all uncommitted capacity can compete for this?

MR. KOSTEREV: I think most resources are probably fast enough to provide frequency response in the timeframe that Bob showed in his chart. Typically gas turbines will be lightening fast, if they have enough headroom, again.

The steam turbine can provide fast response initially. And then as you open the valves, you know, the steam pressure drops so you have some kind of setback in the response.

Hydro units typically are on the slower side, but they can still provide the full response by the 20-second timeframe that NERC requires.

And I think wind is also fast enough.

MR. LOUTAN: Wind is fast, but the problem is a little more involved than just, you know, the response. As Doug and Dmitry said, the frequency response is really an interconnection issue. So it depends on how we design this product, right?

If it comes--well, even today we have an issue, as Dmitry said, with COI. We have a contingency with one large unit in the East that frequency response flows through COI. And in some cases, depending on COI peak disturbance,

we see an overload. And it depends on how quick the contingent dispatches its reserve, you know, that response is sustained.

So I have seen where we had to drop load to relieve the loading on that tie because we had the PAD operator. So now with frequency response being an obligation on all BAs, this may alleviate that problem. You know, when all BAs are now going to be responding to an event, we may see less response from the north, less flowing from the California ISO, and we can resolve potentially, you know, most of our problem.

The thing is, though, if we make frequency response a sustainable product, you don't have an issue. Right? Today, you can rely on frequency response from any BA, regardless of where the location is, or where you transact. Let's say we decide to procure 20 megawatts of frequency responsive reserve from BPA. The contingency happens in Colorado. We do not care how that 20 megawatts gets to the contingent BA.

So if you tie in transmission reservation, if you try to make this sustainable, you need to tie in transmission reservation into play. Now you're going to need things like network transmission service, because you're going to have to sustain this flow from a BA that you contracted with to a third BA that has this problem.

It's not like spinning reserve where you can track from a Balancing Authority to provide you with his service and you know exactly where that's coming from, and you have transmission reservations, right?

So we've got to be careful how we design this product. If we want this product to be tradeable, then we need to think about sustainability, right? So barring transmission reservation, we seriously need to think about do we want this to be sustained or not?

The other thing is, even though you have in some cases like in our case back TD regulation, we have a lot of regulation capability. We have over 5000 megawatts of units certified to provide regulation. That does not mean that we have access to that at all times.

And as Nick said, off-peak is where our problem is. And if you try to commit resources that have this capability, you go into an overgen situation, or you're going to a situation where you cannot really commit the resources to provide it, even though you have that capability within your Balancing Authority.

So the same thing with frequency response. You may have resources that are frequency responsive, but you cannot commit those resources to provide that service because you may go into an overgen situation, or you may have some other problems like the load may be too low.

So this is where renewable resources comes in. You know, can they provide that frequency response, you know, for you? And then again it comes back to the sustainability. Because if it's sustained, then the wind resources may not have helped because they give you that significant inertia, but then they take it back with interest. So we've got to be careful when we design this product.

MR. GINNETTI: If I might just--oh, I'm sorry.

MR. LOUTAN: I'm done.

MR. GINNETTI: I was going to chime in. I'm kind of where Clyde is. I was listening to the discussion on there wondering how you were going to reserve the transmission. Because I'll use the example of if somebody in New England sold the frequency response to somebody in PJM, that there's real energy that's going to flow out of New England into New York and into PJM, one way or another.

And you have to have that transmission available. It didn't seem like it was just as simple as saying somebody in one BA will raise generation for somebody in a different BA. I don't think it's quite that simple. So maybe you guys can explain it to me later.

MR. MILLER: Well, you know, we might be able to make it as simple as the current complex reality of maintaining transient stability and voltage stability. In

some sense it's just, in this time frame that plot ends at 60 seconds. In fact, if I'm not mistaken it ends at 52 seconds, right? So that's the only topic, if you want to have the conversation that way. Did you make it through the 52 seconds without causing a voltage collapse or without causing the system to come unravelled?

In which case, if the system models are good fidelity and other sorts of things, then it becomes almost just another face of the existing N minus one. And to some extent, some of this conversation goes away--not all of it. I mean, Dmitry's got to keep COI stable for trip of one of three lines, right?

And he's got a bunch of remedial actions and other things in there, right? So the trip of generation, these N minus ones which we're obliged to meet your obligation, usually leave the system intact from a transmission perspective. So the intersection of the constraints that everyone is living with already, that thou shalt not break the system for loss of a critical tieline, tends to mitigate the risk that the system will be moved into a condition that's unallowable at 52 seconds, just like--so we need to be careful of that.

But it's sort of another thing to watch.

MR. GINNETTI: But the BA who loses the unit has 15 to restore it. You're not worried--you're letting this

flow dissipate after 90 seconds?

MR. MILLER: This--this--I mean frequency response, sorry, maybe I'm being dogmatic here, but frequency response discussion ends at 52 seconds, and then we're into secondary, right? We're into the previous topic, which is--and I'm not saying that regulation isn't important. You've got to have the regulation come from the right place at the right speed to make sure the system stays intact.

But to some extent, frequency response, that discussion is over after a minute.

MR. LOUTAN: Right. Exactly. Now your frequency is still going to be low. Your frequency BAR is going to kick in, and now AGC is going to kick in, typically in our system about 30, 35 seconds after the disturbance. So you know you have, you know, your secondary or your second line of defense that's going to kick in, which is your AGC control.

Then by that time you have your contingent BA should be making arrangements to dispatch that contingency reserve.

MR. AMERKHAIL: Doug?

MR. HILS: I think with what Dmitry had to say, and a few others, it may be that once you are looking at a resource there may be some specific regional things to

consider, to the extent that response can only come from one path.

On the other hand, if I'm speaking of a resource that's sitting in Ohio that wants to provide frequency response, the first contingency could be for something in North Dakota. The second contingency could be something in Florida. So that resource is responding and fixing frequency for anywhere on the interconnection. It's not any particular direction.

But there are cases I guess where you could look at there are areas that may be more constrained to a few paths, to where it would be. To the extent you end up with a significant amount of resources wanting to provide that, it's an additional service but with limited transmission capability in general for the Eastern Interconnection, it would have to be a significant amount of generation to start to be a concern except for some particular areas perhaps.

MR. AMERKHAIL: Thank you. I see we're approaching three o'clock. I think I, at least--oh, go ahead.

MR. SNOW: I'll start with Clyde. Your comment you made is that the limiting condition and frequency response to your light load days when loads are down, the wind is up, all of the things that you can't curtail are online, and so the amount of generation that you get to play

with is approaching nothing. Some of your DUC curves I think actually show it negative that I've seen.

So understanding if that's the limiting--one of the limiting times, how do we modify the use of the screens to look for pivotal supplier, or market power in those limiting cases?

MR. LOUTAN: I think one of the contributors there is really the renewables, the variable energy resources. So we could make this, let's say--I don't want to say--like an interconnection requirement for renewable energy resources to have some of these capabilities.

MR. SNOW: Like a good engineer, you're going to solving the problem. My question is not quite that far.

(Laughter.)

MR. SNOW: How do I--if I want to look--I'm trying to figure out market power. Is there a--can someone have market-based rates to provide the service that at this point in time you need?

You know, I think we agree that you need the service. And because of the time of the year, where the facilities are, there are very, very limited candidates that you can get that from. So does that argue that in those conditions it's all cost-based, or mitigated to the point where it's cost-based? Or do we have--and almost by definition everyone's going to have market power? But I

don't want to really kind of jump to the conclusion that everyone has market power without some analysis behind that.

If anyone wants to help and jump in, please.

MR. LOUTAN: I need help on this one. I'm an engineer by trade, so I like to solve the problems. I can't help you solve this.

MR. SNOW: Doug?

MR. HILS: Bob, I was actually going down to the other hand of saying maybe there isn't the need for a market power screen except to the extent of what Dmitry noted as far as to the extent you have some transmission limitations that need to be recognized for its capability to do that.

But for the most part, for the Eastern Interconnection, I'm not seeing those transmission constraints for the amount of megawatts we're talking about, except for some isolated areas.

MR. SNOW: I think what I'm kind of getting is where you're at min gen almost everything is offline, or at a point where it can't move for physical reasons, how do we look at market power at those timeframes? Or is what you're saying that in the RTOs there will be mitigation approaches. But in the non-RTOs, that entities want market-based rates, how do we do the test?

(No response.)

MR. SNOW: Are you guys going to flip a coin, or?

(Laughter.)

MR. AMERKHAIL: I think we can interpret that that's a difficult question and they're not--I guess what I heard, then, is that if we assume someone wants to sell frequency response, and someone wants to buy it, and those people want to avoid many of the requirements that market-based sellers get to avoid at the wholesale level, then they might be able to come in and argue that the home BA is the default geographic market, that most resources within the market can compete to provide the service--bearing in mind that it's actually an interconnection-wide service, but just to test for market power they might be able to make that case.

There is a question, as with regulation, as to whether you should be looking at peak load conditions, or some other limiting condition. And that may be something that people have to work out in their proposals, assuming there are any to seek market-based rate authority for frequency response.

And again, one BA sounds like it may be less controversial, but imports may require some kind of additional thought because of the scheduling provisions or other related matters.

Does anyone disagree with that summary?

(No response.)

MR. AMERKHAIL: All right. Are there any additional questions from our side?

(No response.)

MR. AMERKHAIL: Any wish to make an additional statement on your side?

(No response.)

MR. AMERKHAIL: Well I want to thank everyone. This has been a very interesting workshop. We actually made it ontime, mostly. People can make their planes, hopefully.

Oh, yes, and those who wish to comment, in one of the notices I believe we said that June 9th is our requested deadline for filing written comments.

So thank you everyone here and on the Webcast, and we're adjourned.

(Whereupon, at 3:05 p.m., Tuesday, April 22, 2014, the technical conference in the above-entitled matter was adjourned.)