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Rapporteur's Summary*

Session One.
Storage and the Economics of Clean Electricity: Can Expanded Storage Solve the Challenges of Increased Penetration of Intermittent Resources?

Storage of electric energy has always played an important but relatively small role in the operation of power systems. Changes in load, power supply and transmission congestion all interact to create substantial variability across time and space. This variability creates the fundamental value of storage. Increased variability from increasing penetration of intermittent renewables is a central focus of planning and analysis for the power sector. The increased variability seems to call out for a great expansion of investment in storage. The recent CAISO storage "roadmap" is an example of the potential reach of storage to help moderate the economic and environmental footprint of the electricity sector. Do advances in storage technologies and a proliferation of new storage models create the prospect for a transformation of the electricity sector? Will storage be able to eliminate the effects of transmission congestion? What are the current economics of storage for energy arbitrage and ancillary services? What are the values that storage brings to the power system? What regional strategies are being pursued? Will storage be truly transformational, merely valuable, or highly overrated?

Moderator.
Good morning, everyone. Thank you, welcome to California. We're very excited to begin this discussion with our panel on "Storage and the economics of clean electricity: Can expanded storage solve the challenges of increased penetration of intermittent resources?"

I am a very big fan of storage as something that we should be looking at. So just a little bit about some of the things that California has been doing with regard to storage, just to sort of set the table. And before I talk about this, let me also just remind you for the sake of

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commissioners in the room, we need to keep our comments general. Please don't advocate about particular proceedings, particularly any proceedings pending before any of the commissions represented by the commissioners or the commission staff in the room. We don't want to have to file *ex parte* notices, and let me just state for the record that I have granted no meetings, so no equal time will be given, if anyone does say something. That being said, we really believe that it is important for commissioners to be informed by dialogue like this as we decide what is actually needed to help to balance our grid.

So in California's our storage decision which was adopted in 2013, we ordered the utilities, San Diego Gas and Electric, PG&E, and Southern California Edison, to procure at least 1,325 megawatts of energy storage for biannual solicitations. So they have targets, and these are divided into domains: transmission connected, distribution level, and customer side of the meter applications.

And eligible projects have to address several policy goals, which include grid optimization, integration of renewable energy, and reduction of greenhouse gas emissions. Their pump storage can contribute, but there are limits, so no more than 50 megawatts is eligible. And there are also time limits. So the projects have to be installed after January 1st, 2010, and in operation by December 31st, 2024.

There has been some work as well, as this has been implemented, including working between the CPUC, our sister agencies, the California Energy Commission, and the California Independent System Operator, on looking at storage procurement and the California Energy Storage Roadmap. It's a great document which I commend to your plane reading.

A couple of the challenges and opportunities that have been identified in this roadmap document have been the issue of expanding revenue opportunities, in terms of the opportunity for storage to participate in the ISO market. Of course the whole PPA procurement process has also been a topic that the California Public Utilities Commission has been focused on. And then another topic that frequently comes up with many renewable resources is reducing the costs of integrating and connecting to the grid.

I would add that the whole issue of interconnection is an issue that is faced by a variety of renewables. We heard this last week when I was at a meeting on the water-energy nexus. Our state senator, Fran Pavley, had a meeting on the water-energy-greenhouse gas nexus. And people talked about some very exciting projects, for example, harnessing the power when you step down water to the level of the water that is needed for treatment. If you capture the energy there, especially if you do it in areas close to load-serving entities, you have the opportunity to be able to capture some renewable energy and deliver it in a place very close to load. But they said that their biggest challenge has been interconnection. And increasing the predictability of interconnection as well as reducing the cost is really critical.

The last thing I'll say is that the roadmap also identified the need to streamline and spell out policies and processes to increase certainty. We've seen a whole variety of storage plans and proposals already in our first procurements. So I think we're really at the beginning of storage. There's also a lot of exciting ideas for what storage could do, for example, the opportunity for storage not only to help us with balancing renewables, but to deal with California's water problem. We're in a drought. This is now our fourth year of a drought. This place gets a lot of transpiration from the sea, but it is pretty bad, especially the reservoirs on the Sierras. There's a huge need for water. For de-sal, the number one challenge is energy intensity. So the ability to combine storage with renewables and other things to make de-sal economically feasible is something that we're very interested in.

So just having set that table, let me introduce the panelists.

Speaker 1.
Thank you. I'm delighted to be here. I think the Moderator gave a good overview, and I guess my presentation's going to kind of really set a broad context for storage in California, because I really believe that California's going to be the proving ground for storage technologies.

We're positioned where we're going to need it, and need a lot of it. I was in Germany a year ago, talking to some of the grid operators there, and they joked that they were on the bleeding edge of bringing down the cost of solar PV, to the benefit of California. They were looking forward for California doing the same with storage. So I think we're well positioned to take a leadership role there.

So in talking about the California ISO, I do want to highlight California's Energy Imbalance Market. Because when we talk in the broader context of what I'll explain is an over generation issue with renewables, storage is one solution. But greater regionalism is another. And so we're very excited about this Energy Imbalance Market, which is a real-time market that CAISO operates with PacifiCorp, which is another major utility in the west.

And you can see on the map there, that kind of greyish colored area is the California ISO footprint. And then you see the PacifiCorp territory in yellow. They have two major territories, one in the east of, predominantly Utah, Wyoming, Idaho, and then in the west with Oregon and Washington.

And essentially what we've done with them is, with respect to our real-time market, we're doing it in a co-optimized fashion with PacifiCorp. They still manage their balancing area, but they're able to leverage the efficiencies of the real-time market optimization. So we're co-optimizing both systems to meet our real-time imbalance needs, and it's reaped tremendous benefits. We've seen, just in the first three months of operation, benefits to both of us to the tune of about $6 million.

And certainly we've seen periods in California where we've had surplus renewables and have seen net transfers out to PacifiCorp. So it's actually being able to, when we do get in those over generation situations, provide an opportunity for other regions to pick up the excess generation. Because, if you think about it, that's the most efficient solution, consuming it when it's produced rather than having to pay to store it to provide it back later.

I'd also like to highlight that Nevada is joining the EIM effective October of this year, so we're moving forward with that implementation. And then in Washington, Puget Sound Energy announced they're planning to join the Energy Imbalance Market as well. And there are a lot of other entities out there that are talking to us, doing benefit studies on what the Energy Imbalance Market can do for them, and we're very optimistic we'll have more entities joining as well. So we're really excited about that. I think it's a really big deal.

I know we have a lot of Californians in the room here, so forgive me, but I know we have a lot who aren't. So it's worthwhile just highlighting the full context of California's energy landscape. California has very ambitious energy and environmental goals: reducing greenhouse gases to 1990 levels by 2020, the 33% RPS goal by 2020, 12,000 megawatts of distributed generation by 2020, and on top of all of that we have a major water environmental compliance goal of eliminating all of the coastal power plants that use one-through cooling water technology. That impacts about 12,000 megawatts of generation. And we've been working, over the past few years, with PUC on how much of that needs to be replaced from a grid reliability standpoint.

And then, more recently, Governor Brown announced in his State of the Wtate address in January some new goals for 2030. We're looking at a 50% renewable goal by 2030, 50% reduction in petroleum use vehicles, doubling energy efficiency, and making heating fuels cleaner. So, very aggressive, ambitious goals, and they certainly play into the storage discussion today.

This chart is highlighting what we have today in the way of renewables. So you can see that, basically, at the end of 2014 we have roughly 17,000 megawatts of renewables. And then, if you look out to the right, by 2020 what you see is that almost exclusively all the growth in renewables is in solar PV.

So we'll be going from roughly around 5,000 megawatts of solar PV today to doubling that in 2020 to over 10,000 megawatts of solar PV. And solar PV, from a grid integration standpoint, presents some challenges that I'd like to highlight for you. And I will do this quickly in deference to the other panelists.

This is a traditional load shape in a winter day. This is a projected load for 2020. And typical load is low in the middle of the night. In the morning when the office load picks up, you see the ramp in the morning hours, then it flattens out in the middle of the day. And then as people head home (and this is probably a January), you see the lighting load, the residential load, picking up. So we actually peak in the evening around six, seven o'clock. And this is a load our operations know very well. The resource fleet's been designed to manage this quite effectively.

So when you look at renewables for that same, winter day, wind, at least wind in California, is very variable this time of year. This is a particular pattern we saw on one particular day. But the solar, as long as the sun's out, is very predictable. And what you see is a very dramatic ramp as the sun comes up, hits those solar PV panels, the solar just takes off, and you go quickly up to, in this case just north of 9,000 megawatts.

This is winter, so the sun's not up for long, and you see it dropping off around 4:30 or four o'clock in the afternoon. But in the previous graph, our peak was later in the day. We have an evening peak of around 6:30, seven o'clock. So you have this misalignment with the solar output and the peak demand for this time of year. (I would note in the summer months it's much better. Solar's actually incredibly helpful for meeting our peak in the summer.)

So what this graph is highlighting is what we call our net loads. So that gross load I showed you, if you subtract out the output of wind and solar, the red line here is what the net load is that the grid operators have to follow. And this is the integration challenge, if you will, where you still have that morning ramp in the morning as the workload demand increases.

But then at 7:30 when that sun starts coming up, you have to start backing down the rest of your fleet to make room for the solar. So that you have this kind of roller coaster of bringing up the fleet, predominantly gas in this case, because that's what we have to follow load, and then you have to back it back down to make room for the solar during the middle part of the day. And then when you get to 4:30 in the afternoon, or five, solar's just vanishing, and you have to race the fleet up to make up for it, not only to compensate for the loss of the solar, but you're also chasing that evening load ramp.

The magnitude of the ramp isn't as dramatic as the timespan of the ramp. Because you're talking moving a generation fleet, 13,500 megawatts, in two hours.

So the ramping issue's one aspect of the renewables. The over generation issue is another. Where you're in that trough with the solar production, when you couple that with all the base load resources that we have on the system, and the gas fleet we have to keep on at minimum operating levels, we have surplus power. We have more power than the system can accommodate.

And as we get more and more solar on the grid, that issue becomes increasingly challenging. I think that even if you're not from California, our duck curve has national recognition now. I see it pretty much everywhere we go. And it's simply highlighting what I just went through, but showing how it changes from where we are today. As you add more solar, the belly of that duck gets lower and lower, and the over generation issue becomes increasingly more challenging.

So with respect to the options for addressing over generation, we did a study looking out to 2024. We're at about 25% RPS right now in California. All indications are we're well on track for the 33% by 2020. And we will very likely overshoot it. So the notion of 40% renewables by 2024 is a very realistic, if not base case, for us to consider.

And if you look at the over generation issues in the analysis we've done, what this is showing is, the axis is measuring the amount of renewable curtailment we project will be needed to keep the system in balance. So each of these dots is an hour in the simulation where we've had to curtail renewables. And it's the magnitude of that amount. So the striking thing is, you see the bulk of the renewable curtailments in the spring and early summer. That's when we have a lot of solar and wind on the system, but our loads are still pretty moderate.

So that's kind of the prime season for over generation. Particularly in the March and April months, you see up to 13,000 megawatts in one hour of renewable curtailment. So I just want you to appreciate the sheer scale of this issue, because this, to me this is the poster child for why California is so ripe for storage. Because there's going to be a lot of ways to get after this over generation issue, but storage has got to be a big piece of this solution. Because this magnitude…13,000 megawatts, that's half our load during those times of the year. So we're curtailing that amount of renewables.

So storage can play a big role. There's lots of other things. Our moderator hit on it. You know, there are some synergies with other sectors, such as transportation and water, where with the right policies you can actually incentivize consumption during these periods where we have over generation issues. Regional coordination I hit on already. So there are a lot of ways to get after this, but storage is going to have to be a big part of the solution.

Our moderator hit on the PUCs and their storage procurement targets, so I won't dwell on those. But I will note we've had over 2,000 megawatts of storage projects come into our interconnection queue. So the development is already starting to happen here.

The Moderator mentioned the *Roadmap*. I'll just highlight a few things with regard to some of the action items coming out of the *Energy Storage Roadmap*. Rate treatment was a big issue for storage developers. There was a question of, "Well, if I'm a storage resource participating in the wholesale market, am I taking retail service from the utility, or am I buying wholesale power off the grid?"

And I'm not a business major, but generally when you buy a retail and sell at wholesale it doesn't work out too well. So clearly we have to solve that issue. The good news is that our tariff's quite clear that we view the charging as essentially not consuming power that would require retail service, but essentially holding that power to put back on the grid later. So we view it as a wholesale rate all the way around.

There are a lot of questions around market participation. We have a lot of new players in the storage community that haven't interacted with the ISO. So there are a lot of gaps in understanding in terms of what it takes to participate and what are some of the market models we have for storage on the market.

So rather than jumping to all the asks that we are hearing from the development community, we said, "Let's start with an outreach and education session on what we have, and make sure you have that understanding. And then if there are gaps, or new market products, you take that on as the second phase." So we're kind of in the middle of doing that currently.

Our Moderator hit on some of the action items for the PUC. There's a lot of work going on in the planning area in terms of, where are the optimal places for storage to locate on the distribution system? How do they count? We have in California something called resource adequacy, which is basically a year-ahead obligation to procure sufficient capacity to meet the grid's needs. There are questions around how you count storage for meeting those capacity needs.

With respect to the rate treatment for storage, if you have behind-the-meter storage, what are your rules around how storage is settled with regard to the net energy metering tariffs? And then, as the Moderator mentioned, there is the interconnection issue. How can the interconnection process be better streamlined, and the like? And I think that's a fair question for the transmission interconnections as well as the distribution.

The storage community obviously is very interested in extracting as much value as they can from their resources. And so they've posed some very interesting dual-use scenarios. I won't get into all of them in much detail, other than to just quickly highlight that storage can be a transmission asset where it's actually providing a grid reliability service. It can actually be rate-based under FERC rules. Or it can be a market resource. But it can't be both under current rules.

And the storage community is asking, "Why not? Why can't I have my cake and eat it, too?" So that scenario related to how you deal with a rate-based asset participating in the market creates all sorts of issues we'll have to work through. Can they provide service both to the transmission and distribution system? And that raises issues about who's controlling the resource. Is it the distribution system operator or the transmission operator? I'm not saying it can't be done, but it raises some interesting challenges. And then, if it is a resource actually providing some local load management service, can it also be a market participant? So these are three examples of some use cases that there's interest in.

In terms of participating in our market, we provide for full participation of storage today. We have a model called a non-generation resource model that actually is designed with storage in mind. And under it they can provide energy regulation and spinning and non-spinning reserves. We have a new flexible ramping product we're developing that they'll be able to provide as well. In the interest of time, I won't get into all the details around the functionality of the model. But suffice it to say, it's really built to manage a resource that has both positive and negative energy capabilities.

When we talk about the business model for storage, I know a lot of the discussion is around, "Well, can the spot market provide sufficient market revenues for storage to be a viable resource and actually develop?" And California really approaches capital investment differently. I call it the belt-and-suspenders approach of really relying on long-term planning and procurement decisions to drive the investment.

In California we have the PUC long-term procurement plan, which is looking out ten years. And it's looking at the needs of all aspects of the system--peak service capabilities and certainly, more recently, big attention to flexibility needs. Do we have sufficient dispatchability in the portfolio of resources to meet our needs? And the resource adequacy program (another program that's actually a joint program, there's an ISO piece and a PUC piece), that's looking a year ahead.

We recently introduced requirements for flexible capacity to be part of the resource showings that the utilities make, along with offer obligations in the ISO market. So it's really through these proceedings, along with the storage decision at the PUC, that we see the investment happening in the storage technologies.

And then the ISO market is really looking at, "OK, once we have those technologies on the ground, how do we optimally use them, and how do we compensate them for the value they're providing to the grid?" And that's where the day-ahead and real-time markets that the ISO operates come into play, and the market products that we've developed specifically to accommodate resources like storage.

Speaker 2.
Thank you. I call my presentation a cautionary tale, because there's a lot of enthusiasm about energy storage, but you have to think about whether or not it makes sense in terms of, is the economics there, and what are kind of the market challenges and policy challenges to the deployment of energy storage? So this will be a little bit of a deep dive into some of the things that I'm concerned about in terms of whether or not storage is on a level playing field, and whether or not it's value is being appropriately considered in today's market operation.

In the storage community, we all agree that storage is undervalued in today's marketplace. That said, storage is really still expensive. So in the near term, when we talk about the flexibility supply curve, we don't put storage as a near-term solution. We do consider things like Energy Imbalance Markets and demand response and just changing the way we operate the system.

But as we consider whether or not storage is economically viable, we do have to look at some of the challenges associated with whether or not storage can get paid properly. And one of the things that I get concerned about are some of these price suppression effects, as well as making sure that really it does require the system operator to optimize the dispatch to capture all the values, including some value streams that aren't actually monetized in today's marketplace.

So this gets to the question of, why are we interested in storage? There is a perceived need for storage with renewables. And I always kind of put "perceived" there as a bit of a provocative statement, just because it looks like we need storage, but, again, the question is, where does storage fit on that flexibility supply curve?

So my question here is, can the duck pay for energy storage? Does this over generation thing that we see coming actually incentivize and create a better market opportunity for energy storage? So now we have to get into valuation. We have to throw a bunch of math and modeling simulations at this to figure out whether or not we should invest in energy storage, and whether or not we're going to pay for it. So we have to look at what we might do with this energy storage, and then apply a bunch of valuation approaches.

If you go into any of the storage literature propaganda produced by storage folks, they'll show you all the wonderful things that energy storage can do. And then you have to say, "OK, well, can I get paid for that?" So here's a list of some things that you can potentially get paid for. And quite frankly, when we talk about over generation mitigation, that's energy arbitrage plain and simple. Buy low-sell high, hopefully.

So now we have to think about what it's worth. And there are two simulation approaches that we use. One is, we just kind of grab last year's market prices, we go on the ISO's website, grab last year's prices, we do a storage simulation, we see what we would have gotten paid if we were a price taker. Maybe for a little bit more sophistication we can look at some price suppression effects.

But what I spend most of my time doing is doing full simulations of the marketplace using a production cost model, because what I'm really interested in is understanding the future, not the past. So I spend my time doing simulations of 2020 and 2025, putting lots of renewables into the system and seeing what storage might get paid, and comparing what storage might get paid to what storage is actually worth. And for a lot of places and a lot of times, those are quite different.

So there are tons of price-taker simulations. It's all in the literature. You can go look at that. It's all fun. One obvious thing, though, is, "OK, well, how do you dispatch a storage device? Do you bid in, do you self-schedule, will the ISO optimize that?" And there's still uncertainty about how that's going to evolve.

But the nice thing about now is that you can predict prices pretty well. At least you can predict price shapes pretty well. Because pumped hydro plants, they charge in the middle of the night, they discharge in the day--that's pretty predictable.

This is a really simple simulation where we just did tomorrow what you should have done yesterday, and you captured 85% of the value. That's great.

You can even do better than that. But we put lots of renewables in the system. Now you need to understand not just historic load patterns, but what the wind and solar resources is going to do tomorrow. Well, who has that data? Who has all the data? Well, the ISO has the data, the individual power plant operators may have the forecasts. But the storage plant may not have that information.

So the ability for a storage plant to actually accurately capture tomorrow's prices gets a lot harder with putting more renewables on the grid. That's really important. Again, that gets into this scheduling problem. OK, so you do a bunch of math and you find out that in historic markets storage isn't worth very much. It'd have to be way cheaper than it is today. That's no surprise. Which is why everybody's focused on frequency regulation, or secondary reserves, whatever you want to call it. And then you can look at that, and you find out that that's why AES and everybody are going after frequency regulation markets.

But that's not why we're here. We're here to talk about renewables. So we can't use this price-taker approach. We have to use something else. So we use a full-blown production cost model to do our simulations. It's the same one that the ISO uses to do their forward-looking analysis.

So here's an example of some analysis from NREL. Now, this is not a summer day. The top one is a winter day. But you see all these little blips, indicating storage dispatch. And that storage is providing ramping services, and preventing power plant starts. You can't predict those. The ISO is doing the optimized scheduling, and they're figuring out which power plants to turn on and commit and dispatch. And the storage owner doesn't know when those starts are going to happen. So they can't predict when these values of these starts are going to happen. This has to be done by the system operator to obtain maximum value from energy storage.

One of the wonderful things about energy storage is that it can respond really fast. It could prevent power plants from starting up. It can provide these ramping services. And to maximize its value, somebody has to optimize how that storage plant's going to be dispatched. So you can see these kind of little blips where storage gets started up and shut down to avoid these starts, and that's a really important part of this. In fact, in this simulation about half the value, and it's kind of a low-renewable scenario, was from avoided starts. So that is a very important part. And if your LMPs don't capture starts, if you're not optimally scheduling this to avoid starts, you're not going to capture this value from this kind of energy device.

So the first market challenge that I want to highlight is that I don't see how self-scheduling could possibly work in order for storage to capture maximum value. It's got to be a system operator optimized device.

The second challenge is, of course, obtaining capacity value. We've done some studies here, we know that if you've got a six-hour storage device, you basically are equivalent to a peaking plant. So you need to obtain the capacity value. Everybody knows about missing money problems and whether or not scarcity pricing captures that. We don't need to talk about that now. But, again, storage is a peaking plant. It's going to have all the same problems as peakers do in recovering its capital costs.

So what happens when you add renewable penetration? Well, you've got more starts, because you've got more volatility in the net load. Again, there's your scheduling problem. You've got a decrease in both on-peak and off-peak prices, but primarily the off-peak prices, and you've got some increased reserve requirements. So we see that, yay, the value of storage goes up as a function of renewable penetration. Great, this is a wonderful story for storage. But my last cautionary tale is whether or not you're going to be able to capture all this value.

This is a busy chart, but the thing to notice here is the little red squares. The red squares are why you make more money as you see an increase in renewable penetration. You're suppressing off-peak prices more than you're suppressing on-peak prices. You are suppressing on-peak prices with solar, but you're suppressing off-peak prices at a faster rate, if it works, than on-peak. That increases the arbitrage spread. The difference between on and off-peak prices increases. Great, yay for storage, that's wonderful.

But the question is, what happens when you add storage? So this is an interesting fact. We all know that if you add a base load resource, if you add a nuclear power plant, a low-cost coal plant, you're going to suppress prices. But storage suppresses the on-peak prices, and it increases--whatever the opposite of suppression is, that's what storage does to off-peak prices, right? So it gets hit both directions. Unlike a base load plant which just kind of decreases the on peak prices, storage both decreases on peak and increases off peak prices, at least those marginal prices that you get paid or you pay in a wholesale market. So storage is uniquely exposed to this price suppression effect in both directions.

So we can look at what happens to the prices when we add storage to a system. I cherry-picked this data. You know, I picked some particularly good or bad days for storage. These weren't actually the worst days. So you've got some marginal prices with storage, or before storage is the red line. So the prices go up to zero or negative. So this is your over generation situation in the middle of the day. We've got too much solar. Again, yay for storage, we can suck up all that excess carbon-free, price-free energy, and then we can sell it during on peak periods.

But what happens is, I unfortunately sucked up so much solar energy in the middle of the day (combined cycles were then on the margin), that even thoug I didn't really charge with any combined cycle generation, I happened to suck up so much that combined cycles are now setting the price. So instead of buying at $0 or minus $23 or minus $100, whatever the marginal price of renewables was, I'm now buying at $30 or $40 per megawatt hour, and then, oh, I also unfortunately took the single cycle units off the margin because I suppressed the on peak price as well.

So I did a bunch of calculations and said, "OK the benefits to the system in terms of all the gas that I avoided from operating the storage plant was somewhere in the order of $86,000. But my net revenue is basically zero, because of the fact that I'm buying wholesale prices with combined cycle setting the price. My revenue went away. I'm providing significant system value, great value to society, reducing carbon emissions, all that wonderful stuff, but I'm not getting paid for that."

And then when you look at the difference between the system value and the market value, the blue lines are the system value and the red lines are the market value. And so depending on the configuration of my storage device, I'm capturing anywhere between 40 and 80% of the actual system value using wholesale market prices.

So that's my cautionary tale about storage and renewables. I think that there's a tremendous opportunity here, but we have to think about how we actually let storage play in the marketplace. And I make some analogies to transmission--how transmission should be priced, and whether or not merchant transmission makes sense. That's a little bit of an extreme example, but I think we need to think about some of these things because storage is a unique asset that does many wonderful things, but I'm not sure it can get paid for all those wonderful things. So that's it, thanks.

Question: In the slide we had with the $50, what was that the quantity of storage versus the system peak or some sort of metric of quantity?

Speaker 2: This was a simulation designed to show this particular thing. So I added a 300 megawatt storage device. And it turns out that that was right about the right amount to collapse the price in kind of the optimal way. So, again, this was designed to be provocative.

Moderator: I'll just put something on the table which I'd like to come back to later, which is that I'd also like to talk about, how can we deal with the over generation through things such as load shifting, different rates that might incentivize load to move towards those times, or also critical needs such as desalination? If we look at the price of water here in California and the need of water for energy and cooling, as well as just the need of water generally, those might be other examples where we could essentially load-shift to other uses. So I just want to throw that out. We'll come back to that later.

Speaker 3.

Most of the conversation so far today seems to be relative to the bulk power market and the ISO market. I'll touch on that a little bit, but I also want to take some time to look at questions related to storage in a vertically-integrated utility, not an ISO market, especially at the distribution level.

I think too frequently we get wrapped in, alright, well here's what's going on in California, and what's going on with ISO, or the PJM market, the frequency regulation market, or ERCOT. But there is a lot of the country that is not in that type of market, and is vertically-integrated.

So to start with, my slide really looks at the last several years, and what Duke Energy has been doing around energy storage. We see energy storage having a big part to play in the future.

So over the last several years, we've done a number of projects. The one in the upper-left is the Notrees site in West Texas. You may be familiar with 36 megawatt, 24 megawatt hours. At the time it was the largest such project. One may have passed that one at this point. We've also done a couple different substation-scale projects in the Carolinas.

We've done community energy storage. The upper right shows one at a mall parking lot in Carmel, Indiana, integrated with fast charging of electric vehicles and a solar canopy. We've done a small-scale community storage project, shown in the bottom center, a 25KW battery system sitting next to a 25KVA transformer. And what is the opportunities that that provides?

So as we look at these projects, we've looked at different locations, different chemistries, different applications. And really there are a lot of things to learn that you don't learn until you put something in the ground. The modeling is great and definitely needed. But from a utility adoption standpoint, we're not going to be comfortable until we can put it in the ground, touch it, operate, see what lessons-learned there are.

And through all this, there are quite a few lessons-learned. We don't care about the chemistry per se. Once the fundamental environmental, safety, and performance metrics are met, energy storage is really a black box to us. You know, whether it's lithium titanate or sodium nickel or lithium phosphate or cobalt, you can go through all of those. Ultimately, what are the performance specs, assuming that the safety and environmental reliability needs are met?

But we do need to understand that from the standpoint of what the capabilities are. What is the direction of the market? Where is it going? So internally we've started some planning that, says, alright, in the year 2020, there's no economic or operational reason why we can't use energy storage as a distribution asset. What do we need to do to get there?

As we look back, it's really been about understanding the technology. How does it work? What issues do we encounter when we put it in our system? What lineman training is needed, what safety procedures need to be looked at, what operational processes are stressed? Because energy storage is really not even comprehended in our operational procedures. But now we're looking for the roadmap as we're looking forward to, alright, we do see a point in time when energy storage is going to be attractive to us. What is our roadmap? What are the gaps that need to be addressed as we get to that point?

So as I look at what we've been doing the last several years, I think this kind of illustrates the mindset we have right now. If you think about installed cost of storage on the vertical axis, and time on the horizontal, if you look at current technology (just assume that's lithium chemistries for the time being, obviously, as you go out over time, the price is coming down. So we want to understand, what's that price coming down to? But then at some point, when is it cost-effective?

So let's just pick a value. What is your favorite value proposition for storage? For ease of illustration I picked grid parity versus a CT. All right, we need a four-hour peaking asset and here's what it would cost us to put a CT in. What would the price of storage have to be that we would put in a battery instead of building a CT for a four-hour peaking need? Any location may have its own value proposition you want to compare storage to.

Well, based on that value proposition, there's some time when, alright, this is when it really is going to make sense. Based on the projection of the storage cost, based on our integrative resource plan, when we need storage, this is the point where we're going to get started. But what about that ancillary services value? What about the volt-VAR management value? What about the customer value or other…again, pick your favorite value proposition.

And depending on which list you look at, this is a list of 20, 30, or more value propositions that are out there for energy storage. Well, if you are able to capture those different value propositions, now you have a time sooner where, OK, we can install storage now at a new time one because we're able to capture multiple value propositions. And I think it'll be a long time before storage is justified based on any single value proposition. I mean, it is going to take multiple bundling and multiple value propositions before storage really makes sense.

So when we start looking at this, and especially as we look forward, we start having some questions. What is the slope of that price curve? Do you believe every announcement you read in the paper? The latest one coming out of Stanford or MIT or whatever every week? Probably while we're sitting here there's somebody that's hit $50 per kilowatt hour in the lab. So what is the slope of that price curve? What are these values for Duke?

Well, especially as a vertically-integrated utility, we really haven't had to calculate a value for those. When we're looking at our system, the price of ancillary services is just integrated into the way we operate, into our planning. So pulling out the value of frequency regulation in Duke Carolinas is really a tough nut.

Then you get into volt-VAR management. Well, what is that value proposition for improving the voltage characteristics based on renewable integration or some other need? Then you get into the customer value. What if we're able to integrate some reliability value to the customer so the customer can share a part of this cost? Well, obviously that customer value is a big question mark. Are you talking about just enough storage where they can keep their freezer from spoiling in the event of a power outage, or is it somebody that wants to run full back-up for a couple days? Or is it just somebody that wants to be able to run their PV for a few hours when they're off grid?

Well, when you'd look at those value propositions, it's not as simple as just stacking those. Which of these can be stacked? Or are some mutually exclusive? Well, if you're trying to do energy arbitrage at the same time as you're trying to use storage as a DR resource, at the same time you're trying to do voltage mitigation of intermittency, renewable intermittence, well, maybe you can't do all those at the same time. Or at least maybe you have to de-rate that bundle.

So it's one thing just calculating the value of each of these value propositions, but when you start bundling them together that's going to change the value proposition. You may have to de-rate some of these values. Oh yeah, we have a nice plan that we know works and then what about the potential transformational technologies that are out there? And not just from a storage standpoint, but one of the things we're looking at is, what about virtual energy storage?

We talk about physical storage. When I say "physical storage," I'm thinking of a battery asset or a pumped hydro asset. Virtual storage, when you look at what's happening with ubiquitous connectivity, the Internet of Things, the advanced demand response capabilities, maybe there's a way of using virtual storage to get a good bit of the value of physical storage.

And if physical storage gives you 100 units of value for 100 units of cost, maybe virtual storage only gives you 60 units of value, but it's only 30 units of the cost. So maybe that is something to look at. So actually our storage work is closely related to, what are we looking at in terms of advanced demand response, the whole Internet of Things and the ability to control devices on the grid?

Then you get some of the things that a utility is going to look at that generally don't make it into the news cycle. It doesn't make it into the lab announcements of the next great technology.

What about the safety procedures? You know, we're putting a DC device on the distribution grid that no lineman has had to deal with as a distribution device before. What about DC arc flash? What about our visible disconnect requirements from an operational procedures perspective?

And those are the things that, as you start installing storage you realize, "OK, that's something we didn't think about." Those things are generally less of an issue when you're on a large system, on maybe actually the transmission system. But, especially as you're getting to a distribution asset, what are the safety procedures? What are the operational processes that have to be adjusted? Whether it's outage response or whether it's protection coordination, what are the different operational processes that are going to need to be adjusted because we have this new type of device on our grid?

And is the equipment utility grade? And what I mean by utility grade is, we're used to installing assets that sit there for 30 years, and you rarely have to touch them. You know, a transformer or a capacitor or a regulator. You can sit there and do some preventive maintenance…you may lay eyes on it each year, you do some data acquisition. But it's something that we put in there and we know it's going to last.

In our experience so far with energy storage, on the tests I showed earlier, for lack of a better term, we had to control-alt-delete quite a bit. You know, so alright, this isn't working. All right, somebody needs to go out in the field and hit control-alt-delete. You can't afford to have personal intervention in distribution assets on a regular basis and have it be cost-effective. And it's not the underlying battery technology. That works great. Frankly, we've been very impressed with the basic capabilities of the storage devices. It's when you get into the battery management system, the control algorithms, and the communications, and the integration back to the grid, that's where the problem is. How do you integrate it back to the grid, and all that communications and control planning that has to work seamlessly, without having to go hit control-alt-delete once a week?

Something else that comes up as we're thinking about this is, alright, where is the highest value point for energy storage? I mentioned that we've put storage at a number of different places on the grid. So, again, this is illustrative purposes only. When I show this graph, don't read into it too much. It's for illustrative purposes. But if you look at the installed cost of energy storage on the vertical, and battery size on the horizontal, well, generally speaking what you would understand is, alright, a large central plant-scale storage creates value of economies of scale. You know, you can put a lot of batteries in one location. So you're going to have a relatively low cost per kilowatt hour.

So now, as you make the batteries a little bit smaller and you're coming back into the grid with a substation scale battery or community energy storage, that price is going to start going up. But then you start noticing something. If you get small enough, that price starts coming down again. We talk a lot about the battery cost. And most of the time when you hear cost about energy storage and batteries, people are talking about the cell. How much does the cell or the module or the pack cost? Well, once you have a pack, you have additional electronics and balance of systems. But also the installation. And the installation costs, when you get down into the distribution system, is not inconsequential.

I can let you know that in one of those installations, you could have given the battery for free, and we still wouldn't use that installation again. With that much of an installation cost, it's not a battery cost issue, it's just too cost-intensive to try to integrate into the grid.

So I think what is interesting to think about is micro-storage. And obviously integrating this into the grid could be interesting. But when you think of people like LG Kim and Samsung, they make appliances and they make batteries. What would happen if they stuck a few hundred watt hours of batteries in their refrigerator on the assembly line? Your installation cost went to nothing. Now there's a refrigerator that can keep your food cold through a certain hour outage because it's got on-board energy storage. With the communications and smart appliances coming, maybe you can aggregate those easily. You know, how do we get the installation costs down?

And if you get small enough, your installation costs can maybe get next to nothing. And kind of a theory we're looking at is whether you end up with the barbell effect. You end up with extremely large storage systems at transmission volt power level, and then extremely small systems, but maybe not much in the middle where that actual barbell is. That's really more a hypothesis at this point rather than a definite vision that we're working toward. But it is something that we've seen, that the most ideal place on the grid from an engineering standpoint may not be the best place from a cost-effective standpoint.

Now, the other thing we're trying to do is tackle that top of the hump there. Are there ways to bring that cost down? Let's take installation. Instead of a battery system that takes a special installation, you have to dig a hole in the ground and do all this to keep a battery, can we use standard construction equipment? How do we have batteries that we can just use a line truck and different things to put in? Maybe it is possible.

And, again, this is for illustrative purposes. But we talk a lot about the cost of energy storage just from a battery cell or modular pack standpoint. Its installation cost in some cases can be a third or half or more of the cost of the system. We have to make sure we get that down.

So the battery cell module costs are coming down quicker than the installed system costs, just to reiterate what I just said. There is a lot of focus, a lot of advancements. We talked with a lot of battery companies. Any one battery company, I probably don't believe the numbers they tell me. You know, "Here's what we're going to be able to sell you a battery for." And everybody knows the old adage, "There's three kinds of liars: liars, blank liars, and battery suppliers." So we have people saying, "All right, here's what the price of our battery, our cell will be in 2017." Any single one of those I don't believe. But in aggregate, there's starting to be a trend. You know, somebody's lying to me, but there's some that are not lying to me, because there's just too much…

So we are seeing some really good advancements in the battery cell and module cost. We are starting to see some of the power electronics being looked at in a little bit more detail. We haven't seen as much focus on the installation, alright, how do you get an installation cost down? So that's an area we're focusing on, whether it's home energy storage in a cost-effective manner, whether it's micro-storage, or whether it's something we can put on our grid using standard construction practices.

I mentioned this earlier-- utility-grade reliability is still a question mark for distributed energy storage systems. That's not as big of a deal in the bulk system, where you're pretty much going to have a person there. If you have tens of megawatts of energy storage, you're probably going to have a person there, if not all the time, you're going to have somebody there a lot. And you're going to have instrumentation, and you're going to have some controls. You're going to invest a lot. But when you have a 50 kilowatt hour unit, or a 10KW unit something you can put there and you know it's going to work and you know it's going to keep communicating and it's reliable from an asset standpoint…

Existing tariffs and interconnection standards really do not anticipate energy storage, and could have some unintended consequences. It does seem like in the interconnection, which has already come up several times this morning, it seems like a lot of times when we talk about interconnect we're only thinking about the bulk system standpoint.

And I've seen, both in the Carolinas and other parts of the country, kind of the assumption, well, storage needs to follow the interconnection standard of generation. All right? And that's kind of fair, everything works the same. I tell you, that makes me nervous as a distribution utility. Because we look at what the value of energy storage can be--do I need an interconnection standard to put a capacitor on a line, or a line regulator? But what I plan to use storage for is, I'm going to use this instead of a capacitor.

So when you start thinking about interconnection standards when you look at a distribution asset…wait a minute, am I going to need interconnection for a capacitor or a regulator or a transformer? I think as we move forward this will be a part of the distribution system, and a piece of equipment that we use to manage the distribution system, because of this advancement of distributive resources.

And it may actually put off the number of capacitors we need, or the regulators we need. We're using it to offset the tap changer on a substation transformer. So, something to think about--all storage based on location is not the same. A rule that would apply well to a transmission-sited asset that's tens or hundreds of megawatts is not the same as putting 10KW on a pole somewhere. We have to understand those differences.

These multiple value streams, most of them not easily quantifiable, make an energy storage business case difficult at this time. If you go into a structured market, PJM, here's the price, OK, I still have some uncertainty in my progression of what frequency regulation prices are going to be, but I can still build a business case.

But when we're looking inside a utility and say, "Alright, what's my business case? I'm going for this much value for help on the IRP, I'm going to put this much value on the intermittency mitigation, this much value on volt-VAR management, this much value on a customer offer that provides some value…" That is extremely difficult. And I'm not ashamed to admit, we can't do that yet. We don't know enough about all these value propositions to be able to build that business case in a confident manner.

And, finally, the inverter, especially the new inverters, the smart inverters--the value of those cannot be underestimated as well. That is actually a key component of this value proposition. Over the last year I've kind of had an epiphany. Maybe it's been obvious to others. But you know, a few years ago I would have thought, "Well, the inverter, that's just a part of a PV system. Or that's just a part of an energy storage system that allows the pass-through of energy, the conversion from DC to AC. And you know, it's just kind of a necessary evil. That's part of the system."

But with the smart inverters we're seeing today, it's almost a standalone asset that happens to have something else attached to it. I've got a smart inverter that may have energy storage. I've got a smart inverter that may have PV installed into it. In terms of the four quadrant, the volt-VAR, leading-lagging power factor management, we had one of our installations that was on that first page, we removed the battery because it was a test battery and it wasn't meant to be long term, but we left the inverter there. It's been there for more than a year. And the inverter is sitting there adding value, providing volt-VAR management, providing power factor correction, even without the battery there.

So something to think about is really this low-voltage power electronics, attached to energy storage, attached to battery, or attached to a PV, which provides more value. But a lot of that value is in the inverter and actually may eliminate some of the needs for energy storage. We're doing some work now where the solar PV interrupts itself, curtails itself. Not just shutting it offline, but varies its output based on what's going on on the grid, really mimicking storage.

Now, you may lose some of the output of the PV, but from a cost standpoint, is it easier to have a smart inverter that alters the output of PV, taking that decrease in output, compared to the cost of a battery system? So I did want to mention, that inverter's something that's really interesting in this overall process. And especially the further you get into the distribution system. So thank you.

Moderator: All right, thank you. That was fascinating. Just one clarifying point, again, to set the table, is that I think as we talk about things like volt-VAR, some of these are things that used to be endogenous to the system, especially where you have a vertically-integrated utility, or you really had centrally controlled generation. And now as we're going to a more distributed system, they're no longer things that we can just assume. But as you said, part of the problem is that we haven't really created a system to value them. So I think that's an issue that we'd like to come back to. So thank you so much.

Question: Your last comment about the inverter by itself seems intriguing, but I don't know enough about what that does. What value does it actually create all by itself? Could you explain a little bit more about that?

Speaker 3: Well, in essence, that inverter can act like a capacitor, it can inject VARs into the system, or it can take the input the AC input, do its inversion, and create a wave form that's a little bit different than what it took in. So you can do some power factor correction, you can do some VAR injection, you can do things like that that help system voltage. And in some ways think of it as a smart capacitor.

Speaker 4.
Good morning everyone.

So we are all in this business, and have seen quotes like this about the crucial role of storage. My favorite is, "Storage is a rate-limiting step for all low-carbon technologies." So what I'm after here is to question this and say, is it really the rate-limiting step? I mean, how much can you do now, assuming the storage cost doesn't change? And how much can you do later, when the costs are drastically reduced? So I want to just question this and go back to the rationale behind this, and basically quantify these claims.

So my only focus here is cost-effectiveness. Basically, my objective is to minimize the costs. It's different from, for instance, renewable portfolio standards, which aim to maximize the integration to a certain level of intermittent renewables. So if you consider cost-effectiveness, then you can raise questions like, for example, how does bulk storage compare with other technologies in our low-carbon technologies and toolbox? OK? So, basically if you want to minimize the cost, how much storage would you build compared to CCS, compared to nuclear, etc.? Almost alternatively, you can say, how much storage do you need to back up your wind? And as I said, the main parameter here is the cost of the storage.

So there are two key components here. The first one is that I only focus on bulk storage. Basically large batteries and pump hydro. And also I'm talking about deeply decarbonized grid. So if you fast forward, hopefully not that far into the future, 50 years or something, and if you cut your emissions by 70%, I'm looking at that case. Or at what happens if you have a carbon-free grid. What would it look like if you are minimizing the cost of that, of supplying electricity?

Before we go there, the primary question is, what does storage cost? I'm going to make a simplification here and treat bulk storage as a black box with fixed technical parameters, but a variable cost. So I'm going to vary the cost of storage in a wide range, and then answer the questions in the previous page at each storage cost. And I also assume that the total cost of the storage plant is made up of two separate costs. Costs associated with power, and costs associated with energy. So if you have a hydro facility, for instance, the power-specific costs are related to your turbine machinery. And the energy cost is related to your reservoir. OK?

And why do I do this? Because the costs in the literature are all over the place, so I can play with these two, and also I can talk about the relative importance of cutting one of these two. So are you off better reducing the cost of moving dirt in your pump hydro facility, or reducing the cost of total machinery? And do this same thing for flow batteries. Does it make sense to focus on reducing the cost of electrolytes, or the cost of your electrodes?

So I did an extensive literary review trying to figure out how much the estimates for storage costs are. So for the rest of the presentation I'm going to show you graphs like this. On the X axis is always the energy cost, which is in terms of dollars per kilowatt hours. And the Y axis is your power. And so I did a literature review, and these are the estimates for different technologies. So each box corresponds to a specific technology, and the location of the box is estimates for its capital costs.

So then I can go and ask my question. How much storage do I need? So I did a series of optimizations, and the objective was to provide low-carbon electricity at the minimum cost, while the emissions of the grid were capped at a certain level. Let's say they are capped at 70% compared to business as usual. OK? What I'm solving for is the size and also dispatch of your generation fleet. So let's say you want to build a grid from scratch, how much storage would you put there? How much wind would you put there, to provide or to meet a variable load?

And what's in my generation portfolio? So consider wind, gas turbines, both single and combined cycle, and storage. And also I have a generator technology that I call it DZC, or dispatchable zero carbon. This is to represent technologies which are currently too expensive, but emit no carbon and are dispatchable. Pick your technology. It could be geothermal, biomass, nuclea…if you call it dispatchable, it could be CCS.

So technologies that are too expensive, but that could potentially solve the problem if the costs are also reduced along with the cost of the storage. OK? The reason I didn't pick a specific technology is that their costs are uncertain, too. And you need to do some simplification to do the analysis. And I had a variable load from Texas ERCOT based on historical data at 15 minute time resolution. And I repeated this simulation over one year at different scenarios.

So, again, what I'm solving for here is to meet the load at the minimal cost. My main constraint is the greenhouse gas emission intensity of the grid. It's capped at some certain level. And what I'm changing from one scenario to another is the cost of storage. Remember that graph I showed you earlier? I picked 320 points in that two-dimensional grid as the cost of my storage, and then I resolved my optimization. Then I can tell you if the cost of the storage is this much, then this is how much it costs the grid to provide electricity.

So here is a sample result. What I'm showing here is the grid average cost of electricity supply. On the Y and X axes are the capital cost of the storage. And the numbers you see here are the parameters I'm talking about. Here is the level of the cost of the storage. So, basically, if your storage is costing this much, $50 per kilowatt hour, and $200 per kilowatt, this is the average cost of electricity, which is roughly $59/MWh.

Why is this important? Then you can quantify, if you reduce your cost of storage, how much would you impact the total cost of electricity supply.

So this is for the scenario where you don't cap the emissions. So this is business as usual. And it turns out that emissions are roughly 450 KG of CO2 per megawatt hour for this system. When I solve it, this is the average emissions.

Then in the next step I put a cap on my emissions and see how this figure changes. Basically, the cost should go up. I want to see how much it goes up, and how much storage helps to bring it down. So, for instance, here, you see the 70% case. So if I reduce my emissions by 70%, then this shows how much the availability of low storage changes the cost of electricity supply.

So you can see two things here. The first one is that availability of cheap storage does not impact the cost of electricity that much, unless you are aiming for this here, for basically a carbon-free grid. Which is pretty astonishing. I mean, even at the top right, the 35% cut, it's a big cut compared to what you have today. And again, see that storage doesn't really impact anything. The reason that you don't see any lines on the top of there is that there is no variation in the cost of electricity. So if you change the storage costs in that range, you are not really impacting the grid average cost of electricity.

And the second observation is the relative importance of what's going on on the X axis, basically the energy costs compared to Y axis. Which makes intuitive sense, because we are considering bulk storage. So your energy cost is far more important, compared to your power costs. And it has implications for different technologies—for example, whether you have a pump hydro facility versus a lithium ion facility.

From now on I'm going to focus on the 70% cut scenario, just for the sake of time. In the appendix there are graphs for other cases. So the second question I was after is, how much storage do I really need to back up my wind if my only objective is, again, reducing the cost? What's the economically optimal amount of bulk storage I need in my system?

To do that and to basically find an upper bound for the market share of bulk storage, I removed dispatchable zero carbon from the generation fleet. I take it out. So the only way to decarbonize my grid is to integrate more wind. OK? So I'm virtually putting more wind in than was economically optimal. And then I asked the question, how much gas turbine and storage do I need to supply my load again? OK, so this gives you the upper bound for how much storage you need at each storage cost.

And for here, I'm going to show you two sets of results. One of them is for a sample mechanical system. So it's a pump hydro facility. And also an optimistic system, and optimistic battery system. So a very cheap battery system, considering to today's costs. OK?

So here's my mechanical system and battery, and you can see the capital costs. So these are my inputs. And in a second I'm going to show you the outputs. What we are after is the relative importance of storage compared to gas turbines. And as a proxy for that I'm going to use the size ratios. So for every megawatt of storage that you build, how many megawatts of gas turbine power remains in the system? It gives you a sense of how important storage is compared to gas for wind integration.

So there are a lot of numbers here. You don't really need to read them all now. Just look at the last one. It's the ratio of gas to BES, bulk energy storage capacity. So it's roughly three if you are using a mechanical system, and roughly 11 if you use a battery. So if you consider the battery case, considering today's cost, you can say that gas turbine power is 11 times more important for wind integration, again, if your objective is to minimize the costs. Which is pretty astonishing.

I'm not saying that storage is not important. If you look at the share of storage to peak load, you can see that the ratio is 22%. Today you all know that it's less than 4% of the peak load. So you need to build a lot of storage into the grid to integrate wind. That's very true. But, still, you need a lot of gas then.

And these other results…if you reduce the cost of your battery and mechanical system by 50%, you can see that for the mechanical system, the ratio, the last line, is 1.3. So for every megawatt of gas, you need one megawatt of storage. It tells you a lot. And batteries are improving, but still mechanical systems are far better.

So following the same lines, what does this mean for the existing technologies? So if you put back different technologies into this contour, then which technology is closer to make a difference? Again, for bulk storage applications. So I'm going to show you the same graph for the levelized cost of electricity at the 70% cuts, but I'm going to put back my technologies on the contour.

Here you are, if you look at the top one, each arrow corresponds to a technology. So compressed air storage, pump hydro storage, and the batteries. So the starting point is the current estimate, the center of those boxes I showed you earlier--how much they are costing today. And the end of each arrow tells you, if you reduce both the power cost and energy cost of that technology by 50%, what happens?

So these arrows tell you what happens if you reduce the cost by 50%. How much difference will they may? And again, you can see that the batteries are still not there to make a huge difference. But the compressed air energy storage case is looking very promising, and so is pump hydro storage.

And the lower graph basically shows you the same thing, but it's a graph of the share of bulk energy storage from the annual supply of electricity.

So just to keep it very short, these are some highlights and conclusions. I'm more than happy to talk about them in details. So the first one is that larger scale integration of storage compared to gas turbines and DZCs (dispatchable zero carbon sources) is not really cost-effective, even if you drastically reduce the cost of the storage. So this may be the glass half-empty side of the story. But the glass half full part is that you don't really need to wait for cheaper storage. It's good to have cheaper storage, but if you don't you still can reduce the emissions by 30%, by 70%, and you don't need cheaper storage.

The second conclusion is that gas remains very competitive, even when you cap the emissions down to 30% of what we have today. And I'm using the gas price of $5 per gigawatt joule, which is not ridiculous today. But I did a lot of sensitivity analysis, and up to $20 gas, the results are the same. They didn't change.

There are a lot of assumptions going into this analysis, and almost all of them favor storage. So I can claim I'm giving you an upper bound. You can debate that. In slide 20 there is a list of all the assumptions that are going to there, and it tells you whether they favor or disfavor the position of storage.

And the third point is comparing the batteries and mechanical systems. Well, I guess if you are arguing based on these results, the mechanical systems are much stronger for this specific application, but there are a lot of caveats there. Batteries don't have siting limitations, they can be deployed at smaller scales, there can be spillovers from other industries into them. So from that perspective it is more likely that the cost of battery systems are reduced further. So if you reduce the cost of batteries, if you manage to reduce their cost much faster than the mechanical systems, it's a no-brainer. I just want to make sure that we do not pay disproportionate attention to cost-reduction as for different technologies.

I didn't show you any results for this, but the maximum energy capacity of my storage facility was less than two days. I didn't observe any economic rationale for seasonal storage of energy. And again, there are a bunch of sensitivitis. Most important is the gas price and the capital cost of dispatchable zero carbon and wind. And of course the results changed, they're all in the appendix, you can go through them. But if I have a quick comment, it's that I did a case that I said, "OK, let's reduce the cost of storage by an order of magnitude and see how much the cost of electricity changes." It was about 15%. So it would lower the cost by 15%.

Then I said, "Let's reduce the cost of DZC by 50%." OK? And see what happens. And the effect was 30%. So I'm not talking about how much money you should put into different technologies. But if you're only considering how much reducing the cost of DZC compared to the cost of storage would impact the levelized cost of electricity, you are far off better if you manage to reduce those DZC costs. Again, this is only one side of the story. The other side is, can you reduce the cost of wind or DZCs? Thank you.

Moderator: Thank you very much. And we'll come back after the break and among other things talk about what would change any of these conclusions. For example, comparing this to the solar case and any other things that might shift the cost justification for storage. So thank you.

General Discussion.

Question 1 (Moderator): I think there are a lot of topics that we can discuss. Since I put a couple of topics on the table, I wanted to start with one topic which I heard several of the speakers address, which is, when we think about storage and we also think about integration of renewables, that really storage is one facet of a whole system that you need to integrate--not just renewables, but all of our resources.

And so as we think about things like the over generation issue and what we have to do now to integrate renewables (and of course the over-gen profile is going to vary tremendously based on your particular balancing authority and location), one of the things that we've been talking about is also, how can we create incentives to shift load? I mentioned the imperative, for example, in California of the cost of water and the issue of de-sal.

So as you know, the main barrier to de-sal has been its energy intensity and thus its cost. It's really energy which drives the cost of de-sal. But to frame that in modern terms, about when is the cost of something worth it? So in 2013, the cost of an acre foot of water (enough water to cover a football field to the depth of an acre) was about $120-ish per acre foot, more or less, in California. That was in 2013.

So in 2014, by the time that we got 0% allocations from the Federal Water Project, and then State Water Project cutbacks started at 0%, went up to 5%, the cost of an acre foot of water in 2014 in California was up to $2,200 per acre foot. So this year, Metropolitan Water District in Los Angeles recently paid $700 per acre foot to some rice farmers, so it's more lucrative to sell water than to grow rice.

But there are others who, in California this year, have paid $2,000 an acre foot. The de-sal plant, Poseidon, that is being built in San Diego has a commitment to sell 48,000 acre feet of water to San Diego water authority. They have been criticized about how expensive this water was. It is $2,000 an acre foot. So it's actually now looking about right in the money. And you need to 200 gallons of water per minute to cool a gas-fired power plant. An acre foot is approximately 893 gallons per day for a year. So that means that for the electricity sector you're going to run into an acre foot pretty quickly. The electricity sector is actually the largest consumer of water nationally, when you look at power plants and various means for the extraction of energy that uses electricity.

Some of the electro power plants in this last year just haven't been able to get water at all, right? And so if you can't get water for cooling, you can't run. And so then you end up in a situation where you're low on water and now you don't have electricity. So when we think about things like this, and we're now in the fourth year of a drought. We don't know if this is going to be a ten-year Australian drought, or even whether this is going to be permanent. You know, what are we going to be facing? But we need to plan prudently.

So might we be able to use storage or some combination of solar storage, conventional generation, and also rate design to shift load so that we can do things like make de-sal more economical? Any comments or thoughts?

Speaker 1: I think when you look at it (and I apologize for this being so California-centric, but, as I said, we are kind of on the leading edge of this with regard to storage), when you look at the goals I summarized--the governor's 2030 goals with the 50% renewable energy goal, and importantly the 50% reduction of petroleum use in the vehicle fleet, that goal alone's going to have huge implications to the electric sector. So when you look at what it's going to take to achieve both those goals, you have to look at them together.

And to return to the Moderator's question about how, if you truly are going to have 50% of the vehicles out there being zero-emission vehicles, whether they're hydrogen or battery, how do we structure that so the electric loads being produced from that actually align with the over generation that we have, I think there's a lot of opportunity to do that. But one of the challenges is, that's a very ambitious goal that requires consumer adoption.

And how much confidence can we put in that level of adoption in that timeframe? Because at the end of the day, when we get there, the question is, will we need all the storage we think we need today? So you can think of storage as potentially a bridging mechanism to getting to where ultimately we think we can get with regard to our climate change policies.

But those other integration solutions are highly uncertain with regard to timing, quantity, and effectiveness. And I think it really points to the need to at least do something over the next decade to mitigate the huge over generation issue we anticipate. And I certainly agree that the water area in California is another area where de-salination, waste water treatment, just water movement in general across the state could be better coordinated to help with some of these integration challenges as well.

Speaker 2: On demand response, I might just suggest that given the complexity of the issue with price formation, the status of Order 745, and rate design, I think you need a whole session on that. Maybe next time you could have a whole session on that.

Speaker 3: This is an interesting question to ask, and we've just asked it at the surface level. If you could pick your load shape, what would it be? If storage gets cheap enough, maybe you'll face that. And your gut reaction is, "Well, it would be a 24/7 flat line." But then you say, "Well, maybe not," for some of the reasons, based on generation. But storage is getting us to ask some of those questions that have really never been asked before.

Speaker 1: It's interesting. Traditionally, for decades, we've planned the system where consumers do what consumers do, and we built the supply portfolio to match what they do. With obviously some incentives for peak load reductions. But now we've kind of turned it around and said, "Well, here's the supply fleet we have. How do we shift consumer behavior to align with that supply portfolio?" So it's kind of a reverse dynamic that we're dealing with.

Moderator: Great. So it's part of the whole system as we talk about the interaction between supply and demand. So load shifting is part of it in terms of demand, as well as supply. And then we also mentioned, and it'd be good to discuss as well, FERC Order 745, enacted in 2011, which increased the pay for fast-responding sources like batteries and fly wheels. And then we also have a FERC order 784, which will help to open ancillary services markets for the storage project developers. So, any comments about the impact of those FERC orders as we look at the market effects, integration, etc.?

Speaer 1: I think in response to those orders, we have evolved our market products in the regulation market. We now have a feature called regulation energy management where a battery can participate in providing regulation, and we actually manage the state of charge for the battery in providing that regulation service. We have something called pay-for-performance regulation. We traditionally paid regulation for capacity, we're now paying it for the mileage, how much we actually move the regulation resource throughout the hour, as well as a premium for how accurate they are in responding to those dispatch signals as well.

So those were reforms that were all triggered in response to FERC Orders, and actually provide, I think, a good opportunity to extract the value that a battery can provide in providing very accurate responses. Some of our big plants have traditionally provided regulation. It turns out they have horrible performance in terms of responding to the AGC. And we make it up in volume, but as there's more emphasis on the accuracy of the signal, I think batteries can realize some value there.

The flexible ramping product I touched on in my presentation is a product that's under design. And the goal there is really to incorporate a payment for capacity if, in the forward-looking market optimization where we're projecting what our ramping needs are and projecting the future intervals, and if we have to hold resources back so that they're available for that ramping, we actually provide some compensation for the opportunity costs. And we're looking at both upward and downward directions. So I think that's another market product that can be available for batteries in addition to the traditional operating reserves we have.

And of course, energy arbitrage, as Speaker 2 mentioned, is kind of the bread and butter for storage. And I think all indications are we're going to see huge spreads, such that in the belly of that duck you're actually looking at negative pricing. And our market prices can go as low as negative $150, and as high as $1,000 in the upward direction. So there's going to be a huge gap there. Obviously the more storage comes in, as Speaker 2 noted in his presentation, the the more the price suppression impacts will be there. But nonetheless, I think there's a good opportunity there.

All that said, I still think that when you look at the capital costs of these technologies, you need those additional procurement tools to get them in place. You need the resource adequacy program that drives the utilities to go out and procure these things, and we're trying to, in our market, provide opportunities to capture the value. But I don't think it's enough alone to actually get people to invest in these technologies. They're going to need something more permanent in the way of a long-term contract.

Moderator: Thank you. And this is a point that both Speaker 2 and Speaker 3 brought up as well in their presentations--the value of a variety of storage services and really needing, as a grid, to recognize those values, but also to create a market that accounts for those who contribute to the values.

Spekaer 3: And I think incorporating these values into the market could cause the rest of the country to think, "Wait a minute, there must be something to this. If they're willing to pay more for this, maybe I need to look at this in a different way." As opposed to just assuming the battery's the same as a pump hydro.

Question 2: So I thought this was very interesting and very helpful and depressing. [LAUGHTER] I'm involved in a research project off at Harvard with a group of people in the School of Engineering working on trying to make really cheap batteries. So I'm kind of trying to be optimistic about batteries, and trying to think about really cheap batteries.

One of the things we discovered that did not come up, but I think Speaker 2 will agree with this, is we found that when we did these backward-looking simulations of energy arbitrage and all that kind of stuff, the message that we were getting out of this is, if you build a large storage battery (I'm talking about bulk storage things now. But you can see the implication for distributed as well), you should build it on a truck. Because the place that has the most value this year is not the place that's going to have the most value next year. And we're finding that you're going to want to move your storage to someplace else, largely in response to what's happening. The thing that was driving it was transmission congestion. And if you start changing the pattern of use and building transmission lines and all these kind of things, they're moving all over the place.

And this actually complicates the story, both for the bulk storage, and also for distributed storage, which is by definition place-specific. And so it might be economic in 2012 ERCOT, but it's not at all clear that it's going to be economic at this place in 2013 conditions, and it might be economic someplace else. Which is another dimension of the uncertainty and the problem. But I'd be interested in any comments about that.

Speaker 3: You're right. I mean, by its nature you're affecting the market. You can't touch it without affecting it. And so when you do storage, you are changing the dynamics from location to location, year to year. I think a corollary of that is that some of the exuberance at times that we've seen--the idea that, if one unit of storage is worth \$100, a thousand units of that storage would be worth \$100,000—may not be justified. The value of storage changes the more you have.

So you have so many dynamics. And that's one of the reasons energy storage is fascinating. As soon as you think you're getting it figured out, you look at it from a different angle and you realize, I don't know anything. Or the more you know, the more you realize there's even more you don't know.

Speaker 1: With regard to the renewable integration and over generation issue, we see that as more of a system-wide issue, as opposed to a transmission-constrained problem. So I'm not sure in that context that the location is as critical as the capability to arbitrage those two different time periods of the belly of the duck to the evening peak. We design the transmission system so that we minimize the curtailment of renewables, because we have the policy objective of achieving the RPS goal, so we design the transmission to support that and minimize congestion. So in our view, the over generation issue is really more of a system-wide one, where location may not be as critical.

Moderator: I would note, though, that location does come in, of course, especially at the distribution level. But we also see it at the system-wide level. But in looking at your point about whether you can do storage on wheels, I actually saw a lithium polymer battery installation that Kansas City Power and Light has operating. It's a megawatt, and they've had it going for over a year and a half, and they've reported it's done very well. They also built it right next to a substation. They built it on a trailer, so they built it to be moveable. But it worked really well right in that location, so they ended up bolting the trailer down.

But the point is that it's flexible. And so the answer might be that it might be good to have a variety of resources, some of which are stationary, some of which might be moveable, to be able to help you deal with particular conditions that might arise, or where things turn out to be different than you expected and you want to bolt it down.

Question 3: My first question might be directed at Speaker 3. My understanding is, the cost to reprogram smart inverters to better manage your rooftop solar arrays is actually low. And they're owned by the homeowner who owns solar, or owned by the leasing company. And I wondered, in your view, will there be an increased need to cede some control of them to the utility, and will the utility even want to control devices that they don't own?

And I also wondered if you could touch on some of the EE benefits for the grid if we do get voltage control right.

And then my second question, would be directed to anyone. We're trying to infuse a free market approach to the process, in terms of seeing if storage can compete with a new generating unit. And we basically ordered our utility to get bids from the market in a type of all-source RFP. And I'd be curious if anybody would wish to comment on the rightness or lack of rightness of that approach. Thanks.

Speaker 3: I'll start with the first question, especially relative to smart inverters and the possibility of ceding some control to the utility, if it's a customer-owned asset. I think that's a possibility to think about, through demand response programs. That's already occurring. You know, ceding some control over thermostats or water heaters or pool pumps and different things.

So in that context, I think it could make sense. Where it gets more complicated, obviously, depends on the net metering arrangement or the tariff structure. You may be changing the impact on the tariff, alright? It may make sense to curtail PV or have it follow the load a little bit differently. So I think that's where it gets more complicated.

But inherently I think ceding some control to the utility or to whatever entity might act as an aggregator, I think there would be some value to that. Because the highest value proposition for the customer and the whole ecosystem is if you're able to capture value on both sides of the meter. That's the lowest cost for everybody, if we can capture value on both sides.

So what's the most effective way of doing that? Is it a price signal? So you're actually not ceding control, but you're responding based on a price signal? Or is it direct control? And that will vary from location to location and among different programs. But I think we do need to get to that point, and it'll be interesting to see how that applies to solar PV and/or storage.

Speaker 2: I can speak to the part of your question that had to do with storage versus CTs. We get that question a lot. From kind of a classical integrated resource standpoint, you use something like a capacity expansion model and do the optimum build-out. And storage is either not represented or very poorly represented in capacity expansion models. So that's been one of the problems about understanding whether or not storage is economic.

Now, that said, storage is still two to three times the cost of a CT at least. So there's a value gap that you really need to understand. And that usually requires doing production simulations. And even production simulations sometimes struggle to incorporate storage. They're much better now. I'd say now they're fine, but even five years ago, production simulations struggled a little bit to capture the value of storage.

So a classical capacity expansion model will chose the CT. You don't have to run the model, I can just tell you that. But you really have to do a scenario analysis, probably using multiple model runs, using a production simulation, to see if the extra value that storage adds outweighs the cost difference.

Speaker 1: I would just add, too, it depends on what your objective is, particularly if you have carbon goals that you're considering. The value of storage in an over generation situation is based on the fact that you can take carbon-free power and consume it, which a peaker can't. So you're mitigating the over generation issue, taking zero-cost power, carbon-free, and then you're putting it back on the grid to help with the ramping issue, in our case. So you're avoiding the GHG emission of running a peaker plant as well. So those are the kinds of additional values that need to be brought in.

Speaker 2: And a production simulation, properly run, can absolutely capture those values. I mean, whatever carbon price you want, you can put into that simulation.

Moderator: The CPUC has had a proceeding on smart inverters, and my legal and water advisor actually was the one who directed it. So we would be happy to share information about what we've decided on smart inverters and how we've also tried to integrate it with our other programs, including of course the solar program.

Question 4: This has been a very interesting panel. We've been looking at the role of storage for quite some time now as part of AB 32 compliance. And where this actually seems to work is in Chile. So if you want to find out the future, you have to go to Northern Chile. Last November I was down there and visited the 30 megawatt battery storage project in Angamos, Chile that serves the North. Ironically enough, five of the 30 megawatts were at Huntington Beach, California for a couple of years, but never got hooked up because no one could figure out whether they were distribution or transmission, and who was going to pay for what. So they got on a freighter and went down there. So it seems that the money does matter. And I think that this is kind of the elephant in the room when we're talking here in California, because how are we paying for this?

In California we do not have any sort of long-term capacity market. We're also unlike Chile, which has very high energy prices and where the resource is basically used for regulation, and it's used for basically spinning reserve. It basically discharges in 15 minutes, as the CTs kick in. So it's not an either-or situation there. But because the market's structured the way it is, and the energy has the value it has, it makes economic sense in a way that it would not make sense here, because our markets just don't support that.

The second issue I think that's interesting has to do with how we keep talking about storage as if it's a renewable fuel. The interesting thing about this particular battery pack is that it's tied into a brand-new state-of-the-art coal plant that's burning long-dead Australian dinosaurs and ferns. Basically, this is Tupperware. So how it gets utilized is really important.

And then the final issue is this question of location and what can of worms does this open up? It's one thing if you have a large battery package that's tied to a power plant. I think that's a fairly easy model to understand. But if someone has got a battery in his garage, who pays for that? If something goes wrong, is it a PUC problem or do I have to go to FERC? There's all these issues that are floating around out there. And this issue is front and center.

So if your primary mission was a policy to encourage more battery energy storage, what are the three top things that need to get done quickly in order to make that move forward?

Speaker 1: Well, in terms of advancing the ball on battery storage, I think the 1,300 megawatt target is driving a lot of procurement. So I think that is happening. I think the challenge will be, in the context of the utilities, looking at the mix of storage resources that are responding to those RFOs. What's the maximum value there that these different technologies are providing? I think that's the real challenge.

And we've had some interactions with the utilities on looking at, if they had this mix of storage resources, what do we see the grid value being for that? Some of it's localized, with the loss of the nuclear power plant in the Los Angeles basin. So there's some locational value there.

There's also renewable integration value. So the value proposition for each of these technologies, I think, is still a struggle to really sort out. Does it make sense to pay a premium for a technology that might give you an added dimension in terms of grid operations? We really don't have a good framework for evaluating that. I'm really not an expert on the issues around distribution and how you extract the value there. I know there's an ongoing proceeding at the PUC to address some of that stuff.

But the one thing I would highlight with regard to the over generation issue is that we keep talking about batteries, but when you look at the scale of that issue, we're talking about 10,000 megawatts of potential curtailments during the spring months. Batteries may be a part of that solution, but we've got to look more broadly at storage in general and think about large-scale storage, pump hydro facilities in particular, to help manage that issue. Because I don't think that with today's technology it's going to be cost-effective to try to solve this all with storage. Whatever you do with storage, you're going to need a lot more than just batteries.

Speaker 3: In terms of the three top things to move battery energy storage, the first one is that costs need to come down. Another is that to help energy storage you need gas prices to go up. Because that's actually the biggest competition to energy storage right now, cheap gas.

That shared value that you talk about is a big part of it. How do you share value across distribution, transmission, bulk, and what are the rules?

And the third thing I thought of was that when you advance other distributed generation, you're going to advance storage, because the more things get on the system, the more value that storage is going to have.

Speaker 4: If I may be the devil's advocate, I can question your question. So, why do you want to do that? I mean, going back to my presentation, is it really the most cost-effective way to do this? I don't want to look very bad. I spent five of the best years of my graduate school on this ,and I'm really passionate about it. But we should have a frank and candid discussion about it.

So I guess my comment is that location matters, and also the scale matters. How much storage? A couple years ago we had an economic analysis of compressed air energy storage. It was in

Alberta. And we did an analysis, and it was basically a money-printer. I mean, it was a hypothetical case. If you build it today, would you make money or not? And yes, it was a money printer. But would someone build it today or not? Maybe not. And what happens if everyone starts building them? So, again, scale matters. The market saturates quickly. You just need to pay attention to those factors.

Speaker 2: I think that if you look back at all the wind and solar that was built in this country, the vast majority of it wasn't purely economic. So I guess one question is, why are we building storage if it doesn't make economic sense?

I skeptically think that if you do a fair market valuation for storage, you're still not going to be in the money. So that gets me into the real question of whether maybe we should do it just because there are all these external benefits about deploying all new technologies. And so, 1,300 megawatts, we deploy storage, we learn some things. You know, it's only a few billion dollars. We can afford that.

Speaker 3: I will add that most of the in-the-money cases that we're talking about are relative to a bulk power application. If you go to Hawaii and I'm resolving a distribution circuit problem with PV penetration, storage is getting in the money. But, again, it's very location-dependent. And it's one thing to say it's applicable for Hawaii and these circuits in Hawaii, and another to say, alright, we're ready for gigawatts all around the country.

Question 5: I have a quick question for Speaker 1, and I have a question for the panel. The quick question is, you mentioned 2,000 megawatts in the queue. What technologies?

Speaker 1: Almost all batteries.

Questioner: The other question is, we have been using a battery of sorts for quite a number of decades for energy arbitrage, but also for reliability purposes. But we want to use it for an anti-dropping of renewables purpose. And that's thermal energy storage. For a couple hundred dollars, you can store the equivalent of about 21 hours. Why don't we spend more time looking at thermal storage? I realize it doesn't solve all of the problems, but it certainly solves a lot of the current problems very cheaply.

Speaker 2: Just one thing about thermal storage. It's a great idea. But (I'm really serious about this) it's not sexy. Batteries, super cool. Thermal storage, super boring.

Speaker 3: I think you have a valid point. And that fits into what I was calling virtual energy storage before. I guess thermal storage is still physical storage, but it's not batteries. So I think it's valid. So at the same time as we're looking at when do batteries make sense, we're also looking at, alright, what about demand response, advance demand response, whatever you want to call it?

And especially with this "ubiquitous connectivity." Right now it's tough for us to have water heater programs, because you have to go send an electrician and install something, which gets out of the money. But as you look at new standards that are coming, alright, can you get a port? We've been working a lot with the CA245 port that's the standard now, so that when the commodity water heater that comes off the rack at Home Depot or Lowes has connectivity to it and can do these things, I think there's a lot of validity to that. And there's interesting water heater technology, like an external mixing valve, you can heat the water up to 160 degrees or more and effectively double the amount of storage you can have. And there's some really interesting things. But you're right, it's not sexy. And it's --

Questioner: And it's cheap.

Speaker 3: Yes. But there are some…I know Great River Energy is doing a lot with it. There are some pockets of some very interesting programs around water heaters. And I think that is viable in the future. And not just water heaters, other loads.

Speaker 4: And if I may just add two quick comments…the first one is that I guess it's very location-dependent. You want to have it ideally close to concentrated solar power if you want to do it at a larger scale. So you can't do it everywhere. The second one is that it becomes interesting if you pair it with HVDC. So a combination of concentrated solar plus thermal solar plus HVDC. The combination of those gives you basically an expensive but doable dispatchable zero carbon, which is pretty interesting, yes. And I love Speaker 2's comment on how it's not sexy. Same thing for pump hydro storage. But it makes sense.

Moderator: Well, I think for pump hydro, part of the issues is, especially on the larger scale, that there are a number of environmental impacts.

Question 6: Two observations and one question. The first one is, there's a lot of price information associated with the duck curve. And as best as I can tell from my retail bill from PG&E, zero content of that duck curve is what I see at retail. The second observation is that what Speaker 2 is referring to as price suppression suggests that the quantity you're looking at may be too large, in terms of what the market will bear for the sensitivity in your examples. And that's not a new response.

If you go back to the late 70s, the Bath County storage facility was justified based on forecasted imports and exports with a spread that would have been a couple hundred dollars a megawatt hour between peak and off. And as it went operational, you were lucky to see $10 or $20 at most. And it's just the phenomenon you're talking about, but it just simply says that 2,000 megawatts of storage in a single location against that kind of market has obviously diminishing value. And at the margin, it wasn't justified.

I thought it was interesting that 50% of the value of storage that you found was linked to startup costs. But in an offer structure that repeats every day, wouldn't you expect the storage to bid its flexible startup and performance costs as part of what the security constrained unit commitment system sees? And that money to transfer back to the facility?

Speaker 2: On the first part of that, I would just state this. If you've got 100 megawatt hours of curtailed energy, how much energy should be stored by a battery? I mean, without any other information. I would claim it would be 100 megawatt hours. If you absorb exactly that amount of energy, the next marginal unit is no longer curtailed energy, so the LMP will go from minus-$23 or minus-$100 or whatever it is, to a thermal unit.

So, yeah, I mean, you could only store 99, and then the LMP would still be minus something. But I don't think that's the socially optimum solution, right? I mean, you're throwing away that last unit of carbon-free energy. I mean, we're splitting hairs a little bit. But it gets into this issue of, well, who should decide what the optimum amount of storage is to build? I mean, it's not a step function.

Questioner: Right, but it's hard to criticize a market mechanism for an externality that's not there, and link it to a flaw in the market mechanism. If you can't internalize, in your case, the carbon cost, at least for the element which is the energy arbitrage (not the startup costs), then this says, don't build that much.

Speaker 2: Right. And I guess I keep coming back to, who should be determining how much storage to build? I mean, it gets back to one of the things that I've always been curious about with structured markets versus integrated resource planning, which is, the person that's trying to decide whether or not to build the storage doesn't have perfect information about how much over generation there might be, because they don't know everything that's going to get built. So I don't know how you would figure out what the optimum amount of storage to build is in this environment.

Questioner: A generator or a demand response provider faces the same problem.

Speaker 2: Totally understood. Demand response is a perfect example, because it has the same problem of both increasing off-peak prices and suppressing on-peak prices. To me, storage and merchant transmission would be the same thing, right? It would be kind of arbitraging LMP differences. So I always struggle with this this observation that, gosh it's interesting that while if you're a nuclear plant or basically a coal plant or a wind plant you suppress these on-peak prices. But with storage it's interesting that not only do you suppress the on-peak prices, you also raise your charging costs. And with the exception of demand response, that is fairly unique to storage. And an interesting observation. I don't know what to do with it. I'm not a market design expert, so…

Questioner: Yes, but the design conclusion is that phenomenon doesn't take place with a lower quantity. Your observation is correct, so the price would tell you to build less. And don't forget the SCUC.

Speaker 2: I think I'm going to have to punt on that one. I've read a little bit about extended ELMPs and how they're going to solve some of these problems, but I'm at the edge of my knowledge there. I'm not comfortable talking about that. So I'm going to defer.

Question 7: I actually try to work on the other side of the water-energy nexus, which is working with water companies. And they're having a hard time. There's actually about 500 megawatts of water load in San Diego County, which is about 10% of the ISO's customer load in that area. And they can provide load-shifting; they can provide two hour ramp; they can provide two-second signal management.

But because the metering requirements are pretty onerous, it makes it impossible for them to participate. And the water companies are trying to find out, how do they get in the game? How do they unlock the value that's in their process management? It's process optimization as a form of storage. What's nice about water companies, especially freshwater systems, is that they are distributed. They can provide voltage support.

I've been working on this problem for a couple of years now, and we haven't been able to crack the nut. So I'm looking for some guidance as to how we get behind the meter into these resources that are a form of storage, but just aren't able to overcome these barriers to entry, which I don't think are unique to water. I think that electric storage would have to overcome the same thing. But there's no focus on unlocking what's already available in the system. So I'd appreciate some guidance on that.

Speaker 1: We've had an ongoing initiative last year looking at metering and telemetry requirements for demand response, and whether we could relax some of those. And there are some proposals that are out there that we're considering, and we're working to drive to resolution this year.

As part of the stakeholder initiative around the storage roadmap, there will be opportunities to raise the very issues you've mentioned there. Because I think there will be a lot of interest in that. And that's one of the items identified in the roadmap--how do we relax some of the requirements for these resources to participate? So there is an ongoing initiative to try to address that.

Questioner: If I can just press the issue, is anything being done toward figuring out the retail side? Because it's one thing to be in the

CAISO market, but these are all retail customers. So they have retail tariffs; they've got demand charges; they've got all kinds of different challenges. Even if you crack the ISO piece of this, there's still another part. So I don't know if anybody can speak to that. Those are some additional challenges.

Speaker 3: I don't have a resolution to the challenge, but I think it's going to be bigger and bigger. Especially with basically everything containing power electronics now, and the fact that power electronics is getting better and better, cheaper and cheaper. So I think the individual devices are going to be getting more and more intelligent. They're all going to have metering. It's not traditionally utility-grade metering, but it's good metering. I think this is an issue that is bigger than just energy storage. It's a question of, how do we use individual devices in loads behind the meter and appropriately value those? And how do you compensate? And changing our traditional paradigms of measurement and verification.

Speaker 1: I would just add that the energy storage roadmap initiative goes beyond just ISO issues. It's really looking holistically at what it takes to evolve storage. So the PUC is a partner in that roadmap, and it's looking at issues that are more on the distribution system as well. So I think there'll be an opportunity in that venue to raise those issues as well.

Moderator: I would also encourage you to file your comments. I participated in the water energy nexus proceeding at the CPUC. And that would be one place to discuss some of these issues. I also co-chair the state's water energy team of the climate action team, the WETCAT. And our WETCAT meetings are also public meetings. And I just went to a meeting last week that Senator Fran Pavley led where she was really interested in making sure that our water energy discussion looks at the water energy GHG nexus.

So, again, to the extent that you're looking at how can you do things that contribute to GHG reduction and energy and water management, and how do you make sure that you're properly incentivized to do that, I think these are two forums where we would love to discuss those issues.

Question 8: I should note, I work for a regulated California utility, so there will be no advocacy at all in this question. [LAUGHTER] First a little bit of context. In Speaker 2's discussion, he was looking at price gaps of maybe $50 a megawatt hour, where price suppression could reduce those substantially. And while Speaker 1 talked about extremes of minus-$150 and plus-$1,000, those are price spikes. So I'm imagining that if we had even as much as $100 a megawatt hour sustained day-in, day-out price gaps, that would be a relatively interesting proposition for storage to pursue.

But now I want to contemplate a couple of trends that I've seen emerging. One is more companies getting into the residential energy storage space. And another is the movement towards more time-of-use pricing in the residential space. And when I look at time-of-use rates that we see here in California (and I suspect it's similar elsewhere), the gap between on-peak and off-peak prices on a sustainable basis can be 30 cents a kilowatt hour, or $300 a megawatt hour, day in, day out. And the rate at which they're subject to price suppression is not the rate at which a market moves. It's the rate at which rate design changes are made, which typically happens over years.

So I'm wondering about the nexus of these two trends, and are we going to be seeing an opportunity in the future where home energy storage is, from a customer's perspective, a good value proposition because of our time-of-use rate designs? And I'm wondering about what impacts that could have overall on our systems in the future.

Moderator: I want to make sure that we don't veer into any ex parte land. But one idea that I've floated at the discussion with Fran Pavley in the Energy Nexus Group, and I mentioned it to Speaker 1 and some others, is that when we talk about rate design, on-peak, off-peak, we're also trying to balance issues like over generation, which we do see system-wide. When you look at certain classes of customers, the price that they pay is based upon what their peak demand is, right?

So this actually drives people to do very elaborate things for peak shaving, some of which we encourage through our self-generation incentive program, or, for example, there's a company that does storage where they will basically toggle you between the grid and a battery to try to shave the peak.

So, if we know that solar in California tends to produce a lot between noon and two, what if we made the hours from noon to two exempt from the calculation of peak, right? So, basically, tell people to go for it between noon and two to help absorb some of that generation, and then your peak would be based upon the rest of the hours. That would be the all-carrot approach. You could add a stick around six o'clock or so. But a little bit of carrot, right? Noon to two, go for it, to help us deal with over-gen. Any thoughts about that?

Speaker 1: Well, I would just add, looking back to the earlier comment from someone about how he doesn't see the duck curve in his utility bill, that I think as a general matter, the whole time-of-use structure needs to be re-looked at in the context of the duck curve. And the good news is, that effort is going on. We have a joint agency effort to look at the question, what sort of time-of-use blocks does the duck curve call out for when you look at it across the year?

And if we structured time of use rates to align with that, what are some of the potential load shifts we could see from that? So there's an ongoing effort to do that, and it remains to be seen how much bang we can get from that kind of structure. But I think it does have to get done, and hopefully it will.

Speaker 3: I think storage is going to exacerbate some of the rate design issues that distributed resources in general are creating. Rate tariffs are designed with a lot of purposes in mind. If they were designed purely for one purpose, then it would be less of an issue. But since there's so many purposes embedded in a rate tariff, its complicated, particularly given that the end result has to be to meet certain revenue requirements.

So now you start throwing things in and changing the load shape. Well, wait a minute, now I don't have the revenue requirements that I expected. So I think that's just going to put more and more pressure on rate design, especially given how we were talking earlier about the amount of energy storage you're going to need. What's going to happen when we've got this great time of use rate, and everybody puts it in storage because it makes sense—then, "Well, we've got more than we need," so now we change the rate in two years.

People are going to say, "Wait a minute, I did this based on a five year cost recovery. You need to grandfather me." You know, it's going to be ugly. But I think energy storage is just exacerbating this whole issue that rate tariffs have been created for all sorts of purposes, under the assumption that load will be the shape that it was going to be. But now, with the ability to change that shape, tariff design really needs to be viewed differently going forward.

Speaker 2: So when you're talking about that kind of spread, that sounds like a critical peak pricing type of number to me.

Speaker 3: No, actually, I was just talking about the energy rates. Critical peak pricing can go up to, I think, $750. So that's a much bigger gap than the day-in and day-out price variance--say 40 cent on-peak, 10 cent super off-peak. Roughly. Those aren't exact, and I don't know what the exact ones are, but --

Speaker 2: And you can see that during even the fall and spring and winter? Or is that just summer?

Speaker 3: I don't know all the exact tariffs for everybody. I think that's roughly speaking what it might look like year-round, generally.

Question 9: You were talking about the need for storage and the moment-to-moment valuation of storage. And probably more than any other element of resource planning, storage seems to have the highest degree of just sheer change, randomness, and variability in outcomes. And that plays into a point someone made earlier about an attribute of storage which already exists today, particularly in terms of affordability.

We have, over the past several years, filed with FERC on behalf of a storage entity that actually has ten 18-wheelers with two-megawatt modules mounted on each trailer. We started in upstate New York, in ISO New York. We've moved it now twice in PJM. And that 20 megawatts has been injected into the grid at different locations based on changing market conditions and changing needs.

The timing required to literally unplug, move, re-plug, is minimal. The constraints have to do with the fact that when you park in the parking lot of the regulated utility whose substation you're located at, you're doing a lease agreement, which is a jurisdictional agreement, which has to be filed under Section 205, which has a 60 day timeline, plus the data request from staff.

The only point being that we're still dealing with an administration process in the context of storage that seems more designed for large central station power plants, and something that you put on Route 81 and the Pennsylvania Turnpike and relocate in 48 hours was not meant, back in 1935, to be subject to "just and reasonable rate" procedures. So we have some catching up on relatively simple items that can make existing technology a lot more workable.

Moderator: I think this gets to the point that you brought up earlier about how we're designing interconnection really more for large central power plants than thinking about it like a capacitor.

Speaker 3: Yes. My only comment is, "Amen." That's an issue.

Question 10: A couple of things on the whole question of economic feasibility. We had an interesting demonstration, really still in process, at the Commission, where in order to replace the San Onofre nuclear plant and some of the once-through cooled plants that are scheduled to shut down, Southern California Edison did an all-source solicitation seeking replacement resources, and we did put some parameters around that, including strongly encouraging the company to get some storage as part of that. And a lot of the details are confidential, but there was an enormous response in terms of storage projects bidding into that solicitation.

And Edison ended up purchasing quite a bit more than the minimum that the Commission had encouraged, even in the face of some of these wholesale-retail issues that hadn't been fully worked out. So I think that was a very tangible demonstration that maybe we've been underestimating the cost-effectiveness of storage. I don't know, maybe others have observations about that. But I thought that was a pretty striking response to what was really the Commission kind of dipping its toe in the water. And that was prior to the 1,300 megawatts requirement.

The other thing I thought was interesting is reflecting on the natural gas market, where storage has been part of the mix for decades. And we have potential third-party gas storage providers building on spec in California. You know, they'll come in for a CPCN (Certificate of Public Convenience and Necessity), and they have to get environmental clearance, which is not always easy. But people have added new storage with no rate-base treatment, just based on the competitive market. Which is certainly not something we see on the electric side, but it's a very interesting development there.

I also wonder if Speaker 1 could speak to the two-hour versus four-hour issue that seems to be a hot topic in California right now. The issue is whether, in order to account for resource adequacy, a storage project has to be able to maintain output for four hours, and various parties are asking for that to be changed to two hours.

Speaker 1: We're certainly open to taking a look at whether we could, in the context of the resource access program, accommodate a two-hour product with some limitations on the quantity. For example, if you have an arrow peak that you could meet with that, but not so much that it becomes problematic. So we're open to looking at that from a grid reliability standpoint.

We have done some work with Edison on some of their procurement where, at least in a local area operationally, we've seen that two-hour products can meet the local operational needs. But whether we would have a similar finding looking at the needs of the whole system, and the need to meet a system peak, and the uncertainty around that, it's something we'd have to look at. But we're open to doing it.

Question 11: I have two questions for Speaker 1. Your slide seven shows a 13,500 megawatt ramp up, and it's largely due to the solar decline that you show on slide six. Do you have operator tools that would allow you to back down the solar early, if you needed to dampen that ramp out? And my second question is related to inertia. Are you seeing any potential inertia issues with the reduced amount of thermal generation?

Speaker 1: With regard to your first question, the short answer is yes. We have the ability through our market optimization to try to position the fleet to manage that ramp. But if we find that it's not manageable through the market dispatch, we can take out-of-market actions, including ordering renewables offline. So we have the procedure, it's a formal procedure, for how we would do that. It's a manual procedure. But we have the ability to do that.

The other thing I would just note on that is, is the objective here to never curtail renewables? We don't think that's the objective. The objective is to actually incentivize renewables to provide bids, to be part of the solution, using renewables to integrate renewables. But of course it's all in degree, right? Obviously, if they're getting curtailed down all the time, you're undermining your policy goal on the environmental side. So rather than us forcing renewables off, we'd like to see them put bids into our market to help manage that ramp as well.

On your second question about inertia, that is something that we have looked at and continue to look at, obviously, with the loss of the nuclear power plant in southern California, along with the planned retirement of some facilities there. We are concerned about whether we have adequate inertia on the system. I think the last study we did was a couple of years ago, and it didn't show any problems, but we're updating that analysis with more current data. And I'd be happy to work with you to share what we're finding on that. But it's something we're keeping a close eye on, because it's a big change to the system, taking all those big machines off.

Speaker 2: The National Renewable Energy Laboratory just completed a study called The

Western Wind and Solar Integration Phase Three Study. NREL worked with GE and did transient stability and frequency response simulations in the Western Connection. So it dropped both units of Palo Verde under very high renewable scenarios, looked at the frequency decay, and also looked at the potential provision of primary, synthetic inertia and primary frequency response from wind turbines, for instance.

You know, you actually do have some stored energy in the rotor that you can suck out for a little bit. And then there's other ways that you can do that with the smart inverters as well, by selective curtailment. So the study found no show-stoppers in those high scenarios. That's publicly available information.

Question 12: Hello, thank you. Probably one of the few people here from an energy storage company. I was telling my neighbor, after the first session, "Whew, I think our business model's still intact after that." And I think our business model is intact because we are utility-facing, we have a ten-year contract with Southern California Edison for 50 megawatts of storage. And I think that helps. That ten-year contract makes it such that we are project-financeable. It's something that the renewable energy industry had to have with PPAs, as well.

We were very thankful that Edison was very open minded in terms of comparing all resources with combustion turbines on an equal footing, and not discounting them to start with. And we were thankful that the PUC pushed that. And as you have all mentioned, we are looking for multiple value streams, especially with the systems that we're putting in.

Speaker 3, I liked your point about looking at the inverter, and what other values an energy storage system can have. My question is to Speaker 3, and you're sort of the utility voice on the panel today. How far along are utilities in valuing that? We are putting in these systems, we're getting the capacity payment from Edison, we're providing some energy bill savings to the customer because of time of use rates and critical peak pricing. But to really make it look more economic, how do we value volt-VAR optimization and power quality, or phase balancing? We would love to provide that to the utility and provide distribution referral. But our issue is that the utilities don't know how to value that and how to price that in the market. With our capacity payment in our contract with Edison, we have clear event parameters--when they can dispatch us, how they can dispatch us, how many times, what they're paying. And we can build a product for that. But on the other side, on these other distribution benefits, it's harder.

Speaker 3: Yes, and I don't have an easy answer for you, because we're still trying to understand that. And, actually, some of the work we're doing with our pilots is really demonstrating that capability to others within Duke Energy--to the planners, to the distribution operators, showing, "Alright, here are some graphs from energy storage showing their response. This is responding in less than six cycles."

And they go, "Oh, I didn't realize it could do that." So a lot of this is through education going on within the utility. Sure, people in my position and others understand this. But the utility industry at large is still trying to get its arms around this.

And then valuing things at a local level is another issue. Putting a value on the voltage performance on this circuit versus another circuit … it's just extremely tough on something that's just integrated within our whole operations. You know, the substation transformer settings and the line regulators and the capacitor settings. There are so many moving parts.

It's going to take a while for us to figure that out. But the good news is that some of the things we're doing with smart inverters, just in our early testing, are really amazing, and are getting people thinking, "Wait a minute, we could do 'X' with this." And so there's no easy answer, but I would say directionally that value is getting more and more understood.

Question 13: Since we've talked about how thermal storage is not sexy, let me go for something even worse. Let's go for downright frumpy. Look at where we're sitting right now. We're sitting in a building, right? Buildings are great storage devices. The thermal inertia in buildings is a tremendous storage device. You don't need to build a battery, you don't need to deploy it, you don't need to build anything new. Just send price signals to that load, and guess what? During that peak, when the duck curve is way down there, I'm sure folks here would be more than willing to either heat in the wintertime or cool in the summertime, especially during the heat of the day in the summertime, I'm sure they'd be willing to run an air conditioning full-out to help you out there. But; yet; we don't seem to have that. If we're talking about storage, that's just a comment and observation.

But let me step back for a second. Why is it we're doing this, other than renewable resources? Maybe there are transmission and distribution benefits to this. But at the end of the day, why are we so fixated on storage when there are other mechanisms available--as I just mentioned, the frumpy storage? There are other mechanisms available to help integrate renewables. Speaker 1, you mentioned it at the outset--the EIM (the Energy Imbalance Market). But what's the purpose of the EIM? California's got these issues, the Pacific Northwest has these issues, you've got a lot of geographic diversity with fossil resources in Wyoming and Montana and Arizona. This makes perfect sense, to balance this all out. There are economies of scope and scale to this.

Why do we need to look at small things when we have this big wide interconnected system in front of us to do exactly that thing, and we're already doing this? And if we do that, to Speaker 2's analysis, it kind of shows that storage is not in the money.

I do have a question, though, for Speaker 2 in particular. Your comment was that you had an opinion that storage is undervalued in current markets, yet your analysis and Speaker 4's analysis shows exactly the opposite. How can you make that statement, given what your analysis shows?

Speaker 2: I think it's consistent. It's undervalued, but it still may not make sense.

Questioner: What's the purpose of storage then? That's my next question. If it's undervalued, tell me why it's undervalued. I think this is to the earlier point, that if it's about climate policy, then put a price on emissions and let the market take care of this. Let's not try to put in another little widget when prices could help us here.

Speaker 2: Prices can help. I'm very skeptical about distributed LMPs, but, you know, I'm looking forward to having my opinion changed. But, again, take the example of a capacitor bank. That costs some amount of money, right? There's no market for capacitor banks on distribution networks. And distributed storage can provide that, in addition to all these other things.

All I'm saying is, storage can do X. Existing markets cover some fraction of those applications. It's that other fraction of the applications that storage can potentially provide that's either undervalued in today's market, or just not valued at all because it happens on the distribution network. So I don't think there's any inconsistency about saying it's undervalued but still probably not in the money for most --

Questioner: May I suggest talking to state regulators, then?

Speaker 4: Can I have a quick comment on that, please? Don't take it wrong if I say storage is not needed. We need a lot of storage. I said gas is three times more important than storage. So right now we have almost 20 times more gas capacity compared to storage. What I was going to say after that is that this ratio should be three. This means you still need to build a lot of storage. OK? We need a lot of storage. But still it's smaller than gas. OK? So if you want to decarbonize the grid, you need a lot of storage.

Question 14: Thank you. I'm perplexed as to why electric vehicles aren't part of the discussion, especially in California, where there are about 130,000, I think, EVs that have been registered in the last five years or so, about half of these in the last year. And the growth trends seem to suggest there's more storage there than any of the scenarios you've talked about. And if not part of the solution, it could be part of the problem, in the sense that Tesla keeps updating its operating characteristics to try to get the fastest charge possible to its vehicles. And so that could essentially exacerbate the problem. So why have we not talked about this?

Speaker 1: That's a great point. And I did try to mention a couple times in my talk today the importance of the carbon goals in the transportation sector, and the question of how do we align the impact that vehicle charging or hydrogen production will have on the electric load, and align it with the renewable output and the duck curve issues? So that needs to be part of the strategy, because if we're serious about getting 50% of the vehicle fleet to zero emissions by 2030, that's a huge impact to the grid. You know, you'd be looking at close to doubling the electric load on the grid with that kind of impact.

Questioner: Isn't that a lot of storage, though? Isn't that where all the storage will be?

Speaker 1: Absolutely. Part of it is just incentivizing the charging when you have the surplus renewable power. And then the other issue is whether the vehicles can actually be used as an integration resource. And there's potential there, and it needs to get looked at. But that's the other piece of it. Because I agree with you. The last thing we want, when you look at the duck curve, is for millions of vehicles to come home at four o'clock at night and plug in, in addition to doing everything else. That's just going to exacerbate our ramping issue in a big way. So it's something we have to get on.

And just to reinforce Speaker 2's comment, the reason we're talking so much about storage is that that was the topic of the panel. But we're looking at the whole gamut of solutions to solve the duck curve integration challenge, and demand response, energy efficiency, all the things you're mentioning are all part of the solutions space. So we completely agree with you on that point.

Moderator: So for electric vehicles, we want to incentivize charging at the right time, which might be noon to two. It really creates problems if you charge at the wrong time. And it could be a moveable source, and so CAISO's been working on a vehicle-to-grid initiative.

Question 15: First a comment on your presentation, Speaker 2. I thought your comment about how the price suppression works from both ends was very interesting. I guess the way I would think about it is that if and when it ever really were in the money, if it were really being developed, it would initially access the energy market to capture the delta there. But over time as that became squeezed, more of the revenues would have to migrate, and would come from the capacity market, which would need to be robust enough to be able to support that. Or if it couldn't compete in the capacity market, then it would fail for good reasons, because other sources were more competitive. But what I would see would be a gradual migration in revenue stream from the energy to the capacity market that would help alleviate the concern that you articulated.

Then I had a couple of quick questions. One, I don't mean to sound provocative, but wouldn't a very simple way to solve the problem with the duck curve be to eliminate the subsidies for net metering for retail customers? I just pose that as a hypothetical question. The other question, which is very straightforward and very serious, is, could somebody just give me some sense of price data, of data points here? What is the current benchmark that you're thinking of as the cost per kilowatt hour of storage? I've heard numbers in the range of $300 or $400 per kilowatt hour. But I really don't know. I'm curious to know what you guys think. And where do you think it can get to, plausibly, over, say, the next five or ten years? What is that curve? Rather than just setting it hypothetically, actually fill in the data for me, or projections, and give me some sense of where that can go. Thank you.

Speaker 3: We've had multiple companies tell us that they'll be under $200 a kilowatt hour by 2020. You know, do you believe them or not? I've had some that say they expect the installed cost to be under $350 or so. I don't know. I'll believe it when I see it. But just to give you an idea, most of the curves built around the electric vehicle market show the plateau coming in around $200 a kilowatt hour, maybe a little bit less.

Questioner: Installed or just for the…?

Speaker 3: Well, for EV that's for the pack. So the installation's a little bit different. So EV batteries tend to be the baseline upon which battery prices are measured. And you start seeing all the estimates from the different agencies and groups generally have that plateauing, coming down to around $200 or maybe $150 to $200. Then once a week there will be somebody that says, "Wait a minute, I'll be able to get to $50," or whatever.

But what we're thinking is, generally speaking, the cell pack itself, I think it's realistic that it'll get to that $200 per kilowatt hour range in the next several years. The question is, alright, what's the adder for putting that into a stationary storage installation? Because you've got more adders than you do, actually, in the vehicle. You know, the transformer requirements, the power electronics, the installation. So the installed cost may be twice that or two and a half times that. We'll see.

I'm definitely trying to hem and haw a little bit here, because I don't want to be quoted exactly, but those are the trends that we're seeing. But we've had people tell us, "We'll sign a PO today for under $200 for the year 2017." And of course it's not installed anywhere today, they're not manufacturing it today. So there's no way I would sign that. But you're starting to hear those kinds of numbers.

Question 16: Two quick observations and a question to close out the panel. Looking at California and picking up on Speaker 2's comments and some of the other earlier comments, there's at least one potential study that suggests that if you just control or influence what happens within the dead band of a degree or two of temperature in thermostats, water heaters, and refrigerators, you would have, throughout the year, about nine gigawatts of storage just in those residential dead-band capacities. And for more than 2,000 hours of the year you'd have more than 20 gigawatts of virtual storage, just in the residential sector, not to mention the fact that probably in the commercial and industrial sectors that virtual storage capacity is large.

And then I look at the distribution side. In addition to smart inverters we know that there are others out there who are working on other kinds of advanced power electronics that at the secondary distribution side not only get you the kinds of benefits of storage, but also can get you voltage equalization, such that you could potentially save 5 to 7% of your generation requirements. And the question that I have is, are we just sort of fixated on storage because it's a technology which looks like other technologies we've done in the past?

And shouldn't our next session at HEPG be on how to take advantage of automation that gives you much more granularity and control and can do a lot of the functions? So that you don't ask the question, "I have a hammer, what are its values?" Instead, you ask the question, "What are we trying to accomplish, and what are all the tools that might potentially be available?" This is particularly important as we're getting more into this Internet of Things, and we're getting more control technologies that can give us finer, more granular control over what's going on in the grid on both sides of the meter

Speaker 3: I think one of the reasons we're fixated on energy storage is because for the last number of decades, the Holy Grail has been low-cost distributed energy storage. So we've all been conditioned for that. And obviously low-cost energy storage is a game-changer. But I agree with you, the power of the solid-state transformers and the secondary power electronics are huge.

And we're doing a lot of work in that area, and it's all about ubiquitous sensors, ubiquitous communications, the ability to control things at a very granular level. There's a lot of potential. I still think energy storage, if it's low cost, can enhance that even more. But the advances in power electronics, and ultimately a solid-state transformer, something like that, can be huge. And you do get a lot of the benefit.

Moderator: I think that your point is also about automation, which depends on communications for management, right? So, I mean, this is what a grid operator does, whether it's a utility's or an ISO's grid management. But one of the things I've always said is, what makes the smart grid smart is communication.

So I think that as we look at communications, and of course the variety of ways in which you have communications, some of which may be owned by the utilities, some which could be not owned by the utility, and varying degrees from the open Internet, there are a variety of issues in which communications comes into play.

And so people in this room need to be thinking about communications policy in a way that the electricity sector hasn't.

So I think we've got some great ideas for our next panel. We had some really terrific information. Let's thank you panelists, and thank you all for coming out. [APPLAUSE]

Session Two.
Distributed Energy Resources and Distribution Systems: Are "DSOs" and More Sophisticated Planning and Network Pricing Needed?

Distributed energy resources (DER) in the marketplace give rise to many issues, including the valuation of the units and pricing of their output. How does DER fit into the overall framework of the distribution system? The impact of a significant DER presence on the system is not only economic, but physical as well. Energy flows on the distribution grid are affected, the amount of investments in distribution upgrades and equipment such as transformers is likely to be heavily driven by the presence, location, and configuration of DER on the system, and the interaction of DER may, from time to time, adversely affect the ability of some DER to export from the premises where they are located. Distribution owning utilities themselves are entering the DER business and are effectively competitors of other DER providers, raising issues associated with vertical market power. Providing incentives for more efficient deployment of DER and accoutrements, providing for the possibility of more efficient alternatives to distribution upgrades, obviating vertical market power issues, and locational real-time prices for distribution, are all issues that policy makers, regulators, and market participants face now or will inevitably have to consider. Will we need independent Distribution System Operators? Should LMP distribution pricing be deployed? Should smart inverters be required of all DER providers? Finally, with or without all of the potential changes to distribution networks, how should planning and the processes for planning distribution networks be carried out to deal with the changing circumstances?

Moderator.
This afternoon we're going to delve into the distribution system. There was a very similar panel about six months ago at a group called the Committee on Regional Electric Power Cooperation that has commissioners and state energy officers from around the west. And I think it was quite eye-opening for some of the folks from states other than California that haven't had to deal with these issues in quite the depth that we have. I think most folks are probably at least generally familiar with what's gone on in New York, where they have really taken this issue on, head-on. Hawaii is another state where, because of their abundant solar and use of oil as a primary generation source, they've really been getting distributed energy faster and in larger volumes.

In California, we're taking a little bit different approach from New York. The California Public Utilities Commission has a proceeding underway called the Distribution Resources Planning Proceeding, and it's looking in much more granular detail than it has in the past at the makeup of the distribution system--what are good locations for distributed resources, what are not so good, what are the values at different locations on the grid?

And then there is also a partner proceeding called Integrated Demand-side Management that is looking at the suite of potential distributed energy resources and how to make them available to meet the needs that are identified in the Distribution Resources Plan, if cost-effective.

So we've got these two prongs that hopefully will meet up at the end, or at least that's the goal.

Speaker 1.
Really what we're talking about, in summary, is the opportunity to leverage distributed energy resources for the operation of the distribution system specifically, which is the focus of this proceeding. But we're also talking about how we should think about distributed energy resources in the broader context of the planning

that goes on in California in terms of the long-term procurement plan and also the transmission planning process.

We're also looking at how we should address the ability of customers to be able to adopt distributed energy resources for their own purposes (what we call "hosting capacity"--or in California we didn't like "hosting," so we called it "integration capacity.")

How do we think about the power system, the distribution grid in particular, as evolving to be able to accommodate greater amounts of distributed resources from a customer standpoint? This is a very critical issue in Hawaii, where some of the interconnections have stopped as a result of not having enough capacity on the distribution system to be able to accommodate them.

And over time, how might we be able to optimize the system as a result of transactions occurring across the distribution and from distribution to transmission?

We need to address the systematic issues and elements about how we plan for distribution and how we think about design build. What does the infrastructure need to look like (both the physical and the information and communication technology layers)? And as part of that--distributed controls and protection schemes and so on--how can distributed energy resources provide services to either augment or be viable alternatives to traditional investment or traditional approaches to managing the system? And how do you manage the operations of such an integrated grid?

Now, diving a little bit into the distribution planning process, in general, what California's heading towards is sort of an evolutionary approach. We would start out with an initial Distribution of Resources plan. The idea being, let's understand how this would work and what methodologies would be employed. Let's test this out. Let's do an analysis for one distribution planning area (DPA), which generally encompasses a few substations and many more circuits underneath that.

And then, once we better understand how this would work, we can then roll this out system-wide on an ongoing basis.

In the near term, there's also recognition that we need to do a hosting capacity analysis, and this is something that's been identified that would be an annual process to basically look at how we should think about the ability of the distribution system to accommodate distributed resources. And as part of that analysis, we would modify some existing visual information that's provided in California's Renewable Auction Mechanism maps to essentially reflect where there may be areas of constraint, in terms of being able to connect DER, or those areas that actually have sufficient capacity to accommodate DER. And so that's part of an analysis that's been identified that would be an annual ongoing analysis.

Now, switching gears, the other piece that we've been focused on in California was looking at locational net value of distributed energy resources. This relates to some of the questions that came out of the last panel. What's the value of deferred capital? What's the value of voltage management at distribution? What's the value of reactive power of our control and distribution? What's the value of certain reliability capabilities or resiliency at distribution?

So there's a whole set of values that are ascribed specifically to distribution. And the analysis that we're talking about combines both the distribution and linkage to the analysis that would be done at transmission and the long-term procurement plan for the bulk power system. Those are generally system-wide values. But there may be elements of those that are locational in nature as may be related to particular, you know, local capacity constraints and the like, that may exist.

But a lot of the focus is on the distribution side and articulating those values, and then starting to define what the services are that may be related to it. The analysis itself would then basically look at the sub-station level to start with. Ultimately this may go down to an individual feeder level, depending on what data are available. And the number of values that would be used in this process would expand over time.

The Commission identified a set of roughly eight values in its initial guidance. It's expected over time that perhaps we may get to 20 or more values that were identified in the "More Than Smart" group, some of which we don't have the tools to do yet today. It may take us several years to develop the analytical methods.

We may not have exactly all the data, and we may not have methods that have been defined and agreed upon in the state to actually do the analysis, as well. So this is part of what we're working through, including also how these processes need to interact with each other, given that some of this DRP analysis needs to link to the procurement and transmission planning as well, and vice-versa.

The other thing that we started to look at more specifically, as I touched on is the question of what we want the grid to be, and in particular what the distribution grid should be. And we had this discussion partly informed by the Rocky Mountain Institute's grid defection paper.

And we're on a current path, which is kind of the smart grid path, and do we want to enhance that and think more of the grid as a potential platform, not unlike what New York's thinking about? And obviously we've got discussions going on in the state around potential convergence with things like water and other potential networks. So should we be heading that way? Or do we say, "Look, this is all going to be done on a distributed resources basis. We don't need to make any investment in the grid, and we should just think of the grid as a backup." In that case, we would kind of revisit where we were in the 90s, thinking that distribution really was irrelevant. A lot of investment in distribution sort of tailed off in the 90s. And I think that, overwhelmingly, people saw that as not the way to go. And really what we ought to be thinking about is capturing the value potential on the distribution, not as a one-way street, but rather as something that's much more multi-directional, enabling much more network-type value and potentially convergent value as we think about these possibilities.

As we look to a world of the Internet of Things, how might we think about that as increasing value, both for the customer, those providing services, and also for the system as a whole?

Now, the other thing that we started to talk a little bit about last summer, and we will be talking more about it as part of the "More Than Smart" project is how we need to think differently about operating the distribution system a little bit more in line with how the bulk power system operates.

And what I mean by that is, when we start to procure services from distributed energy resources, there will be some scheduling coordination functions needed. To make the value proposition you have to have more than one value stream to make many of these work.

And so therefore people are going to be looking to optimize both the bulk power system opportunities and also these new emergent distribution opportunities that are going to happen in California and New York, for example. And so therefore there needs to be some coordination between the distribution operator and the transmission operator, and this is a new relationship.

This doesn't exist today in the way that systems have been operated. This also means that we need to think about how information is passed along. What visibility is needed in terms of one versus the other? Who actually does the dispatch? How do you coordinate the dispatch? This is just some fundamental stuff. But it does start to cause us to think about what the model should be as we move forward.

So, how do we think about system operations evolving? One model ("Model A") is really sort of the total TSO (transmission system operator) approach. That is, the transmission operator essentially manages everything down to the individual device, and the DSO (distribution system operator) is really just dealing with kind of the normal sort of daily routing and switching and also outage restoration, those kinds of things.

In Model C, the DSO largely does everything, including physical coordination but also dispatch of all the resources. There would be a single interface to the transmission operator.

And the one in between, "Model B," assumes that you have maybe multiple entities, aggregators, plus the DSO interfacing with the transmission operator, but not millions of end devices, or thousands of end customers, or individuals interfacing. So there's some level of aggregation that's happening, and there's this coordination function.

You've got to start with asking what the objective is. What are the criteria you want the system to achieve? And then the rest of this can kind of flow.

This has been an overarching theme in what we've been looking at, both in terms of how we think about the systematic changes that have to occur (taking the systems engineering approach) and similarly as we think about how the services and the various market structures might apply (more of this mechanism design kind of approach). We start with customer, environmental, and grid values, and then we define specific services for each of those values. And we look very specifically at the market structures and other requirements that are necessary to satisfy that. We haven't done this at the distribution level before. And we're collaborating. And ultimately that analysis will help define what the market structures might be, whether it's a tariff-based pricing mechanism, whether it's a market-based pricing mechanism, where you're talking about program design for energy efficiency or demand response, or where you're talking about a procurement of some sort. So all of those may be at play. But they need to align with what you're trying to accomplish from a service standpoint.

In the near term, I think there's an expectation that we're probably looking at things like procurements for distribution, not unlike in some way the initial RFO that Edison did for transmission purposes that was mentioned earlier from the storage perspective. And this will involve bilateral contracts that call out specific commercial performance requirements and other elements -- liability issues and so on, which is new for a lot of people to think about at distribution.

We are talking about how to think about tariff designs and the energy efficiency program incentives, and how do we think about that in the context of timing, because those take a longer time. You can actually do a distributed energy resource procurement faster than you may be able to change rates and program design. So there is this issue of, identifying when you have the defined need--avoiding a substation, or avoiding a transformer, or something else--and when you may be able to see one of these resources actually being able to achieve it. So this is something that we're having discussions on, and that we're looking to interrelate with some of the other proceedings that are going on around these issues in California. So we're trying to cross-pollinate some of these ideas across some of these proceedings as we think differently about how all this might come together.

The other thing coming out of the discussions in California in particular is that it's not really clear how distribution marginal pricing (DMP) plays in California in the near-term. And that's on two levels. One issue is that the way the DMP has been described by some, it's largely a construct of a variety of values with some approximations to get to a single value which really starts to distort the actual value. And when you're trying to convert things from energy into a distribution-level capacity value or deferred capital-type value and so on, it starts to get pretty kludgy in terms of what exactly you are doing and what you are trying to achieve with it. And the other issue is, from an energy standpoint, most all of what we're talking about is not energy. And it's not clear in California yet that there's any price difference between energy at the distribution and at the LMP levels. And until you do some sort of equivalent of a constraint analysis on distribution, you can't yet start to think about how you might want to think differently about the value of energy somewhere in that system. We haven't gotten there yet.

The other thing that we've talked a bit about is whether spot markets really align the parties' interests when you're talking about capital investment. For example, would a battery storage company or any other distributed energy resource that's putting a fair amount of capital in really want to get compensated on a spot-market basis, given the uncertainty? Because that may not be a bankable solution for them.

Likewise, does the utility really want to not know, other than in the day ahead or intra-day, whether that resource is going to respond or not when they haven't actually built the substation or put the transformer in? Because there isn't any other alternative other than shedding load. There isn't, like, a generator on distribution you've got to ramp up at this stage that's going to offset that need. So this is another thing we're looking at. It's not that it's off the table, it's just that in the near term it's not clear that we're there yet.

The other thing is, we're talking about fairly illiquid markets, right? These are not deep markets on distribution. It's pretty finite in terms of the number of resources, and particularly in the early stage. And it may be that in the later stage, past 2020, we start to be able to look at this a little bit more specifically. So thank you.

Question: I don't know if you read the latest New York Order, but they did include some language about ownership. And I wondered if you've looked at that issue at all? And we can talk more about it later, I'm just curious as to who owns a distributed energy resource facility. Can the utility own them or not? What are the lines there?

Speaker 1: For the purpose of what we've been talking about in the "More Than Smart" project, that's out of scope. There are other proceedings going on in California touching on aspects of that. So, no, we haven't been looking at that, but others may be able to comment on other conversations and proceedings touching on that.

Question: You used the term "system engineering" a couple of times. Are you going to compare the cost of these different approaches?

Speaker 1: The thought is that what the utilities are going to do in the plans is identify the need. And the market will come back with what the answer is. So this is technology neutral. So the thinking is that the utilities will not be trying to figure out the optimal mix of a storage versus all these various combinations that might be in play. Rather, the utilities can let the market figure out what that solution is and come back through some process to signal what it can do, both in terms of meeting the performance requirements and so on.

There's also an underlying assumption that we're still using a best-fit, least-cost approach for distribution with many of these cost elements, whether it's avoided cost, capital, or operating expense. The utility will develop what they see as their traditional (or enhanced traditional I would say, because technologies continue to evolve) technologies. So it may have been an oil-filled transformer today, but in 10 years it may be a power electronics-based solid state transformer. So that technology's changing. But that would then be the reference point. And then you're looking at these other alternatives. So that would set, effectively the price cap, and everything else, if it comes in lower than that, then you would consider those alternatives. And that would be what you need to do to integrate those technologies. So if there's something uniquely different between one technology and another, from the grid side, that that would be evaluated.

Speaker 2.

Good afternoon, ladies and gentlemen. I think because I've been working with utilities for so long, I believe in the belt-and-suspenders approach. So even though it was mentioned this morning that no one can attribute anything I that I say today to myself, just so I have a job when I get home I should say that these are my opinions, and don't necessarily reflect my employer's stance on these items. Belt and suspenders, right?

I'm really just going to talk about three things. The first is the locational sensitivity of distribution interconnection, specifically. In general, the takeaway that I hope to convince you of is that it's like real estate. All that matters is location, location, location. Right?

Transmission is also an issue, and I'll just spend one slide on that today, showing distributed PV's impact on transmission. And although some distribution engineers maybe would argue with me, the truth is that reliability from the distribution system stems from the reliability of the transmission system. The two systems are connected, right? If transmission goes down, you're in trouble on distribution. So I'll talk about that just briefly.

And then, as you can probably tell from my bullet point here, I'm a proponent of using "smart" inverters, or whatever we want to call them, inverters that are more advanced than the ones we've been using. And I'll talk specifically about what my opinion is as far as what we should be using them for.

This next slide shows a project being done jointly by NREL, EPRI, and Sandia National

Labs, looking at alternatives for California Rule 21, basically the interconnection standard for California. The study is looking at this from the technical perspective. There is no actual policy or any of that sort of thing in this study. But the study looks at the locational benefits of where you interconnect PV, both on a small scale and large scale. Small scale meaning it represents what look like net energy metering-type systems, maybe three to five megawatts on a rooftop, that type of thing. And large scale meaning, say, one megawatt PV-type systems, so maybe more like commercial scale or small warehouse districts, that sort of thing.

If you take a look at this graph, what its really showing is that if you don't know where your PV's going to go, and a distribution utility usually doesn't, or at least don't have a great idea of where this goes, one thing you can do is run a Monte Carlo analysis where you basically just randomly place it anywhere, and you do it, say, 5,000 times, which is what this figure shows. And then you basically grade those interconnections. You do an automated PV interconnections study, which is really what's being done here. And for a particular circuit it shows the highest voltage at any point on the circuit.

And if we apply overly-simplistic ANSI voltage limits, we can see that there's basically a green region. It's a place where, given the amount of PV that you install, in this case up to about half a megawatt, it doesn't matter where you put it. You can put it pretty much anywhere you want. Any sort of deployment is going to be OK. It's going to result in the voltage profile to circuit being less than the ANSI range. In the yellow slice of the slide is really where the interesting parts happen. This is where some deployments are perfectly fine and some are not.

So if you can define the instances that fall in the yellow section but are still below the ANSI limit, you can basically deploy more PV without actually doing any circuit upgrades. I should mention one important thing that I forgot to mention, which is that this analysis is for the purpose of fast-track screening under Rule 21. So we're not saying this is the most PV that can be put on the system. This is the most that can be put on without review, or that's what we're shooting for anyway. Basically, "fast-track," meaning that there's no supplemental study, there's really no study done whatsoever.

One nice thing that's coming out of this project is a lot of data, because we had to do all these automated PV interconnection studies, literally millions and millions of them, to figure out what the sensitivity of different PV locations was. And one screen that makes sense, I guess, to a lot of distribution engineers, and it probably makes sense to you, is that if you're close to the sub-station, you tend to have less impact on your distribution circuit. That's not too surprising.

So here is a graph showing, for two different circuits, both a 4KV circuit and a 12KV circuit (of course, every circuit's a little different, but these are pretty good representative cases for those voltage classes…I should mention, these are from California IOUs. In general, the whole study's based on data from them) what you can see is that if you restrict the integration of PV to the first 25% of the circuit distance, so if you have a four-mile circuit you can only integrate PV in the first mile, you can about double or maybe even triple the amount of PV that you can integrate on the circuit before you hit a distribution-level impact. Right?

So this is getting towards that distribution locational sensitivity to those impacts. And this study's looking at a lot of different things other than distance, but what in reality you're trying to use here is distance as a proxy for impedance. Everybody knows that, and that's of course what tells what your voltage rise or drop will be on the distribution circuit.

One thing I'll point out is that the lower bar on this chart is the base case, which is basically how net energy metering is working today, or just PV interconnection in general under the fast track procedure. The reason I say it's net energy metering is because these are small systems, say three to five megawatt type scale systems. And you can see that these two circuits, the green circuit and the blue circuit, are severely limited in the amount of PV they can adopt, as opposed to implementing even, say, this simple screen.

So I'm not saying this screen is a good idea. But from a technical standpoint, there's justification for limiting that. You immediately run into these problems where all of a sudden if you want to install PV you have to figure out where you are on the circuit, and you may be locked in or out of a fast track screen, anyway, depending on where you are. So it's certainly not egalitarian. But from a technical standpoint, this is where things are pointing.

If we look at large systems, we see something very similar. This chart is actually for voltage regulator movement. So when you have a PV system out there (say one megawatt, which is relatively big), the variability of the resources (i.e. clouds coming over) makes it so the voltage changes at your point of common coupling over time. And if you have a voltage regulator on the circuit (this one that was modeled has two), you can see an increase in the amount of voltage regulator operation settings that you have. Again, not very surprising.

But what this analysis is doing is quantifying the locational impact. So, again, if you're close to the substation, sure enough, things look pretty good. I should mention the three different colors are just for the three different phases, because it is an unbalanced distribution system, so it makes a difference. But you can see that if you put your PV system, even though it's only one megawatt, out quite a ways, you can have maybe up to an eight-fold increase in the voltage regulator tap changes.

This is a big deal, because there are costs associated with that. Either your maintenance schedule has to increase, or even your replacement schedule has to increase. And currently we have a really hard time monetizing those. But this, again, gets to the locational benefits of where you interconnect things on the distribution circuit.

One thing we've had to do on this project is basically set up these automatic PV integration studies. And what that means is, we have to say how much impact is too much, within those studies. Because I don't want to grade each one myself, I need the computer to do it. And in reality, that's how PV interconnections are being done today as well, although sometimes they actually have an engineer behind also making these decisions.

But the truth is, every PV system, obviously, has an impact. We're pretty good at modeling, we're pretty good at measuring. I can guarantee that I can tell you what the impact of anything is, even if it's really small, at least from a modeling standpoint. So the question is, who decides how much impact on the distribution system is too much? There are quite a few guidelines that have been developed, but the truth is there's a big conflict between what a utility wants and what the PV developer wants, for instance. So who brokers that deal between those two?

I'm oftentimes asked about PV curtailment on distribution. We actually don't really have this in the United States very often, but I sit on an international panel with a lot of Europeans, and they actually talk a lot about PV curtailment. One of the stories that I've heard lately really has to do with the Swiss farmer that put a 20 kilowatt system on his farm, kind of at the end of the distribution circuit. Sure enough, it raised the voltage enough that it kicked his inverters offline. He calls up the utility angry, because of course he's not making any money off of his investment, right? It's not that his voltage is too high. He doesn't care about the power quality aspects. He wants his PV inverters back on making money. So in reality, in the United States, I think the utilities have done a fantastic job of limiting PV interconnection to places where we really don't have those sorts of problems.

But in general, PV curtailment, especially in a world where we have more DG (I really mean PV DG in this case) than the circuits can support, is an issue. The PV curtailment's really based on simply the voltage diversity that you happen to see on the circuit. So again, it becomes highly locationally dependent. You'll probably either be never curtailed or curtailed all the time, right? So it means you have a lot of winners and losers, and that's not balanced out very well.

Net energy metering systems obviously are getting a free pass from a technical perspective in a lot of ways. It doesn't really matter if you have a lot of small systems or large systems. And one of my fears is, if we end up with a 50.1 hertz-like retrofit, like Germany has seen, the number of systems that you have to go change their operation, obviously, is a big deal. So if we end up with sort of an incentive to have a whole bunch of small systems instead of larger systems on distribution, which might be more economically feasible, we'll actually have a bigger headache in that case.

One thing that I want to bring up is that when we talk about equipment deferral and kind of the stacked value of DG-based reactive power, I always have a little bit of a hard time with this, because in general, with these interconnection agreements, there's never a requirement that the distributed PV system have a certain amount of uptime. Right?

So when a utility puts out a capacitor bank, for instance, to support voltage, halfway down the line, they have a reasonable expectation that it has certain reliability characteristics. And it's their job to know what those are, and basically manage whether it's operating or not. And they might actually have overlaying assets where one can fail but another one near on the circuit still works, that sort of thing.

But in general with distributed PV, other than the fact that you have sort of a disaggregated impact of reliability, meaning that not everybody's PV system would be off at the same time, I imagine they're doing voltage regulation services, there is really no guarantee written into those interconnection requests that they will actually be there, right? So of course the utility has to manage that in some way. So these equipment deferral arguments, to me, become pretty shaky.

Reactive power distribution, I think, is a fantastic thing for managing local impacts. But in general, the reason we use it is because it's about three to four times more sensitive to locational impact voltage metrics. What I mean is, basically, a voltage rise caused by one watt, if you say sink one VAR, you get about three times the voltage impact. That's why we use it.

So when we start talking about using DG-based items, you know, PV inverters to do reactive power support for, say, transmission, and that sort of thing, I sort of shake my head, because you're going to run out of headroom on your voltage limits on your distribution circuit long before you're actually able to export any reasonable amount of value to the transmission system.

I mentioned that this is really about distributed PV's impact on the transmission system. And this was mentioned earlier today, the study that this came out of is the Western Wind and Solar Integration Study Phase Three. And one thing that they did is they looked at really a bookend impact for how distributed PV would impact a system frequency event, for instance.

So this analysis compares the frequency nadir for tripping two Palo Verde units in the Western Interconnect with the frequency nadir for tripping an equivalent amount of DG. If you trip the same amount of power, but it's distributed generation (so this is 2.7 gigawatts, roughly), you get almost the same frequency nadir. So from a technical standpoint, I don't think anybody was too surprised about this.

So everybody says, "Oh, this is nonsense, because you're never going to get a frequency variation across the whole system that makes these trip." That's absolutely true. But one thing that it leads to, I think, is that if we really start seeing distributed PV, or maybe DG more generally, really grow in ways that we think it will, we're going to see more than 2.7 gigawatts of DG in areas that can suffer from a fault-induced delayed voltage recovery incident.

What this means is that a transmission fault that's relatively near in can pull the voltage down on the whole distribution system, at least temporarily, enough to actually cause more than 2.7 gigawatts of PV to trip offline.

Even today, I would venture to guess that the largest single contingency that's possible on the Western Interconnect is actually the loss of the distributed DG in certain areas where we have high concentrations, like Southern California or something like that. And obviously it's only going to get worse. 2.7 gigawatts isn't much when we're talking about 12 gigawatts from Governor Brown's initiative. The Department of Energy's talking about hundreds of gigawatts. And a lot of that, of course, is going to end up on the distribution side as well.

I'm a big proponent of smart inverters. I think they should be used. But the question is, for what? I think as a minimum they should be used to support the bulk system. As I mentioned before, if there is a close-in fault, the distributed generation has to hold through so it doesn't actually trip offline, causing an even larger event on the transmission system. Again, this is just to support transmission reliability.

And then the second use for smart inverters is very simply to mitigate PV's own impact on the distribution system. What is shown here is a graph of, the top graph is the voltage of the point of common coupling of a five megawatt PV system that's on distribution. The bottom graph is the amount of reactive power actually being absorbed at that same PV system. And this was a field demonstration done around Thanksgiving last year. And one of those graphs shows is when the system is operating as usual with a power factor of one. And you can see, in the middle of the day, sure enough, the voltage goes up, because real power's being exported all the way through the circuit to the transmission system. Because it's a light-loaded circuit.

The other graph shows the implementation of an advanced or smart inverter. And this is operating with a fixed power factor, absorbing power factor. And you can see, sure enough, that the reactive power goes up and down as the sun is occluded by clouds and that sort of thing. Bu,t amazingly, the point of common coupling voltage is almost nearly flat, or at least much flatter than it was previous days.

So in this way a smart inverter is a great way to reduce the impact that the PV system is having on the distribution circuit and all the customers that are connected, as well as potentially allowing more PV to be integrated on that same circuit without causing impacts.

One of the things that kind of gets me right now is how everybody's talking about all the different functions that can be used. I think that's great, and we have a really long laundry list of those items. The real question in my mind is, what settings should be used? What are common settings? We're not going to be able to go through a very complex study process for every PV interconnection request that comes in. So we need to come up with more standard settings that are used more broadly.

And the last thing I'll mention is that when you talk about mitigating PV impacts in a way that requires energy storage, for instance regulating down-ramps or something like that, I always get a little nervous on distribution, especially when we're talking about small-scale systems. Very few people are talking about this. But I think when you necessitate energy storage as part of, say, a mitigation solution, you're really almost prodding people into defecting from the grid. Right?

Because you're basically handing them a requirement to build their own power system, you know, in a box. They buy a battery, they buy a PV system. If they throw a little bit more money in there, get a little bit bigger battery, a little bit bigger PV system, they pretty much can run their own system if they so choose. So to me that's an area that I think is a little dangerous. So thank you for your attention.

Speaker 3.

The life of a big idea in the electrical utility sector is seven years, judging from the life of the terms "intelligent grid," "smart grid," and "integrated grid." The only piece that hangs on in here is "grid."

I am going to talk about four questions: Do we need an Independent Distribution System Operator? Should LMP pricing be employed? Should smart inverters be required? And what planning and operational processes are needed?

This is a map of solar penetration, probably as of 2014. California, New Mexico, the real bright ones are slightly over 4%. The oranges are down to 1%. And the other colors are 0%. So it's not striking. You know, you hear the sky is falling with the solar thing, and you look at the map and you say, "Well, it's going to grow all out."

But somewhere in the course of this analysis, my management got this notion and they said, "Well, let's see. You've got this solar, and it's getting a feed-in rate. It doesn't use electricity, it gets a feed-in rate, it's not paying for the distribution cost. If it's not paying for the distribution cost, somebody else must pay for it. So if somebody else pays for it, their rate goes up. And if it goes on, that will make more people go, and you get this insidious ball rolling." And they said, "Gee, could you calculate what the last guy in the system would pay?"

So I did, for a utility with a million customers, and I said, "Well, he'd be paying about $250 million a year in fixed distribution costs." And I pointed out that somewhere south of $1,000 a month everybody would be gone. But this is part of the notion that motivates the hysteria.

And there is all the talk of Hawaii, where there is substantial growth of rooftop PV. And then why? Well, because electricity is extraordinarily expensive, because they rely on fuel. Everything is imported except their natural winds. And so in Hawaii, even now, 25 to 30% of demand could be supplied by solar sometime during the day.

Everybody knows the German story. This has been a boon for Germany, because everybody goes to Germany and comes back convinced. But it's raised this sort of hysteria about, all this is coming, what are we paying customers for, what is the reason for doing this?

This chart assess PV retail rate parity across US states. So if you start out on the left, that's Hawaii. The blue bar is the levelized cost of electricity. But we estimate 15 year levelized cost of buying from HECO or one of the island providers. And the red is levelized cost of PV, as near as we can figure out from gathering data. That's the only state where the LCOE for supplying your own energy is lower than the levelized retail electricity rate.

As you go across, notice in every other state red is bigger than blue. And I sort of stacked them in order about, of how much the self-owned PV LCOE exceeds the retail LCOE. There's a big margin. So who's buying these things? There's not a lot of data around, but one of the things I've read recently was that the average customer who's buying rooftop PV makes $150,000 a year and is 58 years old.

That was in 2013. Now they've moved to leasing, and 85% of new systems are no longer sales, they're leases. And it's gone down to an average income of $125,000, and the average age is 56 or 57. So when you look at this, you go, who's buying these things? They're people with a very low discount rate. They essentially have attached some other value to this. They want to be free, they want to get away. But there's still a substantial gap.

But nonetheless, this has raised the issue properly in the industry, because it's not just about solar. We've got combined heat and power, demand response, home energy management, electric vehicles…I could go on and go on. And what's common in all of these is that these are additions to supply, real or virtual, to an electric system that aren't coming from the utility, they're coming from people.

So you can dismiss the solar, or maybe you don't think a home energy management system is going to work. And you also can say the rabble was not at the gate because you put earplugs in. But essentially what's happened is you've seen the confluence of technology, sort of people wanting to take back the night, I guess, and they can do it. And there are lots of opportunities on the board. So we're going to see a lot of this. You could say, "I don't have solar in my state." Well, what about demand response? What about rooftops on a large scale, or combined heat and power? All of us are going to have to deal with these things in the system.

So that's what's motivated EPRI to develop what EPRI calls the integrated grid. I want to just take you through what our thinking is, and why we think this framework important.

Storage is a big element, a big player in this--or not, depending upon factors that are out of the control of a utility. But you still have to deal with them. So if you're going to do strategic planning you need to say, these are scenarios. So if you had to do a strategic analysis, you need to drive by scenarios.

But here's what we've tried to do. We put some principles in place. So, number one, it's bottom-up analyses. What you'll see in the arguments is, people come in and say, "You're charging 14 cents a kilowatt hour for electricity. And I know there's dozens and dozens of value streams in there. So I want you to unpack them. I'm going to hack into those because there's value and you're keeping it from me, right? I deserve it."

And they spend a lot of time arguing about what's fixed cost, what's variable cost, how much of the cost of distribution you should pay, but maybe I should pay it because I'm putting power into the system… And that's a fool's errand, because rights are the last thing that happened, not the first. The way we run a system is, we do a study, we look at demand, we look at how to meet it, we do a security constrained dispatch, we do capacity expansion models, we get a revenue requirement for the utility, you know, a municipal utility, it could be a cooperative.

And then you've got the revenue requirement out of the rates department, and those bums (my life is spent as a rate bum) figure the simplest rate they can, and you divide dollars by kilowatt hours. So that rate isn't unpackable. There's no trace at that point because all these complications and interactions in the system, the physical impacts of how we put a system together and how a different system's put together.

So let's reverse this. Let's take a look at an integrated rate, let's look at how to integrate DER, distributed energy resources, from the bottom-up. Just like we were planning a system where they're at the margin. And we've got scenarios to do it.

The second principle is accommodation. From EPRI's point of view, we're not here to tell you can or can't do it, we'll simply tell you all the impacts, all the positive impacts and all the benefits all the way through the system, lay them all out, stack them up on a table, and you can argue later about whether you think environmental impacts should be in or not. But essentially the idea is, to make it more of fact based.

So we count all the benefits that count once. You see people with lists of the value of, fill-in-the-blank--solar, storage… My favorite is "customer satisfaction." What's the value of customer satisfaction?

And there's the problem of double counting. People say, "OK, there's an avoided cost." So let's take the avoided capacity cost. And then the customer saves, because he or she doesn't pay. So people say, "Let's take the customer bill reduction, and the avoided capacity cost, and add them together." Well, no, wait a minute, I already counted those costs once from the utility point of view. I can't count them again. You can consider both, because it has something to do with the distribution of benefits or voters or whatever you want. But you can't add them together. So another thing we're trying to do is make sure that you do real accounting, not like you do your taxes. But honest accounting.

So the system we put together looks like this. We talk about core assumptions. We look at the distribution system, we look at the bulk power system, we look at all the impacts, and we float them off to the right.

If I look at the distribution system, there's all sorts of boxes and models within it. There's distribution network models going in here. There's distribution capacity models going on. But, essentially you're doing three things. The first is looking at hosting capacity (for example, potential solar rooftops). The second is energy analysis, which is about losses and whether there is a change in losses. Of course there's value there. If you reduce losses, then there's a savings in the system. But in some cases that's not true. Losses can actually go up when you put PV solar at a certain place on the system. So you better make sure you understand what drives those things. And then the third element is capacity analysis. How big is the wire? Is the wire big enough, or too big? And if I have to make the wire bigger, I have to make the circuit bigger.

And remember, in all of this, what's happened is that we built a system like US Air runs. So you go to a hub like Chicago and you get a US Air flight, and they fly you to a smaller airport and put you in a smaller plane. And then you go to another airport, and they put you on a regional biplane that's also used for crop-dusting. And so that's a system where you get used to it.

But what happens now is, when you have people way out on the end of distribution circuits generating electricity, you reverse the flow. Suddenly electricity is going backwards through the system. But as it works its way backwards through the system, it hits protection systems. And there are things on here that are meant to disconnect the line under circuits so people can come and work on it.

Well, these things can get confused when you've got power going the wrong way. You've changed the voltage on the system, which also changes the way all these mechanical or electronic system devices work--tap changers and things that have been mentioned earlier. So there's a whole complexity thing that can happen, with goods and bads. And what we're trying to do is trace through all of those.

The hosting capacity analysis I'm showing you is, we actually look at individual circuits. So this is a circuit map. We model every house, business, every meter on there. So this is detailed modeling now, at this level. And in hosting capacity we say "probable issues," "possible issues," or "no issues." We look at an individual circuit and sort it that way.

So generally you have fewer problems closer to the substation, and more problems farther from the substation. But it's also a function not only of where the PV is located, but of the load around the PV on the system, and, believe it or not, the amount of PV on a neighboring system that connects to the same substation. There are all these complexities that you have to deal with.

So what I've got here is a chart showing a set of circuits for a utility, I can't remember which one. What we're doing is saying, we add these loads to the circuit (rooftop PV in this case. It could be electric cars. It could be storage systems. It could be any kind of electric device.
It could be demand response, whatever you want). And essentially what we're looking at is where you run into a problem. So you run into one problem, it's protection of voltage or thermal. And when we hit a problem, we fix it and then move on. And keep going until we hit another problem, and fix it for every circuit.

And if you look down at the bottom here, there are essentially two circuits that have a five MVA megawatt, let's say, capacity, for connected PV. And we load them up with 100% solar and never hit any of those problems. But up here on these other circuits, way down at less than one megawatt, one fifth of the carrying capacity of that circuit, we've already hit them. So you get these sort of heat maps, but now we're looking at a distribution circuit, not a cross-circuit.

Everybody knows about the bulk power system. Essentially, we're looking at resource adequacy and operational flexibility. You talk about the need for more flexibility because of solar. Well, we need to model all that. We include operational simulation, because we want to look at all the impacts and actual operation and actual dispatch that are going to result from having this reverse flow of power and everything that goes with it. And we include in the bulk system analysis transmission performance and transmission capacity.

So, again, you're talking about heavy modeling. These distribution modeling systems turn the lights out on most of the East Coast when we run them. They're gigantic models to run an AC distribution code, network code, for every single node on the system with all these devices operating on it.

So the complete analysis goes through the distribution system and the bulk power system. You may have to loop there a couple times, because there are interactions between the two. For example, I didn't have smart inverters. What if I put smart inverters down there? Do I get any upstream value? Am I solving a problem up here? And then there's the good old benefit/cost analysis, which everybody loves.

And basically what we find is, if you go through the system systematically, mutually exclusive and exhaustively, this is about what you come out with. Everything sort of fits in here. We measure impact, some change in the system, and then we assign a cost to that, or a benefit to that. And if you have to spend money to upgrade the system to accommodate solar, that's a cost. But if that solar causes, reduces the amount of generation, or reduces losses on the system, those are benefits. And you can look to avoided costs. Actually, in the complicated models that we're dreaming of, that would come out automatically. A shortcut is the use of avoided costs for now. So you get all these systems. And, you know, there's a smart inverter. Some of these things are in both columns. So the net on the smart inverter really depends on what it's used for and how it's used in the system.

So what do we end up with? You get a utility cost function. These are the impacts to the utility as a business, the cost. You have also got customer things going on. The customer had to buy the system. I can do a separate customer accounting. Customers may get improved reliability, improved resiliency. The system may be more resilient either for you or for everybody because there's storage, for example, on the system. If I take all those into account, I can calculate customer benefits. And I can also do the social impacts. And this makes most people shudder when you talk about this. But what's important is that if you can measure it, and you believe there's a cost, assign it. If not, then take it out of the equation. Because you can't add money to good will or feeling good about the environment.

So we think it's up to jurisdictions to decide, do you actually want to try to monetize those societal impacts? Or do you have a way to monetize them? Like, say, a RGGI market like in the Northeast? I mean, you put them all together, you get what economists think of as net social benefits. And the idea here is that, you may want to take these things into account and you may not. But we talked this morning about storage. And if you approach it as, it's just a good idea, or it's a noble idea, or we should have some foresight if we're going to do it, then that cost is not a cost that's dollars.

So the first two layers of the analysis, the distribution system impacts and the bulk power system impacts, and the effect that it has on the utility, or the effects it has on the market. That's the world according to the integrated grid, which is good for six more years, so buy now.

Question: Is this bottom-up analysis conducted using estimated models, or sort of snapshots? Or is there enough data to really do a true bottom-up analysis that's comprehensive in a lot of these systems?

Speaker 3: You can do the best of it at the distribution system. Distribution models are getting very robust, and you can actually account for everything on the system, every load. So we specify all the loads (for example, there's a big business fertilizer plant hooked next to the trailer park), and all those difference of loads which affect voltage and the size of the load all could be modeled. They're just big.

The real shortcoming is trying to plan at the transmission grid level. Because we have models but we don't have the quality and the kinds of models you need to handle all this information, like this reverse flow of electricity, particularly if you're trying a flexible product. How much flexible product do you need, and where in the solar penetration curve or an option curve or a storage curve is that happening?

Question: Quick question for you on your benefits and cost slide. At the bottom you have cyber-security as being a benefit as opposed to a cost, which is surprising. Can you just talk about that a little bit?

Speaker 3: Well, if you set aside security standards, it moves up into the utility products function because it's a requirement, just like reliability. People say, "Well, there's more exposure to cyber security issues. For example, you've got all these devices out there talking to one another, running up and down the line through different lines." So is it a cost or is it benefit? And I don't think we've come to a conclusion yet. But that's one of those things that, unless it's priced, unless there's a standard put in place, then it's sort of sitting out amorphous, unpriced, until somebody can put a dollar on it.

Speaker 4.
The good thing about being the last person is, everybody else has talked about much of what you were going to talk about. So I'm going to try to condense this down a bit, but look at it from a utility perspective. Because a lot of what you've been hearing from each of the different speakers--issues on policy, technology, reliability, markets, contracting, customer satisfaction issues, cost recovery, system average rate matters, then the cost by individual customer, customer class, and even within customers in those classes. All of those issues relate, they all come home to roost with the utility that puts those together.

I would like to talk about a few things that relate to the morning's discussion on energy storage, which is one really big piece of a distributed energy resource, but by no means the only one. We talked a lot about PV here, particularly customer-installed photovoltaics.

We have talked some about demand response, energy efficiency, and we've had a little bit of discussion about electric vehicles and the influence that they might have. All of these are distributed energy resources that get put in the new markets through a distributed resources plan. And we can talk a little bit about that, because there is a distribution resources planning proceeding before the California Commission. It is a quasi-legislative proceeding. So we can actually talk about it, although I don't intend to get into anything deeply.

I think it's important to note that in California we are looking rapidly towards going beyond 33% RPS. Legislation pending, the Governor's indicated a desire. We fully anticipate that we will, post-2020, and frankly probably in many instances before 2020, get well beyond 33% as we look to a more robust renewable portfolio in the state. There are ongoing commission proceedings on integrated demand-side management.

How do I put together all of these different pieces of energy efficiency and demand response in a way that makes better sense to the grid and to our customers and provides better value? We talked a lot earlier today and during these proceedings, about net metering. And there's a proceeding there on a successor tariff that deals with the issue of some of the cost-shifts that come around that.

Certainly there are some influences of that that come about as we deal with more of a proliferation of distributed energy resources on the grid.

We talked a lot about energy storage this morning. I won't repeat that now. I will only touch on the fact it is a big issue. And it's a pretty significant driver.

As part of that open-minded solicitation that was done, my company entered into a little over 260 megawatts of contracts for energy storage. Not all of it battery storage. Some of it is actually what they call the "ice bear" technology--thermal storage in the system. But a little over 160 of those megawatts were behind-the-meter. There was more behind-the-meter storage than in-front-of-the-meter storage.

There were some comments earlier to the effect that distributed energy resources really don't impact the grid on the transmission and the wholesale side. Well, I beg to differ. It definitely will. We totally anticipate that distributed energy resources are indeed a way that we are going to meet total customer requirements, and it will materially in the future influence the market that we'll have, both in terms of type and quantity of wholesale generation. That's an inevitable move forward.

So all of this comes together in a Distribution Resources Plan, which is an ongoing commission proceeding. Each of the three IOUs in California will be filing a plan this July.

The pieces of this filing that each of the three IOUs in California will make are, first, just identifying the system limitations and capabilities as they exist today. And anybody who does distribution planning knows that's a fleeting situation, That's a snapshot that can change pretty quickly, and it includes looking at individual circuits. But it's not just circuits. It's really looking at subsets of those circuits, almost wherever you would put a reclose or a sectionalizer in your system, or potentially creating new subsections. We could easily see a circumstance where we would be looking, ultimately, at over 20,000 discreet locations on the circuits within our system. It's a lot of data. It's a lot of analysis. And it's a lot of work. And so it's not something that's going to happen exactly overnight, but we're pushing quickly on it.

The overall goal on this is to take a look at the available capacity across each of the individual utility's grids, and make public information, as granular as we can, about each of those subsections, that tells our customers and third parties who want to put devices either behind the meter or in front of the meter on the system to facilitate interconnection and facilitate opportunities what they need to know.

And there's two pieces of that. One piece of that is identifying where you can distributed generation, potentially primarily customer-installed PV, and know that you can do these installations without a big need for study, and certainly without needing to do an upgrade? That's one piece. Where can we put storage in a place that it works? Where could there be higher concentrations of electrical vehicle charging without it being a concern on the system?

You provide that information, but then you go to the next step, as discussed before, about looking at the locational net benefit analysis around that. And that's benefit, in part, is avoiding traditional grid investments that the utility might otherwise make. And then that next step includes looking at opportunities where a customer can do something that might meet their retail side needs that at the same time is at least not harmful, but preferably beneficial, and therefore they can get compensation for that.

An issue that we talked about earlier in the day is that you're potentially looking simultaneously at two different markets. You're potentially looking at what these resources can do on the wholesale side, and what they're doing to benefit the individual retail customer if it's something that's deployed on their side of the meter. In our storage awards, we are looking at both sides of the meter. So we're going to be looking at those types of changes.

And then ultimately the next piece of this plan is to have, in our case, five demonstration projects that we're going to deploy in our system as part of this plan to try to, as quickly as possible, real-time show how this all works at a scale that's meaningful that will test different pieces of our system.

So when you look at the grid as kind of an integration platform, you have the two functions. You've got grid design on one side, where you're looking at making it a very robust and available opportunity for deploying resources. And then trying to look at a way to enable benefits for parties, and lay out those benefits. You've still got a grid function, the other piece, that still has to meet the requirements.

It's kind of the traditional, boring, dull requirement of delivering energy to our customers when and where they need that. Melding together these DERs with kind of traditional grid operation to assure that we have grid reliability ultimately will become the utility's responsibility. We believe that will continue irrespective of the business model and what happens with the distribution system operator. Probably the utility will retain that responsibility. So we're trying to get to a more plug-and-play environment that was described earlier, and we'll spend more time talking about that now.

So when you're looking at things from just the physical side, that's one thing. And evaluating what you can do, where you can do things in the system, where the capabilities are, where the opportunities are, circuit-by-circuit, sub-circuit-by-circuit, is one thing. And around that you kind of have these two different groupings of a distributed energy resource market, one being the infrastructure market, which frankly is the easy piece. It's a lot easier to determine how your distribution system operates and where there are opportunities for putting in DER capital investments on the system that might avoid the need for other traditional upgrades, conductors, substations, etc., which creates some incentives for that investment.

The tougher part is the dispatch market. Short-run markets for these types of devices is kind of a new and brave world right now to deal with.

And there's kind of a range of continuity shown up here. To the left side of the screen there are kind of the simple retail tariffs, payments per kilowatt month, fixed lump sum incentives that are paid for someone to put a device in a location, those types of activities. Going over to the right, we talked earlier this morning about time of use rates. When you get to the full extent of getting to local marginal prices within the distribution system, we're basically taking an ISO-RTO kind of market, and then making the distribution version of that. That could be 20,000 nodes. It could be a little tough. I'm not going to say it's impossible, but it's a challenge to do that.

Just in closing, I believe that we're going to meet the challenge of getting the information that the Commission needs, and frankly that we need and the market needs, to lay this out much more granularly than we've ever done before. But there are a lot of issues and design considerations that we still have to sort through--like just the whole issue of what these incremental values will be, what the price signals will be for the different locations on the system. Because it's a little bit different than the wholesale world. In the wholesale world, generally, once you get a long-term generator interconnection agreement and a power purchase agreement, you kind of expect that you're going to be there for 20 years, and you pretty much know what your pricing is going to be on that. And if you're a merchant generator that's basing part of their operation on a nodal analysis in an ISO market, things don't change rapidly in transmission systems, and therefore you have a good handle on how things operate.

Not so on a distribution system. Individual customer can change load on the circuit. We don't dictate when customers, the rate at which customers decide to put PV panels on their homes or properties. The numbers of electric vehicles charging can change fairly quickly. It's a dynamic situation that we have to recognize.

Now, I'm not saying that that's a reason that we can't do this. I think we can do this. But we have to keep those types of dynamics in mind when we pick among that array of markets, ranging from fixed tariffs all the way over to local marginal prices within a distribution system. And I do believe that we will have direct bids in the wholesale market through aggregations. I think that aggregation, or an aggregator of aggregators approach, probably makes a lot of sense.

I can't see a circumstance where you have individual customers bidding much into an ISO market. But I certainly see an aggregator that would pull those together in a way that makes sense. And as we work through how our customers get more efficient and how we work through making the grid operation consistent with the customers' needs, I think we'll find some issues around how we get customer equity and the prices that we need, because we've seen this situation with net energy metered solar that is pushing some costs over to those who are non-participants. We're working through California, trying to work through settling that out through some rate reform efforts. But those same types of issues can crop up when you look at a multiplicity of other distributed energy resources and putting new market opportunities on the grid.

There is the potential for there to be winners and losers among customers. And we've got to work through that as we implement this system. We saw, at the wholesale level, what market power does in the early part of last decade in the California energy crisis. So we've seen what happens on a big scale. Our goal is to make absolutely certain this doesn't happen on a small scale, and I think that if we go into this right we can avoid market power problems. And we have to be mindful of that.

At the end of the day, I think we'll have a very robust grid. I think it's going to create opportunities among the Internet of Things, opportunities that we don't even know exist right now, new business opportunities.

We need to be thinking about what these new business models look like. What is the utility's role in that? What are other parties' role in that? What's the customer's role? What's an ISO's role, if you're in an organized market? And how can we make this all work in a manner that meets customer needs, provides high customer satisfaction, maintains reliability, and allocates the costs, not perfectly, but reasonably fairly? I think we need a very careful eye on that.

It's probably something the Commission's going to have a real strong interest in, in terms of making sure that as we enable that grid to be more robust, that we do it in a manner that creates affordable costs on a system-average basis and then that these costs get allocated fairly across that system. But I'm convinced that California will be doing it in the right way. There's an interesting race, regulatorally speaking, between California and New York right now. And I'm hopeful that we can actually learn from each other as we go through this process to create something, as utilities, and as customers, and as grid operators, that works. Thanks.

General discussion.

Question 1 (Moderator): This question is for Speaker 4. Could you describe what Edison is trying to do in Orange County with the Preferred Resources pilot that I think is kind of a demonstration project in itself?

Speaker 4: Well, it is. The system was designed with the expectation that you had a 2,200 megawatt San Onofre nuclear plant, which is now closed. So in the area just north of that, at the southern end of our system in Orange County, California, we volunteered to put together a plan that we called our Preferred Resources Pilot. And it's an area that today has a load served by two substations of about 1,200 megawatts. It's about 5% of our system.

And it also happens to be an area where we have the fastest growth. And, generally speaking, across the board, Edison's looking at about a half a percent a year today average load growth energy, or load growth overall. And that area is tending to grow more at about 2.5% per year. For those of us who have been in the utility industry for a long time, the idea that 2.5% is high load growth kind of dates us, but it is.

So the plan is to basically negate that growth through a Preferred Resources Pilot, through a combination of distributed generation (which for that area basically means it will be solar), energy efficiency (and more structured energy efficiency that is more likely to have a higher expected level of reduction over the peak hours of the day), energy storage, and demand response.

And cumulatively we're looking at displacing the incremental need for 30 megawatts a year in this area over basically the next decade. We've done some solicitations for that. We've been doing a lot of work with customers and outreach on that. One of the things that we've discovered in doing that is that in order to test some of these devices more robustly, and these combinations of resources more robustly, we wanted to actually pick a subsection of that territory that had some of the greatest current constraints.

So this is kind of a little piece of what I was talking about earlier in terms of looking at those locational benefits and constraint analysis. So we looked to see where are the constraints were, first. Where are the circuits within that 1,200 megawatt area served by those two substations? That has a more likely constraint. So let's test putting distributed energy resources on that smaller set of feeders first to see what's down there. So it is a pilot within a pilot that we're looking at to try to get some quicker learning on some of these very intensive issues that we were just talking about.

Question 2: I think I heard two different things said with respect here to the rate design issue in terms of fixed variable cost partition to be more equitable in terms of people that are payingsingle part rates.

I thought I heard before, earlier today, a partitioning between what's being considered in California in terms of time of use and dynamic rates. Are they coupled together in what's in front of the Commission, or are they not, now?

Moderator: There is a current proceeding that is looking at specifically residential rate design in a fairly comprehensive way. It includes both, you know, fixed versus variable rates, time of use rates, a variety of options. And that's all on the table right now. And I think that one we can't talk about, is that right?

Speaker 4: Well, we can't talk in any detail about it. I mean, at a high level (and this you can talk about because it's within the legislation that provided for this) it looks at the prospect, on the residential side, of having some component of a fixed charge per month. And then looking at the prospect of flattening tiers down and reducing the number of tiers.

What happens with any changes in retail rates, is that it has an impact, obviously, on customers, customer needs, and what might work where, and penetrations of distributed energy could impact that. At the end of the day that'll all get sorted out.

Question 3: I thought this discussion was very interesting, and particularly the chart that Speaker 4 showed about the dual ends of the spectrum on this continuum here, which captured a lot of this conversation that's going on. And I would like to pose the challenge to see if we can get a response from this group here, which is that the more you know about the problem at hand and the technologies that are available, the more rational it sounds to have an integrated resource planning centralized process where we decide on what we're going to build, and then we sign contracts with people to build it.

And the less you know about what it is that people are going to do and what might make economic sense, the more you want to lean in the direction to the right in this picture of getting the prices and the incentives right, so that if you get more than you expected, you're happy. And if you get less than you expected, you're happy. Because you got the incentives right, but you don't really know what people are going to do.

And then you're going to have innovation take place, of the type that we've heard about here today, about all these things that are out there that nobody's talking about because they're frumpy, you know, or all the things that nobody's talking about because nobody's thought of them. And we don't know what they are. And they aren't in the integrated resource plan because we haven't thought of them. And what I'm worried about here is, the reality is that we don't know what the technologies and the choices are. And we very much like integrated resource planning because it gives us a clean way to spend a lot of money.

And I'm old enough to remember the Blue Book. And the reason we got into electricity restructuring, particularly in California, is because we were going to essentially procure all the stuff by identifying all these hidden values so all these new guys could come in. And we found out that, well, there was a lot of it that was going to come in, and it was going to be real expensive, and it wasn't what we really wanted. So it seems to me that given the nature of this technology and what we know about it on the distribution side, we should be driving very hard to go to the right of that picture, rather than to go to the left of that picture.

Speaker 4: Oh, I'm not sure of that. The reason being that you need three happy groups of parties. All the customers have to be happy. If the customer him or herself is dealing with a third party or on his or her own is putting in distributed energy resources in a manner that meets some criteria that has been laid out, or a market that has been created, they need to be happy with the end result compared to some status quo.

There's the third party that's providing these resources and these devices, or these business opportunities--which may simply be data, right? Then they need to make certain that they're financeable, and they reasonably know the circumstances under which they're going to be operating so they can be financeable. And then the utility needs to make certain at the end of the day they've got a reliable system and an overall system average rate that is sustainable. And I guess you could add a fourth party there in California. In a structured market, if anyone is an ISO or an RTO, they need to make sure that the grid's balanced well overall.

The more you go towards that right side, that LMP side, I think the more challenging that is, certainly in the near-term. And you talk about the experience that we had in California as we went from the Green Book to the Yellow Book to the Blue Book to AB1890 and then kicking off the CAISO and that whole market structure. There were a number of things there that obviously we didn't know when we did that, and we worked our way through it afterwards.

That's comparatively a lot easier to do, to model, to expect outcomes on, than what you might do across distribution systems the size of, particularly, Southern California Edison or Pacific Gas and Electric, or I guess San Diego Gas and Electric as well. So there's benefit in walking before we run on some of this to get some experience as to how these resources perform, what sort of granular information we can provide out there in a way that we all can rely upon and a way that people can make decisions on before you jump right in.

And just speaking for myself (not for attribution to Edison), I think it's something that we need to be careful in how we get there, and make sure that we have a good handle on that first. So I actually think that going to the far right side is the tougher side to jump into first. I believe we'll get there. There's a question, though, in my mind, and that is that the individual transactions that will happen, even if you have an aggregator of aggregators in the distribution side of the world, are going to be a fraction of the size of transactions that you find in the wholesale side of the world. So when you look at that LMP-type market within a distribution system and the creation of that, we need to make sure that we're comfortable with the overall cost of putting that system together. What's the cost of putting together the software, the systems, the settlement proceedings and everything around that to make sure that it works? I'm not saying it's not doable, but it's more complex at the distribution level with the dynamic changes that happen in the distribution system compared to what happens at the wholesale and high-voltage side of the system.

Moderator And the way that we've been looking at this question, is really in two parts. First, the price discovery and then the sourcing for these services that offset defined capital or operational expenses that are part of the ongoing process of the state at the distribution level. So that's one opportunity. And, to your point, those are known things.

But the unknown part is, so what's the adoption rate going to be of distributed resources by customers in and of themselves, independent of what the utility might source for its distribution purposes or the bulk power system for its purposes? And these are related, but there's this other piece. Which is, so how do you send the right pricing for how people should adopt distributed resources? And is that really reflective of what you want to accomplish from a societal standpoint or policy standpoint? Those two relate to each other, but they're not exactly the same thing. And there are different time dimensions on that.

So part of the discussion that we've been talking about, actually just yesterday in a workshop, is this idea that we really ought to be thinking about what we call the three Ps. So pricing, programs (that is, EE and DR programs), and procurements. And we need to think about how they relate to these different aspects, and also understand the time dimensions, because if you put a new pricing structure in, it's going to take some time to basically percolate out and for you to start to see some behavioral changes. It could take five years from the time that you decide that you want to do something to the time that you start to see the effect through the whole implementation cycle. Whereas you can do an RFP, for example, for some distributed resources, and you can have that up and running within two years.

So, again, depending on what you're trying to accomplish, you may pull on different tools to be able to accomplish it. Certainly program design, also with DR and EE, has different time dimensions depending on the kind of program it is. But it's pretty clear that you're going to have probably a portfolio of this that you've got to think about, including procurements and program redesigns.

Some of the existing proceedings are starting to explore that more fully. And then, what are the different pricing structures? So I think it's early days. New York's talking about the same thing. They're starting to figure out that it's much more complicated than just having some sort of distribution signal.

And just to put a finer point on that, Speaker 4 talked about the potential at Edison of 20,000 nodes. That's actually understating it. Because we run an unbalanced distribution system in the US. So multiply that by three. It'd actually be 60,000 nodes at the level that we're talking about. So this is a fairly complicated thing. Where do you draw the line? Is it really at the 60,000 nodes? Or is it at the substation? Or is it some point in between? And I think we're still in the exploratory stage about how that might actually work.

Speaker 3: I'm ready to storm the castle keep. I'm right behind you. Strangely enough, I think this is exactly the best time to let go of the reins and let customers make their own decisions. Because there are so many options. And we always seem to have to have a big bad wolf at the door in this industry so we can close ranks on each other. We'll solve that problem, then we'll consider the long-term problem. (Now it's the big bad duck, right?)

But if you look at the hyperbole about these things, most distribution systems can handle almost anything you throw at them. And by the way, you can drive around, and when you see two Teslas and three solar plates, go back and tell the guys, “We better do something here.” This is not something that’s going to happen so fast. But my concern is that this may be the last chance we have to do pricing right. We don’t need a DSO to do pricing right. We know. We’ve got the price signals coming from wholesale, and essentially you just repackage them. You have everything you need. And this may be an opportunity to jump in, particularly because there are lots of people out there who think they know more than us who are going to mine the rate. So good, let NEST sell you a $400 dollar meter that reads your mind and does stuff, and put you in a demand response program. And when they realize we’re going to pay $22 a KW year, that’s a long pay-back.

But let them do that. And if they can bring their price down, then why is utility buying thermostats? That’s great, we’ll rent them. It’s called bring-your-own-device, kind of. And so we’ve got all these devices out there. People want to put storage in. People want to put solar in. We’ll figure out how to use it. It could be just as simple as maybe having a smart inverter, paying for that. It may take care of any of the problems in the immediate future.

But I also fear that if you look at the recent proceedings (and Ashley put out a paper where he disguised himself as being dispassionate and logical, and it was his usually-manic self, but he has walked through a lot of the issues about trying to solve the what to pay solar problem), and it’s like, I took a pill that made me sick, so I took another one, I took another one, and I took another one. And now I’ve got this tiny bit of solar.

So I’m going to spend all this anxiety about making a separate rate for them, when the problem in the first place is, people weren’t looking at the right price sets. And if the time comes, if people want to get on real-time pricing, and from that they learn, I want to buy solar, or I’ve got to go get someone who can write me a hedge, we’ve got wonderful financial markets that have already been there.

We have all this technology. And I don’t think we have to hand it out to people and spoon-feed it, I think we can just let other people take a lot of those risks for us. But the key is, they’ve got to have an incentive. And the only way we can get a real sustainable incentive for them is pricing. So that’s my piece.

Question 4: I’d like to get back to the question that I asked before about cost-benefit. There seems to be an implicit assumption that the future is going to be wonderful. We’ll have all these devices, we’ll have a robust system, and it’s going to be cheaper. We keep looking at that assumption, and we question it a lot. We’re customer-owned, so whatever our customers want, they’re going to darn well get.

But almost no one seems to be talking about real cost-benefit. And if this wonderful future thing costs 20 cents, and our current thing costs 10 cents, do we want to really wind up like they did in Germany? I question that. And I’d just like to hear other people’s view of the cost-benefit of this wonderful future.

Speaker 2: The model that’s being talked about in California that we’re looking at is actually an adaptation of what Speaker 3 described in more detail. So when you look at DER-provided services as an alternative to traditional utility investment, the expectation is that it’s not going to cost any more, or shouldn’t cost more, than the utility alternative. That’s what I meant earlier by best-fit, least-cost.

And the comparison has to be on an apples-to-apples basis. The idea being that the functional performance of that resource has to look like and perform like what would otherwise be the alternative. So on just that, the expectation is that it wouldn't cost more. It may cost equal-to, but the expectation and hope is that it be less.

Now, what does that mean in aggregate? I went through it quickly in a slide, but there are incremental technologies that are going to be required. This was touched on in the earlier morning panel around things like communications systems, protection schemes, control systems, etc., that you're going to need to be able to have this system be able to accommodate and integrate DER in a way that you get the value. So there's not a free lunch here. There's some additional cost.

Now, net, when you add what they can provide, given the integration cost, presumably it's cheaper, or you wouldn't do it, than you know, the more traditional approach. So that's the thinking. Now, from an overall standpoint, I think the expectation is still that costs are going up. You just may be, you know, reducing the upward pressure on cost as a result of this.

By the way, none of what we're talking about here touches on aging infrastructure replacement. Most of the aging, that's still going on. We're talking about incremental load growth, largely speaking, and incremental as a result of the system being used differently. So just as an FYI.

Question 5: Thank you. First of all, on the spectrum that Question 3 laid out about the left end of a centralized IRP kind of system versus on the right just getting price signals and then letting customers decide, I'm wondering if that spectrum isn't more like a triangle, and there's another point of the triangle which would be a kind of centralized planning, but at the local level.

What I'm thinking about is convergences between energy and waste management and waste water treatment and the drought in California, and a variety of municipal services where cities and counties are really dealing with the reality of these things as well as their own energy footprints, trying to create and customize local resources to meet their needs.

And then at the larger system level, the facilities of the transmission and distribution grid become enablers for that diversity to play out at the local level and let the change be driven bottom-up. But there is a certain amount of planning in order to achieve those kinds of convergences across services. So I just want to throw that out as another model.

The other point I wanted to get to is about pricing and thinking about the diagrams that Speaker 1 and Speaker 3 put up, and of course what we've all been talking about, the huge diversity and proliferation of distributed resources and how that might play out, and the kinds of services that distributed resources might provide. Yet as soon as we talk about the pricing, as soon as that enters the discussion, it's always about a rate for a commodity.

And I'm wondering if that isn't just a really 20th-century concept. Do we really want to stay in the box of everything priced in terms of a rate for a commodity, when in fact maybe the new 21st-century way of thinking about this is as a diverse portfolio of services, and paying for the services that you get in some totally different cost paradigm? Thank you.

Speaker 1: Well, that's certainly part of the conversation, as I understand it, in New York. So how do we think about changing from return on rate base regulation to something that's more around value-based returns for providing network services? I'm waiting to see what comes out of the “Track Two, of the New York Renewable Energy Vision process. There will be something out by the end of June if not sooner. There will be some directional information.

Some of you may be aware that NYSERDA has an RFP out, looking to engage some consulting services to actually explore this question as part of what they’re doing. It will be interesting what comes out of that. I think a report would be done by a September timeframe. So there may be some insights over the course of this year around these kind of questions, at least framing them.

Speaker 3: I agree with sort of the populist notion of how to approach this question. The idea that you’re more comfortable making localized decisions, and you could combine power and water and anything else you wanted to. And if that’s what people want, it seems like that’s what we should accommodate. But good pricing is good pricing, and you don’t need to think about creating a new distribution operator to do that. You change the rules, right?

I think your question gets to, how I would restructure the industry? How do I make sure, if a group of people want to (with or without assets) form another way to relate to the market, that it fits in? And I think you’d still argue that you’d want to have an integrated thought planning process in place to make sure that when you atomize the system, you don’t make it worse. But it’s not Soviet-style planning. You all have to do it. It’s a planning process that just informs people.

And I guess what I’m promoting is a very open planning process that people understand, so you can make good decisions. I don’t expect that in the same two states, looking at the same cost-benefit, you’d necessarily come to the same conclusion. Nor should you. And there isn’t one model for the US. But I’m intrigued by your model. Did you grow up in Russia or something? Are you the last communist left?

Questioner: New York, a little bit smaller. [LAUGHTER]

Speaker 3: Same thing, yeah. Should have known. Must have been the Bronx.

Question 6: I remember a few years ago reading about a software company that was having problems with bugs, so they incented one group of engineers to find bugs and another group of engineers to fix bugs. And they ended up with an underground bug market -- I’ll create a bug if you can fix it, and then I’ll find it, and we’ll both make money. So I was thinking about that as we look at that right-hand side (the more market-based approach), and the LMPs going deeper into the system.

The deeper you go into the system, the less load it takes to move load around, and the ability to create congestion and then get paid to solve congestion seems real. Especially as connected thermostats, EVs…put in energy storage, and water…this connectivity…you know, I can create an energy flash mob, I can change my thermostat with a Tweet right now. How do you avoid that, or is that something that will keep us from going too deep into this system? Is there a way to avoid an Enron on the distribution system?

Speaker 1: So I take it you’re not going to have transactive energy in your house with your kids arbitraging each other against whatever? So, yeah, this I a real issue. Some folks at Cal Tech have been looking at this question, because obviously you’re dealing with a much more illiquid market. And that potential, for all the reasons that Speaker 4 said, has become very real.

So there is a point at which there's a conversation we need to have in the industry to start looking at, how far would you go down that spectrum? I mean, if you took it further down that spectrum for energy, where do you stop?

The other thing is, we've been talking about LMP a bit more here today around energy. But with respect to what I mentioned in my comments about how some people are talking about distribution of marginal price, they're including in those constructs a whole bunch of other stuff besides energy that are not energy products.

And so I guess the question is, if you wanted to have more of a locational value on some of this, are there alternatives to do that across that range of different mechanisms that we talked about that may make sense, beyond just sort of procurement, which is how we've been thinking about some things? As at least a place to get started.

Speaker 3: Let me add to that. I don't foresee this situation where it's just a free-for-all. I know we've talked about the idea of building a robust grid and then identifying ahead an area where you say, kind of, "Have at it. Within these boundaries you're fine, do what you want to do." And then there would be other parts that are constrained, and then therefore we can say there's value in putting resources in these locations, and therefore we will create some market opportunities around that. We'll work with Dr. Hogan to figure out the most efficient way to get that done.

But I guess the point is, there are going to have to be some rules of the road. There are going to have to be some recognized physical constraints of the interdependency of customers and devices on a circuit. Physics ultimately does prevail, and we'll have to be dealing with that, and you have to deal with reliability around it.

If we get to the point that you're talking about, we are basically dealing with circumstances and market power exerted by people gaming the system. Are there opportunities for something like that? Sure, sure there are. There are some really bright people out there. They're the very people that we hope are going to be bright enough to figure out new and different ways of combining customer loads and distributed resources in a manner that creates lower-cost options, and we hope that those bright people get freed up by this. But that same bright group also can find ways to be able to game the system.

So there's always going to have to be some sort of means of oversight, checks and balances. We'll make mistakes as we go down the road. And I think the reason that the Commission's gone the way it has in the distribution resources planned proceeding in terms of proposing having a set of pilot efforts, is to test both market concepts, devices, and things on different types of circuits and load circumstances. So we can at least get some view into that on a relatively quick basis. But no matter what you do, you can't ever anticipate all of it. And there's always going to have to be an opportunity to go in and take a look at it.

Speaker 4: When I speak about real-time pricing and having it out there, it just automatically allows people to hedge as little as they want. By the way, you brought this up. If you have about six or seven percent price-responsive demand, you break the back of the curve real fast. Everybody else is chasing tiny little welfare benefits across the curve. So we don't all need to be in real-time pricing.

But we do surveys all the time, and we find about six percent of residential and nine percent of commercial customers say, when they get to choose an array of pricing products, “We’ll take real-time pricing.” But 70-75% choose some form of dynamic pricing over what they’re on now. And that could be TOU. We offer things, the funny name, “Block and Swing,” it’s like a cell plan. Tell me how many kilowatt hours you want to buy at a fixed price, and then I’ll price over or under every hour or every block of a day right off the wire.

And so I think there’s probably always been a thirst for this. By the way, this is no different than I found in 1999 when I ran this study. But the difference now is it’s real, because you can buy a hedge from some financial firm, or you can go and put in a controllable thermostat with a telephone and wire it into your head and those bracelet things that you wear, and knock yourself out. And you can set it to something like, I’ll never do anything when the price is over “X.” That’s all possible now.

And in fact, you could buy the stuff in a store. So a utility doesn’t have to worry about, “Gee, all these customers are going to be confused and get hurt.” I believe that the market is very ripe, is very diverse. The technology market and information market is why I think now’s the time to do this.

Question 7: If you look at the experimental economics data and you have a demand that’s responsive, that’s really one of the best ways to mitigate market power. So that’s something to take into consideration.

But it seems to me that the most cost-effective things that we can do are largely around control and optimization. They’re taking advantage of the Internet of Things, either on the grid or at the customer level. And the way we’ve seen that play out in other industries is through the creation of platforms that do real-time coordination.

Much of what you’ve been talking about seems very fixed--you know, we’re going to do procurements looking forward for a long period of time, and it seems to me that the real challenges are getting visibility to do that real-time operational coordination. How do you get there if you don’t aim towards a pricing model? And what do you think is necessary to get to the point where you get those operational coordination benefits?

Speaker 1: Well, I think, again, it depends on what you’re trying to solve. And largely at distribution you’re not trying to solve an energy issue, you’re trying to solve, essentially, a capacity issue, as somebody called it this morning. So you are looking at avoided capital investment, largely, and maybe potentially some operational expense, as we may need to think through it. So you’re trying to align that. So how much does real-time pricing really align with that?

You do have these real issues that the counterparties need to get their respective value out of what they’re expecting to get. So the utility needs to know that they’re going to get a service provided, and the other side needs to be able to know that they’re going to get paid, and that that revenue stream is financeable, right? I mean, these are real issues.

Over time, can you start to think about some of these resources that may allow you to have something that’s more dynamic in nature? Possibly. Certainly things like voltage management, conceivably. Especially if there are requirements like in California that everybody has smart inverters, with some amount of headroom associated with, you know, potentially being able to provide services on a real-time basis into something.

And so you may have some dynamic economic indicator of whether we need more or less. That's possible. And because the inverter was essentially paid for, and with solar, you know, it looks kind of like a zero-marginal cost kind of unit, you're not needing to recover the capital dimension.

Mostly what people have been talking about is, to the extent that we start to see energy-related transactions on distribution, how far down do you bring that? Or if you're trying to send price signals in some way about where to locate or where customers should be incented, in effect, to adopt different kinds of resources that might be beneficial to the system from a locational standpoint—yes, people have been talking about that.

But, again, as I said earlier, there has not been real clear understanding that there's a price difference between, say, a substation on distribution and the transmission LMP in places like California. We haven't actually done the analysis yet to determine that there's actually any difference other than losses, which you can calculate. But aside from that, you may be looking at essentially the same values. So this is something we're still talking through and working through. We're not saying no, we're just saying, "What are you trying to solve?" And then, how do you think about this? It's not one-size-fits-all though, it's pretty clear.

Speaker 2: If I can add to that, I think Speaker 1 hit it right on the head for maybe some of the first demonstrations we'll see coming out with these sorts of communications systems where everybody's trying to come to an optimal solution. For instance, it's probably going to be in the voltage space, like you mentioned, where you have many different players on the system, and I'll have some sort of capability to actually adjust the reactive power at their node, that sort of thing. There's a lot of work on how to optimally dispatch that without a central controller, and without some big plant. How does a total system come to what really is the correct solution, say, for voltage management? But it really does, as Speaker 1 mentioned, just to reiterate, it really does depend on what problem you're trying to solve.

So that's the voltage problem on distribution, which is very common. And when you have circuit reconfiguration, that sort of stuff, obviously the whole system has to settle out to a new solution, say, every five minutes, and that sort of thing, depending on what DG you have out on the circuit and how variable it is.

But things like, trying to get the value of a transformer upgrade deferral or something like that, it's much more difficult, because is it the last customer to turn on their washing machine that kicks you over the limit that then makes the utility responsible for upgrading the line? Is it that last marginal unit? Is it a shared asset? Of course, it's actually shared with the entire system. So it gets much more difficult, I think, in that sense, in terms of at least the dynamic market.

Question 8: How much of this conversation on DG (because you seem to use DG to sometimes mean DG and sometimes mean renewables) is really looking for missing price and trying to develop a commodity that is an alternative in your IRP game? And how much of it is actually climate change policy?

Speaker 3: It's both. I'd like to think that first and foremost it is climate change policy. California's obviously ramping up above and beyond a 33% renewable standard. Now, what counts as renewable I guess depends on who you ask. I'd like to think that it includes everything that's renewable, whether it's distributed or whether it's wholesale.

But setting that issue aside for a moment, we're trying to enable the least-cost opportunities that meet a future targeted level of reduced carbon emissions, at least from the utility sector. I'd be glad to talk about the transportation sector as well, but that's a whole other subject. I think that's clearly a major goal. You've got another major goal of saying, "And when we're looking at that, let's look at this in a manner that wrenches as much value out of the distribution grid as we can right now." Because we don't believe we have.

So the whole concept here is that there's value on the distribution side of the substations at the lower voltage, that we can get more value economically, while we're at the same time trying to meet reduced carbon goals. And therefore we talked a lot here about, how can we give the right price signals to do the right thing to avoid distribution upgrades and such?

But at the end of the day, I think a strong piece of this is to reduce the incremental need for wholesale generation of whatever type it might be, whether it's gas-fired or whether it's large-scale solar, frankly, and to try to look at creating some market opportunities for both of these on what should be, hopefully at some point, an apples-to-apples basis. The more granular we can make that market (and I'm coming from a utility perspective), the more we don't have to go enter into procurement opportunities to do that, and the more it can happen without that, the better.

I do think we have to walk before we run to get there to make sure that we understand a little bit better what we're doing about it. But, yes, I think if we could find something that an LMP process works with, and you can get large aggregators to enter into something so that they're taking advantage of that diversity, and the customer's kind of indifferent, the smaller customer doesn't care, wouldn't take the effort to try to learn about it, and doesn't have to, and an aggregator can take care of that and deal against an LMP within the distribution system, that's great.

I think it's a little bit of a challenge to jump to that as our very first step into this market. But I think we're driving towards that whole thing, in the long-term. Long-term. And overall trying to do that in a manner that reduces greenhouse gas emissions.

Speaker 1: Yes, largely this has been a West Coast kind of conversation. When you bring up DG in the Northeast, we'd be talking about how this fits into a reliability dimension. Because a lot of the discussion in New York and Connecticut and elsewhere there is around reliability -- combined heat and power, how backup generation and so on might fit in in terms of addressing reliability needs and resiliency needs relative to what the power system can do.

And to the extent that the power system can enhance its reliability in the context of satisfying customers' objectives, can we think about what that tradeoff might be? That hasn't been as much of a conversation out here, but it's definitely a big conversation on the East Coast. And just to give you some context about backup generation in the US, backup generation adoption at the household level and small commercial has been growing at an average of 16% on a compounded average growth rate for the last 10 years in the US.

Roughly speaking, 3% of households now have a stationary backup generator. And these cost roughly about $1,000 a kilowatt. And the estimate is that somewhere around 12% have a portable generator. So there's a pretty big gap, at least with a certain number of customers, in terms of what they perceive the standard reliability we think of in the power system (and largely this is a distribution issue), and what customers may be expecting given the changes in the lifestyle and the always-on sort of environment we all live in today. So this is something that I think a lot of people are trying to figure out how to address, as well, as part of these conversations.

Speaker 4: That's a good point, because we really haven't talked about islandable microgrids as part of this, and it's probably a bigger issue when you live in a little bit more difficult climate than we have here in California, or at least good portions of California. Things that came out of Storm Sandy and things like that, obviously, have raised the attention and the interest in that circumstance.

So I hear more from some of customers, typically commercial customers, who have extraordinarily highly sensitive end uses on their side. And the prospect of what can they do to try to have higher power quality in an islandable microgrid to meet their requirements is something that they're in discussions with us about. And those are the types of things that we could look at as well.

Question 9: I have a comment, a concurrence, and then a question. First the comment. We're talking about distributed energy resources. But the last time I looked, no one's repeated the laws of economies of scope and scale here, have we? I can still build a combined-cycle gas facility for a lot less per KW than I can build anything behind the distribution meter, from our perspective.

And so the question is, why are we doing it? I think that just got answered, Speaker 4. I think your comment, and, Speaker 1, you alluded to this as well, was that it's not about economics. It's not about climate change. It's not about environment. It's purely about reliability. So that's why we're seeing this. And so to the extent it is about reliability, now we have to deal with that. But I think we're trying to fit something into one paradigm when it's really clearly about something else. By the way, I'm one of those 12% that have a gas generator that's portable, and it sure isn't for economics, even though I get my energy from PECO. [LAUGHTER] (They're going to cut me off now.) But it's because I have a value for reliability and I don't like having to pump out my basement when my sump pumps fail. That really pretty much sucks.

My concurrence, though, is with the person who asked Question 3. I wanted to stand up and applaud the history lesson. How did we get here to begin with? IRP. We thought we were smarter than anything else. We knew exactly what was going to happen. IRP and PURPA. And that begat us, what? Wholesale markets. And here we are today. And now we're talking about going back to that paradigm, and I don't understand why, but it is so. Prices will take care of this. If we get prices down to the distribution level, we can get there.

So now my question, and there are really three parts. One is, why not LMP at the distribution level? There may not be congestion, but there's still going to be losses. And, as I remember one Professor Hogan opining back, oh, some 17 or so years ago, well, then if you have LMP and there's no congestion, then the prices are all the same, and it's great. But what happens when you do get congestion? And I remember on FERC staff when a certain RTO that shall remain nameless (it was not my current employer) said, "We've never had congestion on a system." Within a month, we were calling and screaming for emergency actions because they had congestion they had never seen before. Have you tried LMP?

So why not have that down at the distribution level? It helps get the price signals right in terms of where distributed resources should go, if it is for economics, if it is for reducing losses, and if it is for also reducing those capital costs. But there's also another piece to that. Why not also, and I think, Speaker 1, you've actually alluded to this, but I'll be very specific here, why not something like megawatt mile pricing for the distribution system that many countries in Europe use for the transmission system?

So if somebody's at the end of the line, and they install a distributed energy resource, it actually reduces flow on the line, and obviates the need for that capital expense. Rather than them paying for distribution, they actually get paid. Just like generators in London get paid for providing transmission service, and those in Scotland pay through the nose for it. No different.

And then finally the third question is, what are the prospects for a DSO working hand-in-hand with an RTO or ISO? Because there is a span of control problem. If we do have a lot of demand response, or energy efficiency, or distributed resources, our guys down in the dungeon can't keep up with all of that. But a DSO, or multiple DSOs, can roll that up and provide that information in easy-to-chew packets for operators, so that we can actually operate the system with much more transparency and knowledge, so that we also understand, "Wow, I've got a transmission problem. What do I have behind that meter? Is there something on the distributed energy side that can prevent me from actually having to shed firm load when that first contingency occurs and I have to then shed load in case of the N-minus-2?"

Speaker 1: On the first observation about reliability, that's one dimension. If you look at the surveys of commercial industrial customers and residential customers (and there have been a number of them over the last couple of years), it's pretty clear that the cost of energy is number one, reliability's number two, and environmental benefits are number three, across all those sectors. That's what's driving the decisions.

So in the case of any of the DG, whether it's solar combined heat and power or whatever, and some of these other technologies like demand response and other kinds of energy management, it's around managing the monthly cost better. Both volume and potentially in relation to the price.

The second issue is the reliability, and that's where people are looking at whether you can start to think about combining different components, for example, adding storage to a solar system, potentially backup units, and even some demand management to kind of be able to balance your system and start to create a bit of a microgrid phenomenon. And then, of course, the environmental benefits are a factor, all things being equal, that might be tip it over for somebody.

But this comes back to the pricing signal. I mean, the adoption in the first place of a lot of the distributed generation in particular, and even a lot of demand response, is all based on retail parity, not grid parity, right? So what's the retail rate that they're seeing? And that's driving the economics. And all you've got to do is look at the sales decks that people are using to sell these solutions, and they are all focused on what's the percentage reduction, given what their monthly bill is. It's all about, you know, getting 10%, 20% off what they're normally paying. It's a strong value proposition, it's real simple, and that's how it's sold. So, yes, pricing signals are important.

On your second piece, yes, LMP in the way that you described it is achievable. And I think that's manageable. That's different, though, than what a lot of people are talking about with DMP, which is trying to create something completely different from extrapolating an LMP down to distribution. And that's trying to figure out how you'd actually create a separate sort of supply-demand kind of market, and try and come up with some dynamic price as a result of an interaction at one of these nodes. That is farther down the road and maybe, you know, sort of in the same category as unobtanium. But what you're talking about is something that --

Speaker 2: I think unobtanium's easier to get, by the way.

Speaker 1: But I think what you're talking about is certainly achievable. The question is, how do you want to use that, and how might that actually be reflected in a retail tariff or something else, as opposed to another way?

Speaker 2: I have two words for your first question about the economics. Uneconomic bypass.

Speaker 3: Now it's getting serious. Is there a lawyer in the room?

Speaker 2: Come on, we both know what that means, right? I hope.

Speaker 4: All good ideas come around again, right? These are all issues we dealt with many years ago.

Speaker 3: I still think of the distribution system as being a populist or a pluralistic thing. If you looked at that heat map I had, perhaps those circuits are that way because they're new, and the utility double-sized them for growth, the cost of which got socialized. And so they get to add Teslas and stuff, and meanwhile the part of town that the utility never invested in, suddenly they buy one Tesla and those people have to pay $10 a KW, or $10 a month, more. There are difficulties if you want to discriminate pricing at distribution.

And in my mind there isn't really a need to. You can add a demand charge is as low as three or four bucks to collect all that stuff. And that's probably a pretty efficient way. You've got smart meters? That's fine. You want to avoid paying the demand charge? Buy yourself some solar, charge your car at a public station, or for free at work, and go home. There are all sorts of things you can do. And so it produces the right incentives. I see LMP as really the signal from the wholesale. The muscle in LMP is representing congestion, not the distribution level.

That's why I think it's difficult to figure out what the equivalent of congestion is in a way that is not preemptively discriminatory because the distribution system wasn't built evenly. And so you're going to penalize some people for taking actions the others get for free. That's a complication in rate-making, but it's a complication in trying to make a market out of distribution wires.

Question 10: One of the questions in the paragraph in the agenda is, do we need independent distribution system operators? I really haven't heard much discussion about that here on this panel. And so that's the question. But that leads to another question. And that is, if you have completely unbundled your utilities such that they're agnostic, all they do is deliver, they don't bill, they don't provide default service, they just deliver electricity, then would you need a DSO? Do they in effect become the DSO, because they don't have any skin in the game other than the reliable distribution of the power itself for delivery?

Speaker 4: Theoretically, the answer to that is, yes, they could become the DSO. The question becomes, does anybody trust that they're actually indifferent? Are we as a utility going to be trusted as an indifferent party in that activity? And I think that's something that's yet to be proven out.

Fom a utility perspective, we see our goal as being to enable these resources to happen and to do so fairly, and where there are opportunities that other parties can take actions on our system that reduce costs compared to what we would do otherwise in the way of upgrading the distribution system, then great. We're looking at trying to make that happen. You know, the devil is in the details about the very types of questions that have been asked here. How long-term a cost are you looking at? When you're looking at a deferred cost, is it a year, is it three years, is it ten years? There are a lot of questions in there with respect to how you evaluate the concept of avoided distribution costs, as but one example.

I think the way New York has started out on this is that initially the utility will be the DSO, but with the Public Service Commission looking over their shoulder to make certain that if they don't like what they see, that's a right that could be potentially taken away. We'll see how that all sorts out. The overall goal here is to create a level playing field for DERs with both wholesale resources and with upgrades to the distribution system.

So that's the fundamental premise of this new market that we're trying to create. And I think we're going to have to work through that in steps. It's what the California commission has started to talk about. It's obviously what the New York commission is starting to look at, too. Assuming New York goes forward as they are going, an interesting question is, what will be the criteria by which a commission would say, "We don't think you're acting sufficiently independent"?

Speaker 3: I don't think we need an independent system operator. We need to define a set of rules that we can live by, and incent a distribution utility according to how well they carry out those rules, so they don't have a dog in the hunt. Some of the best pricing and innovation guys are vertically-integrated utilities, and they're very responsible, and they've got a responsible management, and they see the future coming, and they're out there investing in all this stuff and writing all these crazy pilots I look at. And two years later I go, "I sort of get it, you have a bigger vision, you know, than I do."

I don't know what they mean by independent. What does independent mean? Somebody's going to own the distribution assets and somebody else runs them? Well, no, if I own the assets, now I'm really worried about how independent you are.

So I don't see how you could make that distinction, or that you even need to. It's redefining what you do. I thought this was about, do you ask the distribution utility to be the aggregator for demand response? Those sorts of things.

Speaker 1: There were really three different dimensions that were driving that conversation in New York, and more broadly, going on now nationally.

So one had to do with, if you're going to create multi-sided markets, so you've got lots of different people potentially doing transactions with a whole bunch of other different people, who would you have as the facilitator in that market on both sides of this? And I think that's still an open question, because at distribution I don't think anybody sees that happening for some time yet. What we're seeing actually evolve is the creation of many different parties potentially providing services to the utilities. So you have a one-to-many relationship, not many-to-many relationship in that context.

Now, what the customer's seeing, which is outside the purview of the utility and most of the regulatory structure, is many customers sourcing lots of services from lots of different parties. But that's outside the scope of what we're talking about with this.

The other thing was this question about a distribution marginal price. And so to the extent that you had some construct that was creating some sort of price mechanism at distribution that was somewhat related to but independent of the LMP, then, yes, you may need to consider whether there is something independent there that is helping to drive price discovery? But, again, I think that in the conceivable future we're sort of thinking that taking LMP and extending it down to distribution may be the way to kind of think about this conceptually.

So on the question of whether the utility is going to do something different in the way that it sources the procurement of distributed resources that may try and advantage a different part of the organization or an affiliate, this goes back to the old affiliate rule kind of stuff that's been around since the late '90s.

And, again, I think, as certainly was suggested in New York, that there's probably a way to deal with most of these kinds of issues. And the suggestion, I think, that the New York ISO and a couple of other people had in the proceeding in New York was that maybe we need the equivalent of the FERC standard of conduct at distribution as it relates to, how do you think about partitioning these decisions about how you operate the system and so on from any marketing arm, and aspects of what a utility may be able to do.

The utilities in some jurisdictions, like Texas, are actually precluded from getting into those things. So it's not really an issue. In other places maybe it is, because, you know, you've got people marketing solar systems or other things, and so you have to think about what that wall might be in terms of whether you're advantaging or not, or sharing information that isn't public…

Questioner: It seems to me the solution to getting the utility out of the load-serving business, out of the billing and out of the customer business, is that you bring in all those third parties. I know in Texas we've got, now, retailers offering distributed generation systems, airline miles, smart thermostats, air conditioning services, home relocation services… They're packaging all kinds of related services onto their sales of electricity, because they've been exposed to wholesale prices, LMPs. You don't actually have to show the customer the LMP if you show the LSE. I don't want to say it was easy, but it eliminates a lot of the problems that I hear y'all are wrestling with.

Speaker 4: Texas is unique, but not, doesn't mean it isn't right. I think you're a constant reminder to us when we lose our courage and say, "The lights are going to go out, there's going to be mobs in the street running around in the dark," etc. And yet you just seem to keep solving problems.

It's always encouraging to me when people say the sky is falling or something in Texas. The next thing you know, they're going along fine. Somebody's building windmills, somebody's building transmission. I keep looking at that and saying, isn't that evidence that this could work? I was going to say there's nothing special about Texas, but of course there is. But I don't see anything about the circumstances of your customers, their loads, their culture, how they use electricity, that's any different from the rest of the country. Which emboldens me to think it would work.

Speaker 1: It's interesting. I heard this presentation from somebody from a vertically-integrated area of the country, and, the way they framed it, which actually got me thinking about this question a little bit differently, is that they said, "Really what we're talking about in a vertically-integrated company is kind of like Apple, right? Apple has everything." And maybe the Texas model is more like Google. It's kind of an open architecture, it's kind of an open structure, and you can plug and play different components, if you will.

But they all try to accomplish a certain set of objectives. And you can say some do some better than others, and so on, but they're really a means to an end. And so when we talk about this question about a DSO and whether it's independent or not, people have been talking about how there are always these tradeoffs, right? Nothing's ever always 100% perfect. So how do we think about how to work through the tradeoffs between which one works better than others as it relates to the independent DSO? And I think that's where these conversations are getting a little bit more detailed.

I think this year you're going to see some work coming out of DOE and a few other places that are sponsoring some research to frame this up a little bit more clearly so we can parse this out and say, OK, pieces of this might make sense, pieces of it might not make sense. And so on. But to provide a little bit clearer considerations that unfortunately New York didn't really have the benefit of when they were trying to make the decision, and why they in effect kind of punted on it, saying, "We'll take an interim approach here and pick it up later as we know more."

Question 11: When the panel first started earlier today, it was very interesting because it showed the need for doing some very sophisticated modeling and planning and investments, because certain circuits and utilities are becoming overloaded with rooftop solar, and there are questions about how to best deal with that.

And this is an example of a small thing that turned into a very large thing. And you know that prices do matter. Because what's happening here is that basically the fact of the matter is that if you are in the third or fourth tier and you have a FICO score over 670, you're an idiot to still be getting your electric services from your utility. It's just a fact, and basically what's happening is --

Speaker 4: <u>Solely</u> from your utility. <u>Solely</u> from your utility.

Questioner: So that's basically happened. And then of course when I looked at the map I'm wondering what happened to the poor souls who didn't acquire their rooftop solar in time to avoid the problems that are now being caused in the distribution system. Because the people who have peeled off have no financial responsibility for helping fix the problem anymore. So this is an interesting issue. Right now, the wholesale price of solar, in terms of what we see coming out of the RFOs, is less than six cents in California. Wind is very cheap. The gas guys are cheap.

And if the primary issue is climate change, I don't see how it makes any sense to be paying with the equivalent of 40 cents for something you can get for a nickel, and not have to go through all of this.

Now, there may be other good reasons why we want to do all this stuff, but it may not be the most cost-effective way of doing this. And so at the end of all of this, how are we going to quantify or evaluate, how far down this road we need to go, or should we go? Because we've been in a very similar movie before.

Speaker 4: Well, I don't know if I can give you a satisfactory answer to the whole matter, but, number one, that five or six cents is not delivered to the customer, so you've got to take into account all those other pieces. I could just say, generically speaking, without talking to any specific proceeding or project, transmission gets a little more expensive sometimes than you might think. And so at the end of the day, you do need to take a look at it on an apples to apples basis.

And, again, it comes down to an issue of the combination of not just solar, but all the other resources that might get deployed. The reality is, we don't know. We don't know exactly right now what that comparable cost for DER will be against staying with more of a…I don't know if there is such a thing as a status quo. Certainly in California I don't think there's a status quo…but relying more on the wholesale side, until we go partially down this road to get a better handle on it. And we've got to take a look at the combination. This is what this is all about, in my view. Again, there's two pieces here. There's looking at offsetting that wholesale piece that you just pointed out, and there's whether you're offsetting other distribution investment opportunities that net net creates a lower cost.

So I'm going back to another gentleman's comment. It isn't all about cost. It simply isn't. So if you think it is, you're wrong. It's not only about cost, it's about different opportunities, about different customers having greater control, and it's not necessarily about the instant short-term costs either. It's about whether this creates new opportunities for different combinations of resources, customer relationships, business relationships, communications, real-time controls, pushing for better opportunities for end-use control devices that are non-controllable now. All of those things are things that ultimately could come together, whether that in the long-term is lower cost or not.

Here's the big question in my mind that I think is before us. We're going to go down a path in California, we're going to go down a path in New York, and it sounds like probably in Colorado as well, and we're going to work our way through these issues. And the good thing about this is, you don't, this isn't an instant, overnight, every grid, every circuit, every sub-circuit, every customer transformation. I actually do think we're going to move into this at a pace such that we're going to get our arms around how this works.

And I think that when we do that, then we're going to have better information by living it in pieces. This isn't like going overnight and having all three investor-owned utilities in California divest themselves of the vast majority of their generation, and then instantly going into a wholesale market and seeing how it works. This is going to be a lot slower than that, I believe. And I believe we'll granularly be able to learn as we go through that process. The the bigger question in my mind is, once we start down that path, if we find there's a problem with it, will we find ways to fix those problems before it does go deeper? And I don't know that yet. I don't think any of us knows that yet. But I think we're going to learn it.

Question 12: I think a spirit that has come out in all the comments, and I certainly share it, is this view that there's enormous potential in aggregation, that the IT revolution is going to change dramatically the ability to pull together assets that one traditionally might have thought of as retail just because they were small size, and recognize they can be quite large on the wholesale market. But that IT revolution does not obliterate a sense of responsibility.

And what I mean by that is, anyone who participates in the wholesale market has to recognize their responsibilities. If they're going to bid in megawatts, they will have to be under the exact same obligations and service as those who provide megawatts. And if they don't, they will be dinged by the same penalties. In New England, we have a strict pay-for-performance structure which everyone's getting behind and we think will work very well.

And so I think one of the major issues that will arise here, and one of the reasons why aggregators will have such an important function, is that they're going to provide the financial assurance that can give confidence as to what, in fact, would be the results of taking on board that prospective active demand-side management.

So that's one of the other factors that I really want to make sure is emphasized here. There is an equal obligation for those who are going to participate, and I think it's going to be a learning process. But if the ISOs or the other utilities who are responsible for this set out those metrics up front as to what those responsibilities are, that will make serious people get involved, and serious companies get involved, which I think will in turn help reduce some of the uncertainty as to the degree of success of the projects.

Speaker 4: I agree totally. I think it's a great observation, and we've stepped into that pond, at least up to, you know, the soles of our feet, in what SCE has done in our solicitations for all sorts, and seeking both energy storage, demand response, and time of day delivery of energy efficiency. And one of the biggest issues that we have encountered through that process is making certain that those counterparties meet those same types of requirements. It's an education process to make them aware of what those are, because it's a different set of players.

And at the end of the day, I think an aggregator is going to have to play that role, to deal with having the financial wherewithal to do it, the sophistication to deal with it, the collateral that's behind it, and they in turn will be dealing with the diversity among the other customers. They're going to have to make certain that it performs in that fashion. And I think aggregation's going to be a really big piece of this.

Speaker 1: I think the other aspect is that we are seeing that both in the distribution and the bulk power, we are moving away from discreet dispatch and into continuous dispatch, when you talk about something like demand response. And that means we have to rethink how we tap into that capability. Those technologies exist today.

You know, in the PJM, you have firms that are actually doing frequency response leveraging, building control systems to be able to do that. They do it in the Ontario ISO as well, and a couple of other Canadian provinces. So the technology's possible. We just need to think differently about how to either adapt existing programs that might be able, with some enhancement, to do this, or look at new opportunities with emerging technology to tackle this.

But there's a fundamental paradigm shift that we have to move on with a lot of the energy efficiency and demand response to be able to really capture the value that we're talking about today, which is short time cycle, continuous kind of dispatch, as opposed to how we thought about an air conditioning cycling program with a defined peak, and I can only call on it seven times a year, and I've got to pick those seven…

We're moving well beyond that into something quite different. That diagram that was talking about how you dispatch storage to mitigate peak, I mean, look at how many times that's being dispatched, right? So this is the kind of world we're moving into, and it just means that we need to think differently. But, again, the technology is largely here now. If we were talking about this five years ago, it wasn't quite here. Today, most of it's here and ready to be brought into play.

Speaker 3: In my mind, the best thing about this is that we get some adult supervision so we can take the insanity out of demand response. Essentially, why pay somebody who only can get curtailed eight times a year, and the generator's got to be on call? And part of that is, now in the transaction, you've got grown-ups across the table negotiating with you, and you can fine the crap out of them, and they can pay it. Which means they'll be responsible for it.

Also that means that they're responsible for cutting deals with customers other than straight out of wholesale. So if I really think the wholesale market's never going to go above $500 for the next two years, then I'll reflect that in my deal with the customer. Let that risk stay down where it's supposed to be, at the residential level, rather than being socialized. So perhaps one of the biggest things, in terms of the rethinking of this, is get retail out of wholesale, and get people in retail, and figure out how to diversify the product. But take the risk where it's supposed to be, down at that level.

Speaker 2: What Speaker 3 just highlighted is essentially a conversation that happened in the fall with some of the executives from NEST talking about how they handle the interface with the customer and how they price products and how they engage them, and so on. You expose me to the opportunities, and I'll figure out how to comply with that. And so I think there's an interesting opportunity to start having that kind of a dialogue. Which is part, frankly, of what we're talking about in California and New York at the distribution level.

Session Three.
ISO Governance and Processes: Are They Adequate in an Increasingly Dynamic Market? Is Some Harmonization Needed?

The RTO/ISOs have processes and powers that vary from one to another. The reasons for the variations are derived from historical circumstances. Sections 205 and 206 of the Federal Power Act ("FPA") establish the core substantive and procedural regulations governing the filing of rates, terms and conditions of wholesale power sales and transmission service in interstate commerce offered by public utilities subject to FERC jurisdiction. The governance rules of each RTO/ISO specify the internal procedures and stakeholder approvals necessary before the RTO staff is authorized to make such filings. As a result of different governance protocols, some markets are able to respond relatively quickly to changing economic and operating circumstances or perceived dysfunctions in market rules; other markets must navigate considerably more complex and time consuming internal stakeholder protocols before submitting a filing under Sections 205 and 206. In some cases, stakeholder groups may be able to delay or effectively block proposed submissions. At a time of rapid changes in market conditions and the substantial economic harms incurred by flawed or dysfunctional market rules, should FERC consider mandating a more consistent governance framework? What are the conflicts in the RTO/ISO responsibilities to support efficient markets, preserve reliability, and respect the wishes of the various stakeholders? Should FERC reassess the weighted voting procedures and look at reforming and possibly streamlining the stakeholder process?

Moderator.
Good morning everyone. Welcome to Session Three of this excellent conference. I have been involved in regulating electricity since the formation of the RTOs when we were grappling with the question of how these organizations ought to be structured, so that they could act in the public interest, get the market rules right and ensure the liability and a few of the other beneficial things that we saw from large regional markets. The issue then, and the issue now, is how can we ensure that the RTOs, the ISOs will function independently with no skin in the game, with no deference to any particular market participants, that they can act with courage, get the market rules right, and make decisions in a timely fashion?

Speaker 1.
Thank you very much. The goal of my remarks this morning is really to raise some big questions about the role of uniformity and regionalization in the context of RTOs. And these questions come up in the context of RTO governance: namely, should there be more uniformity among RTO governance structures? Should FERC impose such uniformity if RTOs don't adopt it themselves? And another question is, when? Has there been enough experimentation among RTOs to determine which governance structure is optimal? Or do the unique circumstances surrounding each RTO's history, development, location, energy mix, and relationship with their power providers and utilities argue against uniformity, at least for the time being? And ultimately, these questions are important, because there are really big challenges facing the electric grid today, in which RTOs have the potential to play a major role.

Now, during the discussion, I'm sure we're going to talk about many of these challenges. But I'm going to raise two of them in particular in my remarks. One would be helping states comply with the Clean Power Plan, and another is interstate transmission line development and construction. So I'm going to focus on those two issues at the end.

So just to get us situated, we've got about 70% of the electric load falling within RTOs, but of course we have large physical regions of the country that are not part of an RTO. We've got independent, membership based, nonprofit organizations, coordinating and monitoring electric power systems within their footprint and running wholesale electricity markets. They're created by FERC and regulated by FERC. Utilities are not required to join, and they can leave if they want.

Now, as this slide shows, there are significant variations among the RTOs in terms of regional scope, electric load, customers, generation capacity, and miles of transmission lines. So we have some single state RTOs, some multistate RTOs. We have PJM, with over 60 million customers, and ISO New England, having around 15 million customers. ISO New England has only 8,000 miles of transmission lines. MISO has 65,000 miles of transmission lines. So, significant differences here.

And for all the RTOs, we have most of the same key decision making actors in one capacity or another. So we've got FERC. We've got state PUCs. We've got federal and state courts on the government side. And then we've got generation and distribution utilities. We have electricity customers on the private side. And then, of course, we have the RTOs themselves.

Now, how these actors interact depends on the governance regimes and the differences in each RTO based on that RTO's historical origins and practices. So this impacts who can influence decision making and who can't. And of course there can be tensions, and there are tensions, between state PUCs and RTOs and FERC. Certain states may be anomalies within their RTOs, and that can create difficulty. So, for example, Illinois is in both PJM and in MISO. In PJM, it's the only state that relies significantly on nuclear energy. In MISO, it's the only restructured state. I've heard from one former Illinois PUC commission that for these reasons, they always felt like a black sheep in each RTO, even though it was for different reasons in each RTO. And so that can impact whether the Illinois PUC or the Illinois utilities feel that their interests are being met.

And, of course, this plays out in similar ways in other RTOs. Each RTO has stakeholder classes, and they're different among the RTOs. We have more stakeholder classes in MISO, fewer in PJM. And, of course, there are other differences with regard to voting rights among RTOs that some of the other speakers may talk about and that we may talk about during discussion.

So here are some of the key critical dimensions of RTO and ISO differences, just to keep in mind when considering whether uniform governance is possible or optimal: single or multi-state, member state politics/interests, traditionally structured or restructured markets; RTO member, voting, and advisory structure; RTO stakeholder interests, power, and opportunities; the role of FERC (and the shifting politics of FERC); and the dominant fuel source within the state, RTO, or ISO. These differences don't mean uniform government isn't desirable, but it does make one pause before trying to impose any sort of true uniformity on RTOs.

The next slides highlight some of these differences between states that give certain RTOs unique characteristics and may make uniformity more difficult. So we've got major differences in resource mix. Some of that's based on what energy resources are naturally available. Clearly we have a lot more hydropower in the Pacific Northwest. But some of this is based on state politics, in terms of the resources they want to promote. So, for instance, we've got a lot of wind online in Iowa, but not in all neighboring states with similar resources. The same is true for coal and for nuclear. So some of these differences are based on the natural energy mix, and a lot of them are based on which energy resources the state really wants to promote.

We have major differences in electricity prices around the country. Some of that is regional, and of course some of that is policy based, based on the state as well. Do they want to promote renewable energy? Do they want to avoid the use of coal?

Electricity restructuring varies by state and by region. And that creates differences, both among RTOs and within RTOs.

Wind, which is the biggest non-hydropower renewable resource that's available nationwide is not at all evenly distributed. It's the purple areas in the middle of the country, where we have the most wind. And that significantly impacts the need for interstate transmission lines and RTO responsiveness to state policies on renewable energy. So even where most of the states within an RTO have good resources, good wind resources, like MISO, not all of the states within MISO have policies to encourage wind development. So if we look at this slide, which looks at wind power capacity installations by state at the end of last year, you see Iowa's very, very strong on wind. Minnesota as well. You have those same resources in the Dakotas, but they don't have those state policies in place to really promote that.

Many of you have seen this map before. This is what our interstate electric transmission grid would look like if we could build the lines necessary to really capitalize on all the wind energy that we have in the middle of the country. This grid, of course, does not exist. What exists is the top map, which does not overlap very well with where we have our wind resources. So what we need is more interstate transmission lines to bring that wind to population centers, and RTOs have the potential, and are starting to try to really play a role in that.

So, another way to look at RTOs and to think about the question of whether more uniformity in RTO governance is desirable or necessary is, what is an RTO beyond the attributes that we discussed earlier? And this is from a paper by Michael Dworkin on ways to think about what RTOs are. Agents of FERC. It's an entity that is delegated regulatory power from FERC. Are they monopolists? They have monopoly power over transmission operations and markets that have to be regulated by FERC. They're certainly hybrid organizations. They're agents of transmission owners in a region. And they're also a regional planning entity for transmission. So some of these descriptions would seem to support more uniformity among RTOs. Certainly their description as agents of FERC, monopolists, even hybrids, would support this. But other descriptions, the ones at the bottom, would seem to allow for greater differences among RTOs, even in the governance.

Now, there are a lot of future challenges for RTOs relating to reliability, to market design, to addressing demand response, to energy storage. I know energy storage is a topic that you talked about yesterday. But two challenges that I'd like to open up discussion on are regional approaches to compliance with the EPA's Clean Power Plan and also an enhanced RTO role in building new interstate transmission lines.

The second issue is really a thought experiment about whether it would be desirable or possible for RTOs to take over some interstate transmission line siting authority from state PUCs. There's been a lot of discussion over the years about transferring siting authority over interstate transmission lines from PUCs to FERC, as was done with interstate natural gas pipelines decades ago. But of course that's not politically feasible at the present time. But what about transferring that authority to a regional entity, like an RTO? Might that be a better solution? And then that question, I think, ultimately brings us back to the RTO governance uniformity question.

So, first, let's talk about Clean Power Plan compliance. Right now, EPA is placing obligations on reducing CO2 emissions from electric power sector on the states. But EPA has left open the possibility of regional efforts for compliance. And RTOs are obvious entities to be in charge of that effort, and there have been some excellent reports released in the last few months about the ability of MISO and PJM to play a major role in regional compliance efforts. Might this enhance the role of RTOs? Might this encourage new RTOs to form, or utilities to join existing RTOs?

So I think there's a significant potential for RTOs to play even a greater role than they do now, if the Clean Power Plan moves forward. Now, does this argue for or against more uniformity in RTO governance in terms of the need for decision making and connections with Clean Power Plan compliance issues? I'll leave that question open for later discussion.

I want to turn now to interstate transmission line planning and siting. One of the key responsibilities of RTOs is to engage in regional planning for interstate transmission lines. Order 1000 enhanced this role and put RTOs in an important position to consider public policy benefits like state renewable portfolio standards in determining which lines should be built and how those costs should be allocated. But, of course, RTOs have no authority to site interstate transmission lines. Just plan them. So it's the states that determine whether a line gets built. And many state public utility commissions have held up interstate transmission lines, particularly interstate merchant lines to transport wind energy, on grounds that, while these lines may have regional benefits, their state won't see a direct benefit in terms of lower electricity prices or other direct economic benefit. And, of course, there are examples of that all over the country that many of you are familiar with.

The next set of slides summarizes published research that I've done on all 50 state laws governing the siting and the eminent domain authority for merchant transmission lines. I also have another set of slides that I didn't bring today that look at that authority for interstate transmission lines, because they're not always the same. And there's really significant variation among the states in terms of whether they even allow site and eminent domain authority for the transmission lines that RTOs are supposed to plan to expand the grid to increase reliability and to meet state public policy goals, particularly renewable portfolio standards. So these are states that clearly grant the right of eminent domain to merchant transmission lines (Florida, Kentucky, Michigan, Montana, new Mexico, Oregon, Rhode Island, Vermont, Wisconsin, Kansas, and Oklahoma). Some of that is by statute. And some is by PUC order. So there the law is fairly clear. That's not a lot of states where the law is fairly clear.

And here are just some examples where you see the statutory language that makes clear that merchant lines have that right. Here are states that have denied the right of eminent domain to merchant transmission lines, and these laws also often limit or completely prohibit the right to even attempt to get a siting permit, not just exercise eminent domain. So some of these are by statute. Some of these are by PUC order.

New York wanted to ban a particular intrastate merchant line a few years ago. So they had very tailored legislation. And Delaware, as far as I can tell, has just very limited eminent domain for any transmission lines, so they don't necessarily distinguish between merchant lines and lines built by public utilities. And here are some statutory and PUC examples of that.

And here's the rest of the country. States might grant the right of eminent domain to merchant transmission lines, but that's because the law is unclear. All of these statutes, both a lot of the siting statutes, and certainly the eminent domain laws, were not written with the idea that anyone other than public utilities would build interstate transmission lines or any transmission lines. And so the law is quite unclear. My analysis tried to distinguish between which laws seemed to support it, versus not support it. But there's not a lot of clarity there.

And so if you put that all together onto one map, you don't really see regional trends. You don't see uniformity within any RTOs. These state by state laws have kind of developed on their own. Sometimes an issue comes up. A PUC or a court says yea or nay, or a legislature makes a change. But we have a lot of variation, and so a lot of uncertainty with regard to the ability to even build the lines that RTOs are supposed to plan. So this is a big problem for grid reliability, for renewable energy, for Clean Power Plan compliance. Experts have said that new transmission lines to transport renewable energy are going to be critical to Clean Power Plan compliance nationwide. Order 1000 was supposed to encourage new entrants, such as merchant lines, into these regional interstate transmission line markets. And the laws, these state laws, create a major barrier to that goal.

So there's a few solutions, all of which are logical, and none of which really have much chance of happening any time soon. [LAUGHTER] One option, of course, is to transfer siting authority for interstate transmission lines to FERC. That is not happening, unless we have major blackouts, and even then it might not happen. There's just significant political opposition to that, for a variety of reasons. Well, what about interstate compacts to create new regional entities to approve interstate lines? The Energy Policy Act of 2005 already allows that, but at the present time, states really don't have any incentives to enter into such compacts. for a variety of reasons. In other published work I've suggested new federal legislation to require state PUCs to consider regional benefits in making siting decisions. So this would be similar to the Telecommunications Siting Act of 1996, which left siting authority for cell phone towers with the local governments, but created federal mandates and procedures. And most people say that that law has been fairly successful. But of course that would also require new federal legislation. Well, what about transferring siting authority to RTOs? They're already doing all the transmission line planning. They already have most of the stakeholders in the same room. They have a process for decision making on a regional basis. It allows consideration of both regional and local concerns in the transmission siting line process, and actually matches the physical nature of the grid, which is more regionally based than it is state based. This, of course, is only a thought experiment at this point, because such a change would also require new federal legislation, which is not likely to be forthcoming. And, of course, there's a big question of whether RTOs would even want transmission line siting authority. So that may be a topic for discussion.

But in thinking about RTO authority to site interstate transmission lines, it also raises the question of whether uniform RTO governance is necessary for RTOs to take on this task. Would it streamline the process? Or would it hinder it? It also allows us to think about whether any existing RTO governance structures are currently so optimal that they should be adopted by all the other RTOs, or maybe even imposed upon them.

So when it comes to transmission line siting, the state by state system, in my view, doesn't work in today's regional electricity markets, where a major goal is to transport energy, particularly renewable energy, across state lines and serve a regional market. It works in one place, for the most part. It works in Texas, where electricity markets, renewable energy resources, and RTO and population centers are all within a single state. But, of course, that can't be replicated anywhere else in the country. So for interstate transmission line siting everywhere else in the country, except for Texas, we really need an entirely new governance system if we want to meet reliability goals as well as other goals relating to renewable energy penetration.

So I guess the question, is the same true for RTOs in general? Do we need an entirely new governance system? Can we continue with the patchwork system we have now? Or is there one approach that's rising to the top that should be adopted nationwide? Would a uniform governance system be more or less necessary if RTOs took on interstate transmission line siting in addition to their existing responsibilities? So I think I said at the beginning, I would leave you with more questions than answers. So I've done that. And I'll stop for now. And I look forward to the discussion.

Question: Just on this slide here, your analysis about which states are likely/unlikely to grant the right of eminent domain to merchant transmission lines, is that predicated upon a review of the statutes and the likelihood of a legal challenge? Is it looking at the political winds in each state? Can you just help me how you got to the likely/unlikely determination?

Speaker 1: Yeah, it's looking, for the most part, at the statutes, looking at what the statutes say now, not necessarily any trends. Sometimes there's a statute, or other times, like in the Minnesota example, there is sort of dicta statement in a PUC order that doesn't clearly say eminent domain authority's there, but sort of implies that, well, it wouldn't be there for a merchant transmission line. But they didn't necessarily ask for it. So it's really based on a combination of looking at the statutes and looking at any PUC orders or court decisions that have language about that.

Question: I have one clarifying statement and one clarifying question. Clarifying statement: Delaware does not have the right of eminent domain for any electric line.

Speaker 1: Is that right? I originally had that in my slide, but then I went back and looked, this was about a year ago, and I'm like, well, maybe, because there's language about existing transmission corridors, and siting along highways. You say no.

Questioner: That's what they're trying to get you to do. You can go along existing roads, but you have no real right. They can come and change the road, and then you have to move the line. But they have no right of eminent domain in Delaware. They do have the right of eminent domain for gas lines. But that is not what I wanted to talk about. What I wanted to ask about is whether you looked at the governance structure of the Canadian ISOs. New England gets quite a bit of its energy supply and capacity from two Canadian ISOs, from Quebec and from the eastern provinces. So I'm curious if you looked at the governance structure of those provincial ISOs also.

Spaker 1: I haven't looked at it, but it would be a helpful thing to do.

Question: This is a clarifying statement. In ERCOT, or, actually, in Texas, we can grant CCNs (Certificates of Convenience and Necessity), which make merchant facilities become utilities. And once they're a utility, they've got eminent domain.

Speaker 1: I think is that true in Wisconsin as well? That you can just sort of grant the transmission company utility status. That's right. Yes, things work much better in Texas with regard to this transmission line siting issue. But there's just a unique constellation of circumstances in Texas that don't exist anywhere else.

Speaker 2.
I really appreciate Speaker 1 kind of setting the stage with some of the conceptual arguments and picking a little bit at this governance issue. And I think it was the early FERC orders that really set the governance requirements that became the cornerstone of ISOs. And that dialog was a very difficult dialogue to have. It became the cornerstone, because it was voluntary, and as Pat Wood took the road show to various cities across the country encouraging people to be active in this discussion, there had to be some give and take. There had to be a carrot and stick approach to get people interested in this dialogue, because immediately people were saying, "Oh, wait a minute. They want to control everything from FERC." And states had their guards up, and they didn't know how this was actually going to work. So it was the governance documents that became the cornerstone of how FERC allowed the different regions and the different states to become involved and have some say.

Thus, it's very hard today to make an apples to apples comparison when you look at the governance of these ISOs. They have some of the same and similar qualifications, but they also vary significantly. But I think that the unique characteristics that FERC was really getting at, as our moderator had mentioned, was the governance issue. The governance issue and the independence issue were the two issues that became paramount discussions as the ISOs were being formed. And governance in MISO and independence looks very different than it does in New York, for example. It looks different in New England.

In New York, for example, it's shared governance, meaning we share that governance and those characteristics with the market participants, where New England, PJM, some of the other ISOs, have advisory market participant groups and committees. But it is actually a shared governance in New York. And that became part of the discussion and the fabric of how some of these ISOs developed.

The governance documents are pretty much the same filings that take place throughout all of the ISOs. You've got your transmission owner agreements. You've got your ISO agreements. You've got your open access tariffs. You've got your market service tariffs. It's a very complex set of documents that set the stage for how these ISOs operate. And, again, that's all a FERC dialogue with the ISOs.

At the time of formation, when you had Order 888 in 2000, there were some very difficult discussions that were taking place across the country, almost violent in some areas. And it was an evolution, as the discussions took place. It was an evolution, in that you were looking for that independence as you were forming, and the governance documents were being forwarded and developed. But the independence was different in the eyes of the beholder. Is it independence from the financial interests of the market participants? Is it independence in the view that transmission owners don't control, or one segment doesn't control, the atmosphere out there? So you had to avoid a dominance by one sector.

And why wouldn't you have dominance from a sector? The transmission owners were putting thousands of miles of transmission assets into these ISOs that were being formed, and the market participants were hundreds and hundreds in number. So you have people with their own interests that were coming to the table. You have the generation owners, the transmission owners, the end use customers. You had the non-voting entities. You had he public power entities. It was all a very, very volatile discussion that was taking place, and again, FERC wanted this so badly, and it was voluntary, and they had to have buy in and give a little. So the personalities of these regions were allowed to come through in the way in which they were setting up their governance structures.

I referenced New York ISO. It is unique from the others in that they have that shared governance, not advisory, but shared. So it's more than collaborative in nature. It's a real voting aspect of what the market participants do. I think that all ISOs would agree that the market participants have a role in some form or fashion in their ISO and decisions that are made and tariffs that are filed.

This chart shows the New York ISO governance structure, but it is similar in nature to other ISOs in that boards of directors are the ones who help oversee this. There are boards of directors in the majority of the ISOs, and you can see that the NYISO committee members have a direct relationship to the board of directors because it's a shared governance. It looks different in the other ISOs. Participants were coming forward at the time of formation, and, again, they were confronting a very difficult question as to how is this voting weight going to work in a state like New York, as a single state ISO? Some argued that the voting weight would be allocated based on the amount of financial assets you put in, so the bigger your financial contribution, the more weight you had in votes. Or should we be like the US Congress? Now, we know how well that works on given days. [LAUGHTER] But should we be like the US Congress? Or should we be like the US Senate, where everybody has two votes, so Rhode Island is going to be equal in their participation to California? It was an interesting concept, and it was out there.

And in MISO, we had legislators that were coming forward as MISO was being developed and saying, "OK, you're going to put this governance structure in place. It's several states removed from us. Whoever heard of Carmel, Indiana, from a Wisconsin perspective? [LAUGHTER] Carmel? I don't even pronounce it right. Carmel, Indiana." And the legislators were saying, "We're going to turn over our assets to someone who's going to tell us what to do several states away, how is our voice going to be heard?" And, again, it had to be balanced in these discussions that took place.

So there were several FERC orders in New York. There were several FERC orders in other states that set dispute resolution processes in place, and thus today, we have the governance structures that shook out. Most of the ISOs have committee structures, where the market participants participate through a committee, and they help develop the tariffs. They give their input. And I would argue that in a single state ISO, like New York, the fact that you have market participants who have a voting weight as these are being developed can work in a single state.

I don't know what you'd do in a multistate ISO if you had market participants who had a shared governance, who are actually casting votes on how things were supposed to work and what the filings were supposed to look like. It takes a 58% vote from the market participants in order for New York to move forward with a policy, procedure or tariff through their board of directors. But to change the governance structure at the ISO New York, you need a 206 filing, which is a pretty significant hurdle. You not only have to show that the change is just and reasonable, but that the existing provisions are unjust and unreasonable or discriminatory. And so it was a very high hurdle. But it was part of New York wanting that autonomy, and it was part of the state's, in their other discussions, saying, how is it that we're going to be heard?

This pie chart shows the NYISO voting sectors. The sectors are weighted, and then the 58% required to pass is calculated based on that.

The role of the Board of Directors should not be overlooked in these governance procedures. New York ISO has provisions as to what the board members ought to look like and how do we ensure independence, but, again, that independence is different in everyone's eyes. And later on I will mention a little bit about some of the things that FERC may be able to do on a more common governance scheme or platform that would be helpful to some of those. The board, though, has significant weight, and the boards help oversee the majority of the ISOs. They oversee the ISO management. They provide the strategic guidance. They ensure the financial affairs are conducted in a manner consistent with sound financial and accounting practices, law, and effective risk management. They work on the tariffs. They oversee the market. They ensure the corporation is independent of the market participants. "Independent," though, in this timeframe and in this governance structure, is free from financial interest in the market participant. That's all that that independence means.

Again, it's hard to make an apple to apple comparison when you're looking at these ISOs. So how does this governance really play out? You know, in some ISOs, it's quasi legislative. It's very democratic. It allows section 205 and section 206 filings. It gives you the ability to use those, plus use emergency reliability procedures if need be.

But keep in mind that as this governance is playing out in the ISOs across the United States, particularly in the East Coast ISOs, when you have the market participants participating in these committee structures, other than New York ISO, which is the shared governance, you have thousands of meetings going on. It's a full time job to be a market participant participating in these ISOs. And I'm not sure that the structure that is out there 15 years later, which is today, was really foreseen as almost the bureaucracy that some of these have become. If you were going to be a new market participant, if you were going to be someone who wanted to get involved in these markets, I think it's very, very difficult to figure out how these ISOs work. How do you get involved? How do you participate, other than sitting on a committee, which again, can be a full time job, and the technical nature of these committees is significant. You know, there are people who work on the structure of these markets and have worked at these ISOs since conception. And it is their job on a day to day basis to understand the markets and how the governance interplay works. And they still have questions about it on a daily basis. So for someone from the outside who wants to participate, sometimes I think your participation and your ability to get involved could be limited by just the behemoth nature of what these ISOs have become, particularly when you have these multistate entities.

Does it work? You know, it works with the original concepts that were anticipated by FERC, in that we want to have more robust markets. We want to have open access. We want to have price signals. We want to have transparency. And I would argue that the single state ISOs, like the New York ISO, because they are a single state ISO, can meet those qualifications in probably a more flexible way, probably reacting and dealing with the market pressures or the market dysfunctions in a more practical way than some of these larger entities. And I think that you see examples going through FERC and the court all the time on this.

The one thing that I would say is that participants can in fact participate and try to fully vet their issues, and it's a role that's very, very important, because the collaboration is really required as we look at this. But as the ISOs were developed, there was a structure that it was thought would work for the personality of those regions. Are the processes adequate in this dynamic market that we have today? I'm just not sure they are. Are they flexible enough? I think some would argue that on given days they are, and with given issues they are. But at other times they are not. It's a process, but you have to have a process that moves, and that's where I think you run into some stumbling blocks with the nature of what these ISOs have become.

Obviously you have section 205 and section 206, which are safety valves, because using one of these filings gives you your ability to move forward with an issue, and, frankly, the New York ISO is an example of where you cannot block what goes on. The vote takes place, and the issues move forward. I know that others believe that there are sectors that can block discussions and block votes that take place.

I would say that when you look at quickly changing economic conditions and how the market rules keep up with that, it's a difficult task when you layer the political environment on top of it. And I think you touched a little bit on that. There are ways in which these issues could be solved. But does the political environment have the will to move forward? Politicians, I have found, talk big about markets and support of markets. But the first time there is some price volatility out there, you've got everybody screaming and yelling, "This doesn't work! This doesn't work! It doesn't work for me!" If you have someone that is on the opposite end of a vote that takes place, you hear, "This isn't working."

So you've got a lot of those political pressures, and frankly, this is where a single state ISO may feel those political pressures a little more than multistate ISOs. A single state ISO has that target on their back, because, frankly, they're a known entity by the governor and the utility commissions, and there's a struggle at times over control and power, and so you've got some of those pressures that take place in a single state versus a multistate.

I think that the conflicts that have cropped up over the years, the conflicts at the RTOs and ISOs, are about personal agendas at times. And it's up to the Board of Directors to have to balance, sometimes, these interests. I think that everybody comes together for the interest of what is best for the region. But that sometimes can go off course, and I think that there is significant tension at times between the state jurisdiction, between the federal jurisdiction, between the ISOs, and there are many, many things that have worked very, very well out there. There are other things that 15 years later I think we really have to take a significant look at. And it's time to maybe retool a little bit. And I think FERC can take the lead in this, whether it's about defining what independence truly is, or if it's taking the lead as to whether lines should be built in a multistate area, and who should have that authority to do it.

Question: I have a question with regard to the role of the board of directors in preparing FERC filings?

Speaker 2: The board is very actively involved. We generally jointly, with the market participants, the board and the ISO develop our tariff filings. But again, it has to have a 58% vote and pass the board of directors as well. So it has to have a vote on both sides. Now, we don't need a 58% vote in the board of directors, but we certainly need a 58% vote for it to come out of the market participants' committees for a joint filing. If we had to do a 206, we would, and we've done that in the past. But it leads us to a more consensus collaborative process, and there are only two or three times where our 205 filings were rejected by FERC, and it's because that collaboration takes place on the front end. But if we have to go forward with the 206, we would.

Speaker 3.

Thank you. My presentation is maybe a little back step. I think Speaker 2's comments about buy in are really important, because there are always two views to go on. An enormous part of modern progress was made at the beginning of the markets. And whether you agreed or not with any of the details, that was almost unilaterally done by the transmission owners, at least in PJM and New York, where I'm most familiar. And the people were presented with almost a finished package, and it certainly had some bumps and things, but that progress would never have happened in a stakeholding process. It would have been impossible.

But selling of those to be approved required buy in, and a lot of governance we see today is part of the bribes that went on to get the buy in. [LAUGHTER] And it's bad. I mean, you talk about the 58% majority at MISO, there are things that have languished for political and stymied vote reasons for six, eight years. You look at the Hudson Valley Capacity Zone, raised by the market monitor probably in 2005 or '06, direction from FERC in that same timeframe, barely staggering into existence seven to eight years later, with a lot of opposition.

So I'm going to talk more about these kinds of things, but I think it's important to put a little backdrop that the most progress ever made was before the governance came into existence. At least that's my view. Usual caveat, these are my opinions, none of this represents any of my clients' opinions.

Going back to the beginning, there was a need for buy in, and, as usual, compromises on a number of things seemed good at the time, because they got it out of the way. They have long tails, and I think the governance process, and particularly the stakeholder process, which I'm talking about, is a great example of that long tail of a lot of bad results.

It started out good. These are the general statements of the objective for the stakeholder process. It's to educate stakeholders, explore different solutions, improve communications between the participants and the board members and the RTO, implement the powers vested in the committees.

PJM has a split structure. Some portion of it is 205. The rates reside with PJM for the RAA, reliability assurance agreement, and the tariff, but the transmisson owners have separate authority with respect to certain revenue issues, and then the operating agreement resides underneath the members. So it creates some problems, which ultimately, if things get totally stuck, result in independent action. There is, I think, a drop dead or a reliability exclusion that would come back under 205 for the RTO.

All of these mixed governance structures have thorns in them that impede progress. But the objectives sound pretty good. I mean, what's not to like? I like this. The education piece, I think is particularly important. We have a complicated environment. Because people have a voice, it's not realistic not to have the education, because it's bad enough with a number of participants who really don't understand the details of the market. And probably one of the most valuable things that the RTO does is educate people. And I think it's gotten to the stage where there would be few, if any, even among people in the RTO side, that would feel comfortable expounding on the rules across the tariff. I mean, that's how much it has grown. Tariff documents, the package in PJM of agreements and the manuals probably are like, 7,000 pages? It's on that order. I mean, there's 34 manuals, so that's like 3,500 pages right there. The tariff is close to 3,000. The RAA's 100 and something. The operating agreement's like 500. So you're in the 7,000 to 8,000 page range. And a lot of stuff still isn't written down. So education --

Comment: They make for a good doorstop.

Speaker 3: It makes a good doorstop. You may be the only one that has it printed. [LAUGHTER] But the continuing education is a good thing. I mean, I look at that, and there are things that I think I know about, and I can read and listen and learn about it, and I think that really is good. I think that improves participation.

Looking at different solutions is another goal of the stakeholder process. If it doesn't take forever, this is also a good objective. Working together to identify problems and solutions in a finite world, not an unlimited world, is good. Thinking through those, there is unquestionably a difference of diversity of perspective that's valuable. You really do hear people voice concerns that you may not have thought of, simply because of the play of different selfish interests. And so that's not so bad.

But, and there's a big but in this realm of the stakeholder role in the governance process, unintended consequences abound everywhere. We could spend the whole day just talking about one proceeding and how things flip and flop based on people lobbying one side or the other, lobbying for different administrative relief at FERC based on the contention of one group being denied rights and not getting enough representation, or trying to accommodate one state or another state's interests. Or one sector's interests, be it load or generators. We have a big issue now in PJM with allocation of balancing congestion that is 100% an unintended consequence. People knew when it was done that it was wrong. It was done as an accommodation to move forward about 13 years ago. It's become a major oops. And you can't undo it.

So that's another thing is, much of what gets done is not readily, if ever, reversible. You know, "The road to Hell was paved with good intentions." And it's true. Also, "No good deed goes unpunished." I think the whole stakeholder process is an example of that. [LAUGHTER] You know, you read the objective functions, and it's like, you know, waving the flag. It sounds wonderful. You try and implement this. You get a horrible, horrible set of results.

One of the worst parts of the results is that "justice delayed is justice denied." These things take years. And they take years before they get to another place where it takes years. And that's probably the biggest frustration. And along the way, there can be all sorts of detours and side roads, both internally and externally. But nothing that goes on here, and I talk about this a little later, really improves the FERC process, which might have been a worthwhile trade off. If things had gone through a stakeholder process that was meaningful and other than an expression of selfish interest, a rational FERC might have said, "Great. They did all the work for me. I just have to read the positions of the people and make a decision." That doesn't happen. If anything, the stakeholder process has the propensity to expand what then goes on at FERC, and so it makes things worse pretty much across the board.

Now, we may all not agree, but with people having that kind of perspective, the need to get in front of somebody that can make a decision and move along is important. And most of these processes just don't do that. And then, of course, "be careful what you wish for." We got exactly what people thought they were wishing for on paper, until you look at the governance structure. When you look at all the different committees in PJM and the subcommittees, and the meeting schedules calendar… All those things are there, and they take forever, and they don't work. Why?

I tried to figure out the basic flaw, and where there was an original assumption that doesn't pan out. And this may be an oversimplification, but it's good for discussion purposes. And I think the basic flaw is the notion that consensus building is very desirable. And I think that's a true statement in the political process that probably initiated things. I think it's a horribly naïve statement in the reality of stakeholder process linked with what is ultimately an adversarial process. All it has done is really moved the adversarial process down a notch to another tier or activities. It has not worked to build consensus. And it's not at all surprising when you think about it.

This is a little bit of a misuse of the term, but I'm creating something I referred to as "negotiating" or "multi-participant" Pareto-like efficiency. In general, things are Pareto efficient when I can't do better without you doing worse, and that's said across the spectrum. Most of the issues in front of the RTOs today either have that property, or the participants believe they have that property. And in terms of negotiating and what happens at a stakeholder or committee level, no one will give. Literally. I joke that we can think about very big thoughts, but if we try and move a nickel around between people, we get years of litigation. And that really is the truth. There is very, very small willingness to accept transfers of any kind. And if you have a voting process, and be it 58% or 60%, coalitions between who gets what side of a transfer usually can block progress.

PJM has instituted a ministerial process of conducting these stakeholder function that actually, again, looks great on paper. It is horribly inefficient. And the combination I think, constitutes this fatal flaw: you're just not going to get people to build consensus about transferring money among themselves. It's very, very, very hard.

Another way of saying this is that many, many of the decisions we address in all the RTOs are about who pays. You can go back to MISO. It took five or six years to get to the multivalue projects. Multivalue projects were a derivative of the need for expansion planning across the footprint for wind and other integration. And the only way it went forward was that there was a portfolio requirement, and essentially there needed to be something for everyone, distribution by state and benefit and rate payer, in order for any progress to be made. So the win/win was that there was something for everybody. It wasn't necessarily the best package, and I'm sure I'll get pushback on that. But it was certainly a package designed to satisfy everyone's interests. And that was only an outcome that occurred after years of fighting about cost allocation for any individual piece.

And when you couldn't make progress like that, you said, "OK, well, I'll build something for everyone."

The other side of this, which I wish happened more, is that sometimes there's a right answer, and when there is, I think people tend to be even more intransigent. This is a minority situation. But consensus building isn't very helpful. If you're asking someone to say, you know, two plus two equals four, but we're going to go around the room and negotiate about it, it's not a good environment.

So we have one world where everybody thinks that if they give at all, they lose, and other world where people think that if they believe they know what is right, they're being pushed into a negotiating process where everybody else is saying, "But don't you want to give on that? Can't we reach a compromise?" The net effect is usually stalemate.

The governance structure, which I've talked about, makes this work. The supermajority rules are tough. The split governance, the split in the 205 and 206 and PJM is very cumbersome. And the requirements for vesting for the ability to participate are minimal. And so people with small interests, narrow interests, are positioned to delay processes extensively. This is sort of a tyranny of the minority. But at the same time, they'd be idiots not to protect themselves, given that this process goes on the way it does, because there is the squeaky wheel element. And if you're not around to protect yourself in the process and express your selfish interest, you may get rolled over.

So it's a bad form of governance, at least from the way I look at this. FERC makes this worse. My most cynical view would be that they defer to the stakeholder process when it's convenient for them to do so, and use it to rubber stamp things where they don't want to make a decision. And they ignore it completely where it doesn't happen to coincide exactly with what they want to do. And it's just become some sort of a crutch to really divert hard decision making at the commission.

For example, a recent FERC decision about an issue related to New York's Reliability Support Services. Someone files because maybe they're frustrated. The commission takes two years to decide. And the commission does two things. They say, "We deny your complaint." OK? Two years later. And they say, "And a portion of the proceeding we want you to go back to the stakeholder process with." And then for another portion they open up a new docket and say, "Hm, maybe there was some merit to some portion of your complaint. We want you to file something. There is a compliance issue. But we also want you to have a stakeholder process about this." So now on this issue, we're at four years and counting. And if it's done in two more, I'd be surprised. The Hudson Valley zone for capacity is a similar six or seven year issue.

These are not efficient processes. They are very expensive in time and people and an enormous distortion of funds. A lot of money is going to the wrong people. And the participants have to play the same game. You know, they're sitting at the same table. As I said, they'd be foolish not to take advantage of the same deficiencies in the process for their own benefit. And so they say, not too facetiously, “Consensus is good when you agree with me, and I’ll try and play the game to do that.” But stalling, explicit stalling is a viable tactic. I mean, people sit there and say, you know, when will this occur? How many meetings? You know, you have an issue statement, a problem statement, a problem charge, and issues statement. And each one of these steps may take one or two meetings that extend over one or two months, and then you sit down, and you decompose elements and try and put together their matrix. Then you have education processes. And suddenly a year goes by, and nothing has happened. And it’s not very constructive.

The net result is another layer of bureaucracy, another time step that accomplishes, for the most part, nothing. And the cost is staggering. Just look at the calendars and take a look at the number of participants. And the participants often directly conclude that getting nothing is not necessarily a bad result.

FERC wasn’t so bad in hindsight. Just people complaining and going to FERC. There’s a quote here by Bill [LAUGHTER] which I urge you to read. And it is regarding the FERC deferring too much to stakeholder processes, and bottom up approaches and consensus agreement. And I agree with that completely. The commission is really shirking responsibility in this. And it needs to be undone.

And is there something constructive? I’d like this to go away. I don’t think it can. Is there a way to harness it to at least be minimally destructive? We recently had in PJM a short process, only four and a half months, but that’s short, where PJM put up a proposal. I think the market monitor may have had a counter. People were allowed to comment. They revised their proposal based on comments. We got a second set of comments. People were allowed to talk to the board. And then they filed. And they incorporated any last minute changes based on those arguments. Now, it was four months, in this world very quick. It meets the criteria at the bottom, which are tough deadlines, limited debate, and you go forward. And if we have to keep having these, that would be a good solution. Thank you.

Question: You mentioned that the shared governance process in PJM may have been something that was deliberative in the initial conception. Can you clarify on that? Do you think we ended up having this shared governance with the tariff and the operating agreement as a sort of fallout of political issues? Or was it truly a deliberative kind of process to say, this is how we really want to have this done?

Speaker 3: I think that was deliberative. I think that was bad coalition building and it was working with the states. I think the (now, again, this is me, and it’s my observation being a participant) transmission owners, once they isolated any cost exposure, and got the fundamental design they want, were willing to trade. I know I had several very tiny issues that actually are interesting now, which were the reservation of incremental rights and merchant transmission provisions in both tariffs that I negotiated for my clients. And we got those added. And we agreed to vote yes on everything. So there was a lot of that going on.

Question: You mentioned Pareto efficiency. And did you mean just straight up Pareto efficiency, or Pareto optimality? Or Pareto efficiency with potential transfers?

Speaker 3: There’s no no transfers. This is my trying to grab something that hopefully communicates something to some people that is really a behavioral observation. The more dominant phenomenon is, I think, almost everybody watching those rooms thinking that if the other guy got what he's suggesting, they'll be worse off. So it's a social phenomenon. But it has Pareto-like characteristics, at least in the way they're interpreting it. There's not like a cooperative game going on with side payments and things like that.

Speaker 4.

What I wanted to do is kind of framed after Speaker 1's presentation, which is around a set of questions. And I've actually proposed a set of answers to those which hopefully may stimulate some debate along the way.

So, first, kind of from a broader perspective, is this RTO process working? And if I go ask people who are in the market design staff, who are those people that you spoke of that were there at the creation. They are the people who live this. It is their entire job. Those hundreds of meetings each year, those thousands of pages, that is what they're consumed with, and they were there at the creation, they think it's a good process, because it's their life. And if I've asked them to grade the outcomes on this, they would say, "Well, depending on the issue, it either can be an A or a C." It really does, I think, depend on, you know, does the outcome suit them, and did it match their philosophy?

If I go up the food chain to senior management, and talk to them about this, they think it's crazy. These are people who essentially have evolved up in their success in the company, on the theory of what I call the benign or maybe not so benign dictatorship model, where you reach decisions quickly, where there is a certain amount of debate, you put a peg down, and you move on. And the idea that you have this thing that looks like I think you mentioned Congress or the United Nations…It is a kind of a staggering amount of cost that the company puts in for the people go to these meetings. And you don't get what you want on a regular basis out of this. It's a perplexing thing to them. And honestly, I try to talk less about the process to them, as opposed to kind of working through it, because you don't want to tell them too much, because it really is important that somebody continues to support this, and it take some selling in your company that this governance process that was really invented by government, which has all the benefits of speed and efficiency of the government, is what is so determinative of a lot of your commercial success and the success of the markets.

Now, when I ask myself about this, I kind of have conflicting views on it. It's somewhere between, it's a great process that I spend my life doing, and it's a ridiculous process that eats up an enormous amount of time and resources, and I don't get what I want most of the time. I think it actually is very good (and people have mentioned this) from an educational standpoint. Filings, I think, are better as a result of the learnings that come through this. But it does need some help. And we can talk a little bit about that.

The second question is, from the different perspectives, does the process provide meaningful input? I think one of the audiences of this clearly is the Federal Energy Regulatory Commission, FERC. We have a distinguished former commissioner and another distinguished former commissioner, and looking around the room, quite a number of FERC alumni, who I hope, as we have discussion later this morning, can provide some input on that question.

I think one of the things to look at in terms of whether the process provides meaningful input to FERC, is whether, when they do look at those filings that are made under 205 or 206, FERC is looking at it under the question, is this just, just and reasonable? Or are they looking at some of the broader shareholder or stakeholder comments--some of the other ideas, some of the things that weren't filed? So I think part of that question is, how does, are they looking at it procedurally? Or are they looking at it more broadly? I think if FERC looks at it more broadly, it's more valuable. To the extent they limit it to a procedural issue, it is less valuable.

Is it meaningful to these representatives of the different stakeholders? I think it can be valuable if there is adequate time for those people to consider the inputs and the alternatives. And where an RTO brings or puts forward something that is essentially a baked cake, in the cake box, with a bow on it, and says, "What do you think?" it's not going to be particularly meaningful, because there's not really an opportunity for them to digest and respond and be responsive to stakeholder input on that. So that's something I think that has to be a piece of the equation for it to be important.

Another question is, do the stakeholders themselves understand the issues? These are deep and dense and very complicated issues. The range of those, I think, continues to grow, as you have more issues regarding bringing in alternative resources, energy transition issues…those get deeper and more complicated, and the people and the expertise that you need there at the table, they need to be well educated on these issues. And I think it's important for companies to put forward that expertise. In some cases, that happens, and in some cases, they just don't understand those issues.

We can throw rocks at the RTOs, and we can throw rocks at FERC, because that's fun and easy to do. But some of this that comes back to the company is, do we empower our stakeholders to really discuss and support alternatives? Or do we send them in with marching orders to vote yes, vote no, and it's based on a very narrow commercial perspective? It's been mentioned several times here that one of the infirmities of this is that it's limited by everybody's commercial perspective. There are winners and losers in this. But I think at some point you have to have a little bit of a broader perspective about the market. We occasionally get a chance to do that, because our company is engaged in generation. We're on the retail side with retail electricity sales, and we're in the LNG business, so we have gas perspective. So we have some internal discussion about, what do you do, and often times we get back, what is the right thing for the market? But if you're only in this sector, or you're in the load sector, or the transmission sector, you may not have a chance to have those debates and discussions about maybe what is the broader right answer. So I think it's important to give some people who do this some latitude on coming up with what's kind of a good market design, as opposed to what is a short term commercial win for the company.

Another question: is the weighting of the stakeholder input and voting shares adequate? And the answer to that is probably a resounding no, because whoever you are, you want a bigger voice. [LAUGHTER] As a generator, I think we feel that way from the generation perspective. I can tell you our executives feel that way. When you sit down and explain to them in this whole UN, congressional process that we have, you say, "By the way, we've got 20% or one sixth or one seventh of a say in this stakeholder process," they're like, "What do you mean? I'm the one that has invested hundreds of millions or billions of dollars in this market. And I'm this small fraction of that voice?" And I'm sure you can just replicate that for the other sectors, and how they feel about that.

So I think it probably is worthwhile to have a discussion as to whether or not those sector allocations and weighting is appropriate.

Another issue is that in terms of the weighting, you do have sometimes the issue of what I call "sector shopping," when you can be in whatever sector you want, and sometimes you'll see a cogen that's associated with a big company that uses lots of loads, and I'm a generator. And they show up to essentially foil the generation sector vote and discussion. So I think there are some issues that we look at in terms of the voting shares, where those are, and how those are allocated.

The next question that I've got is, has the scope and scale of the issues for participants become too big? I think the answer to that one is, maybe. Certainly, the advent of what I call the energy transition--microgrid, distributed generation, demand response, all of these--has injected a lot of new issues that probably weren't anticipated when these were set up back when, and that can bring more participants to the table. So you have more people debating more issues with different perspectives and a process that was not actually designed to do that when it was created, I think that probably does invite a new look at that.

The next question: can this be improved? I was thinking of doing show of hands here to say, how well is this working? [LAUGHTER] And can it be improved? But I'm willing to bet that there would be a lot of hands that go up that say, can we improve this? The answer is, yes. I think there are some models out there. PJM did their enhanced liaison process when they were looking at their capacity performance. I think there were some very favorable votes on that. Transparency, I think, is critical to this. I think the stakeholders need to have access to information in a timely way. And I think the one thing that resonates that Speaker 3 had said was about the need for time management. And that is to set deadlines, limit debate, and move forward.

Do some RTOs work better than others? Clearly yes. I think that for those that have a better control over the scope and scale of those issues, it works better. And where does that work better? Where there are smaller geographic scales. And the one thing I think about is clearly the ERCOT model. But I don't know that it's easily replicable around the country, because it is not FERC jurisdictional. It's not going to be FERC jurisdictional, ever. [LAUGHTER] So in Texas the PUCT plays the role of FERC. It is closer to, and I think more aligned with, the issues and the markets and the impacts than you have if you're a PJM spread over many states, or even New England spread over many states. You have a legislature, rather than the Congress. Any time you don't have the Congress, any alternative is better. It really looks at the laws that impact this. They have a real interest in this. I think they have mature views about the market. Again, the market is aligned. They have a pro-market view that goes from the governor to the legislature to the commission, and within ERCOT itself. And I think the ERCOT board process actually does better at getting to consensus. I think it's really become actually quite difficult for some of the other markets to look at actually getting to consensus, but, rather, it's educational. I think ERCOT actually does that fairly well.

Briefly, some other issues. Politics. We've had some discussion of the role of politics in this. I think RTOs are what I call SMTs, slow moving targets. [LAUGHTER] Particularly when you have capacity prices, reliability issues, and new energy transitions. These are easily attracted to the larger public policy process. And I think they need to think about what it means to be a slow moving target. They need to be more transparent about their costs, about their revenues, about the governance process. I think they need to be looking at and taking more seriously publicly advertised, publicly displayed performance metrics. And I think they need to be more engaged with their critics. And that's hard work. It's not easily done.

So I guess to wrap up, and I look forward to questions and discussions, there's a convergence of things coming together, now, that I think RTOs have to pay attention to. There are more stakeholders. There are more issues. There are new and different issues. They are more visible publicly and are more subject to public scrutiny and politics. That leads to the potential for more Balkanization of the views, and less likelihood of getting consensus and more likelihood that the process will only be able to get to education. That means that there may be less flexibility in the process, less consensus, and more frustration. And I think it really is incumbent on the leadership of RTOs and FERC to think about what that means and to get in front of that process by looking at some potential reforms, as opposed to reacting on a fragmented basis. And with that, I thank you, and I look forward to your questions.

General Discussion.

Question 1 (Moderator): I want to thank you panelists for excellent presentations. Taking the privilege of the moderator, I have an initial question. Why is it a good idea to set just and reasonable prices and just and reasonable terms and conditions by consensus? Why should that be? Why shouldn't the *right* decision be made, rather than a consensus, watered down decision? One key question in the RTOs now is whether they're getting the prices right. And everything else flows from that, in my judgment, in the marketplace. And I cannot believe that you can end up with the right price by consensus within the RTOs. That's my own personal opinion, but I would like comments from whoever wants to comment, and then we'll move to the audience questions.

Speaker 4. I think they shouldn't have consensus. The consensus can be wrong. The majority can be wrong. And I think when the stakeholders come with specific individual and commercial perspectives, the objective is not getting to the right, best policy. And while sometimes it is painful to have, essentially, the ISO holding the trump card of the filing rights, to be able to file at FERC, it's probably a good thing, because the stakeholders will not necessarily come up with the right outcome. In fact, I think it's dangerous to think that they would.

Question 2: I think that the ISOs get a lot of pressure from their market monitors and their economists, that the market look like this on paper, and it's nice and neat, and there's pressure from those economists that this is how the market should work. This is how it should look. But in reality, it doesn't play out that way. And you have all of these other pressures, and you have self-interests that are at the table. And at some point in time, somebody has to be the decision maker to move forward, because you've got a lot of people with self-interests that are casting a vote.

Speaker 3: And that's why consensus building doesn't work. Everything has been set up for a long time as an adversarial process, simply because we're transferring money around, or we're doing something that our moderator is characterizing as "right." And that's how it should be. Nobody votes to pay more and to get less. And we have a process at FERC. We need to get good things in front of the commission, and I think there's a reasoned process for that. But for exactly the reason you said, it shouldn't be consensus based. And I think the RTOs that attempt to do that do all the participants a disservice, because they sit on stuff that is not popular. They delay things that are not popular. There are all the constituencies that you can think of that have a selfish interest, and they're not just at the table. They're state commissions. They're state legislatures. They're the federal legislature. All of which beat up on the RTOs, and I'd just as soon cut that part of the process out and get to the commission.

Speaker 1: Well, we seem to have consensus that the system doesn't work very well, with a few exceptions that we've talked about. So then I guess I would ask, what do we do instead? Do you blow up the system and create something entirely new? Or are there modifications that you can draw on from some of the pieces of RTOs that work that could be adopted in other RTOs, where the structure seems to work particularly not well?

Speaker 2: I would say, from maybe a more knowledgeable perspective of the New York ISO, that a single state ISO, while it's not going to give you the regional scope that was envisioned, does give you a single state concentration, and while it may create issues outside the borders of the state, the New York ISO's markets work pretty well. And I think a lot of people are satisfied with the shared governance process. Now, that's not to say that there couldn't be changes, but I see more significant issues when you come to these large regional organizations. And I say that maybe from a naïve perspective, because I'm more involved with the New York ISO at this point. But I think these large entities have become very bureaucratic and unwieldy.

Speaker 3: I have to take exception with that. I think the New York process is awful. I mean, I've been involved in the stakeholder process there for almost 20 years, or 18 years, or something like that. It's as bad as PJM's. It's possibly more politicized than PJM's. PJM showed that they could move things forward once. In general they don't, and they only did because there was disaster looming. New York has, and PJM, and New England as well, avoided and danced around issues for years. And to the extent that they have shared governance or consensus-type criteria, they're not getting things done, and the commission keeps punting back to them. The game is sort of, "Touch, you're it," in terms of decision making. Texas is in a good position. Your world ends at your commission, and you guys take things on. Again, it doesn't matter if I agree or not, you're generally on schedule. That's what's required. There has to be a fixed time deadline, a fixed agenda, and an end point, where somebody with authority says something. And that's missing at the RTO level.

Question 3: I have a set of questions about shared governance in PJM. And I think, Speaker 3, you helped elaborate a bit on the key issues regarding the challenge of having 205 rights tied up within a stakeholder process that requires a supermajority, and in which the proceedings and processes devolve into people just asking, "What's in it for me?" and not really talking about the market at all in its general sense.

I wanted to ask a bit more about how we got there. Because I'm not an attorney, but as I understand, public utilities should, by statute, have 205 rights over their tariffs. And that's a design meant to be efficient, at least from the perspective of how Congress envisioned this and how the whole regulatory process is set up. So is this a defect or something that came out by happenstance, that isn't supposed to be there? Shouldn't, really, utilities like the RTO have unfettered 205 rights to their markets to address some of the issues they have?

So that's my first question. The second one is, if that's the right outcome, how do we get there?

Speaker 2: Well, by virtue of the fact that folks are in an RTO or an ISO, they don't give up their 205 rights or 206 rights.

Questioner: I'm not talking about the utilities individually. I'm talking about the RTO.

Speaker 2: Oh, the RTO. Well, we have rights to move forward, but under our governance procedures, it's a shared governance. We're the only ones that have that, where there has to be a vote that comes out of that market participants governance process. But we could go alone if we wanted. We could do it under a 206.

Speaker 3: 206, right. And I think Andrew's asking exactly that. The burden shifts materially if you don't get the consensus support.

Speaker 2: They move forward on the 206.

Speaker 3: And that's bad. Because you can't make progress. If you're in the RTO position, and you really believe something is wrong, and you want to fix it, I agree exactly with what the questioner is saying. It's silly that there is a voting process that moves from 205 burden to a 206 burden. It doesn't make sense.

And so the presumption for the RTO under 205 is that what it's doing is right, and you might only have to show that it is just and reasonable, not necessarily the best solution. Whereas on 206, you have the higher burden. And I agree with you, it's wrong.

Now, how did we get there? As best I can recollect, this was all a series of compromises. There was two very important people that most people are not aware of that brought the consensus out of the RTOs, and I think Jack Feinstein did a lot of that in New York, and Andy Williams in particular in PJM. And Andy was one of the few people that actually could get people to reach a consensus.

And my impression was that a lot of the 205/206 cascade into the stakeholder process was not as much of a priority after the 205 rights were insulated for the Tos (transmission owners), at least in PJM.

But in New York, the joint governance was there from the get go. I remember it being in front of us from day one. The biggest fight was, if you have that pie chart, and you see who got what, and there were all these weird looks at what coalitions would yield 42% or 43%. And that, there's literally months of these emails in the middle of the night of people saying, "If so and so group winds up wanting to do this and that, they'll wind up with 43 or 44 percent of the vote." But the joint governance issue seemed to be a starting point. How we got to the 58% or something was a whole separate process. And this was just people dickering.

Speaker 2: My perspective is a little different than Speaker 3's. Just in general, when I go back, I think that the RTOs and the development of them, and what the standards were by which we were trying to get to more players and marketplaces and more robust markets, I think that that was a necessary consequence of where we were and where we needed to go. And, honestly, I think that the boards of these ISOs work very hard at trying to get those markets functional, keep those markets going, make the right decisions. In some ways, it's this process that has taken on a life of its own, that's become kind of an octopus out there, that has created some of the issues, and, again, I guess I'm more optimistic, maybe, that there are solutions for this, and we're 15, 16 years into this, and we need to bring to bear some tweaking of this process. But I don't think it's FERC that can do it. I don't think they have the backbone to do this. And I don't think that states and others want to give up control of what they've got.

Moderator: FERC certainly has the power to do it. You're talking about political courage.

Question 4: I think the consensus here is, the stakeholder process just takes forever. Does anyone know if there's been a cost/benefit analysis of the stakeholder process itself? Not of the RTOs. We have many cost/benefit studies, you know, looking at the RTOs, and with the markets, they've saved money. But I'm asking about studies looking at the stakeholder process cost/benefit analysis.

And then, could the commission issue a NOPR as to having the RTOs come in and look at a more streamlined, time sensitive process, and then they go ahead and make the 205 filing, and they get the 205 rights, rather than necessarily having it where you have to have a consensus on a 205? Thanks.

Speaker 3: I don't know why you can't do that. I mean, I've done back of the envelope estimates that are really guestimates for looking at the calendar, counting the meetings, guessing how many people come, what kind of overheads they have, what kind of support, what they do in prep, travel, things like that. Just literally just line items. And it's $50-100 million of expense, just in one RTO, in PJM, that for the most part is duplicative. Like I said, I think the education process is important, because a lot of this is not transparent. But once you get by that, most of it becomes transparent, and then further litigated. So there's a big hunk of that that there's not a benefit to.

Speaker 1: I would also add into that cost benefit analysis, the cost to companies and to the utilities, as well as all the stakeholders. Because we run a pretty lean shop. We've just got three of us in our organization that work in the ISOs, and one of our folks is just for ERCOT. Two of us cover all the rest of the ISOs. So we call into a lot of meetings and try to pick what we go to. But many organizations, particularly the big utilities, feel that that they have to have somebody at every single meeting.

I know of a situation that just came up in the last couple of weeks, where there was a decision made at one of the lower level meetings, and when it got to the bigger market group, the ISO had to redo the meeting, because several people said they weren't really aware of it, even though all these meetings are posted. They had to redo the meeting, and ended up getting the same result. But it took now another two meetings for it to go through and make sure that all of the stakeholders were aware of it. So I would add that in, because I'm sure there's a cost to the utilities.

Speaker 3: Just in PJM, there's a, for a new problem, there's two readings of a problem statement. It's two committees, OK? So just in order to say that I'd like to discuss something, we're now talking about a two month process, and four meetings, where there may be as many as 400 people, 100 people in each of the meetings. Sometimes there's that many people on the phone lines. I call in and they say, "You are the 99th caller to call in." There is no reason for that level of effort. That part of the front end's a waste. But the education part is very good. Everything after that…I'd like to see the RTOs listen, adjust, and then propose and go forward.

Speaker 2: And I think you raise an interesting point, that the board of directors of these ISOs are sophisticated people who come from varied backgrounds. They have requirements for their varied backgrounds. They have an independence requirement that isn't defined by FERC. And that's a start--maybe independence ought to be defined. But after you remove yourself from the board process, you are knee deep in government processes, and the way that government functions, and the way that a legislative body would function, and hearing schedules, and meetings, and that's where it takes on a life of its own.

Moderator: You might remember the ill-fated Standard Market Design, which sought to standardize a lot of the tariffs. I say ill-fated, not because it was a bad idea, but just because it wasn't the right political stroke at the time. It was Nora Brownel and Pat Wood and I that did that. They sought to clear out a lot of the underbrush and say (this is FERC in advance saying to the industry), "This is what we'd like to see." And I'm not suggesting now is the right political moment either, although I thought it was a good idea at the time, and I still do. But it would clarify a lot of issues and probably face huge political pushback, as it did 12 years ago.

Question 4: Well, I would like to answer Speaker 3's question by telling one funny story. And then I do have a real question. As I look around the room now and think about almost 20 years ago, when the PJM process started in PEPCO's auditorium, I think about this tall guy from Harvard that we made sit in the Hotel DuPont outside the waiting room for, what, four hours? Five? I'm not sure. I remember that day well. But I think there's only two of us who were sitting there with our colored cards in PEPCO's auditorium. But there was a meeting late at night, and finally at two in the morning, the representative from ENRON said, "Do anything you damn well please, because I have 50 guys down in Houston I pay three times what they pay you, and we'll just get around your rules." So, of course, we know where they are now. [LAUGHTER] But that's where some of this stuff kind of happened. And any time anybody wants more history, find the drink in the bar. [LAUGHTER]

In any case, the fiduciary duty of a normal board of directors is to act in the best interest of the stockholders. Now, thinking about an ISO, to whom does an ISO board member have that ultimate fiduciary responsibility? Our stakeholders, our state regulators, the public policy statements, the governors, the federal representative?

Speaker 2: I don't know if the ultimate responsibility is to an individual or if it's to the markets. But you have a responsibility to have efficient markets, and make those decisions in the best interest of what the markets need, not TOs, not the generators, not the private power producers, long term or short term. Well, certainly long term. Short term, you have a responsibility to as well. The short term decisions may take you in different ways to get to your long term.

Speaker 4: It's the consumer. We are all here to serve the consumer. And we serve the consumer best by putting in place the best and most efficient market design. And then sometimes that starts to back up from that and say, what is the best right answer that we get with input from many different stakeholders. But at the end of the day, we're serving consumers. And the market has to be designed to benefit them. That does not mean the load segment. Don't vote with the load segment, because, as I think your earlier comment implied, you're looking at what's long term best for the consumer. And an efficient market is what is best for the consumer long term. And all of these other people have a place and voice in that.

Speaker 3: I'm not sure what the legal answer is, but I would go with the efficiency statement. And I don't think it works that way. Too many of the board decisions, or the RTO decisions, certainly the commission decisions, are couched in terms of short term benefits, costs, savings, non-social savings, really short term pecuniary savings, the individual interest parties. And I think that that would be horrible, if that's even how the board perceived things. But I hear a lot of board statements about how this will lower costs to the customers of X, regardless of whether it's disastrous for the long run or not. And that statement gets used as a crutch to defend a lot of behavior.

Remember, "I is for independent." We used to hear that at the beginning of a lot of meetings. That statement doesn't happen a lot. I think the independence is de facto. The market design and the markets.

Speaker 3: And I would really agree with Speaker 3 on that, that you have to think long term in terms of resource procurement, resource reliance, and also geographic scope. I mean, that's the reason for a lot of the regional RTOs, is to have that regional scope, and not have a single state scope, even if a state is dominant within any particular RTO. So I think regional scope and thinking about the regional best interest, and on a long term basis, even if in the short term, that means higher prices or investment in certain renewable resources, because in the long term, it makes sense. And that also plays into the transmission planning. There's decisions that result in costs up front, but the idea is to take the long term view.

Speaker 2: It's a tough road getting there. Commissioners have to make some short term discussions on projects that are going to impact the rates of rate payers for many years to come, but that are in their long term interest.

Question 5: I think a lot of decisions got made because of political expediency, because of this endless struggle between the perception of who would have the power and what would happen. But it's 15 years old, and those decisions are coming home to roost. So I agree, whether it's a NOPR or a series of tactical conferences, it would be good to examine the various elements. Markets work when they have credibility, and they can justify their efficiencies.

Speaker 3, I think you said that whether it is perception or reality, people do not trust either the independence of the boards or the independence of the management. And they certainly in many cases don't trust how the rules are being enforced. In at least one of the RTOs, it seems to be in the eye of the beholder. So the role of the market monitor needs to be examined, the actual costs, and break it down, because I think if company CEOs knew how much they were spending to send various people to stakeholders meetings who then are trying to work out business decisions in the middle of the stakeholder process, they would realize what a waste it is. And I think a fact based discussion about what's working and what's not, would lead people to say, "You know, maybe this is less about power than about getting the efficiency and serving the consumers," as you've suggested. So I think now is the time.

But the challenge is going to be, the people in this room and the various leaders in the sectors are going to have to step up and give FERC some support and step back and look at their own companies' best interests, which are not well served by the failure of this model at all. Companies and industries restructure all the time. And the time is overdue for this one to do so, including maybe some significant changes at the FERC and in terms of their own timetables and actions. I would argue strongly (I did many years ago and lost the battle) for very clear metrics on the value of the RTOs. And those should be public, as should be the budgets of the RTOs, as should be the disclosure that any large company is required to make in the marketplace. The New York Stock Exchange, FTSE 100, they all have standardized rules of disclosure and independence for their board members. I see absolutely no reason that we couldn't do the same. So comment on that. There is a question, but also a very passionate feeling that the time stamp has run out on this.

Speaker 4: One of the reflections I've got on that is, I support that process. I think it's important not to look to the current people involved in the process to self-reinvent. [LAUGHTER] I think you've got to go to people with experiences outside of being involved in this day to day for year on year, to kind of get some of the outside thinking, like you mentioned, from other agencies or other business models. I don't think the group itself is really well-equipped to self-reinvent. We should involve some really different outside players.

Questioner: You need to get the fact pattern to them. They need to see the cost. There's not enough transparency in this marketplace.

Speaker 3: I agree with all your comments. And any effort you put into trying to estimate costs come out with huge numbers. I mean, informally you get close to, like, $100 million, I think, in PJM. And that's not on the RTO side. That's on the participant side.

Question 6: Before I actually ask my question, let me say that what I'm about to say is my opinion, my view only. A couple of observations, and then a couple of questions. First, there was a comment made about how RTOs seem to be the favorite whipping boy of states and others. And I think there's reason for that. Because the RTOs are FERC jurisdictional and not state jurisdictional, it's easy for the states to beat up on RTOs, especially in, you know, a multistate RTO like PJM or MISO or SPP, in that they have no control over us. It's easy to throw stones and say, "Well, it's not my problem." So RTOs make a very convenient whipping boy in that sense. And so obviously they are responding. It's hard not to respond to certain pressures, but clearly, RTOs are a convenient whipping boy in that sense, and I think we just have to understand that and be aware of that and move forward.

The other comment, and this is an observation from history, is that there are two prominent markets that have actually imploded. We're in a similar situation to the old England Wales Power Pool. Let's go back. The old England Wales Power Pool was centralized dispatch, and it had lots of problems. Part of the problem with the governance process was that it almost required unanimous consent to change market rules. To Speaker 3's point, market rules were flawed, and it embedded winners and losers, and no one was going to vote against their own interests, which made it a very easy political target for the new Labor government to come in, around 2000, and say, "Let's blow it up. Let's get rid of it. Let's go to this crazy bilateral market. Let's actually go five steps backward now in market design and efficiency and everything else."

The other example I will give is New Zealand. New Zealand was effectively a self-governing market, had LMP pricing, and it was an attempt to get FTRs. And everything kind of blew up over that. And now, while there still is a market, per se, they had to create a new energy regulator. The energy regulator now effectively runs that wholesale market. And so I think we run a danger, given the lessons of history in other countries, that if we don't get our act together, politicians will eventually step in and say, "*No mas.* It's time to stop this nonsense." And, God help us, we have no idea what we're going to get at that point.

So with that being said, I have a question and a suggestion. Speaker 3, you talked about the enhanced liaison committee process. What happens if we do something like they do in the UK or other parts of the world, where the RTO is in some sense already in the stakeholder process a quasi-regulator? The enhanced liaison committee process actually is a template for this, where the regulator, let's say, in the UK Ofgem, the Director General, issues its initial findings, white paper, proposals… All the utilities and stakeholders comment on it. They take that in. They respond to the comments. They revise the proposal. And then eventually they put out a final proposal. This is actually not too terribly different from what we did in the enhanced liaison committee process.

Speaker 3: And it's similar to California, too.

Questioner: Of course, now we've got the 205/206 issue. We face the same problem where we only have 205 rights over the tariff, not the operating agreement (OA). All the energy market rules are in the OA, but not the capacity market rules. Hence we could get away with the enhanced liaison committee process. So my question is, is that something that's feasible? And is that something that you stakeholders in the room, might be interested in, rather than the current process, since there seems to be so much heartburn and heartache over it? Is everybody willing to change?

Speaker 2: Are you proposing, then, that we standardize, then, across all ISOs?

Questioner: Sure, why not? (And I was never here, and you never saw the missile go off.) [LAUGHTER]

Speaker 3: If everybody had that process, and had the 205 rights, and you educated people, they gave you comments, and they'd still go file at FERC, why would anyone not want to do that? We have to do it anyway, so why wouldn't you do it quicker? I have to say, a lot of people don't want to change the status quo or are afraid of any change to the status quo, so you've got to get from here to there. But if you can get from here to there, that's a great end point, and maybe the best we can do in terms of the reality that people are going to have to have a say, and then it's going to come to a proposal. You're supposed to be the independent expert that's running things. You compose the proposal, and it goes to the commission with whatever input you got. But you do it in three months, not four years.

Speaker 1: I think that as long as you have all of the rights and the processes, then, later on through the filings and at FERC, it works. You're just skipping the early steps that don't really make a difference in the first place. So it sounds reasonable to me.

Speaker 3: They do cut attorney's fees. That's one of the benefits.

Speaker 1: But then you can try to fix it later.

Speaker 2: The one thing I would say is that you have to look at the timeline that FERC uses as well and how they process this as well, because you could do a lot of things to do the streamlined stakeholders process, get the input, move it on to FERC. But there are given years when FERC is as dysfunctional as anybody else. So what does one do about that piece of the pie?

Comment: There's somebody in this room that has expressed privately that FERC needs to grow a pair, so to speak. And I think that the issue is that if it's a 205 filing, you have a 60 day clock. But that doesn't mean they can't use other procedural issues to kick the can down the road, such as deficiency letters and so forth. So, yes, but I think ultimately this is still going to require some chutzpa on the part of the commission to do something.

Question 7: The point that I want to come back to is, what is it exactly that FERC would do and could do? And one of the things that I'm hearing is that maybe the voting structures are just really outdated, and maybe they don't serve much of a useful purpose. I know that in California, we don't have voting at the stakeholder level. And when I came to California from PJM, it was like, what do you mean, we don't vote? You know? What do you mean we don't vote? We have to vote. Somebody has to vote. And since then, I think it's a welcome change. I think it's made us a little bit more efficient. So I was wondering if that's specifically what some of you are recommending, that voting structures at the RTOs are outdated and unnecessary, and if we have this Section 205 and 206, that works well enough.

The other comment, was, you're talking about metrics. We need to have the metrics of budgets and spending and what's going on at the RTOs. But it seems to me there's a more fundamental metric, too, that we haven't really talked about. Speaker 3, you touched on it, saying that a lot of these things come down to prices. What's going on with prices? And I think it's not just prices, though. It's whether the activities at the ISOs are focused on price outcomes or price formation. And I think if the change in what goes on in the stakeholder process was, you know, an unwavering attention as to what improves price formation, rather than tries to manage price outcomes, we'd see a lot more efficiency in what gets to FERC. We'd be giving FERC a clearer idea of just what it is we want them to rule on. And I just wondered if you had some comments on that.

And I would add to that my own story that dates myself more than I ever want to do in this group, but when I attended the very first annual meeting of the New York ISO, after they went live, one of the first things that someone said, who I thought was a terrific leader, but he talked about one of their jobs being to make sure that prices were low in New York. And I remember literally sitting back in my seat saying, really? Really? I don't think that's it. And I think that we've been caught in that question of, "Is it price outcomes? Or is it price formation?" ever since the RTOs began, and just wondered if FERC has a role in addressing that issue.

Speaker 3: I think when we talked about the earlier question about the boards' fiduciary responsibility, you could say it is formation. OK? When we're talking efficiency, we're talking formation. So I think that those two things answer your question, and that's maybe a more articulate statement of your fiduciary responsibility.

Speaker 2: I agree. There are some who criticize ISOs for not being sensitive enough to the consumer impact of this, but the utility commissions are the ones who deal with the consumer impacts of many of these things, and while what we do impacts the consumer, and our role is to have these efficient markets and things, we don't have that direct role with the consumer at the table making decisions on behalf of the consumer. We have a different decision process that filters down to the consumer.

Speaker 1: And I would just add that on this issue of efficiency in markets, I totally agree. But the formation of the RTOs was for the competitive efficiency of markets. And that, at least in my view, and my view only, and I'm not talking for anybody else, is what makes the competitive markets work better. And I think that is all about price formation, not managing price outcomes.

Speaker 4: You raise the issues about the need to have metrics and budget transparency and spending accountability. I think that's very important for the RTOs. They've got to have the confidence of the public. They've got to have the confidence of the political infrastructure or the political establishment to make that work. And these are essentially quasi-governmental entities that are not naturally exposed to these pressures, like the private sector is. I think all of that makes for a healthier and more focused mission, and more accountability for getting there. I think those are healthy and important components that really haven't been embraced to the extent that they should by the current RTOs.

Question 8: If you want to speed up the decision making at the RTOs, you still need FERC to make the decision and make it definitively, instead of what appears to me to be happening. And I only have a quasi-academic interest in it, but the process at FERC sometimes, particularly if it gets into a contested case, just seems almost Bleak Housesque in that they linger and go on and on and on without resolution until anybody who was involved at the beginning is dead. [LAUGHTER] And so if you speed up the stakeholder process, are you really going to improve anything if the process at FERC is not as efficient as it could be?

Speaker 3: At FERC, we can't change that, per se, but it will be more efficient, because the existence of the process is a crutch for FERC. They point at it and say, "You didn't go through the stakeholder process." Or, "The stakeholders didn't support this." Or, "Oh, the stakeholders like this one," regardless of how stupid it is, and they use that for an excuse way too much. That, coupled with "out of scope," when FERC doesn't want to talk about things where there are direct consequential results, but they try and limit their opinion to one small area, are horrible things. But what we can do here is at least remove one element of what's causing the delay.

Speaker 1: Just to build on that, so you would be replacing two slow and inefficient processes with one. So that's shortening it up. And you're also somehow limiting the FERC review for the reasons that Speaker 3 just said. There's certain issues now that will not be reviewed or won't be reviewed in the same way. So is it perfect? No, of course not. But you're shortening it up and limiting it. So that might be a benefit.

Question 9: I'm pretty much in support of the earlier description of fiduciary responsibility and how important to have a crystal clear understanding of what that responsibility is, and I think what was said about focusing a formation is the right attack on that problem, as opposed to addressing the outcomes. But I was struck by the other comment that FERC has the power. The problem is that FERC doesn't have the backbone. And I think there's a fair amount of evidence of some pretty critical decisions where that has been the problem. And, on the other hand, I can also think of examples of situations where they've had the backbone, and they have done things which were really stupid. [LAUGHTER]

And that's the dilemma here. It can go either way. Right? So you have this organization which says, "I have the power," and they can do bad things as well as do good things. And I almost get driven back to the idea, I hate to say this, but it almost has to do with issues of culture and character about how much people understand what their role is and how much they're willing to stand up and take the heat to do things that they think are the right thing to do.

I don't have a good way of answering the question about what you should do instead of what we have here. I mean, I really don't think, institutionally, that the fact is that they don't have the power. I think they do have the power. I don't think they have this clear vision of the fiduciary responsibility. I think that's a real issue here. And then the backbone, sometimes yes and sometimes no, but it's almost a question of trying to get a conversation about those issues going, is what really I would do. I think this is not an institutional problem, not a design problem, not a legal problem. It's mostly a problem of the people and how they see their job when they're sitting there.

Speaker 4: So we should spend more time with White House Personnel Office. [LAUGHTER]

Moderator (2): Just imagine if somebody with backbone and brains was nominated, the Senate ever confirming that person. [LAUGHTER]

Speaker 3: Even when people are assertive and exerting their responsibility at the commission, people see the world differently. And I think you and I agree on some things and disagree on other things. We probably both disagree with a lot of other things the commission might do. But it doesn't matter. I mean, that's inevitable. That's just inherent in anything where there's participatory democracy of some sort and a nominated and confirmed authority. We're always going to have that.

Speaker 4: I think it's interesting. One of the examples of what's generally, I think, held up as one of the RTOs or ISOs that works well is ERCOT. One guy is appointing all three commissioners kind of has a consistent view of what he wants those markets to do. There's a sense of an awareness of how energy works in Texas. It's just kind of in the DNA of Texas. It creates an alignment and a kind of singular focu, which addresses that thing I think you're talking about, which is the culture question. Now, how do you replicate that nationally? Camp out in the office of White House personnel. I don't know any other way.

Question 10: I think a lot of comments have been made about the issues in particular with FERC, especially around the political courage piece. I think the commission itself needs to really examine how it makes decisions, and I think it needs to come up with a different model for making decisions. And I'll say, in particular, regarding the price formation issue, I think the industry's at a critical point right now. And the commission has opened the door for market participants and stakeholders to file their comments on how we can improve price formation and market design to get better pricing outcomes. And so it's great. We were very happy to comment in that. We were very happy to participate in the process at the RTO level and at the FERC level.

My real fear, though, is that the political courage issue is going to prevent the commission from coming in and making the tough decision about issuing guiding principles, for example, about what good price formation is, and what RTOs should do in determining whether they have good market design and good price formation. So it's a concern of mine.

And I know we've touched on this issue about the decision making model at the FERC, and we could have a whole panel on that. But I would be curious to hear if there are thoughts on how the FERC model could change. So, things that I've thought about are, is it time for the commission to have sort of an independent advisory group of market designers, for example, who aren't involved with the RTOs and ISOs, who don't have an affiliation with any of the market participants, to make these tough decisions, where the commission may not have the courage to do so? So I'd be curious to hear your thoughts on how do we redesign the FERC model for making these types of decisions and evaluating market construct types of issues.

Speaker 2: I'm pessimistic that putting another body in place would not take on a life of its own at some point. FERC has the responsibility, and maybe all of us in this room also have a responsibility to educate FERC, to make sure they understand these issues, and really work hard to push them to do the job that they are required to do and should be doing. You know, there's five of them, and let's really start pushing hard to educate those commissioners so they understand the markets, so they understand the ISOs, and they understand where the gaps are. I think maybe that's the first step that can be taken, because I'm pessimistic that putting another body in place wouldn't take on a life of its own and become something other than what we envisioned it to become at a later point in time.

Questioner: If I can just comment on that, the process of educating the commission is ongoing. I mean, we've gone in. My company's gone in. We've gone in with experts. And I think Speaker 3 in his slide said, you know, that there are cases where there are clear questions with analytically correct answers that we feel we've provided to the commission and the staff, but yet we don't feel as if when they make the decision, that it's really considered.

Speaker 4: I kind of like where you're going, which focusing on the question of, how do you get FERC to behave differently, to vote with more courage, to have greater insight into these issues? I think the issue is that big elephant in the room called politics. What I'd say is, the RTO and the stakeholder process is not the be-all and end-all of getting the outcome that you're looking for. I think it's incumbent on stakeholders, whether you are generators or transmission or load or anybody else, to engage outside of the things that we've talked about here today, that you go see governors, that you go see your congressman, you spend time with your senators, whoever it is that's causing either FERC to want to do something or not do something or be weak. How do you bolster that? And those are going to be influences outside of the hundreds of meetings that occur in the stakeholder process. And think about where those are, and who those are, to shape those outside influences that drive the political realm. That is as an important part of the process as the others. And that may be the answer to the question of how do I get FERC to respond? Find out who they are really listening to, and get to them.

Moderator (2): At the risk of just being too historical, remember what essentially amounted to the assassination of Pat Wood by the Southern Republican senators on behalf of an uninterested party, which I think has left a legacy that's unfortunately felt very deeply at the --

Speaker 4: And what I would say is, we need to be better at managing that process, because it is so influential. We tend to think of it in a bureaucratic context, but there's much outside of that bureaucratic machine that has greater influence.

Speaker 3: Redesigning FERC is obviously not a five minute task. But there are two things that always stand out to me. It's a corollary of the education process--your company going and others going to meet with FERC. One, it's inefficient, and for anything that you say that's right, there'll be five other guys in there with a selfish interest that explain it a different way. So that education process doesn't work. It's not subject to any sort of peer review when sequential good/bad advice comes in, each looking the same.

And the other thing is this horrible penchant of scope limiting the range of FERC decisions. You know, they say, "I only got asked to do this." When A equals B equals C, they're only going to look at A and ignore the consequential impacts on five other things. And they do that repeatedly, and it's very, very frustrating, and there's no reason for them to do that. It's very bad. We have an integrated market design, and when they slice and dice for very narrow decisions, they do a lot of damage.

Question 11: I think we've all agreed, the stakeholder process does have value. I agree with that. There's a great education element. Sometimes I think we think we are the smartest people in the room. We're not always. But I think it's a process that really narrows the issues and focuses the issues. I, to some extent, feel like I'm the Cheshire Cat that just ate the mouse that shouldn't tell the rest of you where it is. But I am thrilled that we have 205 rights completely over all of our market rules. And I think you've almost all answered the question that you think having that for all of the RTOs makes sense. I would argue that if you don't think that makes sense, then we're not independent, and maybe you should get rid of us, which is why I disagree with the earlier comment about getting independent market advisors. I don't think FERC as a government agency can ever design good markets.

My first question is, do you all agree that giving the RTOs the 205 rights after some more efficient stakeholder process makes sense?

FERC has issued two orders specifically dealing with RTOs. One is Order 2000 that says you're supposed to be independent. And the other is Order 719 that says you're supposed to be responsive. And I will argue, playing lawyer, that I think that those two are almost completely inconsistent. And I think the responsiveness is one of those metrics that several people have talked about, that we are all put in the box of saying, "Well, are you being responsive to your stakeholders?" And I always joke with one of my colleagues at work, "Can I have your paycheck?" And she always says, no. And I always say, "You're not being responsive." Because I think responsive is often turned into "yes," and I think that's the consensus problem.

I would give FERC a little bit of credit. I think where the stakeholder process does work, we changed our capacity market design more dramatically than I think anybody has in a long time last year with, I think it was 88% of the vote against us for doing it. We did it anyway, with our 205 rights, and FERC approved it. I think the stakeholder process actually helped that. It made our filings very clear. It made the opposition's very clear. And it gave FERC a very clear record to rule on, and I think that's a real value.

So my second question really is, would you all agree that we should just tell FERC that Order 719 was a really bad idea in terms of responsiveness? And I say that, and everybody says, make the stakeholder process more efficient, the same way they say, make your rules more efficient. And when you're trying to make the rule more efficient, as soon as you take one little thing away that does somebody some good, they say, "But I didn't mean efficient that way!" So my second question is, should we get rid of the responsiveness metric?

Speaker 4: I'd agree that the RTOs should have independent 205 filing rights, because the majority is not always right. That's just the reality of it.

Question 12: I want to follow up on that question about 205 rights for the stakeholders, but I'm feeling a little like my brother's been beaten up for the last hour, and so I have to come to the defense. So I was at FERC for eight years. 205 versus 206 means something to FERC. On Section 205, public utilities, RTOs have the ability to file the proposal before FERC. FERC has to act within 60 days. FERC does act within 60 days. Occasionally there are deficiency letters, usually when something hasn't been fully addressed and developed in the underlying processes.

206 is quite different. That is someone bringing a complaint before FERC, and asking FERC to own the problem: "There's a problem that's been identified. FERC, please impose this solution on the utility." Those are very, very different. So when you get things like limiting scope, it's potentially because the utility, which has the 205 rights, framed the issue in a way that left something out. And FERC has no legal ability to address B and equally C, because only A was brought to it. Now, FERC could initiate a 206 proceeding at the same time to try and wrap in, but statutorily has got to act on the 205 within 60 days. So it can't connect the 206 proceeding, which is going to take much longer to work through. So there are just limitations in the statute that FERC has.

Connecting to the stakeholder rights, my understanding is, four of the six RTOs (everyone except for PJM and MISO) have 205 rights. They can make proposals to FERC without stakeholder approval, and so I'm wondering whether, at least for those RTOs who don't have 205 rights, isn't the question, why are the boards continuing to allow a stakeholder process to exist that's not functional, costs too much money and doesn't support the actual decisions which they need to make in order to authorize a filing?

Speaker 3: Two things. First, we can have a legal debate elsewhere, but if there are adjacent or contingent issues that are linked to what's brought forward in the 205, I think "just and reasonable" very well can extend to related issues, whether they're in the initial scope frame for the commission or not. I don't think you have to be captive to that.

And I'll let others talk about it, but I don't know if the boards could act on their own initiative to change the tariff to remove the structure. I'm not sure of who initiates that.

Speaker 2: MISO can't. It is in the governance documents.

Speaker 3: Yes, that's what I remember from New York.

Speaker 2: But to the questioner, you bring a good distinction forward, because MISO can act on its own under a 206, but we have to do a joint on a 205, and that's where you need the 58% vote from the market participants, unless it would be a significant issue of reliability, and there's a couple of other emergency procedures that kick in. Lake Eire loop flow, I think it was, was one of the issues in which that emergency procedure was used, because something had to be done for the dysfunction that was going on within the market.

Speaker 4: Great, so acknowledging that MISO and PJM and have limitations, four of the six RTOs do not.

Question 13: I think my experience in California has been a little bit different from New York and PJM. We started out in California with a stakeholder board. It was 26 members, representing sectors. And I think that could have worked if not for the enormous pressure that the energy crisis here put upon the board. So that board was scrapped. An "independent," board was put in its place. I was on both of them. The independent board in California is ultimately appointed by the governor, which is problematic when we're looking at expanding an imbalance energy market into other states.

But I look at what's happened here, and 15 years ago, the ISO board and the PUC were at war with each other, by and large. And now that has almost completely gone away. I mean, our ISO does have 205 rights. It always has. The stakeholder process is a lot like what Speaker 3 was describing for this enhanced liaison process. I mean, there is a timeline. It works. The steps are very similar to what you put up there. Sometimes the timeline gets delayed, but it's because there are tough issues that have come up that require it. And I think it works pretty well. I think we also have the benefit of, I would say, a fairly high degree of consensus among all the players about where energy policy is going in the state. That certainly isn't true at the national level, but there aren't major differences of philosophy between PUC commissioners and ISO board members or ISO management.

One of the things that I've observed with an independent board, whether it's politically appointed, like in California, or selected in some other way, is when you have a part time board without any independent staff, it becomes very dependent on management and what's put in front of them. I mean, regardless of who's been on the ISO board over the years, it very, very rarely differs with what management brings forward, and I think that creates a risk of kind of taking on a little too much of a technocratic or philosopher king kind of approach that in a different environment could become very politically vulnerable if it deviates too much from what the public at large wants.

Again, we haven't had that problem here, and I think the stakeholder process, while difficult and time consuming, is a lot more efficient than what I've heard described here for the Eastern markets. But all of this will kind of be put to the test with the process currently underway to try to figure out how to govern the Energy Imbalance Market that at this point is looking at serving parts of seven different states in the West that are even more fiercely independent, I think, than states in the East. And we'll see how all that shakes out there. They've surfaced a proposal just recently that probably won't be finalized until August. But we'll see how it goes.