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Rapporteur's Summary*

Session One.
Grid Resilience: A Problem in Search of a Solution, or a Solution in Search of a Problem?

The Department of Energy directed FERC to conduct an inquiry into whether pricing for power plants should reflect "the value" such plants provide to the resilience of the gird. The Department's underlying assumption is that the inability of many coal and nuclear plants to be economically competitive with alternative energy sources poses a threat to the resiliency of the nation's grid. Is that assumption correct? If "value" pricing is deployed for pricing purposes, what is the value assessment based on? Cost-based regulation? Administrative determinations? How do the intended beneficiaries of the proposed policy contribute to grid resiliency? What are the criteria for determining eligibility for resiliency payments? Are markets simply unable to assure resiliency? Is there something lacking in ISO planning that risks the resiliency of the grid? If policy moves down the path of resource preferences, how might that be implemented to least distort the market?

Moderator.
I'm looking forward to moderating this panel. When this panel was formed, of course, the DOE NOPR was still pending, and I thought, "Wow, that will be a lot of fun. There will be fireworks and it will be exciting." [LAUGHTER] And I was thinking that we could talk about what was the most reprehensible filing that was in the mix. How would you have written the NOPR if you had the pen and you were at DOE?

But now that FERC has acted, it probably makes more sense to be forward-looking, to look at what might be coming down the road, like, what do we think the RTO submissions might look like? How different might they be from region to region? What kind of comments will be filed in response, and how aggressive or cynical might some of those comments be? What kind of changes might RTOs propose, and what kind of requirements might FERC establish?

The FERC order is interesting, and it really shows an appreciation that resiliency extends far beyond generation and very much far beyond onsite fuel. For example, in Florida, resiliency means

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hardening poles and undergrounding. That's what we do outside this building. And the FERC order seems to recognize that T&D is at least a big part of the resilience solution. Speaker 1's slides suggest it's 95% of the resilience solution.

So one thing I'm hoping the state regulators who are here will engage in is the question, if T&D is much more important than G when it comes to resilience, is the D more important than T? And, if so, the FERC proceeding at some level has to be coordinated with state policy. Because if you take an assumption that you could actually quantify resilience, and if the resilience of the FERC jurisdictional part of the system is now five, and after supreme effort FERC could increase it to a seven or an eight, but, in a hypothetical four state region, state resilience is one, three, five and 10, then what would FERC accomplish through that supreme effort? So it seems there has to be some kind of coordination with state policy.

Speaker 1.
Good morning you all. Let's jump straight into definitions. Reliability has short-term and long-term dimensions. Short-term reliability is about keeping the lights on. The fundamental role for an operator is to work the grid you've got and be able to meet load without an uncontrolled cascading blackout. Clearly, a controlled blackout is fine, because you did that one on purpose. Long-term reliability is about resource adequacy. It's a planning dimension and has significant regulatory implications. It's been defined for a long time as keeping supply and demand in balance. That has very different implications, now that we can deliberately change demand, and now that it's up to customers to choose how much they want to demand and when. And we have not yet managed to rethink the rules appropriately for what reliability and supply and demand balance means and for a whole new paradigm of customer managed demand and having supply behind the meter. So, those are things that we're going to need to work out.

"Resiliency," (this is the definition that FERC included in its Order, which comes very close to the definition that we included in the DOE report) is "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from an event." If you remember nothing else from this panel, remember that definition, because it's the game for the next few years.

Reliability, it's a balance issue. So, a lot of the reliability metrics, historically, have been generation-related. Reliability rules definitely need to evolve as the pace of the grid changes with faster PV, faster wind, and so much more demand-side flexibility. Those rules have not yet changed appropriately. Resilience is about absorbing and recovering from events, but since events happen to transmission and distribution as well as to generation, true resilience is going to require significant T&D rethinking and asset management instead of just generation readiness, which is how DOE originally framed the NOPR.

It should be understood that better resiliency should improve reliability, particularly if you define reliability from the customer perspective, and if you define resiliency as what matters to the customer, not just what happens to the grid or what happens to generation. I think that's the fair thing for most of you, since our job is to get energy to customers, not to just get energy from a power plant to the bus bar at the start of the T&D system, since 95% (or 99%, depending on how you count) of customer outages come from transmission and distribution failures, not from generation shortages or fuel shortages.

Generation resilience is fun to talk about, and a lot of people have made a lot of money talking about it in the last six months. But it doesn't do much to help customer resilience. I'm not trying to say fuel diversity doesn't matter. I'm not trying to say power plant readiness and inertia and all those things don't matter. They do. But generation resilience in and of itself does not do much to improve customer resilience. My personal view is that we should prioritize reliability and resilience for the customers and measure them from the customer's satisfaction point of view, and we should not prioritize reliability and resilience, nor should we measure them purely and only from the generation standpoint.

So let's talk for a minute about coal and nuclear reliability and resiliency. The advantages of coal and nuclear plants are significant. They have fuel on site. They provide spinning reserve. They provide inertia. And they're a valid and important part of a diverse resource portfolio. The disadvantages are that they are slow starting, slow ramping. They have high capital costs. They're old, and they are very large units that create reliability contingencies. And they are slowing down the grid, in terms of providing essential resiliency and reliability services. They can't provide most of the ancillary services.

Nuclear plants are almost always online. Most of you are aware that coal plants, most of the ones that are now operating, are so slow to move and so expensive to operate that they are not being dispatched very often. So, they have falling capacity factors, and it is often more cost effective to keep your coal plant offline. So it's wonderful to be able to provide inertia, but in order to provide inertia you have to be online. And if a coal plant cannot get day-ahead dispatch for an extended period of time, it won't be there to provide inertia to your system. So, if these plants are online, they can give you reliability attributes like frequency response and voltage control and a little bit of regulation. Coal can do load following. Nuclear certainly can't. Neither of these units can give you fast cycling, fast ramp, low minimum load or contingency reserve.

All that means that, for most of the things that we actually value and need for reliability and resiliency, coal and nuclear can't do them. We can get resiliency attributes of fuel diversity and fuel assurance onsite, but the long-term value of that, relative to operating the grid day to day, hour to hour, minute to minute, is significantly lower. So, you can't get important operational and resiliency metrics and benefits like black start, distributed operation, transmission and distribution improvements, and we've certainly seen a lot of instances (hello, Pilgrim Nuclear Plant), when they are vulnerable to transmission and distribution, weather (hello, flooded coal plants in Houston, or frozen coal piles in Philadelphia)—there are a significant number of weather and climate problems, like having droughts make your cooling water disappear for nuclear plants and other gas and coal plants. So, we know there are significant problems that coal and nuclear plants face that make it very difficult for them to contribute fully to reliability and resiliency.

This slide is my cheap, smartass version of the excellent PJM analysis that was done last spring, in terms of major threats and impacts to electricity service and why we want resource diversity. And you probably have other favorite threats and impacts that aren't listed here, but this seemed to me to be an adequate rogues' gallery. Everything is vulnerable to equipment failures. That's why it's good to have a diverse system that is diversely located. I neglected to put in human failures, because as long as humans can touch a system we will manage to screw it up. Either by active choices or by setting the parameters wrong so that it comes back to get us later on.

Since a lot of the argument in the DOE NOPR was about inertia (well, they sort of led with it, and then dropped it because they didn't know what to say about it), let's be clear that we need inertia for frequency response. Inertia is not all that valuable purely for its own sake. Rotating mass-based inertia, as from coal, nuclear and natural gas, works, but, again, you have to have the plant online for it to be there. Electronically-coupled inertia, as from wind and solar, works within a narrow planned performance range. Some of the recent commentary about the value of electronically-coupled inertia is absolutely true. You can't use electronically coupled inertia for a long time. But it does a lot quickly in a narrow band. And that is highly valuable.

Storage and demand response can provide large, precise, fast primary and secondary frequency response at lower capital operating and carbon costs than coal and nuclear. And there is no reason why we can't be turning coal and nuclear plants into synchronous condensers, frankly, so that we'll get some of the benefits of storage. Most importantly, we do not yet know how much inertia-based frequency response we need for a grid with higher levels of PV and renewables. We can get frequency response from a lot of other resources. We have not yet done the analysis, and we need to understand the proper roles and requirements for inertia relative to other sources of frequency response and other flavors and types of frequency response that are needed operationally. So, we should not overstate the need for coal and nuclear plants as providers of inertia and frequency response until we actually have done that analysis and have competent answers, given the speed at which the grid is operating today.

We are trying…well, someone is trying to make arguments about the value of coal and nuclear inertia based on assumptions about a grid that was dominated by coal and nuclear plants and 30 year old rules. And those are wrong, and they need fresh analysis.

Let's look at the numbers for capacity and retirements. The sky is not actually falling. Total U.S. generating capacity this year is 1,190 gigawatts. Coal capacity was 24% of that in the U.S. 59 gigawatts retired over a 14 year period through 2016. More of that converted to natural gas. So, it's still online. Another 21% is expected to retire by 2020. That still leaves a fair amount of coal plants online. I don't think we're all going to disappear (unless you're Larry Makovich, who seems to be the only person who does think it's all going to disappear).

Total nuclear capacity in November was 108 gigawatts. (This, too, is a FERC number). Almost five gig retired between 2002 and 2016. An additional 5.6 gig could retire by 2020. That's still over 90 nuclear plants online. I think we can stagger along for a little while longer with coal and nuclear plants around.

So, you know, if you're an economist, everything looks like a market, doesn't it? It ain't. We design wholesale energy markets to incent generation (and recently DR, although that hasn't gone so well). So, we've got markets for energy capacity and some energy associated ancillary services.

So, we have markets. They still need work, but most of the things that effect resiliency and reliability are not in fact incentivized by wholesale markets, like energy efficiency and transmission and distribution. And we are not effectively or precisely compensating for things that affect resiliency and reliability and, essentially, remember, the ability to keep customers lights on. So, messing with markets will not necessarily solve those problems. We'll keep dancing around, but these are not all nails and not every tool is a hammer.

We get a lot of reliability and resiliency factors through nonmarket avenues, including NERC reliability standards, interconnection requirements, grid operator practices which have become better and better, planning practices, fuel supply and coordination and scheduling, mutual assistance… Most of these affect transmission as well as generation. And what we are doing when we mess with markets is almost exclusively mess with generation. So we as a community need to understand that changing markets isn't going to materially change most of the things that affect resiliency from the customers' point of view. So, we need to be looking at how do we do compensation and how do we target fixes that improve T&D and other things…mutual assistance, we don't have a market for that. Maybe we probably shouldn't. So, we really need to separate your enthusiasm for fixing markets from your ability to solve the damn problem.

A lot of these attributes need to be compensated adequately, and they are valid and important, including zero emissions, inertial frequency response, fast response, and hardened infrastructure assets that can withstand multiple threats. These have significant value, but it is unlikely that we can deliver those purely through market mechanisms. We need to go back to the market and develop better definitions, better metrics, and better products that are relevant for reliability and resiliency, not just for the way we've always done it, and we need to figure out how to compensate those attributes. We need to study a lot more stuff, but not everything needs to be competed.

Question: This is a clarifying question. But the question relates to the old question of fuel diversity. It's a topic we hear a lot about. And you made a case here that it doesn't belong in the category of resilience, if I heard you right, in and of itself. And I guess my question is, did I get that right, and if I did or didn't, what's the home, if any, for that issue? Is that a policy home that belongs somewhere not attached to the word resilience? Does it not belong at all?

Speaker 1: It was not my intention to say that fuel diversity does not matter.

Questioner: Well, what's it home then?

Speaker 1: Does it need a home? Fuel diversity does not provide resilience in and of itself. It improves your odds, and it has implications including for some common modes of failure, but I don't know that it has a home. I think it's more important to look at the impacts of fuel diversity than at having fuel diversity for its own sake. I mean, you will recall that one of the premises of the DOE memo that kicked off the reliability study was that we're losing coal and nuclear plants and fuel diversity's going to help, when, in point of fact, fuel diversity in the United States has in every RTO and ISO improved markedly over the period.

Questioner: Let me just follow up. So, you're saying it's not a mission in and of itself. It's written for policy makers, federal or state. It should not be its own mission. I just want to clarify.

Speaker 1: Yeah. Thank you.

Question: I want to try and home in on that question, because I think it's an interesting one. Speaker 1, what I hear you saying is that fuel diversity is not sufficient for resilience or reliability. But is it necessary?

Speaker 1: It depends. I can have a highly diverse basket of crappy resources and be no more resilient, even though I'm much more diverse. So, I think the answer is, "not necessarily." It may be necessary, but not sufficient, to have fuel diversity. How's that? It is valuable, but not a goal in and of itself.

Question: I think some of the RTOs at the moment have limits on how much DR and battery storage can provide some of the ancillary services. And, from a technical perspective, is there logic to it, or is it possible that that amount could be unlimited from a reliability standpoint. Is that a concern? If you could explain a little bit more about that. I just don't know.

Speaker 1: I'm going to give you a technical answer and a political answer. The technical answer is that, certainly, almost every RTO, every region, every market, that have limits on DR and battery storage to provide ancillary services have almost surely set limits that are significantly below what current analysis of the cost and response capabilities could be. But not all have done that level of analysis, given recently capabilities and market trends. The other answer is that every operating and technical committee within RTOs and ISOs is dominated by incumbents from the generation and transmission communities that don't necessarily think that it's a good idea for demand response and storage to be taking bread out of the mouths of precious generators. And when you complicate that by the question of whether storage and demand response should be controlled by transcos or by competitors to generation, it makes it even more difficult to get reasonable compensation and calculations for what is the technical capability. Is there anyone I haven't insulted yet?

Question: So I had a question on one of your last points, that the markets aren't sufficiently compensating some of these important reliability and resilience attributes. Are you arguing that the solely that the markets need to be redesigned to compensate for that, or are you arguing more for non-market policies to provide that support? And, if so, what types of non-market policies are you considering?

Speaker 1: I am arguing that many of these things need to be addressed through non-market means. And some of those include some cost of service regulation for better transmission and distribution measures. All of the subsidies that were contemplated by the billions of dollars that could have been paid to coal and nuclear plants across PJM could certainly buy a whole lot of improvement in transmission and distribution and energy efficiency and storage. That would do a lot more for customers than buying bigger coal piles. Did anyone bother to mention yet that the average coal plant storage was 60 to 75 days, not 90? I just thought I'd put that out there. But, also, we've got interconnection requirements. We've got a bunch of ancillary services requirements. We've got better planning and analysis. There's a whole lot of ways to do this, and there are good means to calculate a lot of these things and compensate them that don't require market competition. Thank you.

Speaker 2.

These are just my opinions. So, I'm going to give you a little bit of an engineer's perspective on this. I teach in an engineering department, and I'll give a rogues' gallery of stresses on the systems, and talk a little bit about how engineers and economists address these.

One trend in engineering analysis in all infrastructure areas, whether it's water or transport or energy, has been to move from stressor by stressor engineering standards that are very conservative in terms of safety margins to looking at the probabilities of stressors, their impacts, and the resilience with which the system responds to them and then come up with an integrated system-wide measure of the resilience and reliability of the system, so you can compare measures that address different stressors.

So, remember Speaker 1's table of all the different things that can affect the system. How can we decide which of those to emphasize? So, engineers have developed a lot of systems and methods to enable those to be compared. Unfortunately, they work really well with the more traditional RA (resource adequacy) types of concerns, such as a random forced outages or maybe outages of renewables that are correlated, and they don't do well with what we're really concerned about--the big things that could leave Puerto Rico still 20% dark months after Hurricane Maria.

So, anyway, let's first look at how engineers approach this. So, over time, you may have something happen that causes an outage and so, this axis of the chart is the magnitude of unserved load. And from an analysis of this you can come up with several things that engineers like to quantify, such as the reliability of the system, which is the fraction of the time that you expect there isn't unserved energy. And resilience, from an engineer's point of view, is basically one over the duration of these outages. And this is consistent with the FERC definition that Speaker 1 quoted. Given the stress, how quickly can you react to that and get the system back up again? And you can quantify this for a particular stressor, or you could try to do this probabilistically, looking at all possible stressors. And, at least for generator outages, this is what we've been doing for 50 or 60 years. We need more than one set of indices, because two systems with the same reliability might have very different resilience.

Here is an example of a non-resilient system, where something happens and it takes a long time to respond. Whereas, here's a resilient system, where something happens and you're quickly back up again. This is, in part, important because the economic consequences depend on the duration and severity. There's actually evidence that residential customers prefer this ("Let's have one big outage and get it over with, rather than lots of little annoying ones"), whereas industrial and commercial customers prefer this one.

Here's another system with the same reliability, but let's say a one in 500 year frequency of an event like we see in Puerto Rico, where we lost 80% of the power right away, and, months on, we still don't have 20% of it. The system has the same reliability, but very different resilience.

So, FERC has posed 24 questions. I'm going to pose some questions. They're not the same questions. But I'll refer to them several times. You can ask engineers about what the system's overall reliability/resilience is, at least for generation-type forced outages. You can try to diagnose the causes of the problems, and ask how the resilience of the system would change if you do something. Economists will tell you what that's worth, and then what the resulting net benefits might be, which actions might be most cost effective, and, finally, you all are good at least at suggesting ways in which we might rely on markets versus NERC rules versus interconnection standards, whatever, to have these things happen.

When we want to rely on markets is when you have to coordinate the actions of a lot of folks, and you're not sure which particular actions--demand response, or new generation, or what--will be more effective. And so you want a level playing field. If it's a private good, you can trade it. You can see who owns it. And, finally, things aren't really awful. So, when you do have a failure, it's not terribly severe. They happen often enough that you can assess the probability.

Standards and regulations—that's the old way we used to do engineering of just setting a safety standard that's very conservative. You need to do that when, well, if a solution is obvious, and you should just implement it. Or if actions by one or few parties are needed, or when there's a public good. Or where failure is potentially catastrophic, and we have no idea what the probability is.

OK, so let's look at this rogues' gallery. The simplest case is classical generator adequacy. We assume that generator availability is like a coin flip, and you flip 20 coins, and 18 will come up heads. So, some of you may fondly remember the days of seven percent load growth. But this document (*The 1970 National Power Survey*) championed the use of probability methods to comprehensively look at the reliability of a system--things like loss of load probability and expected load carrying capability. Ideas that are still useful today for many, but not all, stressors. So, as an example of this sort of insight, if you have a bunch of generators, a 10% forced outage rate and normally distributed load, and you're trying to meet a one day in 10 year LOLP standard, this sort of method quickly shows that larger generators allow you to support less load or are less reliable than smaller generators. This is a value to being smaller. And this, by the way, is disregarded by ISO capacity counting rules, for reasons I can't fathom. It's very easy to do. Interconnections increase reliability. For two systems on their own, you need a 14% reserve margin. Together, they need an 11% reserve margin. These insights are very valuable and useful today.

Markets can play a lead role with this sort of thing. In Texas we have spot markets being the main way to motivate resource adequacy, inspired by Saint Fred Schweppe of MIT's results, showing that a spot market can deliver the reliability and flexibility you need--in theory, but in a lot of places we have belt and suspenders, the suspenders being capacity markets, and they can be very helpful if scarcity signals are diluted or long and contract markets are absent. I happen to support capacity markets of some form for the political insurance that a capacity market provides that capacity will be there. But you need good rules for them to work--things like forfeiting payments if you're not around when you're really needed. But, of course, the more you do that the more it smells like a spot market system.

And it doesn't work for everything. In California we have this lovely thing called the "Flexible Resource Adequacy Criteria and Must Offer Obligation" (FRAC-MOO) that's being developed, where we're trying to motivate flexible capacity, but we're having a devil of a time, tying ourselves in knots, trying to compare apples and oranges. How do you compare a flywheel with 15 minutes of energy versus demand response that can only be called four times a month versus fully dispatchable turbines? And this is very difficult, and it's arguably arbitrary, how you weigh these different things. So, that's why at least the MSC (Market Surveillance Committee) has recommended that we really work on improving the spot market and try to have most of the compensation for reliability services come through that, rather than through capacity.

Another threat to reliability is correlated outages. This is a little bit more complicated. You all know about duck curves (which to me look more like a penguin curve). [LAUGHTER] Here's an example of a problem where the Northwest lost all its wind for 12 days. There are high correlations. But we can deal with that. Hammers are for nails; wrenches are for bolts, to use Speaker 1's metaphor. I think the wrench of LOLP can still be used here, but for the nails of system wide outages related to transmission, we need a different tool. So, for example, a slight correlation among outages of resources will dramatically increase the reserve margin you need to maintain the LOLP that you want. That's an insight you get from simple methods, and I think that's still valuable.

When you're counting capacity, we need to consider the fact that the marginal value for lots of different sorts of capacity dramatically drops as you add more of it. Namely, wind. It should be locational. But ISO's don't do this. You have one number for all wind throughout the entire ISO's footprint. And it reflects an average contribution to reliability, rather than the contribution of the next unit.

Well, what are the implications of getting capacity credits wrong? This is a simulation of the Texas market, and it's about a one percent difference if you give way too much credit to renewables or way too little credit or don't locationally differentiate. And I think the problems we're talking about here today are not one percent problems. We're talking about much bigger resilience-type problems. So perhaps this is not so interesting, but getting credits right can save you a couple hundred million dollars a year.

All right, the third source of threats to reliability is correlated multiple stressors. "When sorrows come, they come in battalions," said King Claudius, who was in deep trouble because Hamlet knew what he had done. The seven plagues of Egypt coming to California, that, together with severe market design problems, caused the 38 stage three alerts and load curtailment that we saw in 2001. So, better market design could have had California ride through that.

Reading the ISO New England's report from last week reminded me that still even three plagues could really cause problems. And in this report they say, alarmingly, that under nearly all scenarios, in 2024, 2025, they're in trouble because of fuel. So, unfortunately, this is not something that the classic engineering methods can do a good job on in terms of giving you resilience and reliability in comprehensive probabilistic terms. Now, we're getting more towards the old fashion engineering way of doing things, where you have a safety margin that's pretty conservative and pretty arbitrary. It's not scientific. It's a way to waste a lot of money. We need better methods to deal with this—with extreme system-wide events such as the Texas freeze. So, generation can be the cause of problems. We had four gigawatts curtailed then. Not a huge disaster, but pretty awkward there for a few days.

And then, again, LOLP is completely useless for one event at one reactor. They shut down about 50 gigawatts, 17%, of Japan's capacity. Suddenly they had to do without nuclear for a while. It was pretty hot in the offices. These methods aren't very good for that.

But most the problem (I agree with Speaker 1) is on the T&D side, and not the generation side. So, here's some data on that from a paper that's not yet published (and it doesn't include 2017, which, with Maria and so forth, is way up there), and nearly all these customer outages are due to T&D problems, not generation problems. There are all sorts of reasons why transmission problems have difficulties. I was a kid in New York City in 1965. I was luckily not there in 1978, but I was in the Northeast in 2003. And as systems get more renewable-heavy, we need more inertia, more frequency response. And it's a problem that I think is solvable.

Something that may not be solvable is when we have government leaders with twitchy fingers by buttons on their desks. Of course, if that happens, maybe we have bigger problems, but if the grid goes down for months and months, that's going to be a real problem. And people are starting to pay attention to that—and, again, we can't deal with this very well probabilistically.

In California, earthquakes are a really big concern. The really big one is coming, and if you lose a lot of transformers, we don't have the spares available or positioned to get the grid back up quickly, and I think that's an issue that needs a lot more attention.

Engineers can tell you the consequences of stressors. So here's a college of mine who is really good, and this is his prediction, in real time, as the hurricane was heading towards Florida. He got the geographic extent right, but what actually happened was a lot worse. But you can still use those sort of models to explore questions like, well, as the climate gets warmer and maybe the frequency of bad storms goes up, what happens to the extents of these outages? But we can't deal with this probabilistically.

There's a great paper by Roger Cooke on how co-insurance markets are going to be incapable of dealing with these sorts of risks in the future, and so, for this reason, we need central planning and rules and regulation, although markets can still play roles, for example, in acquiring inertia, and bidding can apply, in general, to equipment servicers. There can be performance-based rate making.

OK, so just to tee things up for the discussion, of all these problems, these are the ones we really should focus on. Traditional ones are still definitely of concern, but the long-term ones, or the system-wide ones are a big danger. We need to get a sense of, not just their consequence, but their likelihood, to make sure we're allocating resources correctly among solutions for all of these. And that concludes my presentation. Thank you.

Question: On the insurance issue, when you say, "expensive," does that imply that the benefits of the insurance do quickly repair the systems? So, when you say it's expensive, it might be expensive from a rate payer's standpoint, but maybe not from the standpoint of the benefits to society of having power more quickly.

Speaker 2: Yes, that could be true. The specific point that Cooke was making there is that, with climate change in particular, with correlations among these big storms, as we saw this year, it doesn't take much of a correlation for you to bankrupt re-insurers. The risk tail goes way out, and so, if re-insurers recognize that, they won't provide insurance, or it will be extremely expensive.

Question: So, in the previous presentation we heard Speaker 1 kind of throwing up her hands about markets and saying, let's take a cost of service regulation approach to some of those resilience solutions. And just to try to understand, Speaker 2, where you fall on something like counting resources for capacity value, you're saying, "OK, try to understand their marginal contribution. Try to understand their locational value," and in a market like the one that persists in California and the rest of the West, I'm wondering if you're making a recommendation about market prices trying to figure out that specific contribution, or whether that's really a recommendation aiming toward regulators who, in the West at least, have the responsibility to enter these resources in the market through rate base or long-term contracting.

Speaker 2: So, in the West, if we spread the California market around the West in a day-ahead form, or if the SPP and Mountain West and others do that, they're going to have to wrestle with resource adequacy issues. And the idea that we were talking about a year or two ago, when this looked like a real possibility, was using an ELCC (effective load carrying capacity) type of approach to quantify the value of resources. We were wrestling with the issue of how to do marginal versus average. But there seemed to be a lot of stakeholders who were supportive of using an analytical approach to quantify the credit, and then having market mechanisms. As you know, resource adequacy has been a very fraught issue and in California, where we don't have a transparent way of trading it, and maybe having a more west-wide market would nudge California in what I think would be a more appropriate transparent market direction to deal with that left hand type of resource adequacy issue.

Question: So, you're pointing at the multiple stressors. Speaker 1 pointed at the multiple stressors. It sounds to me like we're not viewing the resource adequacy by itself. We're trying to solve an equation of multiple risk variables. It's not just whether there is enough, but whether there is enough of the right balance with the right resources to be able to address whatever the stressor might be, knowing that there are multiple stressors, and the risk of each one is different, and the ability of a portfolio to meet each one is different. How does an energy market or a capacity market solve for that many variables?

Speaker 2: So, if you go the capacity market route, you can differentiate things. So, where one resource can help you satisfy more than one constraint, it can have revenue streams from more than one constraint. So, in the FRAC-MOO proposals, one example of that is where there's an overall resource adequacy constraint, which gives you a system-wide payment, there's also a FRAC-MOO constraint, and if you're the right type of resource you get some more money there. And there may be also local RA requirements. So, your capacity requirement is actually multi, you're providing multiple attributes, and you're getting paid for that. They key thing is figuring out, what is the constraint? What do individual resources provide to help meet that constraint? And then you need the market mechanism by which the offers are made and are cleared and are paid. So, from one constraint to three constraints in California, to more, it's conceptually possible, and there's no reason why you couldn't have multiple streams. So, the key thing is defining property rights, market mechanisms to clear the market, and setting a constraint that is a reasonable constraint, whose benefits are would exceed the cost of meeting it. So, I think it is possible.

Speaker 1: Speaker 2 just gave you a fabulous academic answer to a very narrow question. If you define resiliency, as I offered at the front, as what happens to customers, not what happens to generation, then the most cost effective, no-regret solution is to give a whole lot of energy efficiency and a whole lot of distributed generation, because, you know, the odds are significantly high that they're going to do far better for customers, whether it is plagues of locusts, or forest fires, or earthquakes. They are going to make customers' experience more survivable in a highly threat-rich environment. So, there are several no-regrets options, like more efficient appliances and significantly more protective buildings, that will make customers and society better off, regardless of how you screw around with the markets and the math on all those other measures.

Question: I was interested in the comment about insurance rates or insurance if you can't get it. Why, in your taxonomy of things, doesn't the point at which a market can't supply re-insurance or lay off those risks, why doesn't that just simply tell you something about, maybe you shouldn't do it, which I think goes to what Speaker 1 just said, versus what you seem to imply, which is, no, go to a different model and centralize the risk, and spread it across load, or whatever it is? Which were you trying to convey?

Speaker 2: I guess I was trying to not draw a hard line, but to say that just relying on private parties to figure out the best thing to do, relying entirely on markets, is unlikely to work, because we don't know the probabilities of these events, and the tails are so thick that you're not going to be able to get insured for them.

Speaker 3.
I'm very happy to be here. And so, I'll just jump right in.

We all know what the DOE NOPR said. And I'll talk about my views on where we are on the market-versus-construct spectrum. I'd like to take this time and note that I don't speak for anyone but myself. This is just me.

And so, the economist in me wants to kind of take a first principles view of things. When I was on the inside, I didn't hear the term "construct" that much. (Inside FERC, I mean, not like a prison or whatever.) [LAUGHTER] I'm on the outside.

We talked about markets in the context of RTO market design or market power or market-based rates. But then I heard this term "construct," which has fascinated me since I've been on the outside.
It's one of those words that's pronounced differently whether it's a noun or a verb. And, actually, there are a number of examples of words that are pronounced differently depending on whether they're a noun or a verb. Construct is just one of them.

On the spectrum of pure markets there's ERCOT and Alberta, maybe, and on the other side you have "constructs"-- the FERC-regulated RTOs that have various degrees of intervention from outside and inside.

And then let's go back to Econ 201. In Econ 101, everything works perfectly, right? That's in your first micro class, but then you take intermediate micro, and you study all the things that can go wrong. And we have externalities. This is one thing that drew me to this industry. If you're an externality fan, they're all over the place in electricity markets. We've got positive externalities, and the classic public policy response is to subsidize the positive. We have renewables and demand response. We think there's a positive externality there. And so, those things are subsidized. And you tax the negative, whether it's NOx permits or greenhouse gas or regulations. And those feed into the wholesale electricity markets that FERC regulates and into the whole host of policies, both external, that FERC has to deal with, and internal, that FERC applies, all in the name of keeping RTOs basically spitting out just and reasonable rates. That's ultimately the goal.

And so, resilience comes up. And I'm not an engineer. Speaker 2's graphs are really cool and they make a lot of sense. He does a great job explaining it. But I'm an economist. I'm not an engineer. But if resilience is a "thing," as they say, then maybe it's worth subsidizing. Or, maybe it's worth having a carve out in a specific contract, and making sure that we have resources that provide us resilience.

And we see this all the time. That was kind of my point in my comments on the NOPR. This is not new. We subsidize lots of things. We have cost-based carve outs for lots of things. We tax things. And so our markets are not pure markets. They're constructs. We try to use market-based mechanisms to solve a problem. But there are so many nonmarket-based mechanisms in there that (and I've argued the other side. I've argued we need to push the other way on the spectrum towards more of a pure market, with fewer subsidies, fewer intervention) given where we are now, and given that we care about resilience, if it's a thing that's providing some sort of external benefit, one possible solution would be this kind of thing proposed in the DOE NOPR.

Can we conclude that these RTO constructs aren't really markets? I wouldn't go that far. I think they're constructs with market mechanisms. I've had a couple of my old buddies from Dick O'Neill's Office of Economic Policy, and I asked them, "Have you given up on markets?" and the answer's no. But, given where we are, and if we care about resilience, we either need to stop all the things that are suppressing prices…and I'm arguing there are a lot of things to suppress prices. There are a lot of public policy interventions, FERC interventions, and they all tend to go the same way. They all tend to push prices down. It's not like there's this random pattern where some things push it up, some things pull it down, and it all comes out in the wash. It seems to be a series of things that push prices down. Related to that, there are so many things pushing the prices down, we're going to push these generators out of the market, and then what?

So, we don't claim to have competitive markets. Joe Bowring's annual report asks whether we have competitive market outcomes. Not whether the markets are competitive. Whether all these series of things that we do within these constructs result in competitive market outcomes.

And so, I've made some arguments that we've done a number of things that have artificially suppressed prices, that are driving certain generators out of the markets.

So, these are some quotes from affidavits that I submitted in the DOE NOPR proposal. And basically, the gist of these two bullets is that these things are works in progress. We are always tweaking these rules. This is another tweak. It doesn't mean the sky is falling. We have figured out ways to absorb these various policies in order to keep the goal of just and reasonable rates, and in order to find a way to compensate that which is not compensated, and that's kind of a positive externality. And if resilience is a thing, then there ought to be a way to compensate for that.

And we've seen a lot of retirement, and recent retirement, in generators, particularly coal and nuclear. It's no secret. It's no secret that was a big topic of this proposal. And Speaker 1 brought up a good point, that in order to provide inertia and the things that support frequency response, the nuclear plants and the coal generators need to be online. I agree. My argument was that the reason they're not online is because prices have artificially been suppressed in these market constructs by a number of other policies. So, either go all the way, go full Scott Miller, and let it rip, with very little intervention, or, if we're going to be here, and we're going to try to value these things, this proposal found a way to value these things.

And so, about the retirement. It's no secret. There's been a lot of it lately. There's more of it that has been in RTOs than not RTO's, but the advanced analytics person in me thinks, well, there's more generation in RTOs than non-RTOs. But there's also different policies in RTOs versus non-RTOs.

And then, this is just sort of the gross generator retirement we've seen over the last five years. And I get that a lot of it is due to cheap natural gas. I mean, two dollar gas completely changes the economics of dispatching an electric system. And it's a wonderful advance of technology, that we have this gas so plentiful and so cheap and right here. But there are also non-market reasons why these guys have been retiring. And if there's a value to having them around, and they provide external benefits with resilience, and because of seeing artificially low prices, they're exiting the market, that's not efficient exit. That's inefficient exit. And the market constructs that we have right now, in my opinion, have been biased against certain types of resources because of the subsidies that are driving down other market clearing prices, whether it's in energy markets or capacity markets. But, full disclosure, I've done most of my RTO work in capacity markets with a foray into demand response while I was at FERC. I was staff then.

But the question is, well, capacity performance seems like a very good idea. And so, there's the notion that capacity performance will provide the necessary revenue to keep these resources around, these resources that provide resilience. But capacity performance prices haven't exactly gone through the roof. Not that they necessarily should, but there are a lot of questions. What should people offer into a capacity market? What's a competitive offer into a capacity market? I agree with the New England Market Monitor and the PJM Market Monitor that it's really an opportunity cost calculation. If you're a resource, and you're there, there's two states of the world. I'm in or I'm out. If I'm in, I get my payment and I face performance risk. And I might be able to over-perform a little and make a little more money. If I'm out, I don't get a payment, but I can make big money if I over-perform during events. But there's so much uncertainty about how many events there will be in a given year, what the performance penalty will be, that I really sense that there's a sort of an attitude of, "I'll believe it when I see it, when I get my bonus payment." So, the opportunity cost calculation is, I think, such that people have incentive to underbid, and so it may not provide the revenues to the resources that we were hoping it would provide. It may not provide the right signal, and that's because of this sort of opportunity cost under uncertainty calculation.

Highlights, conclusions. I made my construct point. Cost-based contracts are woven into these market constructs already. For example, reliability must run resources, they're out there. We recognize external benefits and we find ways to keep things around, and to make sure things stay around that provide external benefits. And, in my opinion, if resiliency has a public good or positive externality element, then it's worth finding a way to make sure they stick around, if these resources provide it. And baseload units have retired due to economic forces, no doubt about it. But also because of non-economic forces--lots of government intervention into these markets and constructs. So, that's it. Thank you.

Speaker 4.

Good morning. I thought instead of slides I would try to just fill in and raise issues that haven't been mentioned. Obviously, from an abstract perspective, we're looking at this as suppliers in these markets from the wholesale generation side, and especially in the three eastern RTOs that were the subject, so to speak, of the NOPR. Obviously, there was a question about MISO, we can debate that later. As the Moderator said, we think just about everybody else except those receiving payments, including those who are not participants, strongly oppose the NOPR. And I think the Moderator properly framed this as us looking more forward than backward, but I think it's important to still talk about some of the issues and debate points around the NOPR, as Speaker 3 did, quite correctly, from his point of view, because this hasn't been mentioned. I think we should talk about it.

While the Commission, in our view, and in the view of most commenters, properly terminated the NOPR, these arguments that were made in favor of it are very much alive and well at the state level, as many of the folks here in our group know full well. In fact, one legislature, in New Jersey, this very morning is considering legislation that would follow the "logic" of the NOPR proposal. In terms of the commercial context, we touched on this a little bit, but whenever we talk about these things, I try to back up and say that there is a commercial context here, and lots of folks in the room are in these markets. But from our perspective, let's not forget that we do have flat demand--seven percent growth is way back in the review mirror. We have historically low prices, or, as Speaker 3 said, disruptive technologies, but the key point is that's affecting everybody in the wholesale market, not just coal or nuclear or any particular subset. And that seems to have gotten lost.

It was four years ago this month that a group of CEOs went to FERC and met with all the commissioners. They said, "Oh, you're here to talk about capacity markets." "Actually," the CEOs said, "No. We're here to talk about energy markets and the need for energy price reform." That need has only grown, and one of my concerns, that I'll come back to quickly in a minute, is that I think this whole idea that the debate, going forward, particularly at FERC, is about resilience or resiliency is, I think, a distraction, and could be counterproductive for all the reasons that we heard from Speaker 1 and Speaker 2. This is really a T and D issue, not so much a generation issue. So, while FERC clearly is a key part of it, I think that for this resilience framing to become the dominating or controlling framework for all of this is going to be difficult.
From our perspective, I know I have CEOs who said that just the proposal itself was negative in terms of how investors viewed a very capital-intensive industry. And so now, going forward, in addition to losing the time from the restoration of the quorum to the present, and time that was largely dominated by this, there's a whole host of things that we have talked about at these sessions that will unfortunately be lost.

The topic was, "Is this the problem in search of a solution or a solution in search of a problem?" I think it leads us to generation again. I put T and D in a different category. If I had to choose, obviously I'd say this is a solution in search of a problem, but really it wasn't that at all. I'll say here what others have said, somewhat more directly, outside this room. This was never about a public good. This was entirely, entirely, provably, about private gain for certain market participants.

In terms of the three questions that were on the list for the topic that I thought were important, the first was, was the Department's assumption correct that the inability of any coal or nuclear plants to be economically competitive posed a threat? I think we've heard all the good discussion about what resilience means or does not mean. In an age of tweeting, I think the Rhodium group probably single handedly punctured the balloon on this. I think it was the first day or two when they came out with the statistic that was actually based on the Department of Energy filings that somehow the Department of Energy itself didn't find before it made the proposal. That it was, what? .0007 percent of outages were from supply, and you've heard that from the other folks as well. I think --

The other thing, not to beat this point too much, is the fact that the assumption behind the proposal…and, again, it's not just a proposal that's been terminated, it's what's going on in the states right now that we're actively engaged in. If anybody hasn't seen it, I'd look to the testimony last Tuesday of this week that PJM gave before the Senate Committee on the performance of the grid during cold weather. Andy Ott was one of the witnesses. Gordon Van Welie from ISO New England was there, and I think there was some good outage data in there. It was the weekend before the NOPR decision came out. People were starting to get nervous, like, how's the system going to perform? And I had trade press saying, well what if it's the polar vortex? Of course, as we all know, and this came out in the hearing in the Senate Energy Committee this week, world history did not stop at the polar vortex. During this debate, and it's true in the states as well, one would have thought that nothing was done after the polar vortex to make the grid…call it resilient, or reliable, or as Speaker 1 correctly says, to make the grid serve customers, and, again, this week, in the Senate hearing, all the things that have been done, from testing equipment to planning, to all the rest, was described.

I will make this very brief. I think a key fallacy in all this resilience debate (and this came out again in the Senate hearing) is that all plants of a particular fuel type have been lumped together as if they're all equal. So, all coal and nuclear were presumed to be some royal charter out for resilience, or whatever we're calling it, and everybody else--gas and renewables and demand side--did not contribute at all. And, again, I hate coming back to the Senate hearing, but I highly recommend people listen to it, and at least get the testimony from the website, because, again, there was a lot of data and discussion to the point that, in fact, there are certainly some coal plants that contributed and some nuclear, but also a lot of gas and renewables.

When the fuels fight, nobody gets anything done. We used to be united, until a year or two ago, but, splitting up I think it's made it harder to accomplish that.

The other quick point I'd make, if you haven't heard this, the Assistant Secretary of Energy at the Senate hearing actually said (it's on the record, it's in the hearing transcript) that he wants an appropriation from the Senate to the Department to study resilience and determine what it is and whether we have enough of it, and so on and so forth. And one would have thought that request would have come in before any of this was done. [LAUGHTER]

Secondly, I have to say this quickly, the second question on here was, if you're going to value pricing because of cost-based regulation, is it an administrative determination? Most of us read the NOPR, I think quite correctly, as returning to cost-based regulation for those with 90 days fuel. I have to say, just for the historical record, I asked several people at the Department of Energy about how FERC rate cases would proceed to determine the cost-based regulation about 90 days onsite fuel, and I was told there would be none. It would be written into the tariff and administered by the RTOs. Similarly with cost allocation, they didn't know how that would work. And then, when I asked about, well you know, you're going to upset the dispatch (back to Speaker 1's point), they don't provide services unless they're running. The point was to keep these on, because, supposedly, they were needed to run in order to keep things resilient. And then, when I asked how was this going to work with dispatch, I was told it would not impact dispatch. Plants will be dispatched as they've always been, and we pay the plants to be on standby, but, as we've heard, unless they're actually spinning reserves, that doesn't really quite add up.

And last, but not least, the question was, if resource preferences are pursued, whether it's for resilience or anything else, how can we do this so as to least distort the market? I think the answer is, you can't. California doesn't work. The mushy middle hybrid is not sustainable. We have to pick the lane, as Commissioner Clark says, and stick with it. And I think if we're going to go down the attribute trail, we spent 21 years on acts of omission. We haven't done lots of other things. We do one thing, which is competitive wholesale markets that are well functioning, but I can tell you, having just come from the Board meeting and talking to investors recently, if there isn't a clear determination this year (I've said this every year for four, years so maybe it will eventually happen), not just at the Commission, but at the

Department of Energy, and in the states, that you want private investment on a competitive basis, then this question about preferring resources and attributes means everybody's attributes are going to be valued. And, Lord knows, I'm not sure there's enough computational capability to figure all that out without seriously distorting markets.

Question: I have a question about Speaker 3's slides--the slides you had at the end where you were showing the capacity market results and showing the threshold dollar amount for units in PJM. I don't understand exactly what the policy proposal is there, because if I go back to some of the other testimony, it said that there's 51 units representing 17,000 megawatts that were called "uneconomic," and that they needed to get $231 per megawatt day to make zero ROE, and then they needed $3.19 per megawatt day to get 10% ROE. So, is the idea that these 51 units would each get paid whatever amount was necessary to get them to $3.19 per megawatt day?

Speaker 3: The purpose of that, in my testimony, was to show that the capacity markets weren't delivering anything close to some reasonable ROE for this class of generators. That was all.

Questioner: Oh, OK. And also there was some reference on that slide to baseload, and I just wondered, what definition of baseload do you have in mind?

Speaker 3: I was using coal and nuclear in that.

Questioner: So, baseload equals coal and nuclear?

Speaker 3: That was not necessarily making that out as the only definition, but that was a generic term.

Question: I wasn't clear, Speaker 3, whether you were saying fuel diversity is a necessary, but maybe not sufficient, element of reliability and resilience, or if you were saying we need to understand the answer to that question.

Speaker 3: I was saying, not as an engineer, but as an economist, if this is evaluable, if this has external benefits to the system, then it is worth finding a way to pay for it, because the system's not covering it now.

Questioner: So, just so to make sure I heard you correctly, you're saying we need to understand whether it is valuable. You're not saying we know it's valuable.

Speaker 3: I wasn't opining as to the exact nature of the value of fuel diversity. It was that if these things provide resiliency benefits, here's a way to pay for them. The only question is, should you, should the Commission move forward with some sort of payment mechanism for these types of resources?

General Discussion

Question 1: 96% of outages are T and D related. We should all make sure we spend 20 hours on T and D for every one we spend on G. But, that said, we all love to talk about G and markets, so let's talk about that a little bit. I'm just wondering, to the extent there are resilience issues in the G part and in the market regions, it seems a little more straightforward to me what you would do about it in the more pure market, ERCOT/Alberta style, where if some event happens it translates into price, and loads hedge or they don't, and if they don't they're screwed, and that's how the market works in the long run. Personally, I prefer that approach, but in more administrative markets in the Northeast, noting Speaker 2's observation that you can't really put subjective probabilities on severe weather or cyber and physical attack, if the mechanism here, as you go through a stakeholder process driven by politics to determine the market rules, if we're putting resilience into Northeast RTO market rules, isn't there a threat here that we further diverge and make them more constructs with subjective rules based on stakeholder interests and farther away from the more pure markets I thought we were always trying to achieve?

Respondent 1: The last point was an interesting one. The question is, I thought we were trying to get to pure markets, and not more on the construct side of the spectrum. And if there was a NOPR out there with a proposal to remove a number of things that I think suppress prices, I would say, let's do that. That's a good idea. But this was a NOPR in the context of, we have sufficiently suppressed prices that we have generators leaving the system, and these generators may provide an external benefit to the system, so it's worth finding a way to keep them around. That's the perspective.

Respondent 2: There's two ways you can do it. Go more towards ERCOT/Alberta, or we can go more towards very administrative type of markets. But FERC isn't really a policy agency. It's a regulatory agency that is a creature of the Federal Power Act and administers the Federal Power Act, and the question before us is would the result be just and reasonable rates? And there's a number of ways to get that.

During the time I was at FERC, whenever we tried to sort of set policy, figure out the way things would play out on the Hill or in the states, we got ourselves in trouble. Whenever we stuck to sections 203, 204, 205 and 206 if the Federal Power Act, we stood on firm legal ground and we made good, defensible decisions.

Respondent 3: How about open access? FERC decided on open access policy. It was affirmed by the Supreme Court 9-0. That policy, Congress didn't impose that. I mean the 211 changes in 1992 were insignificant. FERC exercised 1935 authority to establish open access. That's policy. That wasn't five people in black robes. And interpreting the 1935 language to say that market-based rates are just and reasonable rates--that's policy, too. So, competition policy is completely FERC-driven. Congress kind of didn't object, but it came solely from FERC. So I don't know how you could say FERC's not a policy agency, or that FERC gets into trouble when it sets policy rather than colors by the numbers.

Respondent 4: So, great question, original questioner, about the different philosophies, and when should you resort to creating a construct.

So, let's take a very specific case. In New England, there are risks that it won't have enough gas pipeline to bring in the gas that you need for home heating, industrial, and electricity uses. And, ideally, any market construct rewards directly when you improve system performance. That is, you're providing energy when it's needed, and it's valuable. That's why we have spot markets. What is it about New England spot markets that won't incent enough of non-gas-dependent stuff to deal with that risk? If we really believe the report from last week, and that the gas constraints are a problem, can we justify creating a construct where we set a constraint on stuff that can provide capability during winters when there's a gas shortage. Can you define that somewhat non-arbitrarily? Can you define the contributions of different types of resources, Demand and supply side, and create a level playing field, open access to that, so when the solutions come forward, they can get in there? Or, is that just going to be so hijacked by the political process that it's really not going to help with market performance at all? Is it just going to be a case where somebody's going to grab some rents at the expense of somebody else, and really not help solve the problem?

So, do you think it's possible to define and market construct non-politically, somewhat objectively, that would help improve the situation that New England has in the winter? Or, should we just leave it to the spot markets?

Comment: One of the things New England ISO did in its study is show, under reasonable assumptions of the status quo, that there is a high likelihood the ISO cannot meet top load during cold winters, going out about five, six years. Another fact that is very clear is that, if that occurs, our marginal incentives to generators will be extraordinarily high. Spot performance incentives are about $9,000 a megawatt hour. I believe it's higher than ERCOT. That's as high as they get, globally. The challenge is, is that the right incentive? Meaning, for a generator facing an incentive of $9,000. In an ideal world, consumers would be also facing that price, but you know they won't, because State regulators won't let it pass through on the margin.

Maybe the actual infrastructure we have, and that risk, is something we should just live with. Because to do anything less would cost even more, and it's not worth it. But that's a decision that shouldn't be made in a vacuum--all of the state politicians and FERC needs to be well aware of it, and we need to have a major discussion as to whether that's the right marginal incentive.

Because at the end of the day, it comes down to a core question. What should the incentives be at the margin when a bad event happens? Are they high enough, or are they not? And if we think they're not, we then have the question about what to do about them. If we think they're high enough, then it's a case of society living with the risk, paying a high price when it occurs, because it's not worth paying any more. It's a tricky question as to what's the best thing to do, but at least that's how I think about the challenge before us. I don't know the answer to it. But I think that's the right way to frame the question you asked.

And I'd highlight, for the benefit of everybody in the room who may care nothing at all about the fuel problems in New England, that it's also the way, I think, most of the other questions you teed up in your wonderful presentation should be viewed, in terms of managing these low probability, high consequence events risks. Do we have the right marginal incentives set up to respond quickly to a resilience-disrupting event, or do we not? Once you've answered that question, all the other stuff follows through.

Respondent 2: Somewhere in the incentives you could have the price super high, but the problem might be the political will to allow pipelines to be sited. The generators in New England can't do anything about what Governor Cuomo might decide in New York, or about the political opposition to new infrastructure in the region.

Question 2: I wanted to address a few points in Speaker 3's presentation, if I may. First off, since I actually don't work full time on this market stuff, I don't understand what the difference is between a "market" and a "construct," and why you guys keep thinking there is a difference. I actually went to the trouble of looking up the term "construct" in the dictionary. It's "an image, idea or theory, especially a complex one, formed from a number of simpler elements." That strikes me as a market. So, I'm not sure what the difference is, and why you think that calling something a construct means it's less legitimate.

Respondent 1: My understanding of it is it's just a sort of established way of talking about the level of intervention, whether it's purely market forces or whether it's an administrative market. That's how I would look at it.

Questioner: OK, thank you. I don't know if we have administrative markets or real markets or something in between. I know they're pretty complicated. I do know that competition that occurred through markets and the effect of organized markets on bilateral contracts is what, between 2000 and about 2012, forced U.S. coal and nuclear plants to drastically improve their capacity and availability factors, because they actually were operating at so poor a level of performance that they had to step up their game, and implement significantly better operational practices and capital improvements in order to be able to compete with wind and natural gas and other better performing plants. So, that's just an example of how even crappy completion works better that cost of service regulation, because all of those plants were in cost of service regulation, and they weren't cutting it. They weren't getting better. So that was point number one.

Point number two is, you talked about resilience, and about how, if resilience is a thing, then we should maybe subsidize it. And my issue with that is that you haven't defined resilience, nor have you told us in any clear way how coal and nuclear plants actually deliver resilience, whether it is resilience for generation or resilience for customers, which is what I actually care about, and what, for all of you here, the people whom you left at home care about. So, my view is, I'm not willing to subsidize resilience for the sake of resilience, nor am I willing to subsidize coal and nuclear for the sake of coal and nuclear. I am, however, willing to determine and define very crisply and precisely the attributes that contribute to resilience and then make a difference. And I'm willing to figure out how to compensate those, whether through a market or non-market mechanism. But I am not willing to shrug and say, "Oh, heck, that's resilient, therefore let's just subsidize it." Subsidizing is the last resort, and it's usually because you can't figure out any way else to get the thing that you want. So, if you can tell us how coal and nuclear substantively improve resilience, I would love to hear that.

Respondent 1: All right, sure. You had two parts to the question. The first one was an interesting stat about the increased performance from 2000 to 2012 in the coal and the nuclear fleets and how you presume that that was a result of a competition from wind and efficiencies--and it may be. The one thing I observed when I was at FERC was I did Section 203 mergers and acquisition for a long time, 10, 12 years. And there was a huge consolidation in the nuclear industry. We went from having, I don't know what the numbers were, but say there were 60 plants run by 50 people. It would be like that changing to 60 plants run by five people. And it's like these huge efficiency gains you've seen in the railroads as they consolidated. I would argue that a lot of the big efficiency gains that you saw, and huge capacity factor increases in nuclear, was because they were bought by people who put a lot of effort and expertise into running them extremely efficiently and made a lot of money in the process, and it was well deserved.

Questioner: And would that consolidation have occurred without competitive markets? I'm thinking no, but go on.

Respondent 1: I don't know.

Questioner: So, turning to that statistic in the chart about RTO versus non-RTO retirements, I'd like to offer a couple observations and factual context for that. The first is, as you note, that the reason that there are more retirements of all kinds of plants in RTOs is because there's more megawatts in RTOs, which you observed. There's also much older coal and nuclear plants and RTOs. So, those are the ones that are going to be older and less efficient than the newer ones--much more inefficient plants that merit retirement. Next, the RTOs, the organized markets, make entry and exit very easy, which you kind of observed. So there is, in fact, a very logical reason why more nuclear and coal plants retire. (Also, there were a couple of years where there were zero non-RTO retirements, which made me wonder what the data source was.)

So there are very logical reasons for retirements that have nothing to do with the ineffectiveness of markets. They're just bad plants in places that make it easy to retire. So, that is the explanation for why your charts said what they said.

The other thing that you observed was that the fact that we have cost-based intervention already within competitive markets justifies more cost-based subsidization. You didn't use "subsidization," I apologize, but the fact is that almost all of the cost-based contracts in current markets are for extraordinarily short-term measures that serve very specific and narrow purposes. They aren't broad based, "Let me give you 20 years of subsidy to keep a crappy plant open without any justification for it" subsidies. So, I don't think that that is a fair comparison, in terms of the impacts on the market or the impacts on the customers.

Respondent 1: I would just say there are a number of possible explanations for retirements of coal and nuclear units, and my testimony argued that there were price suppression effects of multiple policies within the RTOs.

Questioner: And here I thought it was just low demand and low gas prices. What do I know?

Question 3: I commend you all for having this conversation, because two years ago, this conversation was not being had, or at least not in this form. If I recall, two years ago there was a panel about baseload issues, and I asked a question about where we are in the evolution of the markets, particularly the deregulated markets in the Northeast, which these issues were never contemplated 20 years ago, when we did deregulation. So, thank you, and thanks for having this conversation.

So, my question is, how do we confront this issue? The FERC has essentially now handed this over to the ISOs to say, "You all come back to us and figure it out." States are grappling with this, because a state like New Jersey is considering legislation, as have others. So, what's the next step? What is the process that we could all collectively--industry, State regulators, Federal regulators--decide how to move this along? Right now, I don't think it's real clear what we're going to do. The RTOs are doing the work. States are grappling with these issues. What do we do? What is the best way to advance this, these concepts, and come to a conclusion? The second part of this question, which probably isn't going to be real easy to answer, is, are we solving one set of problems and not even looking forward to the next issue, which is distributed generation and its continued expansion, and which has become more complicated? But what's the next best step? What is the forum? What's the process that we should all collectively be engaging in?

Respondent 1: Well, a very thoughtful question, and I think the first part of the question goes back to what I started to talk about, which was, what is the "it" that we're addressing? And it seems, I think, clear from all the presentations and the debate around this, that if it's the basket of issues that's really what resilience means, as Speaker 1 has defined it, and Speaker 2 did, then I think Speaker 3 would agree that it's mainly in the state basket, and maybe there's room for work between FERC and NERC and so forth.

But let's face it. We all know what's really going on here. It goes back to the flat demand and the long supply, and if the "it" that we're trying to solve is that there are price signals telling some people to retire, and they should (and kudos to Andy Ott and PJM for being that clear about it in the letter last week). And Judge Easterbrook got it, and the whole argument in our litigation involving Illinois was then that if the "it" is simply to keep uncompetitive generation in the market, that's just at odds with having a market, and then you're just going to have pay everybody.

So, I would first define what is "it" that we're really talking about. Let's not dance around. We should be polite, but we shouldn't be polite to the point of ignoring what's really going on here. I mean, as you know, in New Jersey, they're called "nuclear diversity certificates." As if any one fuel--gas, coal, nuclear, or renewable--is somehow diverse in isolation, by itself. It seems sort of odd. You say, well, fuel diversity or baseload or resiliency all just become different words used to try to hide what's really going on, because, obviously, if you pay any one fuel for diversity, it's only diverse in relation to the other fuels that are in the mix, and they're not paid. And, as the data shows, there's more diversity in PJM than ever.

The next steps, I think, really go to what you said. If there's price suppression going on, then let's address it for everybody. Let's continue the energy price formation agenda the Commission's been working on.

And you've got all these new resources that are not going to stop. People want them. They want renewables. They want demand side resources. And what I learned, sitting in this room, was how those low marginal cost resources are going to impact dispatch. That's the next set of problems that really needs to be addressed.

I'll come back to what I said earlier. My fear after 13, 14 years of doing this, is it's just the nature of the beast that things take time, and we don't really have time, and if everything's now suddenly only those 24 questions, we're going to end up exactly where I think your comments imply we don't want to go, and we shouldn't.

Respondent 2: When I left the Department of Energy with a draft report on July 8th, I left them with an extensive set of recommendations for analytical steps that should be taken in order to better understand this question. We have this set of questions, and as far as I can tell those have not yet been adopted or undertaken. You know that I'm a wonk, and I actually think it would be good to develop policy with insight from actual analysis. And most of that analysis should be forward-looking, rather than looking in the rearview mirror. And I have talked about the need to understand the requirements of the grid, going forward, under very high regimes of distributed generation and PV and wind, and the need to better understand the value of inertia, and the way that different resources can deliver flexibility and different kinds of frequency response and other services that promote both reliability and resiliency. As far as I know, that analysis has not been undertaken anywhere. And if any of you are at FERC or at EPRI, or those of you who are with AWEA and EDF and think it's time to bring some more solid analysis to the table, you should be looking at those issues and helping us with that.

You guys talk about fixing markets, but mostly what you seem to do is to be moving around the deck chairs with respect to existing products. There are new, different kinds of products and metrics that you need to develop, not just by playing the same game over and over and moving the yardstick for how high the offer cap or the price cap ought to be. The California work on time-varying capacity is very important and long overdue. We should be incorporating marginal assets. We should be incorporating locational value into all kinds of stuff.

And so, to get back to the question, we need to be grounding policy work on real facts and real analysis, and we should also be doing better analysis of the reasons that plants close, rather than just people talking about price suppression. They only talk about price suppression when it's prices they benefit from that are being suppressed. We need much better analyses of the factors that are causing these plants to close, and that are keeping prices down. Because, apparently, all of the studies that have already been done keep producing the wrong set of answers. So, my answer is, pound the table for a much better analysis, and then let's base policy on actual facts, rather than just benefits to loud stakeholders.

Question 4: I think there's also another issue here. I think we've got too much hubris, thinking that we know what reliability and resilience are, and we don't have enough humility about the things that we don't know that are out there. As Rumsfeld would say, there're the known unknowns and the unknown unknowns. So, for example, here in Florida, after four hurricanes hit in 2004 and three more in 2005, everybody said:

"We're going to underground the distribution system."

"Beautiful. What's that going to cost us?"

"Oh, it's probably going to double your electricity rates."

"No thank you."

But the politicians still wanted to do that, because they said if we undergrounded it, the lights wouldn't go out. There was a small problem with that. Everybody failed to realize that during the 04/05 hurricane season, it took out a lot of the natural gas infrastructure in the Gulf. So, even if we had everything underground, we had no gas to run the generation to actually serve the load. Did anybody think about that? No, they didn't. So, really, what we're talking about is the law of conservation of risk. Most of this risk we don't even know, but we know it can be transformed from event risk into financial risk. Or vice versa--from a financial risk into event risk. It can be fobbed off, knowingly or unknowingly, from one part to another, which is effectively what it sounds like we're talking about here.

Comment: Financial risk doesn't keep the lights on.

Questioner: I didn't say it did. But what we're talking about here is that somebody's bearing risk financially. The coal and nuclear units are going out. Do we need them for reliability or resilience, whatever that means? No. But they want somebody to pay for it. We're just talking about moving the money around. So, my question, ultimately, is this. Is reliability or resilience truly a public good, or is this really a private good that we can all self-insure ourselves on to a level that we desire? And then the second question I have is, is resilience really different from reliability? Because if you look at the dictionary definition of resilience, it's the ability to bounce back from a change in circumstance, which is exactly what our reliability standards and how we operate the system do today. We lose a generator, we have reserves. We recover from that change. If a transmission asset goes out, we have transmission switches, power flows over other alternate paths, we deal with that change. Is there a difference, and could somebody tell me what that difference actually is?

Respondent 1: I'm going to tackle your self-insurance question. And the answer is, we are already self-insuring. If you put your hand on your wallet, you are going to pay for the consequences of outages or preventing outages, either as a taxpayer, as a rate payer, or as a consumer. And most of us are already self-insuring today, if you look at the number of spare cans of food and flashlights and batteries and emergency radios and PV and backup generators that I'm guessing most of you have in your homes, and then sitting around in the dark bitching. You are self-insuring yourself, and you are bearing the cost of insufficient preparation, or insufficient reliability, or whatever bad event, most recently happened to you. So, every time you replace the batteries, you are self-insuring. And it's that simple.

So, the question to me is, what is the most efficient and effective way to allocate these costs? And how much should we be spending on buying, as a society, more damn batteries and backup generators, versus upgrading transmission and distribution, versus putting on more distributed generation, versus subsidizing coal and nuclear plants or paying for a generation portfolio? There is probably some more efficient way to do that, and one of the things we need is better tools with which to sort of co-optimize. Because we're only getting more risks. If you look at climate change, if you look at terrorist and bad guy threats, there is no way we're going to be living in a safer world. Things are just going to get uglier and uglier, and the probabilities of harm to the grid and to the systems that we depend on are getting uglier. So, we should be much better organized and prepared to deal with it, which goes back to the question, how?

Respondent 2: One sentence. The gap between retail markets and wholesale markets, in terms of how things are priced and valued, is a source of huge inefficiencies in this sphere.

Respondent 3: And, very quickly, in my opinion, from the perspective of the bulk power markets, bulk power system, reliability and resiliency are public goods.

Respondent 2: From where I'm looking at it, they have public good qualities. Stop there.

Question 5: It seems to me that what we've been talking about is this notion of the probability that a particular risk is going to hit us hard and or hit us often. And ultimately, as we talked about these issues, one of the things that escapes the conversation is the prioritization among the risks.

So, there's two ways to do strategic planning. The first way is time-based. For example, if I know that road's going to wear out every three to five years. I'm going to plan to replace it every fourth year. Time-based planning. Risk-based planning says, "I don't know when the road's going to wear out. It depends how much traffic there's going to be. Maybe people use this bridge, maybe they'll use that bridge. I'm going to assess the probability, the risk, of one thing happening versus another, and then I'm going to take the highest impact, highest probability things first. I'm going to spend money to do that."

The challenge here is that we continue to think that the value of this grid is infinite, and therefore consumers will pay an infinite amount. Instead, what we have is a zero sum cost allocation. Consumers will pay only so much, and therefore, given the amount they're willing to pay, how do we define the risks that have the highest priority and highest value for mitigation first, and then tackle those? And some of us from the RTOs will design you market mechanisms. That's the word, mechanisms. We'll design you market mechanisms to manage those risks. But unless and until the conversation is about risk and priority of risk, we're going to continue to spin our wheels. So I ask somebody to speak to that question of probability.

Respondent 1: I entirely agree that the challenge with the risk is that, without good notions of what the probabilities are or even understanding of the magnitudes of what might happen if we have an EMP or a repeat of the geomagnetic event of the mid 1800's, if I don't understand the consequences and the probabilities, the prioritization of the risks becomes a political process, and we may definitely end up barking up the wrong tree. And so there's a need for analysis.

Respondent 2: But I'm sorry. I am compelled here. That is wrong. Well, it is true that we should better understand the risk, but what you are not doing is linking the consequences of those risks to results on the system. And the fact is, there are many solutions. The solution to EMP hitting transformers is having a bunch of spare transformers that aren't plugged in. The solution to terrorist attacks on transformers is having a bunch of spare transformers that you can move to that place. There are many common solutions to a variety of those risks and threats that are no regrets that we could be using that are much more cost effective than planning risk by risk by risk. What we should be doing is looking at all the risks, all of the threats, and then looking at where there are common solutions, such as energy efficiency, such as distributed generation, such as spare transformers and mutual assistance that can help everybody address all of those risks much more effectively, not just doing threat by threat.

Respondent 1: OK. So, some Xes address many threats at once and other Xes are specific. You need to look at the whole system, and that's tough.

Questioner: No, I didn't mean to suggest otherwise. I think that's exactly right. Look at the holistic picture, and you have to think about where your money is best spent to deal with the most risk at the least cost. That's what RTOs were set up to do--to design economic mechanisms to do exactly that. But unless and until we agree, as a community, what the highest priority risks are, we're going to end up de-prioritizing things that might have better bang for the buck, and that would be a bad outcome.

Question 6: I accept the impact of low gas prices on the economic components. But I think Speaker 3 made a very important point. I agree with him on what you might call the discriminatory pricing, suppression, or underpayment. I'd say "structural error," let's leave it at that. The way I keep score, in PJM, over the 13 or 14 capacity auctions since inception, there have been between 100 and 200 billion dollars of transfers between generators and load.

The answers we're hearing from people, particularly on the supply side, can be partitioned into attempts to catch up, which I think most of us, if we think about it, would agree are very bad things to do. And it leaves the subsidies and the logic that we hear about, the deal we know that was based in my mind on an attempt to catch up. Or, we can do something about fixing that. And if you fix it, you want to do the best thing. But you also have the fact that you have this huge, likely inefficient, rolling over of capital associated with that 100 or 200 billion dollars. And so, the question is, does that mean there should be some sort of transition, recognizing that we made a mistake, and the price is wrong or was wrong, and we're going to get it right now and do something else. And what I think I heard in some of Speaker 3's recommendation is maybe there should be some sort of a catch up. I think that's implied by some of the comments you made. And I'm a little uncomfortable with that, but I'd like to hear responses to this idea of, "I know I screwed up, I want to fix something going forward," or whether we have some obligation to have a transition.

Respondent 1: In this context, it wasn't about catching up, it was about, "OK, well, if we do value resiliency, then this is a reasonable mechanism, given where we are." I don't view it as a catch-up.

Respondent 2: I don't know what a catch-up would be. I think, to some extent, there was an element of that in the NOPR, and this was stated publicly on at least two occasions I can recall, and on several occasions stated privately, when I was querying the Department and others about this, which was that this was the rebalancing of the prior administration's tilt towards renewables, and somehow this relatively crude mechanism was a catch-up. So, I don't know how the catch-up would play out.

Maybe I'm overly influenced by what we've just gone through, and the possibility that the catch-up thing becomes a reason to not fix the problem, as you correctly described it, for everybody, but only for some.

And I don't think that the job of a regulator, federal or state, is to make any particular market participant catch up or better off or not. It's to defend the market and the customer. So, when you said "catch up," I wrote down, "At whose expense?" And how would you do that?

My last point would be, if we're going to have, as I said earlier, a system that's not the economic dispatch model that I learned being here all these years, but is something else, then it needs to be a clear decision. If we're going to transition to something, then it needs to happen to everybody. I'm not advocating that. I'm just saying you can't do it only for some and not others. All these solutions, whether it's the NOPR or the state legislation, is like if a hurricane's coming to Florida, but only the people with even number addresses get to go to the shelter. Everybody with odd numbers gets to stay out here at the beach and get swept away by the waters that come off the ocean.

Question 7: Thanks. I'm going to try to make three very quick points. The first is that I don't think you can say that capacity performance is "not working" because prices have not gone up with the adoption of a capacity performance design. In large part, that's because the load forecast has gone down in PJM by 10,000 megawatts.

Number two is a completely unrelated point. One of my many pet peeves is this reference to "baseload," because coal and nuclear units, particularly coal units, are not necessarily "baseload," in the sense of running at high capacity factors. In fact, the ones that are slated for retirement…for example, First Energy's Sammis Plant in PJM, which has been officially proposed for retirement, and which has a capacity factor of 40%, and has had a lousy capacity factor since 2009. So, this is nothing. This is a unit that's 58 years old, and it should retire. OK? It should retire. It should not be paid enough to get it to a 10% ROE. I mean, come on.

And, then thirdly, it's important to understand that in PJM, the EFORd (monthly equivalent forced outage rates, which is the pretty much universal standard for reliability of generating units) of retired units is four times that of new units. So, if you subsidize units to not retire that would otherwise retire, and you forestall or prevent from entering the new units that you would otherwise get, you are directly and meaningfully decreasing reliability. And that is just a fact. Thanks.

Question 8: I wanted to touch on the question about the future of distribution networks. Let's assume that resiliency is a thing. I guess I'm concerned about what the assumptions are that go into doing actual cost benefit analysis for deciding what investments we should make. And one of the concerns I have is, as we do this cost benefit analysis, how do you ensure that some of the assumptions that are embedded in that allow for markets and allow for actual cost benefit analysis, rather than assuming that the public policy role is just negotiating between the interest group of politics about who gets the money, whether it's climate investment or fixing what our consultants would say is our third world transmission grid or resiliency or something else that moves the needle on rate base?

Respondent 1: How many of you grew up in retail regulation? OK, so you remember the joy of the test year rate case? Our problem is we need to be looking at test years that are significantly forward, and not trapped in the present. We are building a transmission system today designed around weather and climate conditions that are 30 years old. We are designing distribution systems, in most cases, for the Ozzy and Harriet grid, not for distributed generation and for advanced demand response capabilities. We need to be looking at risk profiles that assume that there's a lot more wackos in the United States who are able to shoot out transformers or that there are going to be a lot more droughts and a lot more forest fires, much more severe lightning, and much longer heat waves, and much more aggressive violent storms of every kind that last longer and do significantly more harm. We are not designing our systems and our devices and our energy efficiency and our appliances around those conditions. And those are the threats, those are the conditions that we need to be looking at.

Nobody should be doing a prudence case for a new transmission line that can't survive the kind of ice storm that would be considered to be a thousand-year storm today, because we're getting the 500 year flood every—well, ask Houston. Twice a year. Florida is getting those kinds of conditions.

So, the answer is, we should be looking at the entire system in totality, and looking at the capabilities and the problems 20, 30, 40 years out, and how do we move all of those pieces in concert? And we don't have either the policy will or yet enough analytical capability to do that kind of analysis or the kind of co-optimization that's required to do that thoroughly. But that's what we ought to be doing. And this is the kind of thing the National Academy of Sciences and the National Lab should be working on. Not just one RTO at a time. And we need to be looking at it as a multi-stakeholder objective thing, not just from an, "I get mine, these are my issues, screw you," perspective. We ain't there yet.

Question 9: I guess I want to make a plea, at least within this room, if we could possibly apply a single standard for what we mean by reliability and resilience. I mean, of course we all value resilience, if we could possibly define it, and of course there's not a single shred of evidence that subsidizing First Energy's coal and nuclear plants would have incrementally increased it, nor any shred of evidence that letting them go out of business would have decreased it. So let's move past that issue.

With respect to the New England ISO example, there's a possibility or maybe even a certainty that in 2024, 2025, on a very cold winter day, there may need to be some curtailment. And I think the implication is that we're all supposed to sort of shudder in terror at that possibility.

Tuesday morning I went down to the best coffee shop in Key West, 5 Brothers, and they were out of power for 45 minutes in the middle of the morning rush. Do you think that Mr. Paez gives a damn whether he was out of power because it was a very hot day in Florida, and there was controlled rolling curtailment implemented by Florida Power and Light, or because, as it happened, a distribution transformer blew up down the street? No, he doesn't. He's out of business for 45 minutes. That's all that matters. And that happens three, four times a year, in an average year. In the meantime, we have a reliability resource adequacy standard that insists that Mr. Paez experience no more than 20 seconds once every 10 years of an interruption because there's not enough available generating capacity. And there's a danger that we're going to apply the same ridiculously skewed standards in this rush to resiliency.

And what we're really looking at, in some ways, is a combination of rent-seeking special interests and easily manipulated state energy officials. In the case of New England, of course, it's rent-seeking pipeline investors. There's so much of this that could certainly be solved through energy markets. If the system needs to deliver something that customers value, in the first instance we should look at making sure that the system operator is procuring that service in a way that makes sure that everybody who could provide the service is able to do so. And there are certainly services that may actually, in the end, not be particularly amenable to the market solutions like that. But ERCOT just recently proposed a slate of new ancillary services to the commission in Texas. They were turned down, and I think maybe in some cases rightfully so, because it's a little early days. But that's the first step.

But as a customer, I would ask, "Stop trying to help me so much." The idea that the media and consumers in New England would never tolerate a half hour of $9,000 a megawatt hour price, I think, is just silly. There's no sprinkle of magic dust on Texas consumers or the Texas media, such that when prices go to 4,000 or 5,000 or 6,000 dollars a megawatt hour… I looked at this last fall. There was a $4,000 megawatt hour period for several days running. And I looked. And I found not a single mainstream media story referring to that fact. Now, some may say that Texas consumers are different. Sorry, I don't buy it. If it's a lot cheaper to consumers to let prices every once and a while go to $9,000 a megawatt hour than to go out and hand hundreds of millions of dollars to pipeline companies to build firm pipeline capacity that can be used at a 10 or 15% capacity factor and then socialize that across all customers, it would probably cost four or five times to pursue that solution than it does to make sure that the energy market reflects the demand for the energy and the services needed to address these concerns and let prices every once and a while go to a level that reflects the fact that we're short of some things that are needed. And so I'm basically back to the appeal. Let's apply a single standard on behalf of Mr. Paez and the others who are being asked to shovel huge amounts of money to rent seekers on the claim that it's going to solve a problem that they probably don't actually even have.

Question 10: To get back to an earlier question, are there specific metrics that we should be looking at to ask whether or not prices are doing something that would provide the fuel diversity and supply reliability the system operator needs, or to suggest that, for some reason, markets are not working and the system operator should be concerned about something else other than just the political concerns of an occasional $9,000 price?

Respondent 1: If all you are measuring is energy prices, all you're going to get is cheap generation. Period. And you won't get fuel diversity. It's that simple. If you start designing to procure other products that complement energy (capacity is one that we don't particularly want in Texas, because we think that high energy prices will get us capacity), if we start doing a market in flexibility, if we buy ramp speed, if we buy inertia, if we define a number of different products, or if we require performance associated with energy intertemporally, we will get different things, beyond just cheap energy. But if all we are buying is cheap energy, that's all we're ever going to get.

So, we'll get more and more natural gas and more and more wind and solar.

Question 11: I wanted to return back to an earlier, very important question in terms of the difference between a construct and a market. I would argue that there is a monster difference, in terms of commercial implications, because you can create a construct, like 10 minutes spinning reserves, that can't be traded in the commercial market, and that can't be hedged very well. But if you have an energy market, customers can hedge and transact in that in the secondary market. So, the question becomes, when we look at the potential output of resiliency and what we want to do to the markets, are we creating something that customers could hedge, or are we just going to create another product for which the ISO competitively seeks the resource, collects the money from the loads, and transfers it to the generators, and that's the end of that?

Respondent 1: I think it depends on the specifics of what's decided, and I don't think there's a generic answer one way or the other. But I think the construct versus markets distinction doesn't really get you very far when it's invoked to do something that actually moves in the opposite direction for the markets. But your trading question is a good one. I wouldn't hazard a guess. I'd defer to the experts in the room.

Question 12: Two words I haven't heard at all today, which is kind of surprising to me, are "state commissions." I'm not a lawyer, but my understanding is that the Federal Power Act essentially leaves decisions as to what kinds of generation to build and how much to build to the states, that FERC doesn't have that authority, but yet, everything we're talking about today is about markets. I just have a yes or no question that I'd like each of the panelists to answer, including the moderator, and that is, do the state commissions have the right and the responsibility to determine the right amount of generation and the types of generation within their own states?

Respondent 1: They have the authority to decide whether they want to do that.

Respondent 2: They don't have the responsibility, but they have the right.

Respondent 1: They can decide to rely on the market or they can decide to completely regulate it and require 40% reserve margins. They can, yeah.

Respondent 3: But they need to do one or the other. And I'm more comfortable with state commissions making the decisions. What's actually happening, as we know, and that's one of the beauties, I think, of the decision at FERC, was the value of the independent agency. And as we all know, what's not happening is what state commissions that are here represented and others do, which is a process with rules of accounting principles. Instead, we're ending up in legislatures, flinging around numbers that have no bearing on any real analysis.

But I would agree with the first respondent's comment. You could re-regulate, and that's what we've said in these states. If you want to re-regulate, please go ahead, but then we get re-regulated too.

Respondent 4: To this point, the states in the Northeast de-regulated 20 years ago, and I asked the folks that were really pushing the issue on de-regulation, what was driving it, and did you ever think about these issues, like we're talking about now? The answer was, in the Northeast, "No, because we just wanted incremental marginal cost markets to drive the cost to generation, because the economy was so bad in the Northeast. We wanted lower priced energy." Other states, like the southern states, those policy makers said, "You shouldn't do that. You're going to miss something." And my question to a lot of people over the last probably six months has been, "Did we miss this?" And the answer was, "No, because we made a decision. We didn't care about that. Not in a pejorative sense, but that wasn't the driving policy. And, yes, if we knew what we knew now, in the Northeast, we might be thinking about building things like resiliency and other reliability aspects that were just let go. We might build them into a market if we had to redo it today." Just for thought. Just for information. That is what's coming back to me from those were around in earnest during the de-regulation efforts 20 years ago.

Question 13: Let's put aside the point that the demand might actually be decreasing, and assume it's staying roughly flat. And let's imagine that the generators have a 60 year lifetime, which is actually pretty long, but consistent with the one that he mentioned. If you have a million megawatts, and you apply a thing called Little's Law, it tells you that you should expect 17 gigawatts of retirement every year, on average, with a 60 year average life, which is longer than average. So, what's the problem? What is the problem?
I just wanted to put some numbers behind it. In fact, we're seeing less retirement than you would expect from just applying Little's Law.

Respondent 1: That's the magic of cost of service regulation. As long as it's already paid off, you might as well keep running it for as long as possible, until the costs of the incremental generation from your cost of service plant are so radically more expensive than what's available on a competitive market that state regulators say, Gee, that's costing me an awful lot to keep that old plant around. Maybe I should brace myself and acquire something in the market instead."

Question 14: I want to address the comment on market versus construct. I think there's a lot of really important issues wrapped up in that. The first is, we need to recognize that competition always takes place within the context of a legal structure. So the results are always driven by that legal context. That legal context does define who does well or poorly in that market. That means there's nothing magical about any particular competitive result. No matter how competitive it is, it's not magical. You can still go back and decide whether that legal structure, that legal context is meeting the policy goals we want to accomplish.

The second thing is, though, that there is a difference in the way we've been using the two terms. A market is something that gets you, if it's working, a competitive result. A construct is something where you have to trust somebody telling you that the outcome is consistent with what a competitive result would be were there competition. Those are two vastly different things. One actually allows willing buyers and willing sellers to work together in order to address their respective business needs, risk management goals, policy goals. The other one makes a really narrow range of tools available to address a very narrow range of goals. And that's OK, in some contexts, so long as you can contract around that in order to manage your goals the way you want to, in order to manage risks, so long as you still have a wide range of tools.

From the point of view of load serving entities, as long as they can manage around the market constructs through demand response or efficiency or long term bilaterals or building their own resources, they are golden. They can still meet their needs and their regulators' needs. But if we start assigning all of these various attributes to the RTO, to address through their constructs, we are losing a lot of the tools and creativity and benefits of competition as we try and address them.

Session Two.
Demand Charges: Can they be Internalized in Dynamic Pricing Without Diluting Efficient Price Signals?

Demand charges have long been a feature of tariffs for commercial and industrial customers. Some jurisdictions are either applying, or contemplating applying, significant demand charges to residential customers as well. The goal has been to send discrete price signals to consumers to reduce their peak demand, and, hopefully, to reduce overall system capacity and capital spending requirements. Demand tariff provisions, of course, were put in place to complement retail energy prices that have, historically, not reflected real time costs, and, therefore, failed to provide meaningful price signals to end users regarding peak demand and the costs associated with it. Does the prospect of dynamic pricing better reflecting the prices in the energy market obviate the need for demand price signals? Do meaningful dynamic prices internalize demand costs? Or will demand charges play a critical role in providing price signals to end users? If demand charges were to be replaced by dynamic variable prices, would that further exacerbate the problems associated with a pricing regime where most fixed costs are recovered through variable rates, a flaw that leads to net metering subsidies and other price distortions?

Moderator.
Just as a reminder, kind of by way of introduction, of what cost of service regulation looks like (for all those people in here doing nothing but markets), there's really kind of three parts of that style of regulation. You've got the revenue requirement for the utility: how big is the pie? You've got cost allocation: how the pie gets divided up between different classes of customers. And then you've got rate design: whether you eat the pie with your hands or a fork. (I never know how to describe rate design in that metaphor, exactly.)

It's rate design that we're talking about today, and, in the structure of rate cases, there's always a bit of interesting theater of political economy, I guess I'd say. When you talk about the revenue requirement, regulated utilities are obviously very interested in that. It means dollars into their bottom line, and all the other intervening parties tend to gang up on the utility in rate cases. The utility wants a higher number; everyone else wants a lower number.

You move to the cost allocation phase of a rate case, and that then becomes interesting. The utility's a little more indifferent to the outcome of that. It's getting its pie one way or another, and there's a little bit less about who gets that pie divided up to them. And suddenly all the interveners which had been at the utility's throat are at each other's throats, trying to make sure that costs are reallocated on to each one of them.

And then, finally, you've got the rate design portion. And rate design's a bit of an odd one. It's sort of the red-headed stepchild, and plays out, oftentimes, less predictably than the other two parts of the rate case. Sometimes it's relegated almost to a footnote in regulatory proceedings. It's sort of resolved in a calm, quiet way, without much contest. At other times, as recently, it can be the source of the greatest conflagration in rate proceedings. And usually it's the case that rate design kind of functions as a lagging indicator of periods of technological transition or volatile periods of the macro economy. Rate design becomes important for reasons during those periods, and to paraphrase Hunter S. Thompson, I guess when the going gets weird, the weird turn pro. And so the rate design probably fits into that category as a motif of regulation.

We've recently seen, in state proceedings, that rate design conversations regarding net energy metering and demand charges are probably the most contested aspect of rate design, and certainly the most publicized aspects of those proceedings. It also inspires oftentimes the most voluminous public comment, which, as a regulator, you're always sensitive to. I received, in fact, recently, a very succinct public comment in response to a utility's proposal to raise its fixed charge. And the public commenter simply informed me that he was writing on behalf of his mother who doesn't use email, and it merely said, "Dear Commissioner, go F yourself, signed, Tom." As I said, it inspires quite the reaction, rate design. (I did reply, actually explaining why fixed charges were at issue in the proceeding, but I never received a response.)

So obviously customers care about it, as we see from that anecdote, and utilities care about it. We heard a lot three years ago about the "utility death spiral," which probably is more like a mild cold. But they care a great deal about the under-recovery of fixed costs, and here today we have a number of panelists to talk about demand charges, and not only whether they're a good idea, but whether they are a supplement to or a replacement for time-of-use retail pricing on energy. So we're going to harken back to debates over the proper recovery of fixed costs and rate making, which is a time-worn theme of public utility regulation.

Speaker 1.
I am a great believer in regulation, a great believer in our regulatory system in this country and state regulation, cost of service regulation.

Out of seven billion people in the world, only two billion have adequate electricity. Another roughly three billion have intermittent power, and 1.4 to 2 billion has no power whatsoever. Here's a good example--the difference between North and South Korea. Clearly, the reason North Korea doesn't have electricity is not because it doesn't have adequate resources, or it doesn't have intelligent people. It's a function of governance. They don't have a governance system that has allowed investors to come in and to build their utilities. The best example is in sub-Saharan Africa. There, 72 percent of citizens have cell phones. Only 27 percent have electric service. The different cell phones are provided by entrepreneurs, providers, non-governmental entities. Electricity is generally a state monopoly. It's curious to me that every one of those cell phone providers has to build a tower close to the customers with 24/7 power. My solution is, let the cell phone guys electrify.

One of my pet peeves is that too many of us in the industry are sloppy with our nomenclature, and we confuse, and confuse the public, with the difference between "power" and "energy." Power is the rate at which energy is delivered. Residential consumers need both power and they need energy, and we'll go into that in a second. Our grandfathers would have known the difference, and knew it in this form. They knew, for example that the power of 13 strong men is equivalent to about two draft horses, which is about 1.34 horsepower, or 1 kilowatt. They also knew that energy was the sustained power over time, and so that is in kilowatt hours.

I bring that up because we have this electric system designed to bring us both power and energy. If we don't have adequate power, does it matter that the energy's there? And I'll show you that in a second here. But here is what I'm talking about. How many of you know how much horsepower your house takes? Now, I just read the fire code, and it said that houses ought to be wired for about 20 kilowatts--the average house wiring and the various circuits.

Look at this quick example of the different kinds of electric devices we have and how much instantaneous power they take, and of course the more they run the more energy they take. So, yes, a dishwasher may only run for an hour. An iron you may only use for half hour. A toaster you may only use for a few minutes, but you do have devices which take a lot of power. Air conditioning, for example, which can take four to six kilowatt--and if that runs all day, that's a tremendous amount of energy. But at the peak, you could have, theoretically, in this particular case, if mom was home, dad was home, the kids were home, and everybody was doing something different, you could in this household have a peak instantaneous demand of 27 kilowatts, 36 horsepower.

My understanding is that the average California solar array on a residence is four to six kilowatts. Hence few people believe in the grid. My espresso coffee machine and my wife's hairdryer are four kilowatts at peak. Which means if I had a solar panel on my house of four kilowatts, only those two devices could run? We expect the electric company to have the service line capacity to our house of 27 kilowatts, or the 20 kilowatts that the fire code requires. That is the capacity, and the distribution system has to be built to provide the power that we need, or we get very upset.

Now, one of the other problems I have is that my economic friends only read the rate schedule, they don't read the full tariff. If you read the rate schedule, you say, “Well there's no price signal here for exceeding the capacity on my home line.” But the tariff in many utilities says, for example, that if you want a larger service line, you call the utility, they install it, and you pay for it. It doesn't get socialized on your neighbors. I think it was First Energy's tariff which says that you are obligated to call the utility if you add a 25 horsepower load at your residence. You're obligated to call the utility. What would a 25 horsepower load be? Well, it could be the Finnish electric sauna that I had in my house in Connecticut. (I didn't buy it, it came with the house.) Every time the kids would sneak into the basement and turn it on, it would blow the street transformer. I was president of the gas company, so it wasn't my guys, and I’d go out and say, “Hey, guys, what happened?” He said, “I don't know.” He said, “We think somebody here's got an arc welder that is blowing the transformer.” I didn't tell him, “No, I know exactly what it was.” So, if you're a home hobbyist you might have an arc welder, you might have an oven for your ceramics, or if you're a handyman, you might have a woodshop. You might have a metal working shop. I've had friends that have had complete metalworking and woodshops. Many of those motors and combinations would do. But the price signal is there in the tariff. It's not in the rate schedule, it's in the tariff, and obviously utilities will meet your need for supply, but you'll pay for it.

There is another price signal out there that doesn't show up in the tariff and in the rates. (I threw this in to go back to telling you that I do believe in scientific regulation, trained experts, and accounting schedules.) This is from *The Wisconsin Idea*, a book written in 1912 with a foreword by Theodore Roosevelt that lauds the Wisconsin idea of having independent scientific experts. (Now, in Wisconsin, they didn't think electing a commission was a really good idea, because at the time, “Fighting Bob” La Follette thought that the railroads and the big corporations could buy the elections. My understanding is that in Montana, they could buy the governor.)

Looking at the load curve, there’s the baseload--which refers, not to generation, but to how customers use energy, right? Baseload is what customers do. It's not what generators do.

We are talking about two different systems now in the United States electricity industry. I started in this business 40 years ago; I could go to Europe and explain American electric utility structure and regulation in about three minutes. It takes me at least six now, because I have to explain two different systems. One is the continuation of the vertically integrated system, and the other is those states which have decided to restructure--i.e., to order their vertically-integrated gas and electric companies to dispose of their generators. The minute they disposed of their generators, if those generators went back and sold in the wholesale markets, they were fully subject to FERC regulations.

So, for the younger people here, there is no “deregulation” in the electric power industry. The Federal Power Act wasn't changed. The Federal Power Act says the FERC will set the rates for wholesale power generators, and it can use a variety of methods, one being cost of service, the other being market-based pricing. But the FERC can intrude in the markets. It can set refunds, as it set refunds in California. If something crazy happens in any one of these regional RTO markets, and the FERC doesn't like the ensuing price, they have full authority to set refunds. That's not an unregulated market, folks.

So in those markets, the state regulators are only regulating transmission and distribution, and that's it. In the vertically-integrated market, which is about 30 of the states, I think, we still have the state commissions regulating generation, transmission and distribution, with the FERC only regulating wholesale sales.

In both cases, the regulation is called “cost of service” regulation, and the revenue requirement consists of only four categories of cost: operating and maintenance expense, depreciation, taxes, and return. Two of those are predominantly fixed during the year--that is, they don't vary with consumption. They don't vary with kilowatt hours sold. Those predominantly fixed costs are your depreciation expense and return, and, of course, your basic payroll doesn't vary with kilowatt hours sold, and many of your taxes, like your property taxes, don't vary with the number of kilowatt hours sold. So, in many of these systems, the predominant costs are costs that don't vary with generation. You can call them “fixed” or not, but they don't vary with kilowatt hours sold, which has been the basis for rate making.

Bonbright's rate criteria are frequently discussed, and I will admit that, as Bonbright himself has pointed out, there are conflicting objectives. The objective to have rate simplicity conflicts with the objective to have accurate rates. The objective to have rate consistency may conflict with the objective of having rates with recovered costs, if costs have shot up quickly. So, I love Bonbright, I've taught Bonbright, but we do understand that within his principles and rate structure there are conflicts that exist.

What are consumers paying in markets? Many things consumers are paying, voluntarily or by market design, have a fixed monthly charge. For example, your mortgage, rent, your property tax, your car lease payment, cable TV, wireless phone… I licensed the second wireless telephone company in the United States, Milwaukee Telephone 1984. At the time, the phone cost $2800, it fit in the trunk of your card and the charge was 50 cents a minute of airtime, whether you called or they called you. Over time, the cost has come down and the predominant pricing scheme has been a flat charge where you prepaid for a certain number of minutes. Very few of us pay by the minute anymore, it is a flat charge. It is preferred. So we've got mobile telephone, home alarm, insurance. The fixed charge is understood by customers.

One of the things that always sort of astounds me is how many of your fellow consumers voluntarily sign up for budget billing in regulated rates that have all kinds of fancy rate designs. But 30, 40 percent of the customers say, “That's all fine, but I want budget billing, which means I get the same bill every month,” and at the end of the year you can true up or not. They don't want a price signal. They don't need a price signal. They don't see it.

The predominant rate design for residential customers in competitive retail markets is a fixed kilowatt hour charge, occasionally, maybe, variable, but not variable by day, by hour, by minute, but variable by some index. There are many markets where the wholesale price will vary hourly. For example crude oil, but gasoline prices don't. Wheat, on the Chicago Mercantile Exchange, but the price of Wheaties doesn't change. Beef, but hamburgers don't change. ERCOT's hourly prices, but the retail rate in Texas doesn't change hourly, or doesn't change yearly if you sign up for a flat kilowatt hour charge by choice. So that may be the optimum market design there, I don't know.

Going back now, to the early years, where the argument was made to have a fixed charge, because we have fixed or known costs that don't vary, back in 1956, we had Russell Caywood explaining that the customer will understand a fixed charge, because the customer knows that when you lease a house and you go on vacation for a month, you don't get to call the mortgage company and say, "Hey, I'm not paying the mortgage this month because I didn't use the house."

Also, Caywood then pointed out the difficulty in what we're charging. We're charging for electric service, the standby, the fact that the utility doesn't know when you'll come on, doesn't know when you'll come back from vacation early, doesn't know what new electric device you'll buy. A typical family has 26 different kinds of electric devices. And I assure you, right at this moment, for those of us who are grey haired, some of our sons and daughters are out there inventing new electric devices that we can't think of. We can't think of what problem they'll solve, but the minute they show us one, we'll want one. Whether it's a Walk Boy [sic], an iPhone, or one of those Alexa devices, we didn't think of it ourselves. But, boy, the minute we see it, we want one. And, oh by the way, you've got to plug it in. How many electric plugs is each of you carrying on this trip? A minimum of four or five? One for your cell phone, one for your laptop, one for your Bluetooth, one for your tape recorder…so think about that.

We've got here some historic tariffs. All these tariffs, starting from the late 1890s, had a fixed charge. We understood there was a demand component to be recovered, and we had a whole bunch of systems that were tried out: the Canadian Cities System (a two part rate), a Flat Demand Rate, a Straight Line Meter rate, a Block Meter rate… A declining block meter rate was the predominant rate design in the United States before PURPA in 1978, where the first block was designed to pick up predominantly the fixed charges. So, even if you were a low-volume user, you were contributing to the fixed charges. We got away from that, not for climate change reasons, but because the 1977 Energy Policy Act of Jimmy Carter said the United States would run out of natural gas by the year 2000, and the world would run out of oil by the year 2000. So we needed to conserve a valuable resource, which is why we got off of declining block rates.

The answer to the question of whether dynamic pricing should replace demand charges? Dynamic pricing should go with our dynamic costs. I'm not sure they need to replace anything.

Regulation does sometimes produce unintended results, and for those of you who think I ought to be consistent, I'll turn to Bonbright and say, that's not a real expectation. Thank you very much.

Speaker 2.
Thank you very much. Let me say a couple of introductory comments, and then I'll plunge into my presentation.

I'll just go back to the month of December. I was at the California PUC workshop, which was called the "Rate Design Forum," on December 11th and 12th. Professor Severin Borenstein provided the opening salvo. And the focus there was mostly on commercial/industrial customers, and in some ways that's what I'm going to focus on. By and large, Speaker 1 laid the foundation from a residential perspective.

There is certainly a lot of excitement in the United States, as in much of the globe, with the arrival of smart meters. And the point has been made that, now that we have smart meters, let's have smart rates. And to many people that equates to dynamic pricing. And certainly that is part of the opportunity set that's created by the smart meters, but it is not the beginning or the ending. And I say that as somebody who strongly believes in dynamic pricing. I just would like to reiterate the point that we just heard, that when electric service is provided to a customer, the service is both a capacity product and an energy product. The two of them are often intertwined and intermingled, but the grid is separate from the energy that flows through the grid, and that's a fundamental issue which some people would agree with and some won't agree with. But I fall in the camp where I believe the two are separate.

Ten years ago I was saying that they are the same product, and we should only have dynamic pricing of energy, and that's going to solve all of the energy problems that we have in the United States and abroad. But I have thought hard about it, and I have come to the conclusion that the grid needs its own price, and the energy needs a separate price--and that's what we have had, by the way, for commercial/industrial customers for the better part of a century. So it's nothing revolutionary or new that I'm talking about.

What is new, however, is the statement made, for example, by Professor Borenstein, that we don't need demand charges, because smart meters have made them obsolete. Demand charges were like a stop gap measure for a time and an era when smart meters didn't exist. Well, for large customers, we have had smart meters for a number of years. They are not new for the large customers.

So, with that as the background, just telling you what I'll be saying, I will now start to say what I'm saying. I think we all agree that rate design should promote economic efficiency. To promote economic efficiency, some speakers at the rate design forum I just referenced, particularly Professor Borenstein, argued for basing prices entirely on short-run social marginal costs, and that any discrepancy between the revenues from the pricing design and revenue requirements should be covered by fixed charges. And there was a lot of debate about whether there should be the same fixed charge for a residential customer who lives in an apartment versus one who lives, perhaps, in a house or a mansion (like the one nearby), or perhaps whether Costco should pay the same rate as the house. And that was left to discussion. There's a lot of interesting commentary from that workshop that you can find at these links that I've provided. The entire day and a half is there as a video, if you have the time. And I've talked to some people who have actually taken a day and a half to watch it. For example, Herman Trabish, who is the writer at Utility Dive, tuned it in, and he's provided his summary there. You can look at that. You can look at the video or you can look at the papers.

So, I think generally we agree that rate design should promote economic efficiency. I don't think anybody would dispute that. However, it also has to promote several other objectives, equity being one of them, customer satisfaction being another, bill stability being yet another. Then you have revenue stability and gradualism. (These are the Bonbright principles sort of dumbed down a little bit here to get away from the rich and ornate prose in which he wrote.)

The cost of delivering electricity has a capacity component and an energy component, as I mentioned earlier. And here's a little bit of clarification. Power is generated at the power plant, there's no doubt about it. But it is the grid which delivers electricity to the customer. What is the grid? It's obvious, but I thought I'd state it. Transmission lines, substations, circuits, feeders, transformers, lines from the last pole to the customer's premises and the meter. That's the grid. So when customers connect to the grid, in other words, they are not Robinson Crusoe on some island, they are part of the grid, they are buying a call options. A 24/7 call option--they flip the switch; they want the power to be there. And if it's not there, there's irritation, there is a lot of screaming, and there are political consequences if there's a big outage.

So what happens when customers don't consume any energy? I ended up in Fort Lauderdale, and had to be driven over here. And I asked the driver, "So, what kind of people live here?" Which was a loaded question, admittedly. But, basically, the answer I got was that a lot of people have vacation homes here. They're not here most of the time. Well, the grid is still there. They can come any time they want to and flip it on. The grid was built to accommodate their full power. I think all of the examples Speaker 1 mentioned are very much to the point. Whether or not 27 KW is being pulled or not, the grid has to be able to sustain the 27 KW loads, on average. And by the way, the measurements you had, I have done those for my own house with a smart meter. I stood outside, and I got my readings that way. I know there are more sophisticated tools now available, but it is truly amazing what the spa will pull. I had a spa for many years. It was pulling about five KW. The air conditioner was pulling about five KW. The rest of the house is pulling a lot. So I would see, on a hot summer day (and the spa has to be on all the time), it would hit about 12 KW. And mine is a modest, four-bedroom house, so it's not difficult to have that amount of demand. Now, my neighbors didn't have a spa, or perhaps some of them didn't, and so their load was not quite as demanding.

A lot of people are excited about peak period pricing. Time of use pricing has been rediscovered after 50 years, which is great. I'm so excited. It's a bit too late, though. The world has changed. We can't just do time of use; we have to be more sophisticated. I'll come to that in a minute. But the example is given that it is peak demand that drives capacity cost. So the argument is that if the household peak's not there, they shouldn't be charged. And with the 4CP method, or critical peak pricing, or whatever you have, they're just basing it entirely on the peak period. And so you're going to have customers completely switch out of the peak period, using smart technologies. They would pay nothing, if the entire charge is being collected in the peak period, and you'll have a catastrophic meltdown from a revenue collection perspective.

The payment can be made through a connection charge, for being connected to the grid, as they do in European countries. Or through a non-coincidental demand charge, which these days is widely reviled, or a fixed charge. Those are measures to collect the cost of being connected with the grid. It's the price of the call option. The call option is not free.

And so how do dynamic pricing and demand charges relate to each other? My position is that they are complements, not substitutes, as has been suggested. Why? Because we're talking about energy being priced dynamically. Its costs do vary dynamically. And we're talking about the grid being priced based on the capacity cost, which is being collected through a demand charge. So a lot of people are saying that we should not have demand charges; we should instead just use fixed charges to recover the discrepancy—we should have an energy rate, short-term marginal cost, socialized to include externalities, and the delta is for the fixed charge.

The problem is, how do you set the fixed charge for such a diverse array of customers? Large and small, Costco, 7-11's, residential customers, schools, hospitals, factories…you can't have the same fixed charge. And today we don't. But the proposal is that they might get the same fixed charge, going forward. So, a good alternative is a non-coincident demand charge. The non-coincident demand charge is kind of like a circuit-breaker. So, everyone who has a house, who's lived in a house, has thrown a party at one time or the other and had a lot of guests, a lot of excitement. At some point, there was darkness and embarrassment. And so you went quickly to the garage where the circuit breaker is and turned off a few things and flipped the circuit breaker back on and suddenly the light was there. So was that the system peak happening? No. It was not the system peak happening, it was your much localized household peak happening. The house has its own grid capacity constraint.

And so all we are talking about with the non-coincident demand charge is the equivalent of that. It's not such a foreign idea. People tell me that residential customers won't understand demand, and that you need to know the integral calculus--you have to take kilowatt hours and differentiate it, or go the other way using the integral calculus. And I said, “Wait a minute.” When people buy a light bulb, it says 60 watts (or 13 watts). Watts is a measure of power. Everybody knows what a watt is. They don't know what a watt hour is, and the example that everyone was given was, if you leave the light bulb on, and it's a 100 watt bulb, for 10 hours, that's 1,000 kilowatt hours. So we went from watts to kilowatt hours in grade school, or whenever we bought these appliances, to figure out, why are we paying per kilowatt hour? What is a kilowatt hour? You begin with the watt; you go the watt hour, not the other way. So it's not that difficult to explain.

And certainly for C&I customers, as I think we will hear from the other speakers, it has been a very easy concept. They have gotten it for years, so trying to take out demand charges for C&I customers, which was the issue being debated in California, struck me as truly remarkable inquiry into a topic that didn't need an inquiry. Smart meters have been around for a long time for these large customers. They've taken service in three part rates: fixed charge, demand charge, and energy charge. Their presence does not alter the principles of rate design.

I'll give you a couple of examples. Everybody has heard about real-time pricing in Georgia, right? We've had real-time pricing in Georgia for a very long time. It's held up as the world's most successful real-time pricing example for large customers. It goes back to 1992 when a man arrived there from Eskom, the utility in South Africa. They were doing it for the diamond mines in South Africa. And he brought that idea with him, and that idea was implemented very successfully by Georgia Power. They now have about 2,300 customers on real-time pricing. Those customers represent about 20 percent of their retail revenues--not just industrial, but every class. Here's the part that most people don't know. It's a two-part rate. The first part is for baseline usage. It's based on embedded costs, which include a demand charge. So if the customer doesn't change their load profile, if it is their baseline that they're consuming, they're going to pay a demand charge. If they change it, they still pay the demand charge in the baseline. It's only on the delta that they pay the real-time price, which is based on their system lambda. So the example of Georgia Power being a very successful real-time pricing utility is also an example of demand charges being combined with dynamic pricing. It is not one or the other, it's both. And I've talked to them; I interviewed them for the CPUC workshop. I've written up what they have done. I think honestly that is the best way to go--to have both.

Go to Illinois. Commonwealth Edison has 16,000 residential customers and 9,000 C&I customers and hourly pricing, but both of them are also paying demand charges and fixed charges. So it's not pure hourly pricing being done in Illinois, either.

Ideally speaking, you'll have a rate here that's cost-reflective. It passes on the cost of the grid through a demand charge, and passes the cost of energy, which varies by time of day, through a real-time or dynamic price. So, the ideal rate design, in my opinion, should include demand charges for recovering capacity costs, and energy charges for recovering energy cost, and a fixed monthly charge to recover the cost of billing, metering and customer service.

Now, what if the customer zeros out their demand? Say they just have battery storage that kicks in for a certain amount of time, and the demand is just being measured on a coincident peak basis. Are they no longer connected to the grid? Are they no longer imposing a cost on the grid? Do they no longer have a 27KW, 24/7 call option? They do. The answer is yes to all of those questions. And so therefore you cannot just have a volumetric demand charge. You need to have a non-coincident peak demand charge to recover those costs that are truly not deferrable.

And the energy charges, in my view, should be based on various forms of dynamic pricing, which is not to say that some customers would not like to have a guaranteed bill like the one Speaker 1 was talking about, the flat bill. Give them a choice. Put them on a smart default rate, and then, if they don't want dynamic pricing or they don't want what you're offering as a default rate, you give them choices. About 10 percent of the customers at some of these utilities are on the guaranteed bill concept. And so they should pay a hedging premium for the risk that they're putting on the utility to be on that rate. But it's their choice. If they want it, they could certainly have it.

Question: Did you say that the fixed costs of generation should be included in the demand charge, or just the grid?

Speaker 2: In other words, the capacity cost of generation? Is it vertically integrated, or a wholesale market?

Questioner: That's a really good question. I didn't think it through, but you just gave a general principle, and I'm asking what your general principles are.

Speaker 2: My idea is that there is more flexibility with generation capacity costs, and there's distribution and transmission capacity costs. So if there's a certain portion of generation transmission and distribution costs that is fixed and independent of usage, then that portion should be recovered in some kind of a demand charge.

Speaker 1: Traditionally, in a vertically-integrated utility, the capital costs of the power plant are fixed, and only the fuel costs go through. In restructured states, you don't see those costs. All you see is a kilowatt hour charge, right? And so you wouldn't have the ability to do that.

Question: As you look forward, is there any concern or issue that it may become economic for customers to actually disconnect from the grid? That the fixed costs and all the costs get so high and/or that the costs of solar, batteries, whatever onsite gets low enough such that people actually do have the incentive to disconnect from the grid at that point?

Speaker 2: That would probably happen anyway at some point for some customers, because technology's advancing rapidly. Customers have diverse preferences. I talked to a lot of customers with solar, for example, on their roof. Many of them just want to become grid independent. And that's fine. If they truly become grid independent, they cut the line, that's their prerogative. And it's a long-term challenge. People have said that if you do this kind of rate design, you're going to invite retaliation. Well, that's just the way it is. If you don't do it, you're also inviting retaliation. You're having inequity issues with customers who have a lot of DG and customers who don't. So you have to deal with the problems one at a time.

Question: Doing a fixed charge makes sense right now, because there's relatively little happening in the distribution system, but once we start having EVs charging, and all of that, and once we start needing to make incremental investments in new types of capabilities, then the time-varying nature of coordinating all the different loads is going to have a significant impact on the cost of the network. So at that point, would something more variable, or something that accounts for things like power factor, power quality, even black start capability, if we start doing feeder-level micro grids, be needed? And that's coming fairly quickly. So, once we're in that kind of a realm, how does that impact the rate design?

Speaker 2: We already have much of what you're saying today. For C&I customers, we have power quality rates. We have rapid starting and rapid slowing down rates. What we will see is that those ideas will now begin to migrate towards the mass market. And I think perhaps an implicit premise of your question is that it could become terribly complicated, and then how would we cope with it? Maybe the other premise might be that if we do all of this, then the death spiral, which was looking like a cold, will actually become cancerous, if I can use a terrible metaphor. But basically the reality is that the world is moving. Nobody saw the iPhones coming; nobody saw the Teslas coming. They suddenly came, and they're overwhelming, and right now the challenge is inequity among customers.

On the long-term issue of technological change, who knows what the utilities will look like 25 years from now? Who knows if there will even be any utilities around? Maybe the cell phone companies will have taken over. I was actually here in Florida last year in March speaking at a meeting of electric utilities and gave a similar kind of a talk at that meeting. And a person said, "Well, I was very disappointed in what you presented, because I was hoping you'd present some new ideas, not recycle the old ones from Bonbright, and so on." I said, "What were you expecting? What kind of future do you have in mind?" He said, "The future I have in mind is one where there are no utilities, there is no grid." I said, "Are there any people there?"

I mean, I'm not doing science fiction here. I'm talking about what we are looking today, and I'm arguing that if you become obsessed with economic efficiency to the exclusion of equity, we create a humongous challenge. There are tremendous inequities with the penetration of DEG (distributed energy generation). I support the penetration of DEG; they just need to pay their fair cost. I have neighbors. I live in northern California on a court of 10 homes, and two of them have solar. And they're always telling me, "My bill is $30." And somebody else's bill is $8, and my bill is $350. Similar sized houses. And so they're obviously not paying, and they're excited. One person's told me they have negative bills. I don't know how that's happened. So those are the inequities that we are talking about. We have to find a way to be equitable and efficient both at the same time.

And that's why my suggestion is not just to have a demand-charge-only rate, or a fixed-charge-only rate, or a dynamic-pricing-only rate, but to have a hybrid, a combination, because I believe that reflects the cost structure fairly and efficiently for the bulk of the customers--which is not to say that you won't have some customer with two Teslas and solar on the roof with an electric spa. Yes, you would. But that's exactly why we need to have these kinds of rates--to prevent those humongous cross-subsidies from occurring. Ashley and I actually wrote a piece on the cross subsidies arising from solar in the *Fortnightly*, along with Barbara Alexander. And that piece has been cited over and over again, and most recently I got a call from the reporter at Utility Dive asking me about the rate that includes demand charges for DG customers in Massachusetts that Eversource got approval of. And I was put through an interesting line of questioning, but it was clear to me that the reporter didn't agree with anything I was saying, and was soon to write whatever he was going to say anyway. Yesterday, it came out, and basically his point is that this is a terrible idea, that non-coincident demand charges make no sense at all, et cetera et cetera. So I said the issue that rate was addressing was a cross-subsidy issue. I sent him the article that Ashley and I and Barbara had written. And the response back was, "You're just citing utility studies. Cite some other studies for a change." And I said "Well, OK." I've never met the guy, but he's quite friendly. He used to be a chiropractor.

Moderator: He must have found the one less profitable profession. I'm beginning to think that I'm the only one at this table without a spa or a sauna.

Speaker 3.
The Electricity Consumers Resource Council (ELCON) represents large manufacturers, and we do not pretend to represent small mom and pop manufacturing facilities. A typical ELCON member might be a 500 megawatt petrochemical facility that may have most of its power consumption on site served by co-generation units. And also the typical ELCON member is steam driven. Steam is the primary driver of the industrial process. Electricity is a supplement to that, and it has interesting consequences, because they depend on the reliability of the grid probably more than any other processes, and it is very difficult to have backup steam. They have backup power for their co-generation unit, but if the grid goes down, there cannot be a backup delivery. To tie this with a discussion this morning, if you remember the 2003 blackout, billions of dollars of manufacturing facilities were destroyed during that blackout, both in the northeast United States and in so-called “chemical alley” in Ontario. Those facilities didn't care if the grid bounced back at 11 minutes, 11 days, 11 weeks or 11 months. They were shut down, and they had to be rebuilt. And so the resilience issue is front-burner for my members right now, because they think, in a word that the administration likes to use, that it's a fake issue.

ELCON was founded in 1976 in anticipation of the enactment of the PURPA. Our main concern at that time was that state regulatory policy was shifting fixed costs into energy charges, expanding the volumetric component of all rates, resulting in cross-class subsidization. The initial motive of that was to isolate residential rate payers from the high fuel cost imposed by the OPEC oil embargo. We are very protective of two and three part tariff structures. And over the years, ELCON members have spent billions and billions of dollars on retooling their facilities to reduce their consumption of kilowatts at peak times.

Cross-class subsidization dominated ELCON policy-making for about the first decade of its existence. Because of the expanded volumetric energy charges, it became a preferred tool to promote and to fund various social policies that were implemented by the state commissions. The state commissions viewed kilowatts and kilowatt hours as policy variables, not as fixed physical characteristics of the product and service that they had regulatory jurisdiction over. Some of the policies that ELCON fought were Lifeline Rates, DSM, and opposition to declining block rates.

For about the first ten, 12 years of ELCON's existence, the organization funded a survey of cost of service studies across the nation in an attempt to estimate what the level of cross-subsidization was on a nation-wide basis. And a typical survey may have included 100 or more cost of service studies. The last one that was done and published in 1986 involved 84 utility cost of service studies, and the determination there was that the level of subsidy in today's dollars was about $5.7 billion. These are welfare transfers from the industrial class to the residential class. And that got the members’ attention, and in part that precipitated, in the mid-1980s and the late 1980s, policies FERC and growing interest in retail competition. And ELCON members were motivated by what is perhaps in hindsight a naive attempt to escape the wickedness that they saw of state regulation.

Recent attempts to expand subsidies are intended to promote, of course, net metering and rooftop photovoltaic. You can't read any electric trade press coverage these days without those issues coming up. Speaker 2 mentioned the California Commission Rate forum that was held in December, and members of the industrial community representing CLECA, the California

Large Energy Consumers Association, testified at that forum.

The next three slides I have really summarize that presentation, made by a woman named Cathy Yap. I think the title of the slide says it all: instantaneous customer demands drive the sizing of the utility system, and I like Speaker 2's characterization of the relationship as a call option. The size has to be there, it has to be paid for, and it should be paid for by everyone. An important point is that even if customers generate a portion of their own energy needs, they still place demands on the utility system, either when they require power, or when they deliver power to the utility system. Now, that clearly, in California, applies to the rooftop photovoltaic. It also applies to ELCON members who co-generate. And under PURPA, they are all but required to have back up power for their facilities, and the PURPA requirement is that the utility provide that at just and reasonable rates. And so there is the long-standing recognition that even if you generate a block of your own power, you're still leaning on the system, and have an obligation to pay for it.

Some of the rate design issues that need to be discussed start with the problem that without demand charges, customers with low load factors can impose substantial fixed costs on the utility system and avoid paying fully for those capacity costs, because their usage is so low. If you go back to the previous slide, where I mentioned the cost of service studies survey and the $5.7 billion, a typical utility at that time was earning a rate of return from industrial customers of maybe eight, 8.5 percent. From residential customers, it might be 2.75 or 3.1 percent or something like that. The commercial class customers by default got something in between, because even though they're on a two or three part tariff, the ratio of energy to demand is a lot lower than what it is for a large manufacturer. Again, that's because the commercial class doesn't have the business model or the technology, especially at that time, to control their demand like a manufacturer was able to do.

Time varying energy charges are not sufficient to capture the capacity cost burden, primarily because customers are not charged for peak loads outside the peak periods. And also, coincident demand charges ensure that solar customers will fairly pay for their contribution to system costs.

We think the best solution for generation cost is probably a mixture of coincident demand charges and time-varying energy rates. And that needs to be verified at the jurisdiction level by cost of service studies. And to the extent that transmission, sub-transmission and distribution costs are time dependent, coincident rather than non-coincident charges should be employed. And this also should be addressed empirically. Finally, getting the right rate design eliminates the need for revenue reconciliation measures, which moving to a total volumetric approach would require.

Speaker 2 mentioned this briefly, but I'll mention it again. Earlier this month, the Massachusetts DPU, in what I would call an amazing act of courage, approved what's called a Minimum Monthly Reliability Contribution, an MMRC, in form of a demand charge. And the purpose of the MMRC is for all distribution company customers to contribute to the fixed costs that ensure the reliability, proper maintenance, and safety of the electric distribution system. The DPU determined that the new demand charge equitably allocates to fixed costs of the distribution system not caused by volumetric consumption. It also said that it does not excessively burden ratepayers, does not unreasonably inhibit the development of net metering facilities, and is dedicated to offsetting reasonably and prudently incurred fixed costs. I think that is a very thorough analysis of the situation.

You may have seen this slide of the "duck curve". I'm no fan of this bird and I think it's the wrong direction for the electric industry in this country to go. Putting aside what's driving it and the merits of that, this is a potential for disaster. Notice that there are two very obvious peaking periods, and they're driven primarily by residential behavior.

In closing, why does the electric grid exist? It exists to serve the energy needs of consumers and the economy as a whole. Remember, utilities used to have “public service” in their name. The grids do not exist so consumers are subservient to the financial needs of either obsolete or ascending and emerging resources. Resources are committed and dispatched to meet the instantaneous demand of all customer classes. Rates for each should be based on fixed and variable costs they impose on the system. What could be more rational? The duck curve is driving regulatory policies in the direction of regulatory control of personal and business decisions related to energy consumption and investments.

I mentioned that the prime driver of ELCON facilities is steam. Steam comes from co-generation facilities. Several ISOs and state commissions have been trying to get those steam applications dispatched via the ISO, meaning the ISO would take over the manufacturing process, since dispatching the steam requirement, basically interrupts and drives the production schedule of those facilities.

There are also expanding efforts to manipulate rates to force a desired policy outcome. I think that's been a driving force in regulation in this country for as long as I have known it. Maybe things were moving in the direction of more intellectual honesty beginning in roughly 1995, but, as we heard this morning, it's back with a vengeance. I believe the customer should not have to align their home lives, business, and commercial practices for the benefit of resources that are functionally unreliable. And that's clearly what's happening. Honest rates are more important than some social advocate's notion of efficient rates. And we are talking about rates; we're not talking about prices. Thank you, I look forward to questions.

Speaker 4.

The thing that's been sort of strikingly absent, for me, from the discussion so far today is the completely transformational nature of how customers are going to interact with the grid, perhaps in the very near future. And the infrastructure decisions, these fixed costs that we're talking about recouping, some of these are embedded costs, but of course we have to think about the question, are we providing the right incentives for the right kind of infrastructure to be built by the utility? How should the utility be focusing its investment dollars, and where can those services possibly come from other sources?

So we think about the electricity sector becoming much more of a multi-way exchange of services. It's not just about solar power; it's not just about rooftop DG. It's not about these one-off things. It's about a transformation that's coming that will affect what role the utility plays, what infrastructure they should indeed be building, and what should be coming from other sources. Speaker 1 said, early on, that customers don't want to look at all the complicated pieces of the bill. They care about a bill they can understand, for example. I agree totally with that. But people do care about lower bills. And if people can adopt technologies in their home or in their business, in a way where they contribute services, where they contribute to the reliability of the grid, where they perhaps hand over the operational control of facilities within their house to a third party who can manage that, interacting with a market and producing value for the customer, and thus all they see is they have a lower bill…

I agree that the kludgy, the simple initial net energy metering policies (which are really infant industry policies) didn't look at the whole picture, but the whole picture is coming. And so that's really what I'm concerned with.

So are dynamic prices sufficient? I'm actually going to only talk about the first two items on the agenda. Let's try to think about what are some necessary conditions for dynamic pricing being sufficient. That is, where we don't need demand charges, and we don't need significant fixed charges. Perhaps we need those things in a targeted, specific way, but perhaps we don't need them very much. Can we think about a condition of the electricity market place where that could be true, where dynamic pricing is largely sufficient?

My basic answer to that question is that we're not there yet. There are some issues that arise in trying to implement that today. However, the appeal of moving toward that model seems like something technology is enabling. And I'm not sure of the time frame, but I don't think it's as far as 25 years. I think it's much sooner than that.

So the second piece I want to talk about is, what does it look like? We should be implementing policies now that move us toward dynamic pricing sufficiency. So here are some conditions. First of all, if you have locational marginal prices and congestion revenue rights, down to the level of the feeder, so that you've got a price signal about where congestion is happening that people can react to, and people react to it, or to the extent that they don't, or to the extent that infrastructure needs are identified, then that's a place for utility investment, to the extent that this decentralized market can address these needs through combinations of distributed energy resources like storage, solar, or demand response. When I say demand response, I don't just mean peak shaving, which is the traditional peak reduction role. Energy efficiency still plays a role, but energy efficiency plays a much more targeted role, because in this decentralized world, you might want particular types of energy efficiency technologies and programs deployed in particular places and not others. So that's important.

Another condition is free entry and exit on the distribution system. This means the utility moving toward being more of a host of a platform for the electric system where there's free entry and exit, so the service providers, customers working through (probably) aggregators, can enter and respond to opportunities that emerge on the system.

Now, in order for this to work, in order for this utility platform-type approach to work, then the utility has to have the opportunity to be revenue adequate. It has to be a going business concern. This is a dramatic change in the utility role. The type of investment is going to be somewhat different than the investment made today. There was a mention once earlier today of performance-based regulation approaches, and those are the kind of things that I have in mind when I say that the utility's going to have a need to be revenue adequate and so we need to tend to that.

And, finally, there has to be a political tolerance for scarcely pricing. I live in California, and people get very politically active when prices go up. So you have to cultivate, over time, confidence that this model, this platform, works, so that we don't get a political random response when things start looking like there's a high price.

So what are the barriers to dynamic pricing being sufficient? The distribution system is serving the purpose that it was intended to serve, but it was built based on an analog technology, where you have to build a whole lot of buffer into the distribution system to ensure that you can serve whenever people turn the lights on, whatever people are doing on the grid. When you have such an overbuilt distribution system to start with, creating price signals is challenging.

The structural change is massive that we're talking about, so that's why we can't just turn the keys over to dynamic pricing and call it sufficient at this point.

There are barriers to entry; significant evolution in utility regulation needs to happen. It needs to be equitable. I agree with the Bonbright principles. We want equity, we want fairness, but we also want to leverage the capabilities of all the resources on the grid, not just the supply side resources on the grid.

We have a lot of embedded costs that have been incurred in the past, and we have to recover those fairly and deal with that.

And then we don't have political tolerance for scarcity pricing in most places.

So, how do we move toward dynamic pricing sufficiency? I like the Bonbright principles. I agree that they're not wholly consistent, that they don't point to one rate design, but there are things that are clearly relevant to whatever gets constructed out of this. It should be fair, it should be simple, and it should be unambiguous. It should produce a revenue-adequate result for the utility, and it should be a proxy for a competition would provide. And that becomes a really difficult one, doesn't it? Because what does competition look like? We have a picture of what competition looks like from a PURPA standpoint, or from procurement from third parties participating in all-source procurement from a utility. That's competition. But we're talking about this kind of transformation of the electric system. It's complicated, there's no doubt about it.

So, Severin Borenstein's framing was useful, but it was not sufficient. I agree we try to rely on dynamic pricing as much as we can. Short-run marginal cost pricing implies economic efficiency. His definition of short-run marginal cost pricing includes all environmental externalities--not just pricing carbon, but pricing other environmental externalities. All his marginal costs of pricing also include allowing for the full range of scarcity pricing running its course. And then you achieve revenue adequacy with true-ups. He mentioned fixed prices. I actually didn't think (maybe he said this elsewhere) that he was uniformly opposed to demand charges. He did say that they were no longer required, but I think that his point more was that we're not going to achieve revenue adequacy with this economically efficient outcome. There are lots of equity considerations that go through the whole range of power system policies that need to be taken into account to ensure that other revenue adequacy is achieved. So, he at least expressed in that meeting that that's something that kind of needs to be negotiated.

So here are some proposed principles for moving forward. We're talking about a vast landscape around the country where the situations are very different. So, in places where you have dynamic pricing, where dynamic pricing is beginning to go down into the distribution system through a third party market, then great. But in places where you don’t have that, what I'm really worried about is that we get price signals to the customer and to the demand side that people can react to and that are reflective of long-run economic efficiency. And this is where I differ a little bit from Dr. Borenstein, in that I agree with that definition of economic efficiency from a short-run perspective, but we're talking about an industry and massive structural change, and we're talking about long-term investments being made on both sides. So I don't want to subsidize emerging technologies, demand side, whatever. I'm not talking about subsidies; I'm talking about attending to setting price signals that convey value, so that people can respond to them.

So I talk about thinking about long-run marginal costs, knowing that a long-run marginal cost is a fuzzy concept when you've got this future that's so different than the present. But still, when we're tending to economic efficiency, we need to tend to short-run efficiency with an eye towards long-term efficiency.

We need to remove barriers to entry on the distribution system.

We need to attend to specific sources of cost that lie outside of time-varying cost causation, so we draw a distinction between fixed costs that can be aligned with cost causation and those that seem independent of that. So, for example, we think about the dedicated facilities for the customer: metering, billing, customer service, in the case of industrial customer, the local transformer, any dedicated facilities built for that customer. I don't have any trouble with that being recovered with non-coincident demand charges. On the distribution system, we have parts of the distribution system that benefit from sharing facilities and parts of distribution system that maybe are independent of the shared facilities. We need to spend more effort in disentangling that. For those that are independent of shared facility, so it's what I would call more really a fixed cost, then I'm OK with some kind of a coincident peak demand charge. But for those that benefit from coordination of customers, there should be a price signal that customers can respond to and benefit from by coordinating. So that's another principal.

We want to attend to revenue adequacy. We want to do it in a way that doesn't distort price. I do think that the Georgia Power example is an intriguing one, and there’s a sample tariff that is running right now with Southern California Edison that's a subscription based tariff, but one where deviations from the subscription price track the cost causation price signals, so you get the price signals and maybe you get more revenue adequacy uncertainty out of it. I'm not sure; I didn’t look at it that carefully, but seems promising.

And we need to attend to infrastructure investment that leads to dynamic pricing becoming sufficient.

So these are kind of my criteria. If we are headed towards a future where dynamic pricing is sufficient, we should be building the infrastructure that's building toward that. And so we should be thinking about how the pricing signals that we're sending today affect that long-term infrastructure development. That's all I have. Thanks.

Question: I always get confused, when people refer to the term “long-run marginal cost,” about what they mean by that. Short-run marginal cost, properly defined, includes costs that may be incurred in the future associated with a very small change in demand in the short run. So it's not just costs that are incurred today, but if I increase my demand, and that means I need a bigger transformer on my pool, that's part of short-run marginal costs. On the other hand, when I hear people say “long-run marginal costs,” they're oftentimes referring to something like an avoided cost from a planning study that may or may not have anything to do with the incremental consumption by a particular customer at a particular point in time. I'm curious how you're using the term.

Speaker 4: I wish I had a real snappy, clear answer for you, but I don't. The context that I bring up the idea of long run marginal costs in reveals my background, which is as a utility commissioner in a vertically-integrated state. We're thinking about resource planning, and we're thinking about comparing resource alternatives, and we're asking the question, what's the most efficient resource alternative on the table? And so that's done looking at long-run marginal costs.

Questioner: I would say that's looking at comparisons of long-run avoided costs, and that's not necessarily marginal, because marginal refers to the cost of the next increment of power consumption at a particular time and location.

Question: Speaker 4, you spoke about a third party that would be responsible for our homeowner's energy. What were you referring to? Who's the third party?

Speaker 4: If you're in a retail choice state and you choose your retail provider that’s the third party. If you're in California and you have something called Community Choice Aggregation, then that Community Choice aggregator is a third party.

Questioner: Understood. OK. Second thing. You mentioned time varying pricing, dynamic pricing and then scarcity pricing, and the scarcity pricing was like code for, “Just stick with us, because the price is going to go down at some point in your life.” Is that what you meant?

Speaker 4: What I meant by scarcity pricing is, when you experience short-run marginal costs, there are times when the price becomes very elevated because there are shortages. And that's scarcity pricing. And many places have caps on how high that price can go. So if you don't allow that price to fully express shortages, it's not a scarcity price. So, scarcity pricing just means allowing the short-run marginal costs to fully manifest.

Question: I'm not sure I understand what you're proposing. I see a lot of principles. We've frankly seen them as being somewhat inconsistent, but can you just lay out what the rates would look like? What exactly it is that you're proposing?

Speaker 4: In the fine tradition of Bonbright, they *should* be inconsistent, right? In the case of California, we did a survey of non-residential rate designs and compared them against these criteria that are described in those extra slides. And this is the rate design that SMUD uses today for its commercial industrial customers. It's a three part rate. There's a customer charge, there's a fixed charge. There's the site infrastructure charge, which is a non-coincident peak demand charge, and then there's a super peak demand charge that they have, and then there's a coincident peak demand charge. And then there are these time of use rates here. I'm sorry I can't tell you what the definition of super peak is, though. That's per kilowatt. So it's a demand charge.

Comment 1: We have no issues with that rate.

Comment 2: We're totally on board with that rate.

Question: So what I'm taking from this is that, for this commercial customer, there is no system demand charge other than at super peak times. So at all the other hours, there's no demand charge at all?

Speaker 4: No, there is a site infrastructure charge.

Questioner: But I thought site infrastructure charge was just local facilities.

Speaker 4: It measures the number of kilowatts based on coincident peak demand. It's just a coincident peak demand charge.

General discussion.

Question 1: OK. So where we left off was Speaker 4’s description of what Speaker 4 considers a best of class rate design, in this case for a commercial industrial customer within SMUD, the Sacramento Municipal Utility District. And as I understand it, this is a multi-part rate where you have, obviously, the customer monthly service charge. You've got a non-coincident site infrastructure charge associated with the facilities needed to serve that particular customer. You've got a super peak coincident demand charge, and then you've got the various time varying energy charges expressed volumetrically, right?

Speaker 4: Correct.

Questioner: But Speaker 4 thinks this should require some further modification. Why don't you tell us what that is?

Speaker 4: Sure. May we just bask in the afterglow of agreement?

So we surveyed I can't remember how many different utilities’ commercial rates. And the things that are really different about this are that the non-coincident peak demand charge is very small. Most utilities, and most utility commissions, have far more revenue from commercial/industrial customers through a non-coincident peak demand charge than is reflected here. Secondly, the super peak demand charge is also relatively modest, so parts of the distribution system are actually collected through the volumetric rates.

And this paper is joint with Jim Lazar. And Jim has been doing rate design for 40 years. So what he recommended was basically transferring the coincident peak demand charge into a critical peak price, where you would have approximately 50 hours a year of what would be classified as critical peak times. And you'd have a high charge, and this high charge happens to be such that you get the same revenue as you got from the coincident peak demand charge. And then, the other thing that we did was to follow what we think is a better practice. In California, reflecting the fact that there are super off peak periods, there are periods where prices are very low, there is a fourth time of use category for super off peak. So those are our two changes to the SMUD rate, but I'm not sure that you guys really agree with me anymore. But, anyway, there you go.

Moderator: So the point of disagreement might be around whether to bill a true demand charge and the merits of coincident versus non coincident.

Respondent 1: Well, you use non-coincidence if you don't have coincident numbers.

Respondent 2: What do you do when you have an interruptible customer? Does he get zero demand?

You go to non-coincident peak, used to be the practical answer. But there were claims by some that if you're an interruptible customer, by definition, you're not on the peak. So that that customer gets zero demand allocated, which is obviously not the case.

Respondent 1: At least in the case of a manufacturer, there will be part of their operations on the peak. They're just coming down a certain amount; it reflects what the value is to them.

Respondent 3: I believe that the ideal rate is not just a three part rate, but a five part rate. You have a fixed charge, you have two kinds of demand charges, and then you have differentiation of the energy charges. I think the Georgia Power case is probably the best example. The rate we are looking at here is basically a critical peak pricing rate, I believe. The super peak might be dispatchable, in which case it'll truly be a critical peak rate. Or maybe it is just a three period time of use energy charge, I don't know.

Respondent 4: It's three period time of use.

Respondent 3: So the super peak is collected every day during certain hours?

Respondent 4: Every hour. It's a kilowatt hour charge.

Respondent 3: Right. But it's not one of those rates where a critical peak charge would only apply to the top 100 hours of the year, or something. This like a time of use rate with three pricing periods, and the price is known in advance, and the duration of the period is known in advance. There's not a dispatchable rate.

Respondent 4: Right.

Moderator: So it's not dynamic.

Respondent 3: Yeah. It's not dynamic; it's static. And so my only comment would be that this is not best in class. Best in class, for me, would be that the energy portion here would have a dynamic element to the extent that there is a dynamic element, and we have seen in most load shape analysis that the top 100 hours of the year account for as much as eight to 10 percent of the annual peak. So that makes a strong case why there should be a dynamic element in it. As just again, as a comment, I would say this could be improved.

Respondent 4: So, we presented this to the NARUC Rate Design subcommittee, and a staff person from Wisconsin claimed that this looked very much like a rate that they offer in Wisconsin that he thought was superior. Do you know of a rate that has these attributes and has dynamic pricing also?

Respondent 3: Yes. And in California, the IOUs have critical peak pricing as the default rate for all of their large C&I customers. That's the default rate. But they have a critical peak element in it. So that's what I'm saying--what I see here is missing the dynamic element. So this was an improvement over the SMUD rate that we were looking at. So I've been talking to the California IOUs and the Commission. Right now they have a demand charge; they also have an energy charge. The energy charge is a critical peak rate or a time of use rate. You can opt out of CPP and go to TOU. But they have a demand charge--and then the question is, how many kinds of demand charges do you have? It's like what we're seeing here is the site infrastructure charge. I believe there's essentially a non-coincident demand charge.

So this is the call option sort of being captured. The only question is an empirical one. Is $2 sufficient per KW or is it not sufficient? I think that's where the conversation might have to be based on data.

Respondent 4: There's a cost allocation analysis that was behind this. The cost allocation that we would support for the site infrastructure charge are just those facilities that are caused directly by that customer in that facility.

Respondent 2: How did you allocate the cost for the rest of the demand portion--based on 12 months peaks, or one day simultaneous peak, or four quarters? We used to have five different cost allocation studies filed at the Wisconsin commission to give the commissioners the opportunity to fix the rates where they wanted them. And so we had everything, from zero, to everything was allocated to energy to single peak hour, and then you had 12 months peaks, seasonal peaks… You had all these intermittent studies so you could either allocate zero to the consumers or …

Respondent 4: To answer your question, we didn't do that.

Question 2: Let me try and define what I think the problem is that you all are trying to solve. And that is, you now have customers staying connected to the grid who have the ability to generate behind the retail meter and therefore reduce their energy demands, and if they can do that enough, and you don't have a demand charge in the retail rate, then they're avoiding costs that have been incurred to serve them, and they're still connected, and they still need that grid. So people are now saying we need demand charges or some other mechanism like a fixed charge in order to ensure that we get fairness in the system, or else those costs are either shifted to others or not recovered by the utility. Just to start, does anyone disagree with me that that is the problem we're now solving?

Respondent 1: I do. One, it's a different story for residential customers, where what you're describing is exactly correct, that they are no demand charges today in most of the country and a solar cross subsidy issue is creating the need to revisit that whole question of net metering and whether or not volumetric charges alone are a fair means of charging customers for their power. But that same conversation has migrated to the C&I sector, where you had a long history of demand charges being in place. So the objection cannot be that customers will not understand demand charges, because they fully understand them. They have spent all of their energies and creative talents and money to accommodate the demand charge as a piece of the rate structure.

Questioner: But retail customers historically have not had demand-capable meters. That's probably one reason why they've been on one-part energy rates in the past.

Respondent 2: Well, they weren't necessary, because you assumed a lot of uniformity among your residential class. Obviously, in the early electric era, when everybody had just a few light bulbs, usage was similar. Later, as individual residential customers added appliances, their demand changed, and that assumption that everybody's demand was pretty much uniform went by the wayside. The problem was created after the PURPA in 1978, which required all of the utilities in the United States to look at, among other things, the declining block rate, and urged them to go to a flat rate pricing or an inclining block rate. And every state commission was required to hold hearings as to whether or not they would impose time of use rates. Would there be a benefit?

I was a state commissioner then. Across the United States, every consumer advocate group was against time of use rates. They testified that it was just a back door way of raising rates on poor people. It didn't matter what the studies showed or what the distribution was.

Secondly, when it came to getting away from the declining block rate, when you went to a flat rate or an inverted rate, low-volume customers did not cover their fixed charges. We all knew that. The assumption, though, was that if you were a low-volume customer, you were poor. That was the working assumption, that if you were a low-volume customer, you were poor, elderly, lived in a small house…and it was OK. The utilities understood that it wasn’t a correct rate design, but they didn't really care, because the commissions said, “We'll make you whole. We know that there's a cross subsidy. But what do you care? You're going to get the rate of return at the end of the year that you wanted, so that's our business, not yours. And we know your rate experts will tell us its wrong, but we're going to go with the declining block rate.” Now, you've got high income customers putting in solar units and dropping into the lower kilowatt hour rates and people are saying, “Well, geez. It wasn't really the intent of that to subsidize those high income customers who have now dropped into the low rate.”

Respondent 3: In terms of the whole cross-subsidy issue, ensuring equity and ensuring that customers pay their fair share for the platform that they're a part of is one of the issues. But that's not the only issue. The other issues are that private investment is coming to the power sector. And private investment can produce benefits for everybody, if it's designed well. So I don't think it's only about equitably allocating costs. I think it's about wholly accounting for all of the investments and benefits created on the system and taking that into account in evaluating the equity and then ensuring that at the end of the day, the utility that's providing the system is revenue adequate.

Respondent 4: So let's move fast forward. At some point, people are going to be able to disconnect entirely from the system. But that system was built for them, and those costs have to be recovered. Do you believe that people who disconnect from the system should pay a demand charge? Or do we just leave those costs to the people who remain on the system and remain connected?

Respondent 5: When it happened before, there was a lot of stranded cost recovery. We have a model.

Questioner: So Respondent 5 says, recover the stranded costs from the remaining customers.

Respondent 5: Or an exit fee for those who are leaving.

Respondent 2: That's what I'm asking. Should there be an exit fee?

Respondent 5: That's been used. And there have been economists like Irwin Stelzer who said there weren't stranded costs and that was all part of the risk of running a utility, right?

Respondent 2: The street cars didn't get stranded cost recovery.

Respondent 5: If your total revenue shortfall due to volumetric rates is in effect, that argument we called decoupling. And remember, we had that a few years ago. That was when your rate design totally doesn't recover your costs at the end of the year because it's volumetric, and then therefore you have this decoupling. The gas utilities face that every time somebody buys a new furnace. That new furnace is going to drop your demand and your gas requirement by 60 percent. And so there was about a 2 percent annual decline in gas distribution utilities' revenues, just due to a certain number of people buying a new furnace.

Respondent 4: That's a good point, about how, if you have a gradual pace of defections, that doesn't cause the system to appear completely obsolete, but it's obviously less valuable than in the past--sort of the frog in the slowly boiling water, the frog being the customers.

Respondent 2: If you have any growth in your economy, new customers will come in; new housing developments will come in and take the place of those customers who are fortunate enough to be 100 percent independent on the residential side.

Question 3: My question's on electric vehicle charging and demand charges, particularly as we get higher and higher penetrations of electric vehicles. This has a potential impact both on commercial and industrial customers and also residential customers, because, on the commercial side, we have all sorts of state policies and private sector efforts to encourage commercial property owners to get charging stations and then to sell that electricity, but you've got a really high demand charge which, with the electric vehicle charging, particularly the fast charges, then that's going to be a big cost to the site host. So we have those sorts of issues working at cross purposes, and then if you decide to impose demand charges on residential customers, you're going to have the same problem with home charging. So the question is how we reconcile these state policies to promote EV charging, both for commercial industrial customers and for residential customers, with demand charges. Are there rate design solutions that some of you have thought about?

Respondent 1: This is a hot issue throughout the country, and I don't see any reason why any exception should be made for electric cars. They're already being subsidized heavily at all levels. There are a lot of incentives: cash payments, discounts, what have you. They are also less expensive to charge than gasoline-powered cars, in many cases. Consumer interest is building slowly. I don't see why we should start having rates aimed at specific individual technologies. Where does that end? Every technology will have a favorite reason why they should be exempted from demand charges. You'll get into a quagmire from which we would never recover.

That's my position; I know that's not a position of a lot of people in the industry. Perhaps people in the room may have different views, as well. Some utilities are experimenting with what they're calling a "grace period" approach, a three to five year grace period. Well, why shouldn't everyone get a grace period for their favorite technology? "Well, because electricity is good and let's electrify everything." Well, OK, so then let's just have free electricity. Why charge anything for electricity? It should be a God-given right. I was at a meeting at the CPUC where the water folks came in and they said, "Why should we have to pay for water? It comes from God." And there was some debate on whether God's there or not, but it was very clear it was naturally provided, and the response was, "Well, in that case, you can go to the lake and get it yourself." You have a pipe, you have filtration.

Comment: They don't charge for water; they charge for treatment and delivery.

Respondent 2: One of the things that motivated the PUC in California to take on the non-residential rate design issue was that they want to support companies that do workplace charging and that adopt electric fleet vehicles. And the current rate design has a very high non-coincident demand charge. So even if they are charging vehicles in the middle of the sun's blazing height, when there's excess energy being sent to Nevada, British Columbia, wherever…So the company has to put in dedicated facilities to ensure the safety of the grid for the workplace charging facilities. Or, if they have fleet vehicles, they have to put in dedicated facilities. OK. That can be recovered through a non-coincident peak demand charge. But they shouldn't be paying non-coincident peak demand charges for the infrastructure beyond that point. What is really relevant is whether they are consuming at a time when they're putting a burden on the system beyond those dedicated facilities. So a non-coincident demand charge can be very harmful to adopting those policies.

Respondent 1: But you could have an energy charge that's really off peak. If basically the sun is blazing and energy is costing less, then you could just have a time of use energy rate to incentivize the charge during that time.

Comment: You could have both.

Respondent 2: But would you keep the non-coincident peak demand charge that existed prior? The non-coincident peak demand charge established for the customer class was based on recovering all the bulk costs plus I don't know how much of the distribution system costs. The largest portion of revenues collected from these customers comes from a non-coincident peak demand charge. So that needs to be made smaller. It needs to be aligned with dedicated facilities, and then there needs to be the existence of a super off-peak rate that's available to everybody. It's not discriminatory. It's available to everybody; it's a good time for people to consume.

Respondent 3: That's getting a rate design right. I have automobile company members that manufacture electric vehicles. None of them had told me that they're abandoning cost causation principles.

Question 4: Absent legislation, where does the distortion, the net metering, the duck curve, where does it reach a level such that we're doing back flips in the wholesale rate design, and is there ever a non-legislative solution, or are we always going to be doomed to have this distortion? That has a lot of implications for what plants we build, and for all the fighting that's going on about resource adequacy in California, about retiring or bankrupting flexible units that are needed and RMR (reliability must-run) charges.

All those get wrapped together, but underpinning most of this is a retail rate design issue. Did any of you see it getting over the threshold, or is it too big of a bright line, or is there a way to circumvent or short circuit the state role in some of this? Because from my view, particularly as a California rate payer, it's inordinately distortionary. As a residential customer. I face $50 LMPs, thousand dollar retail super peak, and I run a $300 dirty generator on super peak just to disconnect from the system, and doing the same thing for a select group to enable them to get sort of free energy to charge their vehicles, and ignoring the distribution implications of that, is the same kind of stuff. Both of them are very bad for the wholesale design. So a question is, when do we get over the hump that we do something, or do we have to go to a legislative solution?

Respondent 1: Can I just say one quick thing, which is that if the carbon price were fully reflected, then it would be easier.

Respondent 2: Well, if the electric vehicle owner takes advantage of a low pricing period, that's not a subsidy. If the tariffs have been designed to reflect the dynamic cost of generation, and there are periods of low prices which the electric vehicle owner can take advantage of, that's not a subsidy. It's if there's some special tariff that exempts them from normal costs within the system that other customers have to cover, then there's a subsidy issue.

Questioner: The net metering issue is a distortion in cost allocation, I think.

Moderator: You're essentially complaining about designs that are essentially arbitraging retail for wholesale, right?

Questioner: Yes. And, in turn, they amplified the difference. It's not just me; it's anybody who's not rooftop solar. This is I think is part of what one of the earlier questioners was talking about. You're forcing down prices during that period, and now you're saying, "Oh, because of the net metering, which has implied a distributional subsidy, then I ought to do other things to amplify that by dropping the local distribution charges to encourage consumption at that time." And maybe that isn't so bad. But the underlying problem is that now, at least in the current mode, until everybody adjusts; you're essentially creating a significant revenue and operational problem at the wholesale level. They are not independent, and there are a significant adverse consequences that haven't gotten communicated through. And I think, quite frankly, some of it seems intentional by the CPUC.

Respondent 3: I've had several discussions with them. With Governor Brown, policy flows from Sacramento and now San Francisco. But what I was going to say was, if you are going to have low off-peak rates for electric cars, then you should also have low off-peak rates for everything else. It shouldn't be discrimination. If you're going to lower the non-coincident demand charge for electric cars because you think it is collecting too much revenue compared to the cost, that should be true for everyone, not just for the electric car charging stations. If subsidies are going to be provided, they're best given as an income payment or a tax concession. It is less distortionary then putting the subsidies in the price of electricity. Unfortunately, that is well known to the people in this room, and probably to the commissioners as well, but it is very hard for them to implement. I have raised that issue several times with Mike Peevey when he was the head of the PUC in California. And he said, "They're going to hit you if you say that, just stop saying that, because you're going to be hit."

Respondent 2: There are regulatory barriers too, for example in states like Wisconsin. There is a prohibition against sales for resale, which you might want to encourage for people to be electric car charging station providers. And that obviously would be a barrier to them.

Questioner: But this brings back the first question, which was really the main question. Where's the tipping point, in terms of jurisdiction? Or do you think it just will stay independent?

Respondent 2: My opinion is that most state commissions have adequate jurisdiction to deal with everything you've talked about without going to their legislatures, other than for the sales issue.

Questioner: I meant federal versus state--whether the state has the jurisdiction or not in a number of places. California is the poster child for this.

Comment: If you define the sale from the solar generator or from the vehicle to the utility as a wholesale sale, which is what it is, then FERC gets jurisdiction.

Comment: OK. Someone file that complaint, because it'll be really exciting the day that happens.

Respondent 4: The history of federal rate making standards in PURPA Title 1 is that when a lot of states have done something, somebody goes to Congress to force the other states to do it. Just about every rate making standard was done that way.

Question 5: I'd like to try to draw a connection back to some things that were said this morning about focusing on the customers downstream and looking to the future as opposed to the past and all of those ideas. And I'm reminded of an old joke that I actually heard a long time ago from a prominent person in the electric utility industry, which was that the first person to mention reactive power wins the argument. So I think, by definition, I just won. And the argument back then was that nobody understands reactive power, so as soon as you say that, they're afraid to say anything, because they don't know what you're talking about, and so forth. And that was true then, and we looked at this in the wholesale context and came away, broadly, with the conclusion that in the high voltage grid, reactive power and voltage control problems and all that kind of thing are extremely important, and you have to address them, but they're very local, very second order, and most of the problems have to do with the real power flows and all the other kinds of things that are going on--so getting into Fred Schweppe's framework, where you don't have to deal with that explicitly, and that works fine.

This is completely not true on the distribution system, and we've got a lot of loads out there which have big impacts on reactive power, that and they're responding very quickly and they're moving all over the place in response to whatever incentives, and we're consistently sending them the wrong signal. That seems to me like a recipe for disaster. And so my question is about what is the role of reactive power pricing in all of this conversation, and how is this going to happen in this new world that you're thinking about?

Respondent 1: I would start with a technical conference and a pilot study. And then hire Brattle.

Respondent 2: I guess this is going to be an overly simplistic answer, but getting visibility down into the distribution system, building the information, control, communications infrastructure down to the distribution system that gives the utility visibility there and can give visibility to customers or aggregators on what impacts are is a first step. Once you have that information, then you can figure out how to price it. But you can't create a market until you have information that supports decision making on the market. And that's the barrier.

Question 6: I'm going to get back to pricing. It seems to me and I'm curious if any of you all have looked at block and index pricing. It ironically harkens back to something that Severin Borenstein proposed back in the early 2000s in a paper done for the Hewlitt Foundation. But I'm curious if you've looked at that and how it works as a mechanism that could be used in the environments that you've been thinking about.

Moderator: Define block and index.

Questioner: The notion is that retail customers would have blocks of power that they own. And they can use them, or they can cash them out if they don't use them. And to the extent that they haven't bought blocks that are enough to cover every hour that they consume energy, they buy a little bit of extra.

Respondent 1: So that's called "energy" these days. That's the pilot that was mentioned that southern California Edison is carrying out.

Questioner: Well, it's more than a pilot. It's in extensive use across competitive retail markets and thousands and thousands of customers. So that's why I was asking if you've looked at the experience in those markets, and how those have worked in terms of supporting cost recovery and also incentives to retail customers.

Respondent 1: For mass market customers or for large customers?

Questioner: Well, in the mass market it's tended to be described differently than block and index. It's sometimes sold as “free nights and weekends,” for instance. But it looks and functions very much like a hedged amount of energy that you then can cash out against, or unhedged portions that you have to buy.

Respondent 1: It's the two part Georgia Power Company rate. Sometimes it's called “demand subscription service.”

Questioner: The main difference with Georgia is that it's done in RTO markets, where you have a dynamic hourly price you can cash out against.

Respondent 1: So that would be a variation. But basically the concept, from a customer standpoint, is that you buy a certain amount of power, and then, whatever deltas you have, you trade them on the spot market. We do it in the wholesale markets all the time. It's just a question of bringing them out of the retail market, and the practice, as far as I know, is very limited right now. It's mostly C&I customers. The pilot SCE's doing is for residential customers. They want to have 200 customers in the Thousand Oaks area. We are going to try this out, but they are having a tough time getting the 200 customers signed up, because customers don’t want to do this. They're like, “What is this? What are you talking about? I have my life to live.” There's not enough money in it for them, at least today, to engage with it.

Now, you mentioned something that Australia’s regulatory body is looking at, which is locational LMPs plus at the distribution level. Their view is that all you need is energy prices down to the locational level that vary by hour, and that will eliminate the need for any other kind of pricing design for distribution services. I was in New Zealand last August, and the same idea was mentioned there. I have yet to know a single utility or a single regulatory body or a single commissioner who has approved it or implemented it. I think it's a good theoretical concept, but it's similar to what Severin was talking about, which is the short is run marginal costs with the locational element added to it. I think right now the market has no appetite for it.

Question 7: I think people need to go back and read Bonbright, because Bonbright doesn't exactly endorse the eight or the ten principles in his 1988 thing. He talks about them as things that other writers have talked about.

Leaving that aside for the moment, it strikes me that we face two significant challenges in rate design, going forward. One is that we have an increasing number of largely autonomous smart devices. Some of them can provide reactive power, but they are dynamic loads. They're electric vehicles, they're DERs that can do various things, and they are going to continuously optimize, based on their anticipation of prices to them going forward. That's a very significant change in the way the system will have to operate, and you will not be able to essentially dispatch all of those devices.

The second major challenge is, while I think Severin is right that what you need to then do is use pricing and rate design to send appropriate short-run marginal cost signals to all those devices, once one does that, it becomes highly unlikely that a monopoly distribution utility or a transmission utility would be able to recover its revenue requirements, because, being natural monopolies, they had declining average and therefore declining marginal costs, which means that you have a residual that needs to be recovered in some way. That, ideally, would be recovered in a way that did not distort the short-run marginal price signals that you need in order to operate the system efficiently, which suggests some form of fixed charge for a customer with a high load factor and many near peak hours. A demand charge for that subset of customers might act that way. But it's certainly not going to act that way for somebody who charges an electric vehicle once a day or has a pool party once a year that gives them a high demand charge.

So the question that I had for you is, how should we be thinking differently about rate design as we think about it going forward? Because this suggests a very different model from the model that says we're going to take historical costs, which have really nothing to do with forward-looking marginal costs, and we're going to allocate them based on some notion of cost causation. I think we're talking, for the future, about the need to transition to a different way of talking about rate design, and I haven't really heard that come out much in this discussion. I'm interested in your observations.

Respondent 1: I'll take the first stab. Given the uncertainty, OK, stick with your basic principles, kWh pricing. Don't try to jury-rig a rate design that reaches a foregone conclusion based on some regulators' wish for five or 10 years from now. That, to me, is the battle right now. Because some of these technologies may not work, may not be sustainable.

Respondent 2: I was in New York two years ago when exactly the issue you're posing came up at a meeting of utilities, and they said that the cost of service paradigm, that time's come and gone, because the market is moving very fast. New technologies, new competition are coming in.

So what should be the new pricing paradigm? And one person threw out an idea, which is just based on asking, what is the customer's competitive choice option? In other words, pricing to beat the competition. So, the analogy was given that if you're a taxi cab and you have Uber coming in, then you have two choices. You can keep pricing on the basis of your historical cost, with the cab and your salaries and so on, or you can look at what Uber's pricing at and try to match their price. And if you can't, then get out of the business and do something else. It's easier for taxis, at least conceptually, to think about this (even thought, if you are a taxi driver, it probably isn't). But for utilities, it's a huge challenge to suddenly go to pricing based on value that the customer sees in your product versus the competitor's product, as opposed to cost.

I don't think any commission that I have talked to is ready to switch from cost of service pricing to value of service pricing. Over the years I have seen the cycles come and go. When restructuring was a hot topic in the late '90s, it was preceded by a sudden surge of interest in something that was called "customer-based pricing" or "value-based pricing" or "customer-based planning." And examples were lifted up from the Harvard Business Review of how Starbucks makes money, or how United Airlines loses money, and those were transferred over. The problem is, it doesn't work that way, at least just yet, for utilities, partly because the competition is uncertain, and partly because you have a huge rate-base that has been regulated and you are still recovering their costs. So how do you make the transition?

Comment: Obviously, no regulator comprehensively allows pricing to reflect value to customers. But there are circumstances when there's threat of credible bypass where regulators will say, "Sure, we don't want this person to uneconomically bypass." So one could build, one expects, on that example.

Respondent 3: Except telephone rates were set on a value of service basis, plus you paid in advance, as opposed to electric rates where you got billed after. In your old telephone days, we billed you ahead for your basic local service. You paid a month in advance, and we had value of service pricing where a single line to a residence was priced less than a single line to a residence where the resident told the telephone company they were operating an insurance brokerage, under the notion it was much more valuable for a guy in the insurance business to have many people connected than it was for a residence who probably would only call friends. So commissions have had experience with value of service pricing. We might be able to go that way, I don't know. I don't think there's a regulatory barrier to it.

Question 8: I want to return to the point about the federal/state jurisdiction issues. I think that it's not just that we're not internalizing the demand charges for the dynamic pricing. From what we see in the market, the way we're covering demand charges and what's happening at the retail level is really undermining efficient pricing and dynamic pricing. There are all these efforts at the ISO levels to get price formation and scarcity pricing. And it's never going to work, because at the LSE (load serving entity) level, there's so much demand response that happens, and it's not integrated into the price-setting method mechanisms that FERC gives. We see it in ERCOT with the 4CP, and it's a peak day, and people predict it, and there's a massive amount of demand response, and that's great that there's so much demand response. But it's not getting into the prices, and, implicitly, it's probably like $10,000 to $20,000 per megawatt hour, because they're avoiding the transmission charge for the whole year. And it's flattening the curve, but it's not in the prices.

And even in states like PJM, PG&E pays $1250 per megawatt hour for behavioral problems at the LSE level. It's thousands of megawatts that we see on peak when prices are $50 because the load doesn't show up for the ISO to see it, and I don't see the point of all these efforts over the last several years in scarcity pricing unless there's a way to figure out how to get the demand curve to be reflected in the ISO prices. And right now, from the ISO's perspective, that's just load that doesn't show up.

Respondent 1: Several years ago I was at a PJM conference where the title was, “Getting Demand Response Back on the Demand Side of the Market.” And the whole conversation was, “How do we put a slope in that demand curve?” As far as I can tell, that conversation is still going on. I don't know what the hold-up is.

Question 9: I was going to ask a question about another study that was done a couple years ago in the Reforming the Energy Vision proceeding up in New York. I was going to ask about two things that study had talked about. One was reactive power, so now I get second place. And the other was the LMPs at the retail level. And I guess my takeaway on both of those is that it's simply not going to happen, so don't worry about either one. Just move on, I guess.

Respondent 1: There's no customer appetite for it, which is not to say it couldn't happen, but there is no regulatory appetite for it either. People are concerned about even having a time-varying rate, for all the reasons you mentioned. There was a conference in 2010 about the ethics of dynamic pricing. That issue is still there. People are saying, is it ethical to charge a different price by time of day? They will also say, is it ethical to charge a person who's on this side of the street a different price from a neighbor who is on the other side of the street? And then with reactive power, try explaining that to the person next door. It'll sound very reactionary.

Question 10: I am going to ask about another issue, where a distribution circuit is projected to become overloaded, either because of the level of penetration of solar and so the outflow from the customer into the system, or because of the possibility, with EV penetration, of higher loads on the distribution circuits. And where that is projected to occur, I get that upgrading a circuit can be quite expensive. Is it the expectation of everyone that these upgrade costs for those distribution circuits are going to be socialized? Or is there a basis for saying, “Well, if you want this extra level of usage of the system, people on that circuit should pay for that themselves.”

Respondent 1: What's the rule now at the utilities, if I and three of my neighbors all buy Teslas, and we're going to blow the transformer if we're on the same grid?

Respondent 2: Should you have to pay extra for that?

Respondent 3: Personally, I think it's reasonable to pay extra if you have the opportunity to manage your usage so that you can avoid that charge.

Respondent 4: By the way, the city also is struggling big time with that issue given the proliferation of Teslas. I remember talking to them about five years ago about how time of use pricing would be a good thing to have for electric car penetration. They said, “We already have so much of it that we don't want to encourage any more.” I said, “Why is that the case?” They said, “Well, we have these distributors; we have these cul-de-sac phenomena, one person gets it, the second person gets it. Before you know it, you're going to blow the transformer.” So who is going to pay for that? Do we socialize the cost, or assign it to just the people on their cul-de-sac? These are real challenges.

Respondent 3: It needs to be considered in distribution planning. This is why commissions are taking on the issue of distribution planning in some places, and I'm not sure if I was clear or not. But you can combine storage, hire somebody to manage those loads and do the interface with the utility between the chargers and the neighbors. There's the block chain type of model example.

Question 11: This is the ultimate geek panel here on a nice day. I love you all, but this is *deja vu*. We were arguing these issues in the 1970s, and we're still arguing them. I wanted to raise one historical issue with regard to why we did average pricing over the years. And it was really for the sake of universal service, and not just in the form of protecting low income people with programs, but also for averaging customers to deal with customers at the end of the line in a state like Montana. So I just wanted to ask the panel, how do we deal with that issue? Because whatever programs we have for low-income people, you still have people who are at the end of the line in rural parts of Montana or elsewhere. How are we going to address those issues as we move to de-averaging prices?

Respondent 1: I'm not sure we will necessarily de-average prices. There's a social context here. Clearly there was with the extension of the grid, it turned out Sam Insull discovered that running electric lines out to rural Chicago was cost effective, not because it was cheap to run the lines, but because the load imposed by the dairy farmers was off-peak from the residential, and he could run his power plants 24/7, because the dairy farmers came in at 3:00, 4:00 in the morning from milking, and he could get additional revenue, so it was load-building and filling in the peaks and valleys. And so, on that basis, line extensions were made, when otherwise, without that cost benefit, you wouldn't have done it.

I did water rates, and in some areas in New Jersey and others, we have differentiated high water and low water areas. If you're in a neighborhood up on a hill, there are more pumping costs. So we have deviated from averages everywhere. The common problem that comes up is when two utilities merge, and then there's always an argument. So, I have two different cost bases. Now, the question is, do you roll them into one large rate base, where one guy's rate might go up a little, and the other one’s might go down? That's been a classic issue of utility since the first days.

Respondent 2: I actually have a water charge. I'm on a hill, and I pay extra for that. But I've always wondered, you take two large utilities that have different rates between each other, but within their own areas, they are the same rates. And it's totally arbitrary. It's just averaging. If you were to change the service area boundaries, you'd revisit that whole question.

Now, to your question on the line extension element, I actually was doing a survey on that topic a few months ago for a utility that was trying to revisit that whole question. And so we talked to people in the U.S. and abroad--for example, Australia, for example, the U.K. And I discovered that there is no uniform rule. That is totally dependent on which jurisdiction you're talking about. In many cases, it's just being socialized. However, if you look more closely at the tariffs, it's socialized within a certain band. If you're really large; if you're going to impose a significant extra load, then there is an extra charge. But there are tolerance parameters. In some cases, it is very specific; in some cases it is not. It seems to be totally a product of history. And I don't know whether that whole arrangement is going to be grandfathered in the future, or whether it'll be torn apart, and something brand new will come in.

Respondent 3: I think missing from your question is the word “rate base,” and average prices through rate-based assets. That's like the customer having a lease on a piece of the utility system that they're paying for over the long term. And the advantage of that is easy, financing. So there are a lot of practical aspects to it that were useful where and when it was done and still is done.

Questioner: My only point of this whole thing is that you have to sort of think about those issues, the universal service issues, as you move toward more dynamic pricing. It's something to think about. Everything has a cost to it. Is there a cost to doing that? And not for just low-income customers.

Respondent 1: The other issue that comes up is rolled-in versus incremental pricing, for example on pipelines. And the FERC has gone back and forth on that.

Question 12: With rate design, it is really squeezing a balloon. So if there is a demand charge that is higher, inevitably you're going to have parts of the day that you can charge low rates that become an incentive for electric vehicle charging. So in our recent rate case, we had an outcome that allows for super off peak overnight charging, as one example. The time of use window is now 3:00 to 8:00 p.m., so everything before 3:00 p.m. becomes a *de facto* price signal to charge vehicles, for example.

The question we've often asked is, what problem are you trying to solve for? Or what opportunity are you trying to create when you look at this issue? And when we started down this conversation years ago, we had four tenants in response to that: equitable cost recovery, appropriate price signals, technology agnostic, and easy for the customer to adopt. And the question for the panel would be, are demand charges an appropriate price signal that should be contemplated in rate design?

Respondent 1: I believe they are, because they reflect the capacity cost structure, which is different from the energy cost structure. That's why we have had them for C&I customers for such a long time. If that was not true, we would never have had them. They would have been contested.

Secondly, in the Bonbright textbook that everyone has read and wants to read again, I guess tonight, probably right away. There’s a whole chapter on demand charges and why they're cost based. So it's subject to some debate whether the technology of the customer has changed so much that Bonbright should be shredded and replaced by something else. Admittedly, 30 years have elapsed since that second edition came out. It is a long time, but I believe a lot of what he's saying is entirely commonsensical. The only thing missing is that there was no concept of a two-way flow of power in that textbook. There was no concept of DG, because it was written at a time when those things were not practical (even though co-generation was still there as a small activity).The prosumer concept was not there. But I think the prosumer concept doesn't negate the need for cost-based pricing. I don't think any industry, any company, can stay in business if it doesn't recover its costs through rates. Even if it's doing value-based pricing, it still has to recover its costs or it goes out of business.

Respondent 2: Yes, a company has to recover its costs. But are demand charges necessary to do that? There are lots of different kinds of demand charges. And I know we're sick of getting into the details of this but --

Respondent 1: We've been called geeks.

Respondent 2: I know, it hurts, but anyway, non-coincident demand charges, in my view, are harmful. There's a very specific situation where they're useful, and beyond that, I think they're harmful. And I think they're harmful because they don't send a price signal at a time when we need price signals going to the distribution system. And when we use the words “coincident demand charge,” what's the time frame over which we are measuring demand? Is it annual, so the peak consumption that you have on one day of the year determines your demand charge for the entire year? Is it a daily demand charge? Those are very different things. If it's the longer time period, you have less incentive to control your usage for most of that time period. Once you've established that peak, then you've lost the price signal. So I'm not opposed to all demand charges. I think they're part of ensuring adequacy, but I think we have to be careful about which demand charges, and I think we have to say, what purpose are they serving?

Question 13: I think this conversation boils down to getting the most capable system possible at the least cost. And while we debate rate design, technology continues to evolve. So someone mentioned that situational awareness is the next big gap, and based on what I've seen at ARPA-E and more recently, I'm fairly confident that we have the technology now to get comprehensive situational awareness from the edge of the grid at a relatively low cost without the utility. We have very good technology.

So my first question is, if people actually can show, ex post, that they created value, and then they can build capability to maintain the stability of the system, and do grid services and show that they're creating value, how do we deal with that from a rate design perspective?

And the second part of my question has to do with ripping the Band-Aid on real time pricing. I'm sure we're all aware of the study in Illinois by the consumer advocate that found that 97 percent of common customers would have seen savings of at least 13 percent had everybody been on real time pricing, with no change in behavior, which is pretty powerful. And now in Texas, there's a company called Griddy that gives direct access to the wholesale market with real-time pricing through an app. So that's really transformative. What are we waiting for?

Moderator: We are going to let that hang as a rhetorical question, not because it's a bad question, but because we have two minutes. It's a good question, though.

Question 14: It's come up a couple of times, sort of in the background of some of the questions and comments, that rates aren't the only tool we have to incent behavior. There's also direct bilateral contracting. So, we've always managed load control through contracts of individual consumers allowing us to manage their loads. I think we'll be doing that a lot more with vehicles, because if we want to avoid having to change out all of the transformers because everybody plugs in at 8:00 p.m. when the price goes down, we need to be able to have soft starts on charging. We need to be able to have direct control over a lot of these vehicles. The question to the panel is, how do we integrate between rate design and contractual load management in order to get the optimal result?

Respondent 1: I think the easiest way is just to pass on through your dynamic pricing signal and enable it through the direct load control technology. That's what Oklahoma Gas and Electric is doing with their variable peak pricing program. They have 20 percent of their residential customers signed up on it. They are now doing direct load control. They're just giving the smart thermostat to the customer and the price signal, and the customer has a strong incentive to manage their own load, looking at their price signal. And I did ask why they're not doing direct load control of those thermostats. They said, “We believe in customer choice.” So that's one approach.

Respondent 2: I think we're in the situation where we see, like SMUD, we see municipals and co-ops taking the lead in many of these things. And the reason, in my opinion, is the business model more naturally matches adapting to these changes. So I think programs continue to be needed, because these are still new technologies. They're still new; there's learning that's going on. So I think programs continue to be necessary, but they should be connected to pricing, and that's where I'll stop.

Session Three.
ELMP REDUX: What to Do When Locational Prices are Not Enough?

The bid-based, security-constrained economic dispatch model with locational prices provides the foundation of electricity market design in the organized markets in the United States. Under certain regularity assumptions, the model has the property that the locational marginal prices support the economic dispatch. Faced with these prices, no market participant has an incentive to deviate from the economic dispatch. As is well known, the regularity assumptions are only approximately true. In theory, unit commitment and other lumpy decisions can create a situation where no set of locational prices alone can fully support the solution. The extended locational marginal price (ELMP) models incorporate accompanying uplift payments to restore the support for the economic solution. There are many variants, and accumulating experience from different implementations. The subject achieved renewed interest in the PJM "Proposed Enhancements to Energy Price Formation" offered as a main pillar of the response to the DOE NOPR. What are the critical elements of the ELMP pricing problem? What approximations are available to approach the theoretical ideal? What new insights have been gained by practical experience and the continuing research? How do the models integrate with other proposed pricing reforms?

Moderator.
Good morning, everyone. What might have seemed to be an arcane academic debate just a few months ago about convex hull pricing actually has some very real world implications for very significant amounts of money being shifted around the market, different units being dispatched, customers paying more So without further ado let's start talking about convex hull pricing and extended LMP, modifications to LMP pricing.

Speaker 1.
Thank you, Bill and Ashley, for inviting me here. This work partly reflects research undertaken by my PhD student, Bowen Hua. I should also mention that some of this work is being funded very kindly by MISO

So to set the stage, I just want to mention a couple of interrelated policy goals that perhaps will be obvious to many of us, and then indicate where theory and computation related to convex hull pricing is helping. And I think it's important to see that there are ramifications for that in terms of both pricing improvements and also improving the performance of unit commitment algorithms.

One very important issue with LMP is that we have what's sometimes called a "pricing paradox," where we may have a situation where, as demand increases, the price stays flat or doesn't increase, and indeed we even get extreme versions of this, where demand increases but the price, the LMP, drops. A typical example happens when a block-loaded unit is committed. I'll describe that example in a couple of minutes.

And intuitively, at least, it doesn't feel right that the price goes down when demand goes up, and when you have to commit a more expensive unit, so a policy goal would be to seek clearer incentives for both the supply side, but also the demand side, to respond to the supply-demand balance to more fully reflect the prices into the energy price.

And another thing that's somewhat unhappy about our current market, because it has unit commitment and integrality in it, is that we have out-of-market uplift payments for a number of things, including commitment, and by, in principle, making the energy prices better indicative of supply/demand, we can do better at reducing the uplift, and by reflecting more of the total costs into the energy prices, we can give clearer incentives for new investment, for example. So this impacts not just operations but new investment.

So let me try this example. We've got two generating units, and we'll assume that the offers are based on marginal costs. The first unit has a marginal cost of $10 a megawatt hour, and it's, let's say, able to generate from zero to 50 megawatts. We have a second unit. It's rather more expensive. I'll call its marginal cost $50 a megawatt hour, but let's suppose it's actually block-loaded. In other words it's either off, or on at 50 megawatts. So the choices are it's off, or you're paying 50 megawatts times $50 a megawatt hour. So for demand between zero and 50 megawatts, obviously, we'd use the cheaper unit, and the LMP reflecting the price of the cheaper unit would be $10 a megawatt hour. Once we go above 50 megawatts, however, the first unit isn't capable of supplying all that demand, and so we have to operate unit two as well. And because of its constraints (I don't know, it's a Murray Energy coal unit or something like that), we have to run it at 50 megawatts. And that means that the demand minus 50 is served by the other unit. The marginal unit, therefore, in the conventional definition, is the lower cost unit, and the LMP will be $10 a megawatt hour. And that's despite the fact that we had to run a much more expensive unit. So that's the nut of the issue, or one aspect of the issue.

So, when the demand is below 50 megawatts, we see that the LMP recovers the operating costs, but when it goes above 50 megawatts, the LMP stays at $10 a megawatt hour in this example, and it falls short, actually, a long ways short, of recovering the operating costs. So the uplift payment in this case would be based on a $40 per megawatt hour shortfall, so it would be four times as large as the energy price from a per megawatt hour perspective. And the bottom line is that the LMP doesn't reflect the cost of operating unit two, and therefore most of unit two's operating cost would be recovered out of market.

This example had unit one with constant marginal cost, so the LMP stayed at ten, but, to give a more extreme example, if that unit had increasing marginal costs over its range, which we might expect to be more typical, perhaps, then we would find that, as we went from below 50 megawatts to above 50 megawatts of demand, the LMP would drop, perhaps quite precipitously. So that is perhaps even a sharper example of why we think this is a pricing paradox.

So as I mentioned a moment ago, the LMP of $10 a megawatt hour doesn't reflect the unit two cost, and so we can ask, what can we do about it? And we could consider modifying, in particular increasing, the energy price to reduce the out-of-market payments. And we might ask, how could we reduce the out-of-market payments the most and still come up with a nondiscriminatory price for energy? And it turns out that the answer to that question is if you solve a problem called the "Lagrangian dual" of the unit commitment problem, it gives you some numbers, they're called Lagrange multipliers, that minimize the out-of-market payments. And let me qualify this a little bit. In this context, by out-of-market payments, I mean all opportunity costs. Various ISOs don't pay all opportunity costs as uplift, but more or less we could say that solving for the Lagrangian dual minimizes something that's closely related to uplift. It's an old-fashioned approach to approximately solving unit commitment, and back in about 1998 Ben Hobbs and Dick O'Neill, who I think all of us know, put on a conference called The Next Generation of Unit Commitment Models. And up until that time I'd been a practitioner in the cottage industry of developing Lagrange and relaxational Lagrange and dual algorithms, and between the first and the second day of that conference a gentleman by the name of Bixby, who was behind CPLEX optimization software, figured out on his laptop with his MIP (mixed integer programming) software how to solve unit commitment. And I vowed at that time that I was never going to work on Lagrangian relaxation again. Well, that was a bit premature, it turns out, because it's come back as this idea to solve the prices.

So, the classical theory tells us that, fair enough, you can use these sub-gradient and other related algorithms. That's what I was playing around with. There's some classical theory that says you can also solve the problem as a so-called integer relaxation of the unit commitment. So in this story, instead of representing a generating unit as being off or on, which in a numerical sense is zero or one, we allow the variable that represents that commitment to range continuously from zero to one. So, it's not realistic, right? We can only switch a unit on or off, but we will imagine in the formulation that we can relax it. So, we need some more ingredients to get the Lagrangian dual prices. We also have to characterize a couple of things. The set of limits or constraints on us have to be modified to what's called the "convex hull," (and I've put those various things in quotes because I'm not going to define them unless someone really forces me to do it) and we have to change the thing we're minimizing, the cost function, to a thing called the "convex envelope." But once we've done that we can solve a problem, it's a linear program which can be solved pretty easily, and we get the convex hull prices. Having said that, it's in general difficult to characterize this thing called the "convex hull," and in general it's difficult to characterize this thing called the "convex envelope" exactly. And, indeed, in an example of what is called the "no free lunch" theorem, an exact characterization may involve adding so many constraints that the problem gets to be very hard again. So you don't get a free lunch.

However, there are various approximations to the convex hull and various approximations to the convex envelope that can give us tractable (that is to say, computationally reasonable to solve) approximations to convex hull prices. And in that context we could say the current MISO LMP implementation is a simplified single period approximation. It ignores intertemporal issues more or less, but as I understand it from my MISO colleagues, it's going to be updated to include a single period convex envelope enhancement. At least, that's part of the plan.

So, where does that fit into the work that we've done and recent theory and computation? Various folks have been trying to improve unit commitment algorithms, and recent advances by other researchers have helped to better characterize the convex hull and the convex envelope. Some of the work we've done, and some of it's drawing on other people, and in particular there's been a full representation of the intertemporal restraints that limit units to be switched on for minimum uptime once you switch them on and switch off for minimum downtime once you switch them off, and a partial representation of ramp rate constraints. Now, if we put aside ramp rate constraints for a moment, our work has put together a tractable and exact characterization of the convex hull prices with ramp rate constraints. We've got an approximation to it that seems to be pretty good in most practical situations.

So, what does that do for us? Well, it gives us a better way to get convex hull prices, paying attention to intertemporal issues—so, startup costs that need to be amortized over the run time of the unit. But there's more to it than that. These concepts, convex hull and convex envelope, also help the MIP algorithms to solve the unit commitment faster. You can add them into the MIPs and they'll make the MIP work faster. Moreover, they're relatively easy to implement.

They’re consistent with current formulations, they just take some more equations added into the constraint set. So our current work (and, again, I'll emphasize that MISO’s been very generous in funding our efforts on this) is to better understand convex hull in the context of combined cycle units. We want to model the various operating configurations of a combined cycle unit and get better prices. So that’ll not only improve unit commitment but also improve convex hull pricing.

So, convex hull pricing supports a policy goal of better pricing to reflect the supply/demand balance. That theoretical improvement can enhance both the single period approximation and the more general case with intertemporal constraints, and it improves unit commitment. So there’s a lot to be said for this direction, not just for geeky wonks.

Speaker 2.
So I want to be clear what I'm going to talk about this morning, which is MISO’s experience, and the guiding principles we’ve used as we’ve thought about how to implement these concepts. As you can imagine and you will see from the slides, it is very complex, and I've got extraordinary help. Yonghong Chen, who’s sitting over there, is one of the foremost experts, in my opinion, on this, and has made extraordinary strides. Dr. Gribik, here as well, really laid the foundations of this work.

So I'll give you some quick background. I'll give you what we’ve thought about as dos and don’ts in our experience, and then we’ll talk about what’s next.

As I understand it, when MISO was launching its markets back in 2005, we saw these issues, and we attempted to begin thinking about what you should do in the face of those issues. And so the research began, really, on the heels of the market launch back in 2005. So for two years there was an effort to work on the concepts and the mechanisms that would address the shortfalls that we’re seeing in the initial LMP market designs, and ELMP was effectively the result. It was developed to try and address the issues with fast-start resources. It was designed to address the issues with high uplift that were being experienced as a result. And it does, in many respects, represent a first step towards a clear, more discrete way of addressing the reliability needs of the system by sending a better price signal for those attributes, rather than muting the price signal of what it really costs to serve a marginal megawatt. It’s not a cure-all, but it does, in our view, price that flexibility better than LMP, because it’s sending the signal that’s more reflective of what the need is.

So, first and foremost, we should be striving to better price what it costs to serve marginal megawatts. As I noted on the prior slide, what you see here is a process where we worked on the design and then we spent years, literally years, working through a stakeholder process to help people understand it first and then gain agreement on what the right way to do it is. We spent the better part of three years doing that, but we did ultimately get stakeholders to agree, and there was effectively no opposition when we filed ELMP at FERC. Now, there’s always somebody who doesn’t like something, but we moved it forward in a way that was very well received, and in fact, as we’ve moved to expand it in recent years beyond the initial foray, it's been very well received, also. So I think the idea of getting to better pricing is an easy way to sell this, so long as people understand it and agree that the pricing actually is going to continue to reflect the operational need on the system. So, focus on what you’re incentivizing. That’s been important to us--making sure that we’re incentivizing resources to follow market instructions.

The core element of how we operate and have thought about the markets that we operate is that we don't operate markets for markets' sake. We deliver reliability through market mechanisms, and so, to the extent that anything we're doing is sending a countervailing price signal to the reliability need at that time, we need to be very careful before we step down that path. And so by allowing the price to diverge somewhat from the control signal, which is what we did with the ELMP, we were very careful to take small tiptoe steps away from having the control signal not be the price always. So what you'll see with our implementation of ELMP is that it does diverge, but it does it for very short periods of time to send the right incentive price, even if the control signal, the "*ex-ante*," as it's known, is different for those short periods of time. Long periods of disconnect can create, at a minimum, unknown consequences, and we have some theories on what the potential consequences are.

And then, as I said, learn through phased implementation. That's how we approach this. A very small group of generators were eligible initially, and we've since expanded it and we're now looking at further enhancements that will make it work even better--but phased implementation, learn what works, learn what doesn't work. Right now we're getting what we expected, which has been a positive experience, but taking it slow has been an important part of getting that result. So, as I said, don't rush. You don't know what you're going to find when you walk to the edge and step over. You really don't. We saw stuff in the ELMP that we didn't expect, and we've adjusted. We saw stuff that we did expect and we emphasized that, so don't rush. Make sure there's a clear understanding of everything that's going to happen from an efficiency standpoint and from a reliability standpoint. This was our experience.

One of the things that may be a little bit more unique to MISO than some of the other RTOs, although I think everybody has this to some extent, is self-committing demand response. We have utilities that, when we declare even just emergency watch conditions, the utilities will self-commit DR in anticipation of higher prices, so, to the extent that the price signal isn't actually aligned with your control signal, you will have potentially self-committing DR responding to a price signal that isn't what you want them responding to. And these are not resources that are in the market that are following a dispatch explicitly; they're following the price, which is, in most cases, the right answer. You want DR responding to a price. And I'm happy to take questions during the substantive period about what I mean by that. The takeaway from that is don't let ELMP, at least this was our approach, don't let it get too far from the five-minute dispatch instructions. There are unintended consequences that we believe would potentially jeopardize reliability, and the DR is an example.

The loss of potential flexibility about generators is another example of a possible unintended consequence. If a generator is going to get paid the same whether they're flexible or not, they may decide not to be flexible. So making sure that you have the right incentives for people to deliver different attributes that they're capable of delivering and are paying them accordingly is important. And the way that you figure this out is by exploring before jumping, so we are continuing to do our fundamental research.
Again, Speaker 1 was mentioning we are working with academic institutions and have our own teams working on this as well to continue to try and push the envelope (no pun intended). And we're also looking at how these pieces fit together--things like scarcity pricing or ramp capability, which are things that we have, but we're looking at what the next generation of those

things will need to look like in a future that looks very different from the present or the past.

So, what's next? We're looking at how ELMP is going to interact with other products. As I said, we're seeing a future that potentially looks very different, where you have different products designed to deliver different attributes in a reliability environment that has more of your resources being forecast, rather than scheduled. That's a fundamental change that we're experiencing at MISO nearly as quickly as they are in California. We have 19 gigawatts of wind resources today. That's a resource you don't schedule; you forecast it. And when your resource fleet is dramatically or substantially forecast rather than scheduled, and when it's zero marginal cost in many hours, your product set needs to look different to accommodate that. So how these things fit together is important.

So we've been talking about this notion of the energy markets being turned inside out for about two years. That's really how we're thinking about ELMP evolution--it is a complement to this future where we're going to need reliability attributes that deliver flexibility and deliver control that may not, and probably can't, all be embedded within a single LMP price. We're going to need additional capabilities that all fit together neatly in order to get there. ELMP is a step in the right direction, as it's configured to try and manage the inaccurate pricing that happens with single interval LMPs, but the enhanced formulations we're working on are all intended to capture that, as is the notion of moving towards discrete reliability attributes pricing in the future as well. Not today, not tomorrow, but on the horizon, for sure.

Speaker 3.
Good morning, thank you. It's a pleasure to be here. I would like to spend the next 12 minutes here talking about PJM's thoughts on what Speaker 1 called the integer relaxation for electricity market pricing, and this is a very difficult subject and an important one.

Of the three most important things about wholesale markets, I would say number one is the price, number two is price, and number three…you know that. And I would say that to get anyone, any person, any regulator, to set the right price is hard. It's harder for anyone to do that than to probably send a rocket to Mars.

Now with that, I think PJM's experience here is really one of catching up. We build on a lot of excellent work that MISO has led, and 20 years ago there was a debate on a similar issue at the New York ISO. Also, we build on some experience with fast-start pricing that MISO and ISO New England have led. So we are catching up, and we are learning fast here. And, for myself, I must say that a year ago I would not have been on this panel. I felt I didn't know much about ELMP, and I felt that was nice in theory, but it was not really practical to be implemented, and even MISO was adopting some approximated approach. What has transpired during the past year at PJM is that things happened, and we felt that there is a moment that is forging a movement here to solve the PJM problem, so we take a step in this direction, and I will share with your our learning experience and share with your our view on the relationship between integer relaxation and ELMP convex hull pricing and where we are going and so forth.

OK, here is PJM serving 13 states. I will start by saying that the experience at PJM is no different from many other ISOs. I think, as a starting point, that the current LMP pricing method has served the electricity market very successfully over the past 20 years. Last year PJM celebrated its 20-year anniversary, and the market price reached its lowest price in the past 20 years. And over this period the market has attracted 40 gigawatts of entry and has managed the transition between the fuels, gas and coal. As we all know, that's a big transition. And 20 years ago, I will say that no one that I know of could have predicted that the market could actually have been proceeding so smoothly. At the beginning, one couldn't take anything for granted. Even in PJM, the LMP pricing was not Plan A. It was Plan B, after one year trying, and PJM adopted this scheme. So as we move forward we have to be actually learning from the experiences and, as Speaker 2 said, we have to be very cautious and cannot rush into this. And doing no harm is our first priority.

Having said that, I think during the past year we have learned that we cannot really stay there, even though we can easily claim victory and sit complacently, but there have always been circumstances where price could not reflect the underlying right sort of market signals. What is important to realize is that what a market is for is an invisible hand. It provides two things. One is information. That's why people generally refer to "price signals." The other is incentives. And incentives provision is a very complicated issue here.

So over time, and during the year, a growing number of experts have recommended to PJM, and we have gone through a lot of discussion and concluded, that ELMP and scarcity pricing are the right thing to do, based on sound fundamental principles. PJM believes that this is a prudent step. This is a moment when the price is at the lowest point. It is prudent to take the essential first step to improve the foundation of the energy and the reserve market, basically to make sure that the prices are more accurately going to reflect the incremental cost to serve load. And of course we can get into many other policy directions. This is a specific and focused effort. PJM believes it's the essential first step and it's prudent.

Now, why is the current LMP not good enough? There are three things. They are interrelated. The first one is that, as Speaker 1 explained, the current LMP system is based on a pricing model. Let me explain that. The system operator uses a commitment dispatch model. That's what we call a dispatch run, for example. And after you run that model in optimization, there are always two sides, a primal and dual. (Now, you don't have to understand the details.) Basically, they are coupled together, and when you get the optimal solution and the operators send out dispatch instructions, at the same time the software on the dual side produces prices.

Now, the problem that we see here is that this current sort of structure has a limitation. Fundamentally, the limitation is that this dual does not reflect all the resources. It only reflects the cost of those flexible resources. Why? It's a long story, but to make the story short, the answer relates to these terms, "convex hull pricing" and "convexity." The term, "convexity" probably entered our *State of the Market* report for the first time this year. Really sort of a fundamental issue, as we learned over the years, driving a lot of the issues that we face about flexibility, is non-convexity, and in economics this is fundamental. In the 1940s there was a very vigorous debate among economists, the so-called "marginal cost controversy," and Ronald Coase wrote a famous piece that pretty much settled the debate. Basically, in the presence of this non-convexity, what that means is that average cost can decline when your output increases. I'll just leave it there. Therefore, the marginal cost pricing principle, that marginal cost pricing, is flawed, and it's not efficient. And there are also problems.

So, since economists don't have a solution to restore that efficiency, the current LMP, most of the time, will be OK, but some of the time it can create problems, because it does not reflect all the resources' costs. And the consequences of that is that it creates distorted incentives. Some participants have incentives to behave inflexibly, and in the appendix I put in some very concrete examples, and we have observed that. That's number one, and that affects the system operation.

Number two is that the LMP, as Speaker 1 pointed out, has a pricing paradox. When demand increases, the LMP can drop. And, as we know, in the end we want scarcity pricing, and what scarcity pricing is about is that when the load actually increases, we want the price to go up. And if we don't fix this problem, at some point, there will be a conflict. And also we know, as economists, that this is a very fundamental issue, because if this phenomenon is unlimited, you know, we have a market that is fundamentally unworkable, it's called economies of scale and it's natural monopoly, and it's doomed. It's market failure. And fortunately this is limited. Even though this is limited and we have seen that, for 20 years, it's been OK, still this is a good time to try to fix that.

Why is the extended LMP a good thing? It solves these problems. It has some issues. It bifurcates the dispatch run and the pricing run, and it makes it more complicated, and it's computationally challenging, as Speaker 1 has pointed out.

I don't need to go through integer relaxation, as Speaker 1 has explained that. A key insight here is that PJM found that building on the research that Speaker 1 and others at MISO have done, there is an alternative approach that gives us a glimpse of hope. And when we can construct cost functions with a property called homogeneity, then our conjecture here, and what our research is focusing on, is that that actually can lead to exact ELMP at some point, and we have actually validated some of that in the research with Speaker 1's example.

So that gives us hope that different ways to formulate the problem exist, and we can solve some of the computational difficulty, and this chart is an example, and the vertical differences between these dispatch curves shows the uplift size. And then ELMP there is there, and we believe that ELMP can be achieved through integer relaxation with this complementary approach. We believe that the research is complementary. And let me just leave it with this that. [LAUGHTER]

Speaker 4.
What I want to go over is what drove the development of ELMP at MISO, why we kicked it off, and some of the challenges that we faced along the way, and why we ended up with the approximations that we're actually running at MISO today. Before I start that, though, I do want to point out that I'm no longer employed at MISO, so these are clearly just my opinions. They have nothing to do with MISO and it's nothing that PG&E endorses. So you're just hearing my unadulterated opinion.

OK, what drove the development of ELMP at MISO? Well, when MISO first started its energy markets, our market monitor pointed out that oftentimes the highest priced resources we were using in the market were block-loaded fast-start resources, but they could not set price because they were just brought on in blocks. You could not adjust them in response to a small change in demand. The highest cost can't set price. The other thing that happened very early on is that emergency demand response was triggered. We ran into a situation where we were short, and the emergency demand response was called on in blocks, so this is very high priced stuff. We're telling people, "Get off, we'll pay you your high price," and then the market, because we took off enough to make the problem go away, sent out a very low LMP signal. That caused a lot of anger among those participants, who were saying, "You now got me off, caused me a lot of costs, and you're telling me the price is low? I'm not going to give you emergency demand response anymore, because clearly you don't need it." So that was a bad thing. The market was short. We were in a scarcity condition, and we could not send the scarcity price.

FERC ordered MISO to allow EDR (Emergency Demand Response) to set price, so we had to figure out how to allow a block-loaded resource to set price to meet the FERC requirement. The market monitor convinced the Board that we wanted block-loaded fast-starts to set price. The Board said, "Do that," and we then said, "OK, how do we do this in a principled way?"

The first thing we noticed was that New York ISO had a way of allowing block-loaded fast-start to set price. Why don't we just use their approach? The problem was that most of the fast-start resources in MISO were not block-loaded. They had dispatch ranges on them. The New York approach would not apply to that. If we applied the New York approach and said, "If you're block-loaded, we'll let you set price," we've now given those guys an incentive to take away their dispatch range. My operators would've taken me out back and beat me to death, because they would say, "You've just made my job harder!" [LAUGHTER] And I'm very sensitive to that kind of stuff. I don't like physical pain. [LAUGHTER]

So how do we address this problem? The first thing we said is, let's come up with a fundamental approach. What are the goals we're trying to achieve? We first looked at what were the goals that were set for the energy markets at that time. We're saying, well, we want to commit and dispatch to maximize societal welfare. We also want to set prices that support commitment and dispatch. If we tell you to get on and run at a certain level, and you do that, you should maximize your profits by following our dispatch. Same for demands. So, it sounded good.

How are we setting prices, then? As you've heard, we use LMP. We run a security-constrained unit commitment to meet the efficiency goal, to make sure we're maximizing societal welfare, then we calculate LMPs from a security-constrained economic dispatch where you keep a commitment fixed. Those are nice LMPs. The problem is the LMPs may not cover a resource's offer cost at the scheduled commitment and dispatch, or we may tell somebody, "We don't want you to run." They look at the price and say, "Why in hell" – I mean, this happens all the time—"Why am I not running? That price more than covers my commitment and dispatch costs," so it's a problem. We're saying, "Well, the non-convexity you just heard so much about is the root of this problem."

So, we said let's back up and come up with revised goals for market operations and pricing. Well, the first thing we want to do is we want to commit and dispatch to maximize societal welfare. We wanted to keep that. There are other markets where that is relaxed (particularly Europe), but we didn't want to do that, particularly Europe. Then, we said, given that commitment and dispatch, we want to set prices that come as close as possible to supporting the commitment and dispatch decisions that the ISO determined. And for closeness (I'm sort of doing things a little backwards here, since this is where we ended up, this wasn't the start) we said, let's measure that by the side payments. We have to give people incentives to follow our commitment and dispatch. If we tell you to operate, and our prices don't cover your costs, we'll give you an uplift to cover them. If we tell you to operate at a point where you haven't maximized your profit, in other words, you say, "I should be on," and I'm telling you to stay off, we'll cover your opportunity cost. And then, finally, I could be at a point where the prices actually show congestion on a transmission line when it's not at its limit. And we're saying that can cause a transmission uplift. So we were looking at all three of those.

We said, let's minimize that. Well, how do we do that? We run the security-constrained unit commitment to maximize societal surplus. We wanted to keep that. Then, we looked at saying well, let's look at solving the dual of the SCUC (the security-constrained unit commitment algorithm). That is, the Lagrangian dual to that. We price all the constraints of interest, bring them to the objective function, and that produces what we call the extended LMPs. And those ELMPs actually meet the pricing goals that we outlined. So that's where we wanted to go.

Now, we ran into problems. I'm going to say how we ended up moving from solving the Lagrangian dual to the SCUC to what actually was the origin, I believe, of FERC's fast-start pricing approach, because that clearly wasn't our starting point. The first challenge we faced was, how do we reliably solve that dual? It's a hard problem. It's a minimax problem. We weren't going to find commercially available software that could reliably solve that, so we developed test software that we could use to solve that dual. And we were able to solve it, in a lot of cases, but it wasn't production-grade software. There was no way in the world I was going to run a market based on my Breadboard software. So, we then said well, let's look at approximations. Can we get them good enough to get an answer? And the first thing we looked at was, well, let's relax the integer commitment variables. That's what Speaker 3 was looking at. We relaxed them, replaced the integer variables with continuous variables on partial commitment, and we tested it. The testing showed promise. We were coming close, in many cases to the full ELMPs. We said, there's something here. And again, Ross Baldick, Bowen Hua, and Hung-Po are all doing work to develop conditions under which those relaxations will produce exact ELMPs.

Now, that was the first thing, we said. That will get us partway there. The second issue we ran into was that SCUC simultaneously optimizes over multiple periods. It considers intertemporal constraints, ramp rates, minimum uptime, minimum downtime. The SCUC dual simultaneously sets prices over multiple time periods. The cost of actions in one time period can influence the price in a different time period. If I'm looking at one particular time period, cost of actions in that period may influence prices in the future, because I'm taking actions to help meet future conditions. I have to start ramping up early. Or, cost of actions in the past may influence the time in the current time period. I have to look at this intertemporal issue. We were wondering how to handle it. Well, in day-ahead it was no problem. We run the day-ahead market once, we can do it simultaneously, it's done, we can settle. Real-time was a real pain. Real-time, we can't consistently resolve it. There's a window that moves throughout the day. The cost of potential actions in future periods can affect the price in the current period, so in a day I've started a current period and I'm looking at a window going to the future. Future actions may affect price in the current period. That's not too bad a problem. What happens if the cost of actions in the past actually had influenced the price in the current period? So, whenever I've done things in the past, I did things which were going to influence things in a time period in the future, and as time passes, the window moves up, and makes a future time period the current time period. What do I do about those actions in the past? Should I let them influence the price? That was a hard problem.

So, we were asking, whenever that time period moves the window moves, should we ignore the stuff that happened in the past and just say, "We're just starting from the current period and we don't care that we took actions in the past that would have influenced the price in the current period?" Should we keep the window kind of frozen, and always look at the actions in the past but keep the prices in the past frozen? Should we modify our pricing approach? Or should we just wait until the end of the day and calculate prices for real time once we know everything, and treat everything else as advisory?

Well, we started looking at that, but then no decision was reached on it, because we ran into the third problem, and that was that MISO planned to build this on top of their existing market software. The way the markets run is you run SCUC, which optimizes multiple periods simultaneously, and treats all the intertemporal constraints, but only treats a subset of transmission constraints. It didn't treat them all, and it treated losses as fixed. There were no marginal losses. SCED (the security-constrained economic dispatch algorithm) optimized a single period. Periods were handled sequentially, so it did not consider intertemporal effects, did not consider commitment costs. However, it modeled all the transmission constraints and losses we were interested in. Well, in this development there were plans to take the SCED software that MISO had used and make it multi-period, so we could look over multiple periods simultaneously. We said "Ah, that's the answer. We'll build it on top of SCED, because we have all the constraints we're interested in. We'll have the intertemporal constraints, and we can use the relaxation of the commitment variables to get an ELMP approximation." We were ready to go. Then, the enhancement of SCED to multi-period was postponed, but the need to get ELMP in place was not postponed. That basically blew it up, and we were saying, "OK, we've got to do this in a single period." So that's why you're hearing about the single period. It was practicality. It wasn't design as a desired goal, but it was a practicality.

So, what did we do? We treat the price only in a single period. We amortized the startup costs over a short period after the potential decision to start a resource, so we spread the startup cost over a few periods, and we treated the no-load cost for a potential decision to keep a resource online in the period. So we weren't looking at the intertemporal pricing constraints. We just broke it into small pieces through amortization. And the second thing we did was start slow. (Having lived through the California debacle, I did not want to experience that with a billion dollar market.) So I said, "Let's look at startup costs and no-load costs for a limited set of resources. Let's start slow, and make sure we haven't set a bomb here." And so we looked at fast-start resources, resources able to be on line in a limited period after commitment--ten minutes, for a limited minimum online requirement of one hour. That limited the number of resources we were looking at and the ability to blow up the market if we did something stupid.

So, that's where we ended up, and that essentially is the FERC fast-start pricing NOPR. It evolved out of ELMP. So, we have something in place. It works fairly well. We tested it before implementation, and saw that the performance was acceptable. I think after they ran it, MISO concluded that it's acceptable, and they're expanding it a bit.

So in terms of the potential future, I would say let's look at expanding the resources covered, and look at the effect of changing the resource mix. That's, I think, important. I want to evaluate the effects of a changing resource mix on exact ELMPs and their approximations. I want to make sure that nothing bad happens as the resource mix changes and as you get more renewables coming in, and then work on moving closer to exact ELMPs and improve the approximations, including looking at the work today's other speakers are doing. And then, the one thing I would dearly love to see happen is look at adding constraints in SCUC, and trying to solve the SCUC dual directly. I think there could be some promise there with some interesting algorithmic work, you know. For example, we did not use subgradient descent for our algorithm to test the SCUC dual. Those things are notoriously slow, and prone to jamming. I had the developers we had engaged look at their subgradients. I said, “I don't think it's going to work.” It didn’t. For a bulletproof thing we came up with some cutting point algorithms that had some nice properties, but they’re only linearly convergent, and then we also worked with Peter Luh and Congcong Wang at the University of Connecticut to come up with improvements, so that we could take a cutting point solution and refine it, possibly coming up with better solutions. That work has now been abandoned, but I think there’s something there, and I think we might be able to solve the SCUC dual directly, with a lot of work. But that’s the kind of direction I'd like to see us go in.

Clarifying Question 1: My question is related to the question asked yesterday. With respect to utilities that self-schedule their emergency demand response, and not wanting them to set price if they’re actually not in merit, are they setting price when they are in merit? That is my first question, and the second question is, are you seeing utilities having other DR programs at the LDC (local distribution company) level, or state initiatives, that are occurring side by side with the ISO emergency demand programs that are coming in and changing the load during times of peak and resulting in not getting those emergency DR programs? Because we definitely see it a lot in PJM, and sometimes in New York, too.

Respondent 1: The shortest answer I can give you is yes, and yes.

I do want to add a little bit of context to the first question, which was, does emergency demand response set price? We have emergency demand response that is in the dispatch, and to the degree to which it actually has an offer price, it is setting price. In addition to that, we have an emergency pricing algorithm that approximates the price for emergency demand response, particularly during emergency conditions. We have a multi-stage process where the most simplistic way of describing it is that we use the most expensive resource that does have an offer price that is available to us as a proxy for the offer price of DR that doesn’t have an offer price. So we’re making sure that the price does not fall when DR is committed, even if that DR does not have an offer price itself.

Questioner: Then that’s for the DR that the ISO sees, but not necessarily for the DR that may be occurring at the LDC level that the ISO doesn’t see?

Respondent 1: That’s correct, to the extent that there are self-committed out-of-market resources of any kind. It could a behind-the-meter generator. It could be demand response, meaning taking the load actually off line, to the extent that it is not either asked for or in any way coordinated by the ISO. We do not have a price-setting mechanism to account for that.

Respondent 2: I think it’s important to recognize that with ELMP, a resource can only set price if it’s under the control of the ISO. You cannot sit down, commit your nuclear unit, and say, “I have a huge no-load cost on it, pay me for it.” It’s like, “No, sorry. No one asked you to be on.” You can’t do that.

Respondent 1: I want to add to that. It’s an important point, and this is one of the design considerations we have today for ELMP--the challenge is that the price is the control signal, ultimately, and to the extent that you're asking people, whether they're people that you directly control or indirectly influence through price, to do something other than what the price incentive tells them to do, you're going to run into a control problem, ultimately, that potentially threatens reliability. So that's why it's important that the price always be aligned with the control signal over extended periods of time.

Questioner: If you know a certain amount of demand response is occurring outside of what the ISO has estimated, you could add to that to reserves. I think PJM has mechanisms for doing that, is that right?

Respondent 1: There are a lot of things we do to try and forecast what's happening on the demand side and prepare for it and price based on it, but the effect ought to be reflected in the price signal, so that what we're planning for and forecasting is based on an expectation of responding to a price, I would imagine.

Clarifying Question 2: So, three quick clarifying questions. Speaker 1, I might have missed it, but is your model two-stage--scheduling and then pricing--or is it a single model that yields both prices and a feasible schedule?

Respondent 1: Two stage. We're doing pricing quite separate from scheduling.

Questioner: OK, thanks. Second, a couple of the panelists mentioned that the solution times could be faster. And is that why you might get different schedules, because you can have a smaller gap? You can just get more efficient solutions? Or is there something else that's different about the schedules that you might get from the result of these algorithms?

Respondent 1: I think I didn't quite get your question. There are certainly things that come out of this theory that might help the MIP to solve faster, or that, to the extent that it's currently not being solved to optimality, you might change. That was kind of an aside, because we're mostly treating the pricing, and we haven't tried out, except in a few cases, doing any production runs, adding these constraints into the MIP. So then I think I didn't understand the second part of your question.

Questioner: Well, let's see. The moderator, in his introduction, said it might actually change or improve schedules. Do you just mean because you can solve it faster we might get a smaller –?

Moderator: I'm not sure I said that. I'm not sure I think it's true.

Questioner: OK, and then the third clarifying thing, Speaker 1, you said that a challenge has been including ramp constraints, and I'm wondering, does this mean that the price spikes down or up that we see at the beginning and end of ramps might be artificially suppressed, then, if using your formulation? So we get improvements in some types of pricing, but we're going to be losing these spikes at the beginning and end of ramps, because we don't have the ramp constraints appropriately formulated in extended LMP? Is that a risk here?

Respondent 1: I'd have to look at that particular example. I would still expect that there would be price spikes, to the extent that ramp constraints were binding. I mean, it isn't going to eliminate those. If you need a lot of dollars to move people around to pre-position them or post-position them, it's still going to result in those higher prices. The issue with representing the ramps is that if you truly want to represent the ELMPs, it turns out you need to represent the convex hull associated with ramps from one period to the next, one period to the next to the next, one period to the next to the next to the next, and all of them across the horizon. That becomes an exponential number of constraints, so it's not a viable way to put it. We've added a constraint between one period and the next, one period next and next. So let's say the two-period and three-period range. We think that's a good approximation, because it's rare that you get a constraint binding across 35 periods, let's say. But from a theoretical perspective you cannot fully represent, in a polynomial number of constraints, the ramp store, right? However, with two and three I think you get a pretty good job, but, to come back to your question I think you're still going to get the spikes. I would still expect the spikes.

Questioner: OK, that's good. Since the neck of the duck is two or three hours long, that's a lot of intervals.

Respondent 1: So in that case it might speak to adding three or four, and I don't know that we've looked at cases where there were binding ramps across three or four intervals.

Comment: So, I think what we mean by saying that we cannot truly represent the convex hull when there is ramping constraint, is that, when we do have ramping constraints, it's hard to solve to the true convex hull prices using the integer relaxation approach. That doesn't mean that the ramping constraints will not have an impact on the prices. It just means that we are doing an approximation to the true convex hull pricing.

As far as the previous question, have we tried an example with a large number of intervals, for all of which the ramping constraints are binding? We have tried a large example, but I haven't examined in detail the implications of the multiple ramping constraints that are binding.

Respondent 2: May I add in here something about exactly that point? I think there are two points. One is a substantive one. The other one is computational. In PJM's research we actually took your case of a three-period case, example two, and we actually replicated that, and even though you claim that you couldn't solve multi-period ramping, in that example you demonstrated that it does produce convex hull pricing. And in a side conversation I just confirmed that, and this is precisely, actually, how the PJM approach, which is different, shows complementarity here. We implement this formulation differently. We took the formulation, and included in the ramping constraint this commitment variable, and allowed that commitment variable to be relaxed and then matched that with the dispatch variable at the generation level. And we tried it both ways. If we didn't include that, we didn't get the convex hull pricing. After we included that, it produces convex pricing. To me, it's an amazing experience to see that it matches with their results.

So actually I think they (MISO) have insight to include that commitment variable in that example and to produce convex hull pricing. If that is true, I think that the implication of this is that this formulation does not require adding many constraints. It requires adding these switches that drop all these commitment variables into the current model, and we don't need to reinvent the current model, basically, to revise it in such a way that we don't have to use any new algorithms. And that also, in a way, can probably enhance their results.

On a substantive point, PJM is actually evaluating two different approaches. One is to have a ramping product. Another way is really, I think, the ELMP approach that produces the right pricing incentives so that the price itself will have a time trajectory that will induce load-following incentives. And between the two, we have conducted some analysis for our own system, and found that the evidence for a ramping product is weak. And we do have some need, for reliability reasons, to support operational functions for 30 minute reserves. I think so far the experience from the research is that this pricing incentive is a very important aspect, if we can capture that through our formulation.

Respondent 3: There is something I wanted to mention on that ramp. You're talking about ramp over like a two-hour period. Fine. ELMP may look and say, you know, I've got to start ramping this resource right now to meet load two hours in the future. And you're saying, well, because you can't model the ramp constraints exactly in the ELMP, you're wiping those costs off. I contend that LMP has exactly the same problem, because if I start ramping a resource now to meet a load two hours in the future…in real-time you sweep your window forward too. All those costs I've incurred in the past get washed off whenever I finally calculate LMP for the final period. So, again, the thing gets blended. It's not so much ELMP, it's how do you handle the intertemporal effects on pricing? And LMP has the same issue. It's like, if I'm incurring costs now for a future period, whenever I finally get to the future period, should I look back and try to include those costs in the current price, or do I say it's sunk and they're gone? So that same problem shows up in both.

Moderator: Yeah, that's very different than the day-ahead market, of course. Thank you.

Respondent 3: Well, yeah, day-ahead, two hours, we can handle an ELMP because it's all early market. So it's not a big deal in day-ahead. Real-time is the killer.

Clarifying Question 3: At MISO, we spent a lot of time in the past three years trying to improve unit commitment and performance, and one of the constraints, actually, that we worked on is on this convex envelope formulation of the offer. And that one actually brought 30% improvement of our unit commitment performance, and then later on, I discussed this with one of the researchers working on ELMP, and he pointed out to me that it's exactly equivalent to what they proposed, and it is also equivalent to what Speaker 3 is proposing. So that's introducing integer variable into the incremental energy offer and then that can make it equivalent to the convex envelope formulation. So that's actually kind of introduced significant improvement in unit commitment.

And further, going back to the ramp constraint, I think usually when you add the startup and shut down, the ramp and the limit, they may be conflicted. You may not be able to ramp into the minimum limit in one interval. So because of that, it's hard to formulate the ramp constraint to form a convex hull. So I think even in single interval real-time you still have a similar problem like when you act on unit, whether you should hold it at the ramp, because it may not get all the way down to zero if the ramp is not large enough.

Clarifying question 4: It could be my lack of understanding, but somebody said that this proposal eliminates uplift, and my understanding was that in fact it moves uplift into a different bucket, which is all the generators that you have to pay to not respond to the price signal. So I'm wondering, as a clarifying question, did you mean it eliminates uplift, or it switches to a new uplift form?

Respondent 1: I'll speak for MISO's experience, which is that the implementation that we've had running for a few years now has meaningfully reduced uplift total. However, I can't speak to what you would expect to find with approaches that have been proposed by PJM or others. We've looked at some of those elements, and we did have concerns about uplift that would be created. But because of the design considerations we went in with, to reduce uplift, we moved in the direction we did, and we've seen the experience of reduced uplift as a result.

Questioner: As I understand it, the difference in proposal between PJM and MISO is that MISO's is a very temporal pricing, if you will, whereas PJM is suggesting that it could run for eight hours, and so that's eight hours of separate opportunity costs that you have to pay people for not chasing the price signal? Do you think it's a question of magnitude, or maybe I'm misunderstanding the difference between the MISO and PJM proposals?

Comment: Excuse me. To clarify, I don't believe you pay everything through the ELMP. Is that correct or not?

Respondent 1: We do not. We do have a ramp capability product which is similar to what PJM is suggesting they would consider that at least for MISO allows us to reserve ramp needs for future periods. We're basing that ramp capability product as an opportunity cost of having sold energy instead, so if we reserve a ramp capability from a generator, we're paying them for what they could have sold as energy instead of reserving the ramp capability for us. But that payment is, again, tied back to the energy market price, so it doesn't create uplift as a result.

Respondent 2: Again, I think if you look at the fundamental ELMP and solving the dual of the SCUC in setting prices using that, that minimizes uplift. Uplift of costs not covered by price--opportunity costs, the total, that is minimized. No one says it eliminates uplift. It's just that you re-minimize it. And, again, the approximations, that's one of the things you have to be careful about whenever you move away from the pure math theory. We're doing approximations that can cause deviations. That was one of the things being tested, was whenever MISO built the single period approximation, did it have the desired effect on uplift? Experience said yes. But, again, there's no proof of that because it's an approximation.

Comment: One of the other clarifying points to make about uplift, particularly in PJM, is that a significant part of uplift would not be addressed by convex hull. That is, there is uplift that has nothing to do with the issue of convexity or non-convexity. So you also have to think about that. Clearly, as you just said, uplift is not being eliminated by convex hull.

Respondent 3: Just in response to your question, I think it has two parts. One is a theoretical part, and one is an empirical question. I think, certainly, empirically, one can take the result and attribute it to the shift in the way that you describe. But there's no theoretical insight that one can contribute on that. And so I put that aside. PJM has done that, and then it's on a case-by-case basis. There's no general conclusion that can draw across the ISOs.

On the theoretical part, currently the uplift includes basically two kinds of situations. One is, there are units that are needed to run to serve load but are losing money, and the uplift that we pay currently covers that part. And the other part is that there are units that are profitable to run but they should not run, and that's a lost opportunity cost. Currently, we do not pay for that. But in the ELMP, we pay both. And, overall, the ELMP theory is that the uplift cannot be eliminated, and this is really a payment for disequilibrium, and a way to minimize the disequilibrium. It appears those two situations are really indications that the market cannot reach an equilibrium in the presence of non-convexity. To an extent, it can be minimized, and empirical result sort of confirms that.

Clarifying question 5: Can any of you give a general sense of at what times and places the non-convexity is an issue? Is it often during scarcity conditions, in which case scarcity pricing would also be relevant, or at different times of day, or anything like that?

Respondent 1: Right now, we don't often have situations of scarcity pricing. There are cases in the cold snaps. That's not where this non-convexity comes up. So, empirically, we have not really seen that. At this juncture, we see that the problem, I think, is more driven by what we see over there in real time and by a number of inflexibilities in operation that can lead to the situation that you are talking about. And it's not an imminent threat, but the question here is, is that a problem, a pricing issue, that we want to address?

I also want to sort of clarify that this judgment is not really like a policy decision, where we do this to maximize the social welfare per se. Yes, in the long term, the whole purpose of having a good pricing method is really to produce prices that provide the right signals, that provide the right incentives to achieve that goal. But in the immediate term, we look at many of the phenomena that we have observed in terms of behavior that creates inflexibility and also the observation that we actually have situations with decline in cost, and all these situations. We see that non-convexity relatively speaking is an issue that for us, and this is the moment to fix it, so that we can avoid or prevent the conflict that you described when that situation arises.

If I may use a metaphor here, some of you have heard about this, you know, in northern California, this Oroville Dam. This is the world's highest dam. It's a wonderful engineering achievement. And during the drought period in the last few years in California, the water level was low, and it was discovered that in the spillway there was a crack. That is really minor, and the spillway's only used when you have overflow and excess water you need to release. So they postponed that decision. That issue here is not really impinging upon the operation, they thought, and then last year, in the winter, the weather changed, and brought a lot of rain, and then that dam actually experienced excess water and needed to release the water. And when they did that, that leak actually became a big hole. And then when they released water they needed to evacuate 178,000 of the residents to avoid catastrophe.

I think, at this moment, we don't have that crisis. It's fortunate. What I see here is that uplift is like the amount of water in the leak. It's small, compared with the size of the dam. But at this juncture, our judgment is that the cost-benefit, relatively speaking, makes this a good moment to fix this fundamental problem, based on fundamental principles. And if we could get it right, then we can move on to do scarcity pricing and to deal with that situation we have you described, without this conflict.

Respondent 2: I would say it's not just scarcity. ELMP is important just in managing your system. For example, when we first started testing this, we would see situations where we might have an overloaded transmission line. To bring it under its limit, we had to commit a resource inside that area, a fast-start resource. Once we committed it, there was enough energy in there that it pulled the transmission line below its limit. It was always sending out a zero shadow price while we were generating uplift, which gives peanut butter to everybody. ELMP actually sits down and says, you know, to manage that transmission constraint, you've committed a resource, you've incurred costs to manage it. There's a shadow price on that line, and we saw a price separation, so that the people inside the load pocket would pay a higher price, and the amount of uplift that had to be peanut buttered to everybody was reduced. So, ELMP, without scarcity, just in managing the system, sometimes sends better price signals.

Clarifying question 6: Something came up in some of the earlier discussion about the formulation (of ELMP) improving the SCUC solution time as an additional benefit. And I thought I heard that it was done with respect to ramping constraints. And it wasn't clear to me if the statement was that adding it and then relaxing it helped improve the solution time, or just that adding it had an impact--maybe it makes it look a little bit more block diagonal all the way, and it might be more amenable to certain solution techniques. What were you alluding to that is the property that you were gaining?

Respondent 1: So let's start with existing MIP that's got a representation of ramp rate constraints in it. In addition, we're going to add some additional linear constraints into the problem that describe the convex hull of the feasible commitment region with ramps, OK? So we're going to add some additional constraints into the formulation. In principle, that means there's more constraints for the MIP solver to solve, which sounds like it's going to make it harder, right? However, by getting closer to the convex hull of the underlying feasible region, it turns out that the MIP will find it easier to solve it. The "no free lunch" theorem comes in, in that if you had to add an exponential number of constraints, you won't get a free lunch. It won't solve faster. But the cool thing is that the two and three-period ramps capture most of the issues, it seems (at least putting aside the issue of long-term ramps if you were representing this in a real-time market over multiple hours.) But this tightens up the problem. Now, I need to, in full disclosure, say we haven't done this on a full production case, so we really need to test whether or not it's true. But the indications are that this could improve the speed of solution of the unit commitment.

Comment: I was analogizing it in my head, and tell me if this is a bad analogy, to something like an advanced basis in the simplex algorithm, in terms of going in to solve in the full MIP. Is that a good analogy or not?

Response: I would say that it's more general than that. Speaker 3 pointed out that there's a bifurcation in dispatch and pricing in our story, so there are two separate problems that we can talk about separately. So, for dispatch for unit commitment, our approach amounts to adding some linear constraints into the integer program, into the MIP, and these constraints won't alter the optimal solution. The linear constraints we add won't alter the final optimal solution, but they will help to solve the integer program faster.

Question: Is it structural?

Response: It's not an advanced basis, but the fundamental challenge with integer problems is that you want to throw away all the integer commitment decisions that are not consistent with optimality. And constraints chop more of those off.

So, when we're doing pricing, we are solving the integer relaxation of MIP, and that allows us to get a better approximation of the convex hulls. Our object function will be closer to the MIP. It will be tighter, and as a consequence the prices are going to be better.

General discussion.

Question 1: So, I'm going to start off asking a couple of clarifying questions, then go back to the room. So, the very first question is, why are we talking about all of this? So what's the purpose of markets? It has something to do with efficiency, I understand. So, my first question is, what's the definition of efficiency? What's the objective function, initially, of the LMP model?

Respondent 1: So, I broaden that to the unit commitment model. Our definition is to in principle maximize the benefits of consumption, minus the cost of commitment and dispatch. We don't have a very good representation of that benefit side, so let's just move to minimizing the costs of commitment and dispatch. And when we're talking about having two runs, the commitment and dispatch run, the first run is really the thing that's trying to achieve that. Then, the implication is, well, what's the point of the second run? And several people have alluded to giving price signals—so, the first run minimizes, ideally, the cost, but in fact, we get the information in the offers. It minimizes the offer cost, so there are all sorts of implications about trying to get correspondence between the offers and the true costs. So I would say, moving on to the pricing run, some of our goals are to try to make sure, even in these strange conditions, with integrality, that we encourage the market participants to have their offers reflect their flexibility, reflect their true costs.

But I think that argument is, to be honest, a pretty hard one to make. In my example, we had to run a unit that was costing $50 an hour whenever the demand was above 50 megawatts. If you were a new entrant into that market who had a technology that could produce for $20 a megawatt hour, you would never see, from the energy price, which is staying at ten, that you are actually an efficiency-improving entrant into the market, insofar as you could beat the $50. So I think the clearest efficiency connection in the pricing realm is in the long-term or capital entry efficiency.

Questioner: So, one quick response is, why is that $50 unit there in the first place? You're just sort of accepting the installed basis as somehow reflecting efficient decisions, when of course it came from utility regulation. But just to go back to efficiency, so you agree that the objective function of LMP is efficiency. The objective function of convex hull is something slightly different. So let's call it uplift minimization.

Respondent 1: Yes, I think that's the right way to put it.

Questioner: OK, so just to salvage that as a baseline. So, then the next point is I think you all agree that there's a difference in – no? All right, go ahead. You're jumping up and down. Tell us why. [LAUGHTER]

Comment: What Respondent 1 said, I agree with, and it's that dispatch is to maximize social welfare. And if you could represent the demand side benefits and all that, that's better, and you include that, and everything's fine, and you're trying to maximize social welfare. Then you want to have a set of prices which have the property that they support that efficient dispatch. You want to have the prices and payments that support that efficient dispatch. And then you'd like those to have the incentive compatibility property that Respondent 1 talked about, so people have a tendency to essentially provide truthful bids.

And the efficient dispatch story is not changing, the economic dispatch maximizing social welfare. There are many payment schemes that will support the dispatch. The ELMP solution is to find a payment scheme which minimizes the uplift and supports the dispatch, so it's trying to get the smallest outside payments, and then this is a little bit more conjectural, but Speaker 3 and I have been talking about this, it's almost incentive compatible. It's not quite perfectly incentive compatible because of the first price, second price story at the margin, you know, kind of thing, but it's almost incentive compatible. So it's very consistent with everything we've ever tried to do.

It's not going away from that, and the notion that the LMP prices are the only prices that are economically efficient is completely wrong in the non-convex case. Thanks.

Respondent 2: If I may just add a little bit to that, along with what Respondent 1 said, I think the dispatch run ensures social welfare maximization, but it actually, in terms of information, takes the costs bid as inputs. And how do we know that these bids are accurate? And then the pricing run produces results along with the solution support incentives. Uplift, as the ELMP structures it, produces two things. Informational efficiency, in terms of incentive compatibility to ensure that the costs input to the dispatch run is accurate, and then these prices coming out of that then can provide accurate price signals and the right incentives.

Questioner: OK, so despite what was just said, I'm still hearing that there are two runs here. The LMP model is still going to be cost minimizing, efficiency maximizing. And then, in addition to that, and I think I have this right, in addition to that, we're going to have a pricing run, where the prices vary from what you would see under the LMP model. So now you have a difference between the price signal and the dispatch signal, and in some cases people are going to want to follow the price signal, but dispatchers are not going to want to do that, so they're going to manually dispatch them down. They're going to have to pay them opportunity costs, which is a form of uplift, which is why uplift is not being eliminated, but at least it's certainly being minimized. So did I miss something on the two runs?

Respondent 3: Well, just to clarify, our experience in MISO related to how we've implemented this has not resulted in the second piece, nor have we needed to pay people to follow an operating control signal that is different from the price signal.

Questioner: It's pretty hard to imagine why that is. If you have a $100 price and a $50 signal, how is he not going to want to follow the price?

Respondent 3: The main reason is that we've done this in a way that limits the duration of time that the signals diverge from one another. And that's a key element, because if you have an extended period of time when the signals diverge from one another, what you've described is exactly what would happen, and exactly what we're worried about.

Respondent 1: If the $50 per megawatt hour guy had some additional capacity that was not being used, then that's not exactly coincident with being able to have committed him and used and priced with LMP at $50 or $60, so you never needed to get to the $100 unit. Those conditions are not exactly the same, because it's precisely the non-convexity that causes this tension. The tension is only when the prices are inducing wrong behavior for particular market participants. And that's not going to be every market participant. It's going to be a couple of units that are marginal in the sense that they are nearly off or nearly on (not marginal in the technical economic sense). Units that are not fully dispatched and not fully off. So their empirical observation is consistent with your theoretical observation. My point is that that concern occurs in some cases, and, empirically, it evidently hasn't been occurring in the majority.

Question 2. It's not clear why we're going to all the trouble to do the pricing difference, if it's really not changing behavior much. But let's hold that aside as a clarifying, sarcastic aside. [LAUGHTER]

So, one last question for me. If the purpose is to minimize uplift, and uplift is a problem, and everyone can come up with anecdotes about why some units should've set price and didn't, and then, as a more general theory about why that's bad, one level of uplift isn't really worth it. So, uplift in PJM is down dramatically. And we have not done ELMP. Total uplift last year, I think, was about $100 million or so in a 40-billion-dollar market. And at least a third of that has nothing to do with the outcome of the LMP debate. It's black start, it's reactive, it's other forms of direct payment schemes that have nothing to do with this particular discussion. Let's just say we're talking between $50 and $75 million on a $40 billion a year market. Does it really make sense to do this change in pricing, which is going to end up shifting lots more money around, in order to change that relatively small amount of uplift? Aren't there things we could be better doing with our time and intention, including scarcity pricing (which some people have alluded to)?

Respondent 1: Just let me speak to the experience in MISO. So, again, what we have done is to attempt to implement what we believe is the right answer without incurring the negative consequences that you're suggesting would occur. I'm not speaking to PJM's proposal, but to MISO's experience. And the slide that was up a few minutes ago before the break, the first slide in the appendix of my deck, shows that during the recent cold snap, when ELMP actually did diverge from LMP in about 82% of the intervals, you can still see a very tight coupling, except for in just a very small number of intervals, a very tight coupling between them. So we're better approximating the true cost, so the demand side does see it, and we do have demand side response in MISO that is not coordinated by MISO. It's responding to the price, so that's part of the efficiency gain that Speaker 1 was getting at. In addition, during that just few day period, we saw a 9% reduction in revenue sufficiency guarantee payments. So, again, it depends on your perspective of what's material, but we view that as material. And it is not 9% across the whole year, because the divergence doesn't occur throughout the whole year; it only occurs during periods when these fast-start resources would otherwise be incapable of setting prices properly.

Questioner: It'd be interesting to see the underlying data.

Respondent 1: Well, we have the data. Both the LMP and the ELMP are represented, so we actually still calculate an LMP. So you can see what it would've been under LMP, and what it was under ELMP.

Question 3: I have a question price signals and the role in investment. There was a subtle bit that I thought was very interesting in the very simple two-unit example at the very beginning of Speaker 1's slides. If you recall, it had two units, a flexible one that offers at ten dollars, and an inflexible one that offers at $50. Thinking about that example as a forward-looking economist worried mostly about investment, because that's where most of the money is, at least for the purpose of this question, I see that the issue there is not a problem with the marginal cost pricing. The problem is with the investment mix--that the market has an inflexible Unit Two instead of two flexible Units One, which, in your example, would be the cheapest way for the most efficient system to have in that example. That is, the pricing should not make Unit Two whole, as you said in that slide, but rather it should lead Unit Two to exit, so that investors, in principle, depending on fixed costs of, course, instead build a system with two Unit Ones, which, for the numbers you had, is the more efficient solution in that case.

I bring that up mostly just to motivate the broader question I was trying to get at, which is, do we collectively feel like we fully understand the role of convex hull price signals in motivating investment? Do we understand whether it supports an efficient outcome on the investment side, not just in the short-run operational time frames? And in particular, the simple example you had really highlights a case where it clearly seems not to be so, right? ELMP would provide countervailing incentives that would prevent Unit Two from leaving and being replaced with a more efficient mix, at least if the cost of investing in the more flexible unit, the fixed cost of that, was low enough to support that efficient outcome that's being impeded with the price signals in that particular example. Do we fully understand this, or should we be nervous, because we have a lot more work to be done on that frontier?

Respondent 1: Well, I would be the last ever to suggest that you shouldn't be fully funding a research program. But, to your point, a fundamental tenet of an offer-based market is, if the ISO gets to tell you whether you commit or not, it will pay all of your stated cost. So the reality is that if these two units exist in the market today, and we need them today, and PJM or MISO asks the second one to commit, the deal is that it's going to pay the operating costs. So, whether or not your preference is desirable, it's not an option. You can't say, "You have to commit. I know you told me it cost $50, but I'm only going to pay you ten." That kind of is the Takings Clause, right? So that's a fundamental tenet of offer-based economic dispatch. So we can't get away with it. You're going to have to pay him his $2500, whether or not you like it.

The question is, now, given that we've got this portfolio of capital, and given that we had decades of cost of service regulation with the wrong incentives. The world is moving to higher levels of renewables. You might argue about why that's happening, but there's a need for dynamic efficiency. We need to move in the direction of getting to something more efficient, which, I agree with the questioner, preferably involves less inflexible high-cost units. In the status quo, every time I need to commit this guy I'm going to have to pay him $2500. The market price is staying at ten, so someone else's $20 per megawatt hour technology that's waiting in the wings never sees an opportunity to make a profitable investment.

Comment: That's the key.

Respondent 1: And that's the key to the dynamic efficiency story. If you don't see the uplift and don't see the opportunity to make money in that market, you as an investor won't come in. And so that argues for trying to minimize the uplift so that the invisible part of the market. By minimizing the uplift, the argument would be that's giving investors better opportunity to see that some $20 technology is the right thing to invest in.

Respondent 2: The key insight here is that the degree to which we're reflecting the flexibility value of the fast-start resources in the price means that you're going to be sending a signal for the value of having more flexibility in your fleet. To the degree to which you're reflecting a price that doesn't reflect flexibility, then you're going to be potentially incentivizing less flexibility. But the way we've implemented ELMP, and similarly in New England the way you've implemented fast-start pricing, you're sending a signal about the value of the flexibility by allowing the price to actually reflect the cost of those fast-start resources and those short run-time resources. So that's the opportunity that is otherwise missed by not setting the price that way.

Comment: Don't you blunt that, though, by not paying the LOC (lost opportunity cost) to just do the finance?

Respondent 2: No, because what we're seeing is that, because the uplift is going down, they're actually capturing the revenue they need to actually operate. There effectively isn't a lost opportunity cost, because we're dispatching them, and we're paying them a market price that actually covers their cost through the ELMP.

Comment: But they're stepped down when they're in the money.

Respondent 2: Well, that's the whole point of ELMP, that we don't have a dispatch down that's misaligned with a price signal. We don't have a price signal that stays up when we dispatch someone down (except for wind, by the way).

Comment: That's an empirical observation. It's not –

Respondent 2: Well, you're right, it is empirical, but the whole premise we've started from is that we need to take baby steps so that we can use the empirical to guide the design.

Respondent 3: Let me just add one more thing to this question. Definitely it's a good question, and I just want to add one PJM thought. In PJM, looking at flexibility and inflexibility, if we go to the change between LMP and ELMP, one specific aspect that addresses the incentive issue is that currently only flexible units set prices. And then, if we allow the inflexible units to participate in setting prices, the inflexible units will not benefit. They will get make-whole payments when you are on the margin. But that will create an inframarginal revenue for the flexible units, so overall, I think just based on that sort of angle, you envision that, by incorporating the startup renewable costs and so on, that will generally increase the average LMP level, and then who benefits? I mean, this is going back to the earlier question, is there a cost shift here? Yes, I think that the benefit will shift to the flexible units, and that will provide the incentive in the future for investment in that area.

Respondent 2: Just to go back to the earlier point about whether you have an incentive to compete away an inflexible unit that's getting paid uplift, there are other ways to do that. How about making uplift transparent, which we've suggested repeatedly? If you simply told people, "These units have been getting $100 million a year in uplift for the last ten years. It's there, and it's available," then that's another clear way to provide a market signal, I think.

For what it's worth, that's exactly what we're looking at with the 30-minute reserve product in MISO, which is to try and first shed a light on the uplift required to hold units in reserve that would otherwise be resolved with the product.

Question 4: Yeah, in principle I'm all for making sure that the marginal price, whether you call it an LMP or an ELMP, actually does reflect the cost of the highest cost action needed to resolve supply and demand. And I think it's a key part of the answer to how this market design survives in a world with a lot of zero marginal cost resources, which is a discussion that's going on a lot these days, and I and others are desperately defending the security-constrained economic dispatch with locational pricing model against people that want to tear it down for no good reason, and this is one of the ways that we defend it, so I get concerned when people start to be too doctrinaire about LMP being the highest and best end of markets. I don't think LMP based on offer prices is necessarily the be-all and end-all. But that was why I was shaking my head.

I do want to observe that we have to change the earlier definition of a finish line in the race. The winner will now be the first person to say, “Resolving the Lagrangian dual of the SCUC.” That’s the new finish line. [LAUGHTER]

So, some of us thought we detected a pretty important difference between what Speaker 2 was describing at MISO and what Speaker 3 was describing in PJM. I think, Speaker 2, what you’re referring to and what Speaker 4 was referring to was the piece of this which I think a lot of us have no problem with, which is the fast-start pricing. And PJM has a fast-start pricing proposal, and to the extent I understand it, I think it’s fine. PJM is a second proposal, which I think is implicitly what Speaker 2 was saying MISO has not been interested in doing, which is a much more structural, long-term way of adjusting LMPs based on bidding of inflexible units, which I think crosses the line into unduly rewarding inflexibility.

But I'd like to understand that, because if I'm misinterpreting what the three of you were talking about, then correct me. But it sounded to me like PJM has two proposals on the table. MISO is really only describing its approach to one of them, which I think is analogous to the fast-start proposal of PJM. There’s a second proposal. MISO hasn’t gone there, PJM is, and I think that’s the one that a lot of people have problems with.

Respondent 1: When we came up with ELMP in MISO, I mentioned we had two specific problems which we were being forced to solve: block-loaded fast-start and emergency demand response. The problem we had was we had very few block-loaded fast-starts. Most of ours had a dispatch range. So we were saying, how do we handle that? Because we couldn’t just apply New York’s approach to it, which we thought worked fine for block-loaded. Once we had that we were saying, well, we now have to develop an approach. We said, let’s develop it generally. Let’s say it can be applied to anything. Put a stake in the sand where a possible end state would be, and work towards that. We never said we were going to apply it to everything. We were always saying that we will get something in place and we will then look and do studies to say where we should apply it. Again, it could be that we would want to apply it to relatively fast-start units, maybe anything that could be started in three hours with a three-hour or less run time. I think the whole thought process was, let’s figure out where the biggest bang for the buck is.

So, we have an approach. We described it, and then we, to start off, pulled all the way back, because we couldn’t solve the big thing, and said, this is dangerous when we’re doing approximations. Now they’re slowing spreading out, so I think that’s the big difference.

Respondent 2: Yeah, the key difference is two pieces. And I actually think the fast-start proposal and the flexibility proposal are linked in ways that may be not obvious. (It’s not that they’re not obvious on purpose; it’s a complicated subject.) But the notion that MISO has used is that we want to make sure that the signal we’re sending is a sharp scalpel of a signal, not a blunt tool. And the degree to which we are sending a clear and sharp signal about the need for a resource at a particular time, or maybe the lack of need, which is part of how we do this as well, is, I think, different than where PJM is looking at it as a way to incorporate more of the costs of the system into the price signal, which potentially, in some respects, has those prices, such that the immediate operational need diverges from the ongoing price. And that’s where we have not been headed.

As Respondent 1 to this question was describing, we’ve taken baby steps to make sure we understood the empirical effect of each incremental addition of resources to this pricing algorithm. And we've gone from ten-minute start resources with very, very short run times to now 60-minute start resources. I'm not sure we're going to go much or any, even, beyond the 60-minute start, because of the potential for getting some of the effects that the earlier questioner was describing, so the empirical evidence is that we're getting the good without the bad. We've been trying to figure out how to improve the good and not incur what we think are the bad outcomes. I will say that we do pay opportunity costs, but only for wind resources that we dispatch down as part of our dispatchable intermittent, but we're eventually going to have to figure out how to do that better, too. It's a problem in the long run when you have 50,000 megawatts of wind instead of 19,000.

Respondent 1: It's real simple, just make them an offer.

Respondent 2: Exactly.

Respondent 3: Let me clarify that. I think PJM's proposed enhancement will actually align the pricing and dispatch, and the current PJM approach actually has a gap between them. And, overall, PJM started out by actually looking at the problems appear in flexibility incentives. And then PJM also has been, along with the other ISOs, responding to FERC's price formation initiative in the fast-start pricing. And the general approach that PJM is taking is that the overall implementation will be incremental, will have transitional phases, but in terms of fundamental principles, we would like to pursue it in such a way that we are not going to change the pricing for the design principle. And we can build on that without actually redoing it, so PJM chose this ELMP for that reason. And then, PJM is going to implement some aspect of this in response to FERC's fast-start pricing order. So it is not really an issue here of how we are going to jump into an area that will actually create a big change in the system.

As we actually move onto the pricing front here, there is always a question about the pricing and product interaction, and should the product be designed to support pricing, or pricing be designed to support a product that has needs that can be identified operationally or from a market? We opt more for the latter. So, as we actually look at following products we ask the question, do we need that? And then, if we need that, then we develop this pricing approach that can be consistently applied to different product portfolios.

So this is the kind of thinking that leads PJM. I think what we're talking about, practically, here is to apply integer relaxation to the fast-start pricing to meet the requirement. That, we think, is a modest first step. Certainly, PJM has an advantage here. We can start fresh, in some ways, and have that latitude. We want to take advantage of that option.

Questioner: Again, like I said, the fast-start proposal, no problem with that. It's the second piece. And I think, to the earlier point, in the real world of market participants I think in some ways the litmus test is who's screaming the loudest bloody murder about this proposal, or who loves it the most. And at the moment, for the second piece of what you've proposed, it's the inflexible resources that seem to think it's just the bee's knees. And that tells me that there may be something wrong with it. [LAUGHTER]

Question 5: So what I heard some people saying is that going beyond fast start to a broader category than flexible units has potential pitfalls. And I haven't heard a response that speaks to how PJM would address those pitfalls, or why those pitfalls aren't of concern.

Respondent 1: Can you be more specific? I think that’s a broader question. If you have a specific aspect, I'll be happy to answer that.

If I actually take that as a very broad question, I think that PJM’s proposal is a package here, you know, to pave the way for shortage pricing. And, overall, if we dive into some of the details, we can see that there are a lot of interactions in the system that create price irregularities that are explainable by the inflexibilities…

So, this is a first step that can actually create definitely an improvement to enhance the reliability operation management and to get this pricing aspect done right to set the starting point. Certainly, there are other issues that… it’s doing no harm. It’s not a panacea to solve all problems, but in the long term we believe that this is the direction that will combine with further improvements. It’s not a Band-Aid. It’s an enhancement that will induce good investment incentives and operational incentives. It doesn’t really address all problems, but it does not do harm to any of the other problems.

Respondent 2: I don't want to speak to the PJM proposal, but I want to offer what we at MISO have been thinking about as the pitfalls in a little bit of detail, just so you have a sense of it, because I don't know that I did a very good job of that.

So, one of the key concerns we have about using extended LMP beyond the relatively fast-start resources where we are, or maybe just a little bit beyond where we are, is that to the extent that the price is paying for resources that are not very flexible, then it encourages resources that are flexible to chase the price. Now, that can be corrected for with a complementary product that says, “Well, we’ll pay you what you would've gotten by chasing the price.” So the challenge with that is, if you do that, you then raise the question of, why bother offering flexibility in the first instance if I'm making the same amount of money either way? So then you end up with a quandary of operators who could be flexible essentially saying, “Well, I'm just going to offer in inflexibly, because I get the same either way.” So then you have both an operational challenge, which Speaker 4 described as being taken out back by the operators and getting beaten to death, because you’ve just lost flexibility, or you have an investment challenge, which one of the questioners was getting at, which is, why bother building resources that are flexible, which could be more expensive, if I'm going to get paid the same either way?

So I'm not saying you can’t solve those problems, but I don't know how to do it right now. And I haven’t seen a proposal that does it very well, or that does it in a way that I'm comfortable with, which is why we have stopped where we are, and we’re working on improving the algorithm for the resources we have included in ELMP, which is why my slide said, “Don't rush,” because we have a lot of more work to do, and why we’ve hired Speaker 1 and his folks to help us think through how we make this better without causing the harm that we are worried about.

Respondent 3: Thanks. One more wrinkle to that, too, is why would anyone opt to get paid uplift through a complex set of rules, rather than simply getting paid the price?

Respondent 2: Yes.

Respondent 3: You have that choice. The price is clear. The uplift is always a little bit less than clear, for anyone who’s ever followed the thousand page of uplift rules in the PJM tariff.

Question 6*:* I'll try to make this a little clearer. So, I'm sitting here sort of like the June bug at the top of the pond, trying to piece this all together, and here’s what I think I've heard.

At the beginning, Speaker 3 said that most of the time the current LMP is fine, and some of the time it's not. We never got a sense of what that proportion is. Then Speaker 3 said that it was not an imminent crisis, but it's like the dam with the crack, which sounds like we better fix it, and then Speaker 2 is saying, we'll take baby steps, don't rush, and then I think Speaker 4 said they'd been working on it since 2011. And then I hear PJM say this needs to be done this year to be filed so it's effective next year.

But I'm looking around the room at the load folks, who have been noticeably silent, and regulators likewise. What are we supposed to conclude, and how do we stitch this all together?

I mean, I've learned a lot the last three hours. I'm trying to figure out if this is indeed a crisis, or it needs to be done. What do we do at 12:01 PM, as we go back, to avoid the problem that plagues all these issues, which is that every RTO seems to think they have to do it separately themselves. So, are they all going to go through this 11-year process?

So give us some guidance on what I said that was crazy or not, but also, practically, what should we conclude about the speed with which this needs to be addressed, and if it does need to be addressed as fast as PJM's suggesting, what do we do to not let this three hours not be built upon?

Respondent 1: Since I was the one who said, "Go slow," about a thousand times, I'll just offer that I'm not suggesting that everyone has to go through the birthing process that MISO went through. I am suggesting that we have an experience that's worth looking at and learning from, and to the extent that we're going to take steps forward, we ought to be very circumspect about taking large leaps forward rather than continuing to take baby steps beyond where we are today in MISO and, in large part, in ISO New England as well. I think there's a lot to be learned there. Let's build on it, but taking large leaps away and well beyond where we are has issues that we are concerned with.

Respondent 2: I would say that, really, coming up with the concept from nothing, that takes a lot longer. We played around with it, we said, "Hey, you know, solving the dual gives us these kind of prices." I looked at it and said, "Surely somebody else looked at minimizing uplift," and I found Bill Hogan and Ring's paper on minimizing uplift. And I basically gave him a call and said, "Let's work on this." And Bill and Susan Pope came along and fleshed out the theory, and then we went through a whole series of day-and-a-half-long stakeholder workshops to explain this, to bring people up to speed.

I don't think you have to go through that process again. You can go on the MISO website. I believe those workshops are still available. Then, we did a lot of work with the stakeholders to say, "Well, we can't solve this exactly, let's come up with approximations." All that work has been done, so I think you can really cut out a lot of that. It's not a ten-year process anymore.

Respondent 3: I totally agree here with what has been said. To the questioner, you have a very good summary here of all the key points. I would just add one thing. PJM is taking so-called baby steps, in our view, but it's in the eyes of the beholder. But the important thing is that we're trying to orient our steps in the correct direction.

I think a lot of progress has been made during the period since MISO's start with ELMP. One should not take for granted that the ELMP is easy. This idea was proposed more than ten years ago now, and it has taken a long time. It's a long tunnel. I think PJM sees, at the end of the tunnel, the light, and it is important to do that right. This is a hard problem.

So, we can take advantage of all of the work that has been done in these baby steps. We can do it much faster. We can do more and do no harm, and then, basically, once we set a direction, I think we do need actually a lot of communication. This is not an easy communication, and we haven't really met my "grandmother" test here--if I explained this to my grandma, she would say, "Grandson, you don't understand." [LAUGHTER]

Questioner: I feel like Grandma right about now. [LAUGHTER] But a quick follow-up: so this ELMP, however PJM's proposed it, is part of a broader package that includes other elements, correct? I'm trying to figure out, does this all have to move together? Is this integral to everything else that's in the package? Or could the parts of the package move separately?

Respondent 3: PJM wanted to give the market a very strong sort of direction, saying this is what we are interested in moving towards as a target, and to get this shortage pricing and ELMP as a package. Now, in terms of the next move, fast-start pricing, that's no brainer. There is no dispute over that. But we wanted to align what PJM is going to do in the market, and to avoid any of this market reform fatigue, you know, to establish that expectation along a straight line.

Question 7: I'd like to go back to an earlier question and ask each of the panelists, because I'd like to wrestle this to the ground. And it is the incentives for investment question. And I've heard, certainly, Speaker 3's presentation about how, actually, today's system provides incentives for units to bid inflexibly. I've also heard it said that PJM's proposal will provide incentives for new units to be inflexible, rather than flexible. So I've heard this both ways. I think when the question was asked, people answered it in terms of operations and today, and I understood that, but I'd like to go back and hear both sides of the question with regard to looking forward on investments, where the incentives lie as between flexible and inflexible. And let's just have that discussion out.

Respondent 1: Well, I'll offer that the experience we've seen in MISO with the approach we've taken, because it's largely a vertically-integrated environment, is a signal to the regulators and to the utilities about what to build and what to approve. (Hopefully not in that order.) [LAUGHTER]

What we've seen is a strong interest in bringing flexibility, recognizing that the pricing is going to be rewarding more and more resources that can offer flexibly, to the extent that the price was not sending that flexibility signal but was instead carrying more of the costs of the inflexible resources in the price. What you would find, I think, is regulators wondering, at least in our footprint, why they need to approve a resource that has this higher operating cost, maybe, even if it's got a lower capital cost, why do they need to approve this, when MISO doesn't really compensate for the additional flexibility through its market? So that would be an interesting question.

Now, the reality is that we don't have enough experience with anything that diverges from a price signal of the sort we've seen historically to understand fully what the implications are of a change of this sort. And so, to the extent that you're going to make changes, I would say, again, think them through very closely, and take small steps rather than big steps, so that we don't break things in the process. It's a difficult question, but my instinct is that if you send a signal that is out of line with the operational control signal, you're going to incentivize resources to be built that don't need to follow the operational control signal, because the prices are rewarding something else.

Comment: So the question was, what kind of investment incentives does this create?

Respondent 2: Let me just actually go through quickly what I mean by investment incentives. There are two kinds of incentives here, I want to emphasize. I think that is often not really clearly articulated in this kind of policy forum. One kind of incentive is a compliance incentive. On the other side is a self-motivating incentive. These are two different kinds of incentives. The first type of incentive is important for operation, and the second type is important for the overall market price signal.

In this example I have on a slide, we have two hours. We have four units, A, B, C, D, lined up in merit order, and unit B and C are block-loaded units, and you can see that they are not going to be eligible to set prices. And when the load is 700 megawatts here, and unit D is the marginal resource, that's a flexible resource that sets the price at $35. And those two hours are identical. Now, when the demand drops in hour two, the load now is reduced to 500 megawatts. So the optimal dispatch solution is to get the next block-loaded unit C out. And this actually has the lowest total bid cost at $10,500. And the current system basically will set LMP at $35. And what's wrong with that, on the surface? This is really what is happening fairly regularly. If we have a situation like this, we just move on.

I just want to illustrate here that what this unit could do, and what we have observed that they actually may have done, is that unit C was sitting there saying, "My incremental cost is $30, and LMP is $35. I can be profitable if I have a way to squeeze in." The way that plant can actually squeeze in is that all these units, initially their bid parameters are minimum run time one hour. Now, unit C will say, "Let me try two hours. I want to stay on." So, unit C can bid a two-hour minimum run time and in the second hour we must dispatch unit C. We cannot kick it off. What happened here is that if unit C is squeezed into the system, the optimal dispatch at this point under that constraint is to kick unit B out. You know, we still want to maintain the flexible units on the margin, unit D. Now, in that case, the total bid cost is increased to $11,500. And while LMP appears to be still $35, it appears that unit C wins, and successfully got into the market and got their $5 margin. Now, this is happening.

But the situation is more complicated. Unit B can look at this and say, "That does not make sense to me. I have a marginal cost of $25. I can earn $10." And what they do? They play the same game. So we get into a prisoner's dilemma here, you see. Unit B now is bidding at a two-hour minimum run, and then the optimal solution now is to kick out Unit D. And once Unit D is out of the dispatch stack, then this creates a pricing dilemma. Units B and C are higher marginal incremental cost units, but they cannot set prices, and the price drops to $10. And when the price drops to $10, everyone loses. Unit B and unit C actually have a safety net. They got, actually, their make-whole payment. And even though they got their make-whole payment, that make-whole payment actually will eat into their margin in the first hour, because this uplift is taking into account the entire commitment period. So, actually, they lose out. So this is a situation no one wants, but we cannot really see and verify that their operating parameter is really their minimal run, one hour or two hours. PJM sees a lot of units on minimum run times two hours.

Now, let me just get to the ELMP incentive here. Just as has been illustrated here, the marginal unit in a non-convex situation actually is not one unit. In this case, there are two units that are marginal.

One is unit C, and it is a lumpy unit; and a flexible unit, Unit D, is a marginal unit. So ELMP, looking at a competition of the costs of all units, in a way that will pick the right price. It could be $35 and it could be $30, and then this is depending on whether the offline units are allowed to set prices. And that way, I think that will send the right price signals for investment.

Question 8: I'm looking for the connection, if there is one, between yesterday's morning session on resilience and today's session on convex hull pricing. I appreciate, in the presentations, hearing more about the MISO experience and kind of the real-world drivers, what you were seeing in the markets that you wanted to solve. But it seems like there's a further conversation going on beyond just the fast-start resources, like other questions alluded to about what MISO's done and what PJM is talking about.

And I guess my question is, in some of the dialog that's going on, there is a concept that doing ELMP, doing integer relaxation, would price the reliability attributes of certain resources. So, I'm curious, what are we to make of that? Is there a logical connection to be made to these mathematical methods from the perspective of you all who are closer to the mathematical methods? Does that make sense as a question?

Respondent 1: Do you have in mind some specific reliability attribute, and then can I translate it into a constraint? I think I can do that irrespective of whether we use LMP or ELMP.

Questioner: I don't have a specific reliability attribute in mind. I think the attributes people are thinking of are these inflexible resources that we have that are asked to be on, but their costs are not reflected in price. But beyond that, I do not have any concept of any reliability attribute.

Respondent 1: So is it, "are coal units going to set price?" Is that a simpler way to ask the question?

Questioner: I would not have framed it that way, but –

Respondent 1: Should they, and if they should, why? I think this is what the question was.

Questioner: Yes, thank you.

Respondent 1: I'll take a short shot at it. I think the challenge has to do with the extent to which we can identify a unique reliability attribute, right? This was a little of the question I asked yesterday of the panel: is something necessary and/or is it sufficient in order to meet the requirement? Those are the two criteria that we're thinking about. If it's necessary but not sufficient, you obviously need other things to complement it. If it's sufficient all and in and of itself, well, then, you can do it on its own.

In trying to think about pricing a hard-to-define, clear reliability attribute at this point, one that we haven't fully defined, within a price signal like LMP, I think we're going to run into a challenge of, have we properly set the price for that attribute? Or are we using the wrong tool? I would say, at this moment, without further research giving me a better set of insights into this, we may not have the right tool, if there is a resilience attribute that's missing. And I do say "*if.*" If there is a resilience attribute that's missing, it's not obvious that the right way to compensate for it is through what is, at its core, an operational control signal. And if we do have a need, meaning something is necessary for reliability, long-term reliability in this instance, then we ought to be making sure we compensate for it, but let's make sure we do it in a way that is not harming other necessary attributes to running a reliable system.

Respondent 2: So, could I add something to that? One of the things that I think comes up with resilience, not in terms of coal piles, but inertia, is you might end up having a constraint that said that we had to have enough such-and-such inertia in the system. There might be variations on that that think about the compromise between speed of frequency responsive inertia, but let's start with the idea that you have to have at least so many megawatt seconds of inertia.

The natural way for me to think about that is that if the generator's on, it's contributing its inertia. So the natural way to represent it then, is as a constraint that involves the commitment variables. So if you added that into the MIP, it would potentially worsen the integrality gap of that formulation, which would potentially – I haven't checked this out – but potentially split the difference between LMPs and ELMPs to a greater extent, to the extent that it worsened the integrality gap of the problem.

So there's a specific example that I haven't looked it. I'm just thinking about this off the top of my head, where there would be an interaction, but I think one would have to understand it better. It's conceivable that the inertias and so forth would align up in a way that it could improve the integrality gap. In other words, it would make the differences in prices smaller. We would have, in that case, though, an ancillary service called "inertia" and generators would get paid "inertia." And the reason why it might reduce the integrality gap is that certain inflexible generators were getting paid for providing inertia, and that meant that there was less uplift to pay them.

So I think my initial response is, you have to tell me what the specific thing is, and then we'll think about it. Inertia, I think, is one example where I can at least sketch out how it's going, but other, more nebulous notions of resilience, particularly ones that are talking about having three months of something or other in your backyard--it's very hard to see how they fit into the day-ahead market in any context, so I'm not even sure how to think about them in terms of adding them to the commitment formulation, much less see how they affect ELMPs.

Respondent 1: And just very quickly, I would say we have to be very careful to follow the Hippocratic Oath here, first do no harm, right? We've got an operational control signal that allows us to maintain frequency; it allows us to maintain balance on the network. If we do something, and we don't fully understand how it might impact the effectiveness of the operational control signal, we run the risk of creating real havoc. And now, since I'm in the chair, I would get taken out back and beaten to death by the operators.

Comment: OK, a lot of death threats today.

Question 9: So, these are mostly by way of clarifying questions, so I better make it quick. There's a lot of talk about prices increasing, but I think the example shows situations where prices can go either way. I think on average they tend to go up, but that's an empirical question. There's no theoretical reason why that has to be true. So I think people are all nodding their heads. I think it's just important to understand that.

The second question has to do with the multiple ramping intervals, and we heard the answer was that a couple of hours is OK, and that's not a problem, and that's in the day-ahead story, and most of these problems in real-time were a couple of hours, so it's not a problem, but actually we have five-minute dispatch in real-time and I think that implies, as a logical matter, that we have five-minute ramping limits in real-time, so an hour's a long time in that context, in terms of the number of binding ramping limits that we're going to have, so that worries me. But I just wanted to see what the reaction is to this.

Respondent 1: Well, I'll give you the quick answer on the first one, which is, yes, there are times when we see prices go down relative to what would have otherwise happened, essentially the counterfactual. In our case, in MISO, generally we would've gone into some form of scarcity, but for having an offline fast-start that could set price instead, so it's essentially a step somewhere halfway or towards scarcity, where prices go up, they just don't go up as much as they would have otherwise, so that's an efficiency gain, because we have fast-starts that we could turn on to deal with the scarcity, and if we don't have to turn them on, they don't set price, but they're available to meet the need if the operators choose to commit them. So that is true, and we view that as an efficiency gain, where we're not setting a scarcity price when we actually have resources that could resolve the scarcity available to quickly start up and go.

Question 10: I'd like to come back to the question about investment in order to incentivize flexibility, and I'm going to channel Cheryl Terry, who's not in the room, from Alberta. Maybe we should just have a self-commitment market, rather than security-constrained unit commitment. And that would take care of a lot of these problems, because then the units with the low cost, as the earlier example with the dispatch four units showed, would then have an incentive to be flexible. And, therefore, we really don't need ELMP. I'm curious as to the reactions to that.

The second question that I have is, am I hearing general agreement that prices must be consistent with dispatch? If that's something that we can agree upon, then shouldn't we just take out any other potential ELMP solutions that actually result in dispatch solutions and prices being inconsistent with one another?

Respondent 1: So, let me give a two-second response to the first question, which is that only about 25% of PJM megawatt hours are actually subject to PJM dispatch. I know it's somewhat surprising, but if you look at the State of the Market board and other things we've done, most of it is self-scheduled block-loaded.

Respondent 2: Same in MISO. It's actually a lower percentage in MISO.

Respondent 1: And one of the reasons not to compare MISO and PJM too closely is that, as we know, MISO is a cost-of-service area, and everything is done on a cost-of-service basis, so it all matters a lot less to incentives.

Does anybody want to take on the second question?

Respondent 2: I'll just say, I think it's OK to have short bursts of deviation if you're sending a better price signal with that deviation, meaning the demand side is seeing the cost more clearly for what actually is required to operate for that period of time, but if you have extended periods of deviation between the control signal and the price, you're going to have bad outcomea. At least that's the concern we have.

Question 11: Can you help me understand the scale and nature of the financial impacts of moving from one to the other? What is the change in price we would anticipate? How many dollars are moving from who to whom if we make the change?

Respondent 1: I had a slide that was up just before the break that described a few-day period this January, just a few weeks ago. The short answer is we saw prices go up, versus what LMP would've produced, by a little over $10 a megawatt hour, on average, over the period. There were obviously periods when the price was much more divergent, and some, as a previous questioner suggested, where the price was lower as a result of how ELMP operates, because we didn't have to go into scarcity.

In general, prices were higher, and in general uplift was reduced materially. The experience during the cold snap was about a 9% reduction in uplift overall as a result of prices being higher and more reflective of real cost.

Respondent 2: In terms of order of magnitude, PJM's initial preliminary analysis shows similar magnitude. It is in the white paper we have, and to my recollection, the general price increase is on the order of 13%. That's a very rough initial estimate.

Respondent 3: And, Respondent 2, I think you'd agree that that estimate excludes the impact of startup and no-load, which are rather key variables in all this. So it could well be higher than that. So, basically, in PJM, we don't know.

Respondent 2: Yeah, we don't know.

Respondent 3: It's probably between 10% and 20%, but we don't know.

Respondent 1: One last thing I'll tell you about this slide is that it shows we're able to calculate three things. One, what LMP would have been, because we actually still calculate LMP as our control signal. We can also calculate results under phase one of the ELMP, which was the ten-minute start only--so we did the counterfactual. What would have been the price had we only used the phase one resource fleet? And then, we get phase 2 results, based on the actual resource fleet that's used for current ELMP phase two. Those are the prices we actually experienced.

Question 12: In addition to the price impact, is there also a distributional impact?

Respondent 1: I think part of PJM's goal is to put more revenues in the energy market, less in the capacity market. By definition that has a distributional impact which cuts against high-load factor customers, just on a simple-minded basis. So it cuts against high-load factor customers. Anything, when you take dollars from capacity and shift them into energy, it cuts against high load factor customers, and it helps units run all the time, compared to units that are peakier. So it has distributional impacts in both generation and load.

Question 13: The ELMP line on that slide is what MISO is currently doing?

Respondent 1: That's correct. The dotted line is the old LMP, which we still calculate as our *ex-ante* price. The solid green line is the current ELMP price during that few-day period when we had extreme cold.

Respondent 2: And if you quickly integrate under those curves?

Respondent 1: On the bottom chart it shows the old phase one ELMP stats, as what would have been the case had we never moved to phase two. There's not a line.

Question 14: Speaker 4, you had mentioned transmission uplift in one of your slides that can occur when we do this separation and find a convex hull. I think that went by fast. I can imagine this could also occur for reserve constraints or other network constraints that might be binding in the primary solution, but slack in the relaxed problem. I guess the clarifying question is, how do you handle this? And I should confess that I think I know the answer, in theory, about how this arises. What I don't know is what happens in practice. Or is that something still to be addressed?

Respondent 1: At least in the examples I worked, I didn't really see that separation occurring on reserve prices, because we really weren't committing a resource to meet the reserve requirement. We could meet it with offline stuff, so I'm not sure how to answer.

Theoretically, it's possible for there to be some uplift coming out of that, but that, to me, smells just like the standard uplift that I have for a resource's bid cost not being met. If I take so much energy from you and so much reserves from you, and the prices are lower than your offer price, you get an uplift. Or if you're seeing an opportunity cost because I'm not taking it from you, you'll get a lost opportunity cost. So it just boiled into the energy uplifts. The only thing I can say is I haven't seen an example of that, so I don't know how to be able to say what happens in practice. The transmission is vastly different, though.

Respondent 2: But, analogous to the transmission story, you could have a situation where you had to commit an additional unit to get enough reserves. And this might be an unusual circumstance. That meant that you had plenty of reserves, so the constraint on reserves is no longer binding. The price was zero in the LMP version, but we'd have a non-zero price in the ELMP version?

Respondent 1: Exactly. It's just that I haven't seen an example of that, but that's exactly what will happen.

Questioner: So how is the transmission uplift case handled?

Respondent 1: Well, what you'll see in the ELMP calculation is that I may be partially committing that resource to be able to bring the transmission constraint under the limit, or to the limit, and I'll see a shadow price on that constraint.

In the actual dispatch, when I commit the resource, I pulled it off the limit. LMP shows no shadow price, but I've incurred real costs to manage that constraint. ELMP will show a price for the cost of managing a constraint; LMP won't. And what'll happen is I can say, well, what's the dispatch using for that constraint? I may be collecting congestion rents on that constraint from the actual flows, but I may have to pay transmission rates based on the actual limit, so there'll be a shortfall, and that'll be an uplift. And again, that can be handled as any of the other uplifts.