

HARVARD ELECTRICITY POLICY GROUP SIXTY-NINTH PLENARY SESSION

The Mandarin Oriental Hotel
Washington, DC
THURSDAY AND FRIDAY, DECEMBER 6-7, 2012

Rapporteur's Summary*

Session One.

Squaring the Circle of Resources Adequacy

Electricity market design is as dynamic as electricity markets. Experience produces a better understanding of what works and what does not. Market operation reveals inherent inconsistencies that create material policy problems. Recognizing flaws in design creates the opportunity to refashion and reform. Learning from experience is costly but necessary. Learning from the experience of others is sometimes even harder, but need not be expensive. Resource adequacy is a prime area where a developing body of analysis complements a trial and error approach. The now well recognized missing-money problem raised questions about the viability of energy-only markets. Capacity markets in practice revealed numerous problems such as vulnerability to market manipulation and creation of perverse incentives. How can long-term planning assumptions be rationalized with the economics of reliability? How can short-term energy market designs promote long-term resource adequacy? What are the challenges in mitigating the exercise of market power by both buyers and sellers in capacity markets? How can better incentives be incorporated into capacity markets? What is the role of fundamental analysis from first principles, versus negotiation in stakeholder processes? How can these efforts reinforce each other? A comparison of recent resource adequacy reviews, reform initiatives and policy debates across organized markets helps illuminate the field.

Moderator: Welcome everyone. Today you see the overview of our session. The questions or the points are well noted in the variety of issues we are dealing with either as market participants or as regulators. Of course, as it always seems,

we're living in interesting times with new sets of challenges. We only have an overview of all the markets for this session, but we're going to go market by market and we're going to work up with the coast, starting with PJM, going to New York, New England, and then to ERCOT.

* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the discussants.

Speaker 1.

Thank you and good morning. It's a pleasure to be here this morning. My presentation is focusing on the capacity markets in PJM, what's working well and what is being changed, and lessons learned.

A Reliability Pricing Model (RPM) was implemented in 2007 in PJM, and, from our perspective, is working very well. The purpose of the RPM was to both retain and attract needed capacity on a locational basis for reliability at the lowest price. And looking at various indications, the market has worked very well for achieving that purpose. But since its implementation, there have been changes, modifications, and certainly lessons learned.

So what has worked well, and what improvements are still needed and under consideration? I put down my perspective here. I'm sure everyone could probably come up with a slightly different list, depending on your perspective. But on the left side, I've identified some key elements of the RPM that we believe are working are very well. For example, the forward looking nature of the RPM, its three year forward construct, appears to give adequate time to construct facilities. Another element that works well is that once you have a commitment that your facility or your resource is needed for reliability, the locational design and the flexibility of that locational design as the dynamics of the region change are reflected in the RPM design. And there are some other elements that I've listed here that area also working well.

In the category of what improvements are needed, my primary focus today is going to be on the topic of buyer side market power mitigation. I'm also going to touch on three other areas: the duration of the commitment, the participation of demand response, and coordination of transmission planning in RPM.

But I'm just going to touch on those three themes.

With respect to buyer side market power mitigation, in PJM, the primary tool to address buyer side market power mitigation is the Minimum Offer Price Rule, or the MOPR, a well-referenced acronym in my house. My 12 year old even knows what a MOPR is. He asked me, "How is the MOPR doing, mommy?" [LAUGHTER] I say, "It's going really well. Thank you." [LAUGHTER] I don't think he understands what it is but it's talked about a lot.

So the MOPR has been in place in the RPM design since its inception. It's not a new idea. But in 2011, certain loopholes/design flaws were identified in the MOPR rules, and FERC modified the MOPR rules through an Order. Those changes included a whole host of tweaks, but I'd like to just identify some of the key changes that were made. The state reliability exception for the MOPR was removed, and a unit specific cost based exception process was added. The MOPR changes, while certainly improvements to the model and beneficial in many regards, really didn't make anyone happy. I think at least one person from every sector in PJM challenged the MOPR Order and it is currently pending in the third circuit court of appeals on many different issues. There's no agreement about how the current MOPR Order should work and what needs to be changed in that context.

But the modifications to the MOPR went into effect and were applied in this past May 2012 base residual auction. And the result of applying that rule was to allow three of the four state-subsidized generating units to clear the auction. These units were paid far more through the state subsidies than the historic clearing prices in the auction as well as the competitive market price. And the application of this revised rule in the auction revealed several key flaws or issues with the current rule. The primary issue with the current rule that we saw in this past auction was

the concept of allowing PJM and the market monitor to conduct a unit specific review of a generator's cost or going forward cost. In concept, it sounds very good. You have to say, "Well, we're going to let someone below the net CONE (cost of new entry) price if they can demonstrate that their costs are lower." But unfortunately, a unit-specific cost review is really a mini-rate case and it's being done behind closed doors without any transparency, without the luxury of expert witnesses to challenge different theories about weighted average cost of capital and going forward costs and fuel costs, all of those things that you would have different views on and certainly not a clear reference that PJM or the market monitor could say, "OK, here's the answer. We know what the weighted average cost of capital should be," or, "We all agree with what the future fuel price is."

So say you put that together with a couple of generators who have only one objective, and that is to clear the auction. So you have a couple of generators who take no risk because they are being paid through a state subsidized contracts, and they are now demonstrating to PJM and the market monitor, behind closed doors, what their going forward costs are. We don't actually know what they provided, because it's not transparent, but we do know that they were able to demonstrate that their costs were well below the cost of new entry. And that created a lot of concern and lack of trust in the market, a lack of confidence.

At the same time, we saw that many traditional business models for self-supply, whether public power or integrated utility companies who plan their generation through an integrated resource planning model, they're also dissatisfied with the current rules because they have to go in and demonstrate to PJM their cost and their risk that their units that they were building for their own purposes were not going to clear the auction.

So there was a significant dissatisfaction with how the rules were working and that turmoil

after the auction allowed parties to get together. There was actually an event like this in June where several of us were on a panel. It became apparent that there was a common theme that was showing up--that we all agreed that certain types of generators that were clearly intending to have the incentive to suppress the price and were not taking on any risk, that we needed to have special rules for those generators. But, at the same time, we wanted to make sure that competitive entry and legitimate self-supply were not being burdened. So a diverse group of stakeholders got together with the aid of some expert economists. We had more economists involved in that process than I've ever experienced, and everyone worked very cooperatively. We sat down on many occasions, had many multi-day long meetings where we said, "Let's talk about what the problem is, what the issues are, and let's see what the solutions are." And not only did we come up with a proposal, but I really do believe that we have a stronger bond between the stakeholders that participated in this process. I think we understand each other better as a result of this and I think we'll work together better in the future.

So what is that process that the stakeholders came up with? Let me spend a minute to describe that. The goal was to strengthen the MOPR and at the same time narrow its application.

So what we did was we came up with two categories of exemptions. One is what I refer to as "legitimate self-supply." And we have a list of criteria of what constitutes legitimate self-supply. And we also then have provisions that say, "Well, if you have one of these list of things, even if you look like legitimate self-supply, this bounces you out of that process." For example, if you have a material payment from a government entity and it's not through your integrated resource planning process or it's not a traditional payment from your business model, but it's out of the ordinary, and it's tied

to either the construction of new generation or the clearing of that generation, then you no longer qualify. Now we worked very closely with the team in coming up with things that would work and enable legitimate self supply to proceed and hopefully not allow loopholes to be manipulated. I guess the test will still be the next auction.

On the competitive entry exemption, we talked about what competitive entry is not. Sometimes it's very hard to describe what competitive entry is, but we described what it is not. And one of the things that we were very clear about is that we're not saying that anyone who has a contract that is the result of a state sponsored or state mandated procurement process can't be considered competitive entry. For example, BGS in New Jersey is a state sponsored or state mandated procurement process. It's not for new generation. It's not unit specific, but we all agree that sort of procurement process should not be a problem. It should never disqualify someone for the competitive entry exemption. So we came up with the criteria for that as well, and we said, "If you have a state-sponsored contract but it is truly non-discriminatory and competitive..." and we defined what that meant. We didn't want to leave any room for a disagreement about what that meant. And so if you have one of those payments, you're not disqualified from that exemption. And for each of these exemptions, an officer from the company has to submit a certification. We also detailed what happens if someone leaves out a material fact or misrepresented something. There's a clear process for what happens in that scenario. And for those generators who are not entitled to one of these exemptions--if they haven't satisfied the legitimate self-supply and they haven't satisfied the legitimate competitive entry--then that small sub-set, and we believe it really will be a small sub-set, will be subject to the Minimum Offer Price Rule. And we revised that to say it would be 100% of the applicable net cone for the asset class rather than 90%, which is the current rule. And we also said that that generator must bid at

that minimum offer price rule for at least three cycles. So three auctions for three different delivery years. Now, that can be one base residual auction and two incremental auctions. It could be a variety of different auctions. But it has to be three different delivery years. We also agreed on an exception to that three-year rule, in the event that the unit is really needed for reliability, and we came up with a very objective test for what that is, and we all talked about, "Well, how would you know if something's really needed for reliability?" and we talked to lots of folks, and all the parties sat around and said, "Well, what would that look like?" And we came up with an objective test that is in the rule itself, and it says, in that event, then you have only one year that you're subject to the MOPR. So that proposed rule has now made it through the stakeholder process. It received a super, super majority. My document actually says 83% voted in favor but my math was a little bit off. It was actually 89.4% of the stakeholders who voted in favor of that. And we expect it to be filed very shortly at FERC.

So I'm just going to very quickly close out with the other improvements under consideration, just touch on them. Demand response--there's a lot of activity at the PJM stakeholder process about how demand response should participate. Right now we have a significant holdback in the amount of capacity that's procured. It's interfering with the price signals for other resources. We also have some issues about demand response measurability and verification, making sure it's really there when you need it. There's also a lot of discussion about duration. Is one year really long enough? I know we're going to have some discussion about New York and they say one year may be even too long. So there are different perspectives on that.

And then, lastly, coordination with transmission planning is being considered as a potential area for improvement. There's some effort underway to ensure that we're not always assuming transmission in the base case, because

sometimes transmission takes a little bit longer to plan. So trying to separate out a little bit of the large transmission planning, allow it to go on a separate track, and when we really know it's going to be on time, then put it into the base case. So I think we'll continue to see improvements to the RPM design and continue to allow it to evolve and learn lessons and make sure we address those lessons through thoughtful improvements. Thank you.

Speaker 2.

I'm going to give you a little bit of the New York perspective. At the end of the day, resource adequacy depends on investments in generation, demand response, and transmission that happens in your system. And these investments happen because of signals you get from the energy market and in the capacity market. And the two are kind of different. The energy market is in the world of operations. Prices in the energy market react to minute by minute changes in system conditions. Capacity markets are constructed based on planning assumptions, and in a lot of ways, they are somewhat of an artifact. And that's why they're more complex.

So let's spend a couple of minutes on the energy markets and talk about scarcity pricing. So in energy markets, we operate a system in a secure manner. That's the whole basis of the security constrained economic dispatch. The security constrained dispatch software works on operating the transmission system in a secure manner based on N minus one constraints and so on. You look for transmission security. You also look for operating reserves. You want to make sure that you have enough operating reserves to ride through outages that happen in real time. Now, you can give scarcity pricing. That is, when you're approaching shortage, when your transmission capacity is at a limit, you can give shortage prices. You can also give shortage prices when you're running out of spinning reserves, 30-minute reserves, or 10-minute

reserves. And in New York, we have adopted for quite a few years the price mechanisms to give these shortage pricing. However, the shortage pricing is not sufficient to supply the so-called "missing money" problem. So that's why we have the capacity market.

Now, the capacity market is determined by planning requirements. It's based on assumptions about future load growth, and the availability of units based on past history--like what we call "effective forced outage rates"--the units have been historically out, say, 10% of the time, so if they sell 100 megawatts, they get paid for 90. It is based on other planning assumptions based on locations and so on. So the capacity markets are more based on assumptions. We talk about "adequacy" in the capacity market, and we talk about "security" in the energy market. The adequacy is based more on assumptions. And they do not reflect what's happening minute to minute. For example, a unit gets paid for capacity even if it can be out on forced outage.

There are other distortions. The price that we pay for the capacity market must be passed on to the load serving entities. And they typically pass those prices on over a wide number of hours. Typically in New York, it's about 16 hours, 16 of the 24 hours. We did a study, and if you can shorten that number of hours to four or six, you would get a better signal. That brings us back to the energy market. One of the premises when we started the electricity markets was that demand would show up and demand would bid in and say, "At a certain price, I will go away." The history has been that the prices are not sufficiently high in the energy markets for it to be worthwhile for demand to make the investments that would allow them to actually curtail their loads when they need. So one of the things, going back to scarcity, is that a well-defined scarcity pricing regime would help demand response have a more robust participation in the energy market.

One of the things we are doing is coming up with a demand response program in real time. And, again, we don't expect a lot of demand response to show up in the energy market at the current price levels in New York. The study that we did showed that prices need to be in the \$500 to \$1500 range for demand response to have a robust participation in the energy market. So at the end of the day, putting this into context, resource adequacy depends on what kind of signals and what kind of revenues market participants are getting from the energy markets and the capacity markets.

One of the things that Bill Hogan has always urged us to do, starting from 2006, is give more money in the energy market and less money in the capacity market, and that remains our guiding principle in New York. We might never be able to do away with the capacity market, but we'd like to take as much money as possible and give it in the energy market instead, which is more real, which is easier to administer, and reflects minute by minute conditions.

What I want to cover now is some of the unique characteristics of New York. When I talk to my colleagues in other ISO's, they're all designing three-year markets. California, I think, is thinking of a five-year market, and they equate capacity markets to having a guarantee for resource adequacy. In New York, we do not subscribe to that philosophy. We believe that markets should generate prices, and investments are based on market prices. We do not use capacity markets as a guarantee for resource adequacy. So in New York, we base things on self supply. You can self supply capacity. You can have a bilateral contractual capacity. And we run forward auctions, six month and one month, and then whatever is remaining based on the planning adequacy criteria, we procure in a deficiency auction. So that's how the market works. It's really a month to month procurement auction, which produces a price signal that people can make projections on and use to make investments based on projections.

Before I get into a little bit more on the short-term nature of the market, let me talk a little bit about one of the premises behind our market. Very early in New York, we realized that we needed to have a locational capacity market. Capacity prices in New York and in Long Island needed to be higher than in the rest of the state. So we started with Long Island as a market, New York as a capacity location, and the control area as a whole as a location. That served us well. We are in the process of creating additional capacity zones because we now see bottlenecks coming into the lower Hudson Valley, and we have a mechanism to create new zones.

I'm not going to talk a lot about mitigation. But when you create new zones and the zones are smaller and you have concentration of ownership, you have the possibility of both buyer side and supply side exertion of market power, and you have to guard against both supply side and buyer side. We have buyer side mitigation and supply side mitigation in New York City.

Again, in the capacity market, administering these mitigation regimes is much more difficult and much more complex than in an energy market because they're based on assumptions. Speaker 1 talked about forward costs. There are issues on some costs. There are issues on the time horizon you're looking for. So by definition, it is more imperfect and as it is imperfect, it's open to litigation. So, in fact, our counsel says "buyer side mitigation" should be called "buyer side litigation." [LAUGHTER] So it will keep a lot of lawyers very happy and very happily employed.

The other thing we use is a demand curve. The demand curve is a construct which was created because sufficient demand shows up in the capacity market to respond to prices. The demand curve is a proxy for demand response to higher prices. So when the price of capacity is high, there's less demand. When there is more

capacity, the prices will drop. Having a demand curve (as opposed to a fixed capacity requirement) allows more capacity to clear than is absolutely necessary. Where the P intersects with the demand curve, that's the amount of capacity we need according to planning. But the demand curve allows more than what is needed to clear in the market, which gives the generators a lower price--what is called the cost of new entry price. However, they get some price. And they can come into the market ahead of the absolute requirements.

In a resource adequacy system, it is less of an issue to ensure that adequacy if demand can come in ahead of the need and still get a price. So with the demand curve, when the supply exits the market, prices go up. When supply comes into the market, prices go down. Capacity markets are by nature lumpy, so we see gyrations in prices going up and down the demand curve. But one of the things that this helps us to do is decouple the capacity market from planning. New England, in contrast, procures what they need. When you procure exactly what you need, you have to have the capacity market very closely coupled with the planning department, because otherwise you get into a resource adequacy issue. So in New York, having the demand curve allows the markets to come and enter the market ahead of the need and take care of some of the adequacy issues. But at the end of the day, what we depend on to guarantee that we have sufficient adequacy is a planning backstop mechanism. The market signals in the energy market and the capacity market produces investments. And so far, we have not had to use the backstop mechanism.

So if we see a need, we do this planning, what we call the Reliability Needs Assessment. We do a 10 year look ahead. In 2010, we seemed to be awash in capacity. In 2012, because of lower generating capacity due to retirements of old coal units, a slightly higher baseline load forecast and slightly lower demand response projections, there may be issues in 2020

timeframe. So we have identified that in 2012. Then we looked at what the projects are in an interconnection queue and coming in which years and we monitor those projects. And there are sufficient merchant projects and investments coming in through market mechanisms to address any issues that might arise in 2012. We monitor these market projects year by year, but if we did get into a situation where we see a resource adequacy need, we have the ability to use a planning backstop mechanism where we would trigger a regulated backstop solution. The NYISO would request the responsible transmission owners to seek our PSC's approval for a backstop solution. So the so-called guarantee for adequacy happens through this planning backstop mechanism. We have not had to use it so far. We depend on our monthly market clearing prices in the capacity market and on the energy prices to have market investments to drive the adequacy.

In this year, in 2012, we were also proud that we never had a RMR (reliability must-run) contract in New York. We did have two RMR's, one in New York City, one near Buffalo, but those RMR contracts were not for capacity or adequacy reasons. They were for local transmission issues. So that would not have been addressed through a capacity market.

I also want to talk about forward capacity markets. One of the things that people said is, "Your neighbors have forward capacity markets, so why don't you have one?" So we had an independent study look at the need for a forward capacity market. The report has come in. We haven't released it into the world, but it has been released to our stakeholders. Some of the key findings are that if you do a forward capacity market, you tend to do it through planning assumptions, which are inherently conservative, so you procure more, and whatever you procure, you might not have certainty that those resources will actually be there when you need them, and you have to run complex reconfiguration

auctions. So, in essence, the study says that a one-month market is not that bad.

Our market, which is essentially a short-term market, has brought market investments. Since 2000, we've had 9,000 megawatts of new generation, 1600 megawatts of new transmission, 2,000 megawatts plus of demand response. And because of the locational nature of our markets, 80% of the generation has occurred where the need is greatest--in New York City, Long Island, and south of Albany, which is the lower Hudson Valley, where the concentration of load is there and the price signals are there. What we're working on next is creation of criteria and actual creation of new zones to get better zonal signals and improvements in our scarcity pricing regime.

I know that Speaker 4 is going to talk about the Texas market, where they've talked about prices going up to \$9,000 and higher. We believe scarcity pricing is a better mechanism than that, because we have a \$1,000 per megawatt cap, but we have very tight tolerances for mitigation in the energy market. We have conduct and impact thresholds, which are very tight in New York City. So even when generators offer \$1,000, they very rarely get that \$1,000. So we see scarcity pricing as a better mechanism.

Question: On your last slide, Speaker 2, of the new generation by region, how much of the new generation in New York City or Long Island is purely merchant versus coming in as a result of a contract with, say, LIPA or the New York Power Authority through a long-term procurement process?

Speaker 2: There have been some merchant projects. The market allows bilateral contracts, but the prices that these bilateral contracts use presumably are informed by the market clearing prices.

Question: You talked about the backstop mechanism. Supposed the NYISO some reason

has to use the backstop. Do those resources, can they offer into the ICAP market or the capacity market at zero? Or what's the --

Speaker 2: Yes. What typically would happen is that they would get regulated returns like a top off of what they are not getting in the market.

Speaker 3.

Now for something completely different. I'm going to talk to you a little bit about the ever-changing road of the Forward Capacity Market in New England. And the FCM performance incentives are something that we've just introduced to the marketplace, to our stakeholders, last month.

In this presentation, I'm going to talk about the problems we're trying to solve in New England, which are maybe a little more acute in New England for some and not for others. There are similar problems that all the ISOs will end up either solving at the same time or somewhere down the road. And we're going to look at it in the light of our FCM Performance Incentives.

The first three risks and challenges that we're facing in New England is really what we're trying to address with these performance incentives. And we'll talk specifically about each one of these through the presentation. We have five risks. The last risks on my list are risks related to alignment of markets and transmission planning is not directly impacted by this. The fourth risk, the integration of greater intermittent resources, is sort of side touched by this and we'll talk about that as I go along.

We have a growing reliability risk in New England. We've been installing gas fired generators since the late 80's, and I don't remember the last time we've installed anything other than a gas fired fossil fuel generator since at least the early 90's. So we are very, very dependent upon natural gas in New England and getting more and more dependent as time goes

along. What the change in the fuel price associated with shale gas has done is that the coal units in New England (of which there are very few left in New England) are actually out of the market at the current time in New England. And therefore, natural gas is replacing coal, oil, everything but the nuclear and the renewable resources.

The other thing is that we've got quite a few older units that are out there. Many of them are oil units and coal units and now that they're not running quite as often as they used to before, so they don't get a whole lot of revenue in the energy market. We like to see them running in the energy market, getting their revenue from the energy market, but they don't run in the energy market. These units are at risk for retirement, but that also sort of pushes on our fuel diversity because those that are at risk are those coal and oil units. So we sort of run out of any fuel diversity.

So without any new incentives in our marketplace, there's little confidence that the new capacity will perform any better than they do today (and we'll talk a little bit about why they're performing the way they do.) But this is going to put our system at some risk of reliability and our goal is to put these incentives in place ahead of time so that the market can respond.

As you may well know, our Forward Capacity Market is running three years in advance, and our rules are running about five years in advance, because people have to understand what they're going to do in advance of those capacity market auctions. So we're looking at these incentives being in place for the 2018-19 commitment period, which starts in June of 2018 and goes all the way through 2019. So you can see this is a longer-term solution.

What we see is there is no single, least-cost technology solution to our reliability issues, especially to the gas dependency issue. For gas,

it could mean that many of our gas units have no firm transport and part of this is to get them to have either some firm transport, some of their own LNG, a backup supply, or some dual fuel capability (which some of our units have, but we don't have any real incentives in place to make sure that you have dual fuel capability right now). The best option for each unit in our system is different and it's very hard for us to say, "Everybody should do X," or, "So many units should do LNG," or, "Somebody should do a backup oil supply." Our goal is to create a market incentive and let them choose what's the cheapest solution for them to be the most reliable in our system.

Our current FCM market has none of those incentives in place. It really doesn't have a strong incentive in place to be there and it doesn't create a strong incentive for you to invest in some way of making sure that you can be there when the system really needs you. Especially for some of these gas fired generators, if I say, "Put in backup fuel, oil fuel," we may be saying you could run it for 10 years, for 20 hours, 10 hours a year, or some years you could run no hours. It's hard to get somebody to invest in that kind of risk.

So, again, our goal is to put in some motivation for the suppliers to actually deliver some reliability improvements in their generation and do that at their least cost. On a day-to-day basis, our resources are increasingly failing to meet their intra-day dispatch schedules, mostly because of gas procurement issues. That's the most frequent reason. And again, in New England, it's going to just get worse, because all of our home heating is starting to switch over to that same natural gas supply, putting more and more pressure on those natural gas pipelines, and our electricity and home heating are going to fight for it during the colder part of the winter. Really, if we had a very efficient energy market, with very high energy prices during scarce and tight capacity situations, that would provide a strong incentive for performance and

availability. We do have scarcity reserve prices, administrative reserve prices like they do in New York ISO. But those do not create a strong enough incentive, and when they do occur, they're still pretty sporadic, and they're not high enough really to create any investment incentives.

Again, if we don't have a greater performance incentive, in some way, shape, or form, we won't get these investments. Our goal and our design, at least where we're headed right now with these performance incentives, is to do this through our Forward Capacity Market.

With respect to incentive problems on a real short timeframe, we've looked at some of the cases when we get into these reserve scarcities, which lots of times is because you're in a post-contingency situation--a generator is tripped, something in your system has happened and you have to respond. Our units are not responding as fast as we'd like them to respond. And again, there's not a whole lot of great incentive to do that. Some of the generators just don't take the initiative to respond. Now you see the average of 60% unit response (we put the word "non-hydro" at the end because we have some very fast pump storage generators who always respond, because gravity always responds correctly, so they are very, very quick, and if you leave them in the statistics, because of the size of them, they tend to overwhelm the statistics. If you take them out with the rest of the units in the system average only a 60% response post contingency.) That's when the operators really want them to respond. During other periods of time when we're asking them to dispatch to meet the load, we'd like them to respond, too, and if you ask the operators, they would say that's a good time for them to respond when load is changing also. But when the system is in real stress and the operators are trying to recover from a contingency, that's when they're really, really desperate for generators to respond to their dispatch signals.

Again, there's no single solution for improving performance. We've done some things with communication, staffing, training, operating practices to try to get generators to at least communicate to us as to what's failing between us and them, why they're not responding. But again, money talks, usually. So financial signals will get people to do things much stronger and faster, and they'll do it based it on, again, on those financial incentives. They'll do the right thing. They'll respond when asked to respond.

So, again, we're relying on resources with uncertain availability. We have not enough incentives, and we have a risk if too many resources fail to perform simultaneously. Our direction for solving this is what we call FCM performance incentives. And this is intended to dovetail into the main features of the Forward Capacity Market, which is a three-year-out design. It's based on the descending clock, unlike what Speaker 2 said, we're supposed to be procuring just our needs for ICR (installed capacity requirement), but because we've had a price floor in place, we've slightly over-procured by 3,000 or 4,000 megawatts every year. That floor is going away. So prior to these incentives going in, we should actually start procuring what we need.

Again, the performance incentives are meant to dovetail with that core part of the design, the descending clock, three year out option. So the objective is to tailor these design objectives into that core design. That is, to improve the performance, availability, and to still continue to meet the resources adequacy criteria overall, and to use FCM to replace the missing money, which is what its core function and objective was originally. And, again, if you had a very efficient energy market with very high prices--the Texas \$9,000 prices are very high prices--it would provide a really high incentive to be there when those prices occurred. And that is an efficient energy market.

The goal of this design is to create something similar to that. We would like to do that through the Forward Capacity Market, rather than doing it specifically as a very high price in the energy market. We're doing it with what we could consider to be sort of an incentive contract, with a base payment and a performance payment. The base payment is very similar to what the Forward Capacity Market does now. It says, "Based on the auction price, you're going to get this payment." The performance payment says, "Now we're going to check and see if you performed to that contract that you had." You had an obligation. We're going to measure you when the system is in a scarcity condition. And your performance payment is going to be neutral if you performed exactly what we asked you perform. If you perform more, you'll get paid more. If you perform less, you will lose some of your base payment. All resources will have the same measurement and timeframe and be measured together and lose their performance or have a performance payment measured exactly the same. So if you had a megawatt of obligation and you gave us a megawatt during this condition, it doesn't matter whether you're a demand resource, you're a generator, or you're an importer. It doesn't matter. Every resource is treated the same, similar to what goes on right now in the Forward Capacity Market, the loads pay are base payment. So a load is still assured of a fixed price three years in advance. They know the price they're going to pay. And then performance payments are transfers amongst the suppliers.

Right now, there's a ton of exemptions so that people don't get penalized. The performance incentives have no exemptions. This really does try to mirror market energy incentives. It's going to be a very high price, these performance incentives. But it's fundamentally different than the existing FCM. Any time we're in a scarcity situation, we're going to start doing this, which means that for the first five minutes of being in a scarcity, once we're in a reserve shortage, we're going to start measuring. And so the faster you

can respond, the faster you can start getting performance incentives paid or stop losing your base payments. We expect this will change our resource mix a little. We'll get lower cost, higher reliable resources, and highly flexible, highly reliable resources, which is what every market operator wants. We'll also see some exit of some of the older units, and we expect to see that.

One last point I would like to make is that we would expect to see the clearing prices increase somewhat, because there is some risk associated with this. So we expect the FCA bids to reflect the net performance payments that are expected by each of the resources in our system. So some will expect to be there for each one of these events, and expect to make a lot in performance payments. Some will expect to miss many of these performance payments events. And they will then look at that as being a depression of their base payment and bid higher in the capacity market. We expect that to, in essence, help set the price in the auction.

Question: On the performance payments being transfers between generators, and the loads basically having a fixed payment. How's demand response handled in that context?

Speaker 3: Actually, the performance payments are transfers amongst all suppliers. In our market, demand response is a supplier, directly a supplier. So these performance payments will be transferred amongst demand response, generators, imports. It will be one pool that's transferred amongst all.

Question: In listening to your presentation, you start off expressing the concern with having so much natural gas generation. In the future, you're going to have even more natural gas generation. But in your discussion, there is nothing to mention how you're going to get more natural gas into the area to address the shortages that you're already experiencing or

have big concerns about. If you could speak to that, I'd appreciate it.

Speaker 3: If there are shortages, these would become opportunities for performance payments for those who have firm LNG contracts, or who have chosen to install backup fuel supplies--their own oil supplies if they want or some other storage on the system. So we choose to let the market, in essence, decide and the players in the market, the participants who have those gas fired generators, decide whether they want to build more pipelines or support the building of more pipelines. Again, rather than us making a choice and saying, "This is the right way to go," each one of these market participants will make a choice based on the economics. That's our goal in this design.

Question: So if everybody's overperforming when called upon during scarcity, that reduces the marginal benefit? Because it's a single pie?

Speaker 3: If everybody's overperforming, we're not in a scarcity. We procure more than enough to meet our needs. So we procure for our peak load expectation, plus the reserve of 30,000. We'd be procuring 32,000, based on today's installed capacity requirements. So all 32,000 can't be providing. They're all not providing, only because if they were, then we'd have a peak load of 30,000, and we'd be in trouble. We would have to find a way to deal with that, but our expectation is these events don't always occur when loads are really, really high. So it doesn't mean that everybody's overperforming. Usually, in every event, we'll have somebody who is underperforming.

Question: A quick follow-up to the last question. Maybe this is in the white paper, but how often do you think this will be triggered?

Speaker 3: Yeah, that's the magic question.

Question: And the answer is?

Speaker 3: The answer is somewhere between a little and a lot. [LAUGHTER] I mean, statistically, you can look back at history and the problem is history may not be a very good guide, because, like I said, we are right now procuring much more than our ICR, just because of the current state of the market. So the number of conditions that happen where we're short could be influenced by that. We're expecting 20ish on a yearly basis, 20 hours or so of this. But again, how participants behave is going to be influenced by their expectation of how many events will be. We can say, "We think there's going to be this many," but this market does not create any guarantees that if we're wrong, they won't lose money because we're wrong. So each one of these resources would be prudent to say make their own estimate of how many of these events would occur, rather than trusting the ISO to make an estimate.

Question: Yeah, can you just clarify what you mean by overperforming just mechanically? Is that more megawatt hours than you would ask for? With quicker ramp up times? Or...?

Speaker 3: Good question. In our Forward Capacity Market, you get an obligation in megawatts for each resource, depending on how many megawatts cleared in the auction. If you're a 200 megawatt resource, you can choose to only take on 150 megawatts. During one of these events, what we're asking you for is scaled by the load at the time. So if the load is half the peak load, we'd only be asking you for 75. If you're providing 200, we would give you a performance payment up to the 200, above and beyond the 75 we asked you for in that example.

Question: You made a passing comment, at least that's how I heard it, that the older units would not expect to be run as much or not show up as much under this new regime. I just didn't understand--if you could connect the dots for me...Thanks.

Speaker 3: This requires you to be performing during scarcity conditions, and some of the older units are older oil units take a long time to get on and are not generally there unless we've planned the system to a real tight capacity situation. So for unplanned conditions, they would miss those events.

Question: You've described that the mechanism will result in some reallocation of capacity revenues amongst resources. Does it also potentially affect the aggregate quantity of resources, and if it does, who benefits--where do those residuals go?

Speaker 3: There is some potential for the aggregate dollars to be affected. Again, the main core design is that it's a trade between the suppliers. And we expect the total requirement to come down because of that. The total requirement that we buy in the auction actually is informed by the forced outage rate of the fleet of generators that we have in our system. As the fleet gets more reliable and gets better in the system, it actually reduces our requirement of what we need to buy. So it's a long run thing.

Speaker 4.

I'm going to share a few insights from the work that The Brattle Group did this year for ERCOT and the public utility commission of Texas. This was as they were facing what a lot of people said was the biggest, most fundamental question about their market design and its restructuring. I wanted to ask how many people in this room have any activity in the ERCOT market? OK. Well, a few, but I think all of us are interested, because there are a few experiments around the country and around the world that we to get benefit from so we can learn and apply the lessons learned in other markets.

So what we did was we evaluated ERCOT's energy-only market's ability to achieve resource adequacy objectives, in particular, to achieve their current target. And we laid out options for

reform. I'll just review the problem statement, why they brought us in, our findings, and our recommendations, and I'll say a few things about their next steps which remain unclear.

This is the problem they were facing: the reserve margin was projected to fall below target. They've since revised this, or they are in the process of revising this, but it's qualitatively still a similar situation. There's little investment in the face of high load growth and there is no mechanism to enforce meeting their target reserve margin. Their target reserve margin corresponds to the same one day in 10 years or one event in 10 years standard, and they figure out a reserve margin target that corresponds to. But there's no mechanism to make sure they achieve it, and so the outlook looked threatening with this graph. And so then the Texas Commission acted to raise the price caps--and it's only partly raising the offer caps. It much more relied on raising the caps on administratively set prices during scarcity, and raising the caps--they've recently approved going eventually to \$9,000.

But the question was whether that was enough. Was that enough to attract enough investment? And if not, what were their options? It's more difficult now than it has been in the past, because with really low gas prices and now a very efficient fleet, combined with quite a bit of new wind, generators don't earn very much most of the time, except during scarcity. And what this graph shows is a stochastic analysis of how often you would get to scarcity prices at any particular reserve margin. And how would that play out? We looked at 15 years of weather conditions and thousands of draws on what might happen to generator outages, because these are the things that drive scarcity during the summer peak and also that drive load shedding, which we also analyzed. And here's what we found, and this shouldn't be a big surprise. If you look at the graph, we're showing what a new combustion turbine would earn as the reserve margin varies. Below about 8% reserve margin, scarcity pricing would occur, and this

assumes a \$9,000 price cap. We analyzed how often you would get to scarcity prices, and whether the prices would be high enough and often enough to support enough investment. We found this would happen only if the reserve margin is below about 8%. And above that, especially if you go to the 14% or so that corresponds to their target, over the course of a year, on average, generators wouldn't burn nearly what they would need on average to make it worth investing.

And so this points to the famous "missing money" that we've talked about so often in the past. I think there are really two sources of missing money. I think that in this context it's helpful to think about what two sorts. So one is if you don't get the right energy prices, either through a very low price cap or operator actions that tend to suppress prices or, most importantly, if you don't have good administrative scarcity pricing to reflect the possibility that you may shed load if you don't have enough operating reserves. You need prices that I think are much higher than they are in some of the ISOs. And ERCOT has the most aggressive scarcity pricing now.

But even with that, there still can be missing money, because even with aggressive scarcity pricing, even if your energy prices aren't lower than the real cost, a market like that will achieve some sort of economic optimum, but that is not necessarily at all the same thing as the reliability target, which corresponds to really an engineering criterion of one event in 10 years. I mean, under a one event in 10 years standard, prices are just never going to be high enough often enough, to support investment. And so kind of the bottom line here is that we projected that in this market, the reserve margin will drift down to roughly 8% and it will fluctuate around that. And that could improve if market conditions change, especially if more demand response comes in.

But really, the bottom line was that the Commission faced a very difficult choice. They love their market design, and they could keep that and accept lower reliability, or if they want to maintain the current level of reserves, they really do have to change their market design.

The way we tried to frame the problem wasn't just to come in and say, "You need a capacity market or something," but really to just lay out the options and what they achieve with each. And we encouraged them to reconsider their reliability objectives.

The threshold question, I think, is really, what is the minimum acceptable reserve margin, and is that the current target or is it something lower? If the market's likely to be above whatever that minimum acceptable level is, then there's really no reason to go and radically change the market design. And from a Texas perspective, there really had to be a very compelling reason to change their market design. Their energy-only market is pretty efficient from an operational pricing standpoint. There are improvements still needed. There's a lot of skepticism of capacity markets that I'll touch on later.

So I think the minimum acceptable reserve margin should reflect the level below which it's likely that current or future regulators would probably intervene in some way that might undermine the market. And they still have not articulated exactly what their reliability objectives are, for the most part.

Just to provide some perspective here on reliability, this graph shows, for three different general types of reliability, how reliability varies with planning reserve margins. And it puts them on an equal basis, in all cases showing minutes of having no power per customer per year. The solid line shows the number of minutes of load shedding from an inadequate supply during summer peaks. And that, of course, declines as the reserve margin increases. Now, the dotted (horizontal) line on the top shows that the

number of minutes of no service due to transmission and distribution outages is an order of magnitude higher. And this is just under normal conditions--under extreme weather, under hurricanes, it can be as much as 10 times greater. I think that provides some important perspective. Then, if you look at reliability events that really don't have anything to do with the installed reserve margin (for example, two Februarys ago, they had a generation freeze off when temperatures were unusually cold and they had to shed about 16,000 megawatt hours of load over the course of about seven hours. That would not have gone away just by having more installed reserves. In 2006, there was an event where it was unusually hot in April and a lot of units were out on maintenance. Again, that doesn't directly have to do with installed reserves.) What this graph shows is that reliability problems are still there, even if you go to great lengths to have a high installed reserve margin. For example, if you go to a 15% reserve margin, you can pretty much zero out the likelihood of having too little supply during a summer peak, but you still are facing the other reliability problems. Even at 10 or 11%, outages related to the reserve margin tend to be one of your smaller reliability problems, compared to the others.

But we've heard that the public is more intolerant somehow of reliability events having to do with inadequate supply, and the regulators seem quite uncomfortable with facing that prospect of very angry customers and also with the prospect of having the lowest reserve margin in the country. NERC keeps coming out with these reports saying that ERCOT's the least reliable market.

In terms of market designs to consider, let me just talk about broadly three types of approaches. One is just staying with the current energy-only approach. (It's not pure energy-only, but let's just call it that.) And again, that doesn't get to the level of reserves that they call their target. At the other extreme is establishing

a capacity market to support a reserve adequacy requirement. And you could support a much higher level of reserves with that. Of course, as I said, there's a lot of resistance to this idea in Texas, not so much among the generators, but the concern among the commissioners (and they're mixed, in their view of this) is that they look to the Northeast and they see the capacity markets there are forever a subject of controversy and litigation. They are administratively complex and they also have concern about whether capacity markets really buy you reliability. This comes back to the kinds of challenges that Speaker 3 mentioned a few minutes ago.

So there was a lot of interest in Texas in a sort of middle approach, which attempts to get a higher level of reliability while still keeping their energy-only market. There were a lot of ideas that came out in this process, but the two that dominated and that we thought were the best of the bunch were to support, actually subsidize demand response and other ways to further the development of demand response, and possibly to do some what I call "administrative withholding," by increasing operating reserve requirements beyond what's really needed for operating reliability. And when we think about these three options, we can ask what the minimum acceptable reserve margin is. If the minimum acceptable reserve margin is, say, 20%, the only way to get there for sure, short of reregulating, is a resource adequacy requirement and capacity market. There is really no other way at those very high reserve margins. And that's probably true down to reserve margins of 14, 15%. The idea of energy-only with support from DR and some administrative withholding, that can get you several points higher in terms of your reserve margin than an energy-only market. But again, without major changes to the market design, if you start trying to get the 14, 15% type reserve margin or higher, I really think that stretches the viability of those approaches. There's a lot of regulatory instability with administrative withholding and it's very

uncertain that you can get enough reasonable cost DR to support that.

So just to wrap up, on next steps, it's unclear where they're going. There are very mixed statements about what their reliability objectives are and really no direction currently on how to address this long-term problem. The sense of urgency seems to have abated a little bit, because the load forecast just came down. But really, the analysis that we did that says there's a real structural challenge had nothing to do with a specific load forecast. So the problem in meeting the reserve margin may happen a year later. There have been some positive steps to do things that we said are good ideas no matter what. One of the ideas that's gotten the most traction is DR--they're opening a docket on it.

The other idea that it's really gotten a lot of traction is from a paper that Bill did on how to improve their scarcity pricing, and I love it, and, by the way, it's consistent with our recommendations but provides a theoretical basis and a methodology for refining what the scarcity prices should be as you're depleting operating reserves. Great stuff. What not a lot of people realize is that this new pricing approach would take money out of the market, relative to where they are today, when they jump right to the price cap as soon as they get into scarcity. And so, I'll leave it at that. If there are any clarifying questions, I'd be happy to take them.

Question: Do you have a feel for Texas PUC and the ERCOT market monitor that if the prices go to \$9,000 that they're actually going to allow that? They're not going to be sending investigation requests to the generators or the bidders? Can they stomach \$9,000?

Speaker 4: I'm very concerned about regulatory stability and the detrimental effects of ad hoc interventions. I don't think that's the biggest concern, because actually their scarcity pricing is primarily triggered by an administrative schedule. You don't get to these high prices just

because somebody bids that high, and, in fact, that's really not how they got there in the events that they had in 2011. It's really because of their administrative scarcity pricing, similar to what Speaker 2 had mentioned they have in New York. It's just that in Texas, they go to higher levels. The concern I have is that these heat waves can come in a very sustained and extreme fashion, and so even if this Commission has shown that it will ride through these events, because they do believe in the market, I don't know if you can guarantee what will happen. I don't think you can guarantee that future commissions will be so able to resist all the pressure that comes to intervene when the prices get so high in one of those events. And I actually think that one of the things about a capacity market is that it is a big administrative intervention, but in a much more controlled way than what extreme events in an energy-only market, especially one that has administrative withholding, can lead to.

Question: So is it the case that there is not a stated reserve margin goal? Is there an implied goal? So, in other words, the PUC has not said, "Our goal is to have 12% reserves, or 14%?" Or some other reserve margin?

Speaker 4: Well, they had a target for a while, and it corresponds to one event in 10 years, and that currently corresponds to a 13.75% margin. In January, ERCOT will come out with a new number, which I think will be closer to 15%. But again, that's just a target. So what to do going forward? One commissioner has said that we should stick with the one in 10 rule, and whatever reserve margin ERCOT says you need to achieve that. Neither of the other two commissioners has articulated a resource adequacy or a reliability objective.

Question: On the bottom of slide six, in your last bullet, where you talk about keeping in mind a certain perspective on reliability, let me ask a clarifying question. Is that just meant to say there are lots of other ways you can lose service

to load other than lack of capacity, or was there a deeper meaning here about setting the one day in 10 years standard? And if it's the latter, we can talk about it after the break.

Speaker 4: Well, I actually do think there are things to talk about there, too. But, no, it just means that there are other kinds of reliability as well.

Question: In the slide after that one, you showed that graph where with the 15% reserve margin, you pretty much have zero outages, and at 10%, even at 8% or 4%, you still have 20 minutes of outages per customer per year. Is there any attempt to quantify because obviously the impact of a generation outage is significantly economically much more significant than I'm assuming a transmission or a distribution outage, it could happen at other times of the year. Is there any economic impact that you can summarize to compare the different types of outages? Maybe the economic impact of a 20-minute outage from a generation adequacy cause could be significantly more than the transmission or distribution outage impact, from a customer's point of view?

Speaker 4: Well, there are a lot of differences in value. One really important difference is that when you run out of supplies in a summer peak, none of the industrial loads that are direct transmission customers are shed. They're not part of the load shedding protocols. And those are typically the highest value customers. They are also, however, not exposed to distribution level outages. There are a lot of pieces here, in doing an economic impact assessment, including which customers are involved. I think the duration of outages, when the cause is a resource adequacy shortage, is only 30 minutes or so. It depends on the load shedding protocols. Whereas, in an event like Hurricane Sandy, and also in the freaky snowstorm two Halloweens ago, people were without power for two weeks. Is that right?

Comment: Yeah. I was without power for nine days. [LAUGHTER]

Speaker 4: The value is probably higher for longer duration outages.

Question: Speaker 4, earlier in describing the nature of the missing money problem, in addition to the factors you mention on the slide, which are low gas prices and low market heat rates, you mentioned wind. And I was wondering, is that because of the state RPS requirement or the federal production tax credit? In other words, if the federal production tax credit were to go away, would that significantly alter the effect that wind is having in causing the problem that you identified on the chart?

Speaker 4: Well, I don't know all the factors that went into investment decisions, but they have something like 9,000 megawatts [of wind] online now, for that whole combination of reasons, as well as because of higher fuel prices a while ago.

Question: I guess I was getting at the fact that with wind, you can bid a negative price with the production tax credit, whereas if you didn't have the production tax credit, you could not bid negative.

Speaker 4: That's a minor issue. Because the only place where that really matters is that without that, maybe they would bid zero. I mean, the frequency of negative prices is quite low, and it's entirely limited to the West zone. The really big deal is just how much generation there is at the bottom of the stack.

Question: Speaker 4, did you estimate what kind of reserve margin could be supported with the energy-only with support approach? We kind of know what the bookends are. I'm just wondering whether you estimated what you think that could achieve.

Speaker 4: Yes. So it's whatever an energy-only market can do plus what you add from a subsidized or otherwise supported demand response, right, plus the amount of administrative withholding you do at the price cap. And so what are those quantities? Well, we did do a study on how much demand response there is not yet tapped in this market. And actually, the ERCOT market is way below its demand response potential, whereas, for example, PJM might argue it's getting close to saturation. And so we estimated something like 2,000 to 6,000 megawatts. The higher numbers require really a lot of engagement of the mass market at a much higher price. As for administrative withholding, we really were very wary of that approach. I mean, they've already done it. They've already expanded the operating reserve requirement by 500 megawatts, and I think that's OK. It probably compensates for other issues that they have. It's not a big deal, but if you talk about what some of the stakeholders recommended, which was 3,000 or 4,000 megawatts, I think that doesn't work. Can you just imagine the pressure the regulators would be under when you're really in a shortage and the prices are at \$9,000 and some of the load serving entities are going bankrupt? When some of the industrial customers who didn't fully hedge (they don't fully hedge) were having a lot of trouble? Now, you add to that that the prices don't have to be there, that it's because there are these generators just sitting around--I think the regulatory stability of that approach is not viable.

General Discussion.

Question 1: This is directed at Speaker 4 and a little bit at Speaker 3, with respect to ERCOT. In one of the slides you put up, you talked about this tradeoff that the Texas commission is looking at between having a capacity market and an energy-only market with prices going up to \$9,000. It almost seems like on the one hand, with scarcity pricing, we're getting the price signals right. We're actually transferring the

reliability risk and putting in the price risk that both generators and demand response can actually respond to and take action on. But with the capacity market, we're actually moving in the opposite direction. We're actually taking that price, or in this case, expenditure risk, for capacity market payments, and are transferring that into resource adequacy reliability risk, because now we're looking at potentially 8% installed reserve margins over the next couple of years.

Wouldn't it seem like a prudent market design to kind of get everything moving in the same direction--to transfer everything from reliability risk into price risk that people can respond to in a great many ways? And this is also directed to Speaker 3, because it seems like in the forward capacity market (and correct me if I'm wrong), one of the issues is that the offers in the FCM, with the descending clock auction framework, are not benchmarked to expected net energy market revenues like they are, say, in PJM. So that if units don't perform in the energy market or during shortage events or during contingency events, they're actually foregoing part of those expected net energy market revenues. Even though they're getting the capacity payment, they're actually going to find themselves short at the end of the year if they don't perform. And so I'm wondering about whether there could be modifications with respect to that.

Speaker 4: I agree. I think part of your point was that you'll have better reliability and better pricing if you have more of the money in the energy and ancillary markets than in a capacity market. Is that part of your point?

Questioner: I guess I'm wondering why we're having this fixation on whether we have capacity markets or energy only markets? Why are we having this religious debate? And I'm reminded of an article that Bill wrote some 15 years ago or so with respect to locational and marginal pricing, where we used to hear, "Well, we don't need LMP because we don't have congestion on

the system,” but then what does it hurt to have LMP if there is no congestion? And the point is, if there is no missing money, what does hurt to have a capacity market? The price will just be zero. And why are we having that debate, because we seem to have incentives going in the opposite direction between energy and capacity.

Speaker 4: In Texas, I tried to make it a little bit less emotional when people said, “Well, do we really have to get rid of our energy market and instead just go to a capacity market?” And I said, “No, actually you want to keep your energy market and keep the very strong scarcity price signals that I think are most reflective of system costs when things get really tight than otherwise, and if you want a higher reserve margin, just add to that a resource adequacy requirement and a capacity market to facilitate that.” And if all goes well, I agree, the capacity prices will be pretty low most of the time. And I also think, by the way, that we think with PJM has moved very much in a positive direction with its new scarcity pricing reforms and there, too, I expect because of that, and as reserve margins tighten a bit, that you will see a good thing--more money moving from the capacity markets to the energy markets. So I agree with all that. But if suppose they wanted a 15% reserve margin in ERCOT, I don’t think the price of capacity would be zero. I think the price of capacity would be zero if their reserve margin requirement were about 8%. And I actually think 8% or 7, 8, 9, 10% may be the economic optimum. And that is also approximately what I think the market would achieve if you have the right scarcity prices. But if you want to have a 15% reserve margin, you almost never get to scarcity prices, so the scarcity price doesn’t happen. If you’re never shedding load, you’re also rarely reaching scarcity. Then there will be missing money, and so we’ve estimated pretty significant non-zero capacity prices that we expect if they go to a 15% reserve margin requirement.

Speaker 3: In the current implementation of the Forward Capacity Market, there is a linkage

between the energy market revenues and the capacity market revenues--sort of an after the fact peak energy rent deduction. If there are high energy revenues, they are deducted from the capacity market revenues such that, in theory, it could go to an extreme where it would remove all the capacity market revenues. In practice, there are not enough peak energy revenues to do that, and right now actually, in the last year or so, the peak energy rent deductions have been zero. So that really reflects the fact that the energy prices are not high enough, often enough, to form that linkage.

Moderator: I have a question for Speaker 4. My recollection from Commissioner Ken Anderson of Texas was that he had a fundamental disagreement with the existing reserve margin and how it was calculated. I think his contention was that there’s more reserve than is being reported. You must have heard part of that discussion. Can you elaborate?

Speaker 4: Sure. Well, first of all, I don’t think that’s a fundamental disagreement. There are a lot of accounting and forecasting issues on the load side, on the generator side, related to what happens to new generation and retirements. I don’t know exactly where that’s going to go. And any particular projection will be wrong. But our analysis that showed that they’ve got a structural challenge had nothing to do with a specific projection of supply and demand. So that curve I showed you which looked kind of dire for the next few years already looks better because the load forecast has come up. And now Commissioner Anderson is also questioning the supply side assumptions, which could make that better or worse. I sort of disagree with him on the points that he’s making on the supply side, while admitting that there’s a lot of uncertainty here. He’s counting plants that have made no financial commitment and will be crazy to go forward. I think he’s counting all the currently mothballed capacity, which I’ll say is owned almost entirely by one entity with a very large portfolio that is in very serious need of short-

term cash, and I wonder what is the incentive for them to bring all of that back into the market.

So I actually disagree with him on the specifics, but I also don't think the specifics matter. If they have a structural problem that's not going to allow them to meet their objectives in the long-term, I think they should address it at least three years in advance of the shortage. When we first got this assignment, they said, "Oh, 2014 is going to be an emergency, and what do we do?" And I always said, "You know what? This will change. I'm sure some low cost resources will come in. I'm not that worried about 2014. Let's just go ahead and do this analysis in the long-term sense. I don't know whether you'll have a shortage in 2015 or what." So I actually think it's been a distraction, delving into the details of that forecast.

Question 2: So I have a two-part demand response question. I think if I heard Speaker 2 correctly, referencing a study that maybe Speaker 4 did, saying that demand response prices have to get to \$500 to \$1500 to create response, and so the first part of the question is, can demand response actually set the marginal price for all resources in any of the markets represented? And the second half of the question is prompted by someone mentioning that as you get smaller zones, there's a greater market power concern with the smaller zones. Does demand response count in calculating the supply side market power mitigation, and if not, shouldn't it, if the whole theory of what we're undertaking now is that one megawatt equals one megawatt?

Speaker 2: Yes, demand response can set the price in the energy market. They can offer in as a pseudo supply, saying that, for this price, I will go away. So essentially they do participate in the energy market. In the New York market, we have demand response participating in the day ahead market. We do not have it in the real time market yet. We're proceeding towards having them participate in the real time market.

But one of the things to recognize is that we have two types of demand response--demand response that we call "special case resources," which only participate in the capacity market. So they only have to be called upon when we foresee a shortage, and we have to give them a day ahead notice. So, typically, in a very hot summer, they get called a handful of days, three to four days. Now, the infrastructure and the kind of communications and types of controls they need to have to really have a capacity-only product is less onerous than what they would need in order to have an energy product, where they would have to follow the hour to hour prices. And that's one of the studies that we did with Speaker 4, a study of what kind of pricing would make it attractive for demand response to make those kinds of investments so they could actually follow the prices. And maybe Speaker 4 can comment on his perspective of what it would take for demand response to participate in the energy market.

Speaker 4: Well, there are a lot of factors for participating in the energy market. Before I go into that, I think one of the most important questions the questioner raised was about whether demand response can set prices. Particularly in markets with a capacity market, most of the demand response, as you mentioned, is really capacity only, and it really gets called only in an emergency, and it tends to get called in a big slug. And so I really think there is a problem with price reversal in that event. And that's what PJM just solved with the scarcity pricing mechanism that is in place now, as of October 1st, I think.

And ERCOT actually hasn't yet addressed that. (They actually do have a little side program for emergency demand response.) They have not yet solved the price reversal problem. And, really, it's not that complicated. It is complicated to have resources that aren't continuously controllable generation setting prices in real time. That is complicated, and most demand

response won't qualify. But what you can do is use a lot of approaches to administratively make sure the price is at a high level when you call emergency demand response. That's basically what PJM did. It's a little more complicated than that, and a little better than that, a little more market-based. But I think that's the key issue with price setting--what happens when you call emergency demand response? As for having DR set prices at other times, that is really challenging. I also don't think it's as important as the question of what happens during emergencies.

Speaker 2: I also wanted to address the second part of your question. In the New York market where there is mitigation, the supply side demand response is subject to the supply side mitigation measures.

Questioner: Does the demand response count when you're looking at who's got market power and who doesn't? That was the question. Does the existence of the DR count when you're looking at how many resources there are and, therefore, what concentration there is in the market?

Speaker 2: Yes, the demand response, provided it has that kind of concentration, is subject to supply side mitigation.

Speaker 1: And one of the things I wanted to add to this discussion is that the current rules, at least in PJM, allow demand response to be bid into the capacity market without actually yet having a contract for someone who's behind that to commit to the actual demand reduction. It's like a generator bidding in and saying, "Yeah, I'm going to build a generator, but I'm not really sure where yet, and I don't really have a site, and I don't have anything..." The rules are much more lenient for DR, and when we're relying upon it from a capacity standpoint, that causes some concern. So when we're talking about locational capacity and demand response, I really think we need to take that into

consideration. We don't always really know what it's going to look like or where it's going to be, and whether it is really going to be there.

Question 3: This question is directed to Speaker 3, and I know we don't know the answer yet, because we don't have the details of what the performance incentives are going to be, but what I'm concerned about is the argument that's made in your presentation (and I think there was a similar statement in Speaker 4's presentation, but he qualified it a moment ago), which was that scarcity pricing isn't giving us enough money; it isn't giving the right incentives, so, therefore, we have to solve it through the Forward Capacity Market.

That's not correct as a logical proposition. It could be a judgment about the cost and benefits of going one way or the other. But as a logical proposition, it is not true. And what I see is walking through trying to change the Forward Capacity Market so that it makes it look like scarcity pricing. It has the same incentives and operations. But I was trying to think about how this would actually work, and in what you described, it seemed to me if I were a generator, and I expected to be on, and I expected to be paid a performance payment for being on when I'm called upon, then I should shave my bid by the amount of the performance payment, so that I get called on and I collect that payment. So let's say his is another version of the production tax credit?

Speaker 3: Please don't call it that. [LAUGHTER] You're killing me now.

Questioner: So we ensure that the energy price that comes in the market is what the energy price would have been without the performance incentive, minus the performance incentive. So we actually are giving the wrong signal to people who are not participating in the capacity market. We're stimulating demand, and providing less incentive for price responsive demand, in the sense of people who are

adjusting their demand because the prices are high.

Speaker 3: Let me just to try explain a couple of little things in there. The performance payment does not require you to participate in the capacity market. So to get a payment does not require you to have an obligation or participate in the market. So, in essence, if nobody participated, if we didn't buy anything, the performance payment would be very much like an add-on to the energy market. Everybody who was performing would get an additional payment outside the energy market, and then you might as well just put it in the energy market, because it would be the exact same thing. In this case, though, the system as proposed creates a risk on the suppliers, because they have to predict and analyze how many times they're going to be in there. But it also creates a fixed payment, from a load perspective. So load is getting the benefit of not having to project how many times this is going to happen. They're not going to see that volatility. So it sort of gets rid of the volatility from a load perspective, and shifts the risk of that volatility on to the supply. It doesn't matter if you're a capacity supplier or not. You will get a performance payment, so if you decide not to take on an obligation, you will still get a performance payment if you're there when the system needs you, during these scarcity conditions. So it's tied to the capacity. The revenue is coming through the capacity market, but it's not a requirement for you to participate in the auction, if that makes it any clearer.

Questioner: I think I understand that, but I thought the way it was described, it was supposed to be revenue neutral transfers amongst the generators, and what I was suggesting is that I think it has the effect of creating an incentive to actually reduce the price of energy relative to what we were doing if we weren't doing this, because of the change in the marginal bids that come from the generators. So it sends a wrong signal to the load.

Speaker 3: I don't think we've seen it from that direction. I agree it doesn't send the signal to load that, and again, we --

Questioner: Real time.

Speaker 3: In real time, right. We haven't seen any load actually respond to any signals in real time. I mean, other than demand response, other load does not seem to respond, and that's sort of inherently part of the problem. Otherwise, you could let the price go really high, and the load would respond like any other market. We don't see load responding to whatever price signal you put out in real time, because most load is protected from that real time price--at least the actual end consumer of that load is protected. So I agree with you. It does depress that load signal in real time, but protecting that load signal in real time would be good only if load was actually responding to that signal, but we don't see load responding to it, unfortunately.

Question 4: First, a quick question for Speaker 3, and then a more general question. On your slide of removing exemptions for shortage events, what's the philosophy of effectively penalizing a generator for not performing because of a transmission outage, that the generator does not have the capability to correct?

Speaker 3: Yes, I think we've heard everybody give us the reason why they should have an exemption. Very quickly, they all told us why they should be exempted. The argument against that would be that in a pure energy-only market, when there are really high prices during scarcity, if you weren't there, nobody's going to say, "Well, I feel bad for you. You weren't there because of the transmission, and I'm going to pay you anyways, even though you didn't deliver." The energy market is cruel in that way. It says, "If you're not delivering, I'm not going to pay you." So in the energy market, the spot market doesn't pay you for lost opportunity.

In this case, it's sort of the same argument, and that's a risk for the supplier, no matter which type of supplier it is, and we've heard each different supplier tell us about their risk. Wind is a good example. They can't do anything, either, other than buy a battery and stick it next to their plant or find some way to create wind, which if anybody could figure that out... But again, from the ISO's perspective, from the operator's perspective, and from the load's perspective, if you're not delivering the energy, you're not delivering the energy. Yes, it's going to enforce changes in the system. The generators are going to watch those transmission lines, and if somebody's not taking care of the lines or if there's something else going on so that they're getting penalized over and over again, they're going to be very aware of, "Here's the opportunity cost that I've lost." You can make a lot of arguments for why people should be exempted but, in the end, if this is mirroring a very similar thing to a high spot price, you're never exempted from not delivering during high spot prices. You're never going to get that money back. So this does that same thing.

Questioner: The more general question goes to something Speaker 4 wrote about the one in 10 standard essentially only covering peak conditions and not covering other events. And I guess, to me, that seems to imply that the LOLE should be zero, which it's not. One in 10 means you're actually planning to not serve load $1/10^{\text{th}}$ of a day per year, or however you interpret it. So I'm just trying to understand--if this is saying that resource adequacy criteria won't assure you of having adequate resources 100% of the time, maybe, as you said, that it's a political problem or a regulatory problem, but I'm trying to understand the issue. Is it that you need performance incentives on top of this? Or that you need rules to prevent something? If you look at the February 2011 cold spell, the last prior cold spell where Texas dropped load was 20 years earlier. It seems to me that fits pretty well in with a 1 in 10 LOLE. So I'm trying to

see the problem that is trying to be addressed, other than to assure you'll never run out of capacity.

Speaker 4: Well, I guess I'm not sure what your question is exactly. Do you mind just stating it again as a question?

Questioner: I mean, we're talking about capacity markets, and if the answer is, capacity market can't assure that you're going to have enough capacity 100% of the time, I think that answer is self-evident. If there's something more there that, for example, "Well, they don't cover common mode failures; they don't cover..." actually, they do. They cover load forecast uncertainty. They cover multiple outages in their calculations. They just don't assure that the answer is zero.

Speaker 4: And the target is not zero. The target is 1 in 10. By the way, on that graph, it looks like zero because an event tends to be just what, a couple of hours, and you're shedding only a 1,000 megawatts of load, and it just ends up being very, very little loss of power per customer per year in terms of minutes. The goal, you're right, is not zero. But I also say that those studies that set the reserve margin to achieve 1 in 10, yes, they look at a big range of weather outcomes. Yes, they look at generator outcomes, but they look at them as independent events. They do not model conditions like this freeze off. And so the reserve margin is not set in such a way to prevent events like that. And setting the reserve margin at whatever level you do may or may not help prevent that kind of event. So the 1 in 10 really has to do with 1 in 10 with respect to losing load during summer peaks. You will, in addition, have some of these other problems. Now, there are a lot of ways to make those problems less likely through the right incentives in the energy and ancillary markets, or through possibly the kind of thing ISO New England is proposing, because that kind of makes the total payments net of penalties and rewards cover not just installed capacity but also to some extent

operational reliability. So there are ways to set it up so that you're also preventing those kinds of problems, but I've just tried to separate out how these problems are related, or not, to each other.

Speaker 1: I think this question of how much reliability you have, whether you're looking at capacity resources, whether you're looking at distribution lines and transmission lines, it's coming up more and more. I mean the service we provide to our customers, their expectations are changing. Right now in New Jersey, they're having a legislative hearing to look at what is the expectation for storm response in the future. Just because 1 in 10 has been the standard for a long time...maybe the expectation is changing. And I think as an industry, we need to continue to evaluate what our customers want, what do the regulators expect (they're another customer, if you will), and how much does it cost? So I think it's good that we're discussing whether 1 in 10 is still the right standard.

We plan our transmission and distribution system to meet standards that have been around for a very long time and certainly in this last storm in New Jersey and the East Coast, a lot of people did find that acceptable. So what are they willing to pay for to get to the next level? It's coming up also in the black start context. How much insurance do people want to pay for to have additional reliability backup? How much redundancy do they want in the system? Those are the issues I think that we're facing as an industry.

Question 5: I had a quick comment leading into a question. And the comment is that with respect to scarcity pricing, getting the scarcity prices right is really hard, and it really matters how the ISOs actually implement the scarcity pricing. And often the administrative choices that the ISOs end up making about that end up confounding exactly what they're trying to accomplish. So you two just had a nice discussion about how PJM finally had approved the price responsive demand being able to set

prices when prices are high, and I would agree that that's a good thing. When that gets implemented, as Speaker 4 said, the price responsive demand comes in a big "slug." Right? So 2,000 megawatts get called. About 90% of that is treated by PJM as a fixed injection at the bottom of the stack, and so during that period, when you've called price responsive demand...is that not true?

Comment: That's not correct.

Questioner: ...because we've had calls with PJM about that and they said it was.

Comment: With the implementation on October 1st, that will no longer be true. That's what Speaker 4 and I were talking about.

Questioner: I would go back to your staff and find out, because you can set the minimum load on responsive demand at zero, and then it would send the right price signals. But what can happen is you get the price responsive demand actually sending some of the prices up during some of the intervals, but during a lot of the intervals, having them collapse. It's a really important issue to resolve.

Speaker 4: I'm also wondering about that. I think part of the time when they're deemed marginal, they would be setting the price at possibly 2700 or a little below. But because of the block loading nature of some of them, I wonder if there might be some intervals where they still might depress the price. Is that basically your question?

Questioner: Exactly. That it gets block loaded and it depresses the price in some of the intervals.

Comment: I think without getting too deep down in the weeds here for this discussion, we already have algorithms in place to deal with block loading for CTs to set price. They're not actually too dissimilar to what the New York ISO has in

place when they've got block loaded CTs in order to let them set price.

Questioner: ...With 90% block loaded, and 10% allowed to move to set the price. So when you pull 3,000 megawatts in, 2700 megawatts comes in block loaded.

Comment: Let's go ahead and take this offline.

Questioner: Anyway, the larger point is that it's very hard. It does matter what the administrative rules are, and the question to Speaker 3 is that I see that what New England is doing is actually moving in the right direction in making the capacity market look more and more like high energy prices, and my question is, did you consider taking the entire amount of the centralized capacity auction revenue requirement, either in ERCOT or in New England, and basically charging it to load or generators who don't show up, in proportion to the loss of load probability in hours when there's scarcity, and that would create an incentive for demand to figure out how to be responsive in the longer term.

Speaker 3: We've revisited a few times how to allocate the forward capacity cost to load to get the load to do something to respond to those costs, but as of yet, we haven't done anything to change the allocation of costs. But we still are looking at and have plans underway that look at how to make load change their behavior to reduce the need for these costs. Again, the performance incentive is just that for the generator's side. It's really just allocating some of the cost or reallocating some of the cost from the underperforming generators to those who are overperforming.

Speaker 4: You asked whether it might make sense to make all of the capacity revenues collectible on that basis, and actually, if you look at the ISO New England proposal, a generator that's not performing could lose much more than all of its revenues for one year.

Questioner: My question was also whether loads also should have that same incentive. In PJM, for instance, what you see is loads trying to avoid being online during the five coincident peaks that are setting their requirements. So there's a lot of, I wouldn't call it gaming, but responding to the incentives around that. This would be to say, "OK, let's make it more direct. Can they respond when actually the system really needs them?"--which may or may not be the five coincident peaks in PJM.

Speaker 4: For sure. I think that's a key design question. As soon as you get into this administrative requirement of resource adequacy, then there are a lot of design questions around how you structure penalties and payments, and I think the kind of objectives you've outlined are good.

But I want to go back for just a second. You raised a broader question about scarcity pricing. And I'm not going to say a lot about it, but apart from how you deal with demand response, I think the even bigger question comes down to, OK, what is the schedule of prices as you deplete operating reserves? And I'm not going to say a lot about it except to say that Bill Hogan has really, I think, uniquely addressed in the right way the theoretical basis and also a methodology for determining how prices should be administratively set when you're depleting reserves. And there's a lot of good stuff there. I think what several of the ISOs are doing approximates it a lot better than if you didn't have these kinds of scarcity pricing. And what we recommend in ERCOT was, don't just all of a sudden go to the price cap when you start depleting operating reserves, but start at maybe \$500 and ramp up slowly towards the cap. And I think Bill's approach is similar but even better.

Speaker 2: I just want to comment a little bit on the scarcity pricing and when it's called. When you call demand response, it comes in a slug, and it would depress energy prices, which would

be a perverse effect of calling demand response. To counteract that, what we do is that we trigger scarcity pricing if we do a but-for test. But for the call of demand response, if you were to get into reserve shortage, then you get the shortage price, even though you call demand response. Now, in New York our reserve zones were too large. So sometimes you would call demand response, but you would not get the but-for test. So one of the things what we're looking at is making the demand reserve zones more localized so that you can have the correct signal. And, of course, the other piece is what is your demand curve? I think Bill has a recent paper on Texas that he presented in Austin recently, which looks at value of lost load times loss of load expectation as one measure. The other one we've looked at is what it costs to actually do something. If we're running out of 10-minute reserves, maybe the shortage pricing or scarcity pricing should be set on what it actually takes to start up a gas turbine. So there are a couple of approaches to that. But it is very important that it has to be based on something rational. It cannot be just picked out from the air.

Moderator: Great discussion but I'm starting to see some eyes closing. Once again, if you haven't seen Bill's paper, you should read it.

Question 6: I'm going to change the subject here, which many of you may be happy about. Some have characterized what's going on in PJM right now with the states of New Jersey and Maryland as being the biggest threat competitive markets have faced since their inception. We've seen the market monitor for PJM, Moody's, and other industry analysts sort of suggesting that if state subsidized entry continues to be the norm or continues to clear the market, that there will be no future competitive investment. I believe we've seen some companies that otherwise were planning to build new projects in the competitive construct decide to defer or cancel them. I think I've read that about PSEG. Whether it's true or not, I have read it. And I'm just wondering how this is affecting other regions--how closely

they're following it. Are market participants in other regions concerned about what's going on in PJM? It seems that often, at least from my perspective, a lot of what goes on in the ISOs is ISO specific. But this seems to be a threat to the competitive markets even outside of PJM, because of the copycat effect if this is successful. So I'd like to hear some discussion about what others are doing to guard against this.

Speaker 1: Maybe I can just quickly start and just say that I do think the industry and stakeholders and PJM, as was evidenced by this recent vote to change the minimum offer price rule, really do believe that we do have a problem that needs to be addressed, and New Jersey and Maryland been dissatisfied with the capacity market for a long time. This is not something that just came out of the blue.

And so what we're seeing is just another approach to trying to attack, from my perspective, the capacity market, and it does threaten its existence if it is allowed to continue, and the courts will decide, and some other elements will be decided at FERC. But if it is allowed to continue, from the perspective of someone who is putting their own money at risk to invest, whether it's in a gas fired generator or another type of resource that's dependent upon capacity resources, it really makes you question why someone would put their money forward with that threat out there. It just creates too much uncertainty, and it sends the signal that this is the model that is to be expected in the future. There are a couple of generators that did clear on a merchant basis in this last auction. But I think if you look at the facts surrounding those, those were unique situations where you had someone who had already invested in a site and their permits were coming close to an end. So it wasn't like someone coming and investing in a green field project.

Speaker 2: I think New York was the first one to have buyer side and supply side mitigation,

which came about with the market hiccup in New York City, where apparently there was supply side market power exerted, and then the supply side said the load also exerts buyer side market power. So we had buyer side and supply side mitigation for New York several years ago. Now buyer side mitigation is absolutely needed--there was a panel in HEPG a few years ago called "the high cost of low prices." And there is always this tendency to subsidize something, which would give you low prices, but would actually take away a lot of the market for people who have made commercial decisions and merchant plants. You can subsidize a small amount of investments to actually crash the market for a large amount.

So certainly buyer side mitigation is needed. It has to be administered. And, as I said, the administration of the buyer side mitigation is very messy, because it's based on assumptions. It's based on assumptions on sunk costs and forward costs and how far we are looking to see where it would be projected to clear. So one of the things that we are considering actually in introducing a stakeholder process is an exemption if you can prove you're a pure merchant, because power plants might have a longer view. I mean in New York, we look at this buyer side mitigation evaluation over the next six years. Maybe somebody has a 30-year view of the market. But if they can say that they've come into the market and they can attest that they don't have a contract which gives them backstop regulatory rate recovery, then they would not be subject to buyer side mitigation. So we'll see where that goes, but we have introduced that.

Speaker 4: I'd like to respond. At The Brattle Group, we work with people from the whole spectrum of the power system. Generators, states, transmission owners. So I'm not just a voice for the generators, but I have been very impressed by this problem. I think it is an existential threat to competitive markets. And the reason is that prices for capacity are very

sensitive to small changes in supply and demand. And it's really because the demand for capacity is either vertical or nearly vertical. And load growth isn't so high. So with small changes in supply and demand, you can affect the prices a lot and possibly for years. And to the extent that buyer manipulation is allowed, it's very tempting for the states, because if you're shortsighted and you want to lower costs for customers in the near to medium term--probably raising costs in the long term, but if you're very focused on trying to lower rates in the near to medium term, it's really tempting.

And I've worked with and interviewed most of the big investors in generation, and not just owners of existing generation. And I also hear from them, and I think legitimately, that this is an existential threat. And, in general, that power generation, more than almost any other industry, has very high regulatory risk, as really the number one concern of an investor. I can't think of anything to raise regulatory risk more than the specter of being able to come in anytime and depress prices a lot and screw the existing capacity. So I really think this is important, and I think the proposal that PJM may file very, very soon is a very big improvement. And also, PJM has been a model--even though it's true that PJM was pointed to as a model when New England had their alternative price rule rejected.

Speaker 3: And actually, just like Speaker 1 said, MOPR is becoming a word that many kids in New England know. [LAUGHTER] For better or for worse.

So we've been struggling with the same very similar issue, the same issue. Again, it's a concern, especially once the floor comes off of our capacity market, it becomes the main concern of excess capacity. It's there partly because of that same issue of buyer side power. Again, there's a lot of competing interests here. There are a lot of reasons other than just driving capacity prices down right now because of our floor. There is no short-term effect on capacity

market prices, but everybody knows there's a long-term effect if the floor goes off. Most of the other building that's been going on is to effectuate other state policy goals in lots of cases, renewable energy and things like that. So it's hard to weed out what the real reason behind doing something is, because sometimes there are other competing reasons for putting in capacity to meet that, because our markets don't incent people to put in renewable capacity, for instance. So I would say, yes, it's going to be an issue in New England once our floor comes off. It's already an issue, because we've already had lots of discussions about our MOPR design.

Speaker 1: There's one other thing that, listening to the other panelists, I wanted to add. And I think it's really critical, and it's something that our team, this diverse stakeholder group, spent a lot of time thinking about and talking about. And that is, when you're designing one of these minimum offer price rules, I think a fundamental question you have to ask yourself is, what are you trying to protect against, and we all agreed very early on that we were not trying to protect against lower prices. We were not trying to protect against bad decisions by people. If someone wants to on their own take the risk and decide to build a plant when the rest of us are wondering why they would do that, then our group discussed and debated and ultimately agreed that's something they should be able to do. And it's only when it's for the purpose of suppressing the price and someone's not taking the risk that we are trying to address in the rule that was developed.

Speaker 4: I also just want to add one other short point, which is the other aspect of this improved proposal is that it really is only very narrowly applied. We were very concerned that the current MOPR was much too broadly applicable and you'd get to a point where basically the market monitor of PJM was dictating the offer of all sorts of entrants that weren't manipulating the market at all—self suppliers, competitive entrants, etc. So I like the exemption that

Speaker 3 just talked about. I think that's really important.

I have a client who asked for two versions of a capacity price forecast. One where the MOPR would be reformed so it has these exemptions it should have, and alternatively, where the market monitor is inappropriately creating a price floor for all entrants, including those that are not trying to manipulate the price. So I think that's the other half of it that's important.

Question 7: Thank you. I would be remiss if I didn't follow up on a previous question about how is pipeline capacity in New England going to be built. The ISO has quantified the amount of additional pipeline capacity that's needed. We see the need by gas prices, the differentials across the country--Henry Hub is trading at \$3.42 while Algonquin City Gate is \$9.40. We know that many of the generators in New England are relying on interruptible transportation, capacity release—and, well, not interruptible transportation, because that's not even available. And you said that the ISO is letting the market decide who signs up for capacity. And I'd like to challenge you on that, because I think it's your market rules that are actually distorting those price signals, and I'd like to follow up with that.

By your energy markets dispatching on lowest common cost, these gas fired generators are arguing that they can't afford to sign up for pipeline expansions. Because the capacity markets only go out three years, they say they can't afford to sign up for expansions. So my question for you is two-fold. What are you doing to look at this? Because you're relying on these gas fire generators for electric reliability. You've recognized that there is no capacity. You're forcing some of these generators to rely on asset managers or secondary markets. Yet your performance metrics that we talked about a little bit seem to be after the fact penalizing people for not performing, rather than looking at the

incentives originally in curing those to allow these people to sign up for what they need.

Speaker 3: There was a lot there. [LAUGHTER] I'll take it sort of in chunks there a little bit. The performance incentives that we're rolling out are really what we see as a long term solution to get long term behavior. It's not going to take place right away, and as people start to anticipate those long term performance incentives being implemented, they would all anticipate where the prices will go with that, and we hope those prices will influence people to make the decisions longer term of what they do with their fuel supplies and how they reinforce their fuel supplies.

Shorter term, obviously we'll have problems between now and 2018 that we have to deal with, and some of those are inherent problems in the structure of the real time spot prices, inherent structural issues in how we let people offer in or bid into the market and the timing of our markets and the timing of information flow between us and our fleet. And we're addressing those with trying to increase the communication, let them bid more often, or move the day ahead market earlier, lots of things. Again, part of the problem is our operators feel like they're missing something in the communication. They want the generators to tell them there's a problem before there is a problem. They want a longer lead time on communication.

So there are some structural issues that we'll solve in the interim, hopefully, if we implement the things that we've got in place. We'll solve those shorter-term structural problems. With respect to the longer term things of getting people to actually put money into the infrastructure, the current capacity market design will not do that, even if you prop up the price there. There's no incentive for you to do anything, because the loss that you can incur in the market is very limited, and because of that, it really has not incented anybody to take care of the issues of not being able to perform. So it's

two-fold on that. With our new payments, those who are really good performers in the performance incentives, they'll get even more money than they get now, because they'll be collecting not only just the base payment, but in this design, they'll be collecting additional revenues. So I don't think of it as just the stick. Lots of people have looked at it and said, "This is a penalty system," and it is not. Its intent is to have plants give back the base payment if they don't deliver. That's the basic intent--you would give back your base payment if you're not delivering, and somebody else who's really delivering and doing a great job delivering and who has done everything they can to make sure they deliver, they will get more money. And I agree with you. We're starting to see already very early on, the earliest we've seen, the prices in New England for gas diverging, which is really telling you one thing--that our gas supplies are tight. So we actually have somebody in the control room who watches gas supply every day, every hour, so it is very important to us.

Question 8: This last question and your answer kind of reenergized me to say, let's think about some of the things that have been said in this session. You've just said that the current capacity market design doesn't incent infrastructure investment. Speaker 4 has said that the capacity market construct is a very delicate patient. Very small changes can cause very big problems. And we at APPA have looked at, for example, the periodic lists of new resources that FERC has issued. With new generation coming out, we look at those, and we actually try to do our best to trace how come that new investment had been made, and we found that behind a lot of them, there was the investment vehicle that shall not be named here--a long term contract.

There was question earlier on about the new investments in New York. Think about Neptune. Think about cross Sound cables. Think about a lot of the generation in the constrained zones in

New York. Those are anchored by long-term contracts. Yet that appears to be the devil that is reviled in this group. But you all have to think about how, in the long run, if we're going to change out our fleet from coal to natural gas, if we're going to make a substantial new infrastructure investments, at some point, long term contracting's got to come back into the picture. So I just posit that thought for you all to think about. That infrastructure requires a long-term guaranteed stream of revenue and a three-year forward. It's questionable whether it supports it.

Speaker 2: I just want to say that long-term contracting by itself is not bad. Uncompetitive long-term contracting is bad. So this whole buyer side mitigation is subject to a test to see if you're deemed competitive. If you're not subject, you're not mitigated. Everyone in our market is subject to that test. You're saying that there should be exemptions for people who can prove they are fully merchant. But if you make a competitive investment, you should not be mitigated, and you're currently not mitigated. It's only the ones which we determine that they're depressing the prices beyond what you would expect in a competitive market. Those are the ones that are mitigated.

Questioner: Well, let me just say that I have members that may have particular reasons why they, for example, might want new generation, as opposed to existing generation, for example in an area that's generation constrained or where they may want to substitute a new, more environmentally positive resource for an older oil fired resource. I mean there are reasons why, for local and state reasons, people may want to trim what their RFP's contain. I'd just note that to you. I mean we're ignoring those realities in this discussion.

Speaker 1: And we dealt with all of those issues in our PJM MOPR discussion, which many of your members were a part of, and the way we dealt with it was to look at and be clear not to

capture those business models that like public power, self-supply, or integrated resource planning, subject to some rules, and long term contracts where there's not some large net buyer who is making an out of market payment. So you're right. There's nothing wrong with long-term contracts. But unfortunately, long-term contracts sometimes have been used to manipulate the market. So I think it's looking behind that. The PJM MOPR proposal does not say, "If have a long-term contract, you are subject to the MOPR." It looks behind that. What is that contract that you have? Who is it with? What is their position in the market? We have a net short test. We have a net long test. It looks at all of those criteria, and it also exempts out traditional business models that protect against manipulation, such as a state run integrated resource plan or a public power entity that's truly only building for its own supply, whether it does that through building or whether it does it through contracting with someone else to build for it. So I think that we've addressed those issues in the PJM MOPR, and I think we've done it successfully.

Question 9: I have spent more time in the gas pipeline business than the power business, and I think back to a solution on reliability that pipelines use, and I haven't heard it brought up much here, and I just wonder if it's been considered and dismissed for good reason, or what? And that is the notion of interruptible customers who don't have to make the same contribution to the capacity side of the cost. And basically, I felt what made me think that this needed to be raised was there's a little bit of an underlying assumption that everyone is demanding more reliability, and I think there are probably significant loads that would be OK with less reliability for less cost. So I just wonder how much that's been explored.

Speaker 2: We are big fans of critical peak pricing, because capacity market prices are assigned over 16 hours. If you were doing it over four hours or six hours, people who really

are going to want to pay would make the active steps to reduce that demand. And one of the things that I think we've mentioned that one day in 10 years is not one size fits all. So that goes back to this whole issue of dynamic pricing and having people exposed to the price fluctuations hour by hour. That would be a good thing.

Speaker 4: I just want to add to that. I also very much like price responsive demand of all forms, especially the kinds that are more tied to well-formed, short term price signals. But there might be another aspect to your question, too, which is could you have different approaches, apart from customers economically taking themselves out at certain price thresholds. There's also a question of could you offer a service differentiated by reliability. And I don't think that any of the electric systems are really set up to do that very well, to say, "Oh, that customer paid enough for 8% reserve margin, and that one for 16, so we're going to curtail the 8 percenter first." I don't think they're set up to do that.

Question 10: The reason MOPR became a household word, at least in some of your households, not mine, was because of these proposals or the gall of several states to propose that they were going to subsidize gas fired generation in their states. I'm just kind of curious. The federal and state governments subsidize generation all the time. They do it for DSM, certainly. They do a lot of it for distributed generation, particularly for renewables. They certainly subsidize wind and solar through all kinds of tax credits. And there never seems to have been any of the same concerns with those kinds of state subsidies. So my question is, if Maryland and New Jersey had said they were going to subsidize gas generation to reduce carbon emissions in their states, would we still be having this argument?

Speaker 1: I can jump in first. We do believe that the renewables are different. There's no market. I mean, you have to subsidize them at this time in order to have that public policy goal

achieved, and it does impact the market, of course. But it's a public policy choice. It's not a choice to suppress the market and still say, "Oh, look, we have a market but it's really just not going to work, because we've just interfered with it." Clearly, it has an impact. But the idea of a state or a federal government coming in and subsidizing natural gas fired units--we also talked about that in our process, and if you look at the proposed MOPR, it does actually allow those types of subsidies to exist and not require someone to bid at the minimum offer price, provided that it is generally available to everyone. So it's not picking out a particular region where adding additional supply will suppress the price. So if you have a PTC, for example, everyone has different views whether they're good or bad, but they exist. But clearly, they are not intended to suppress a price in Maryland. Its effects are wider spread. So we do believe that is anticipated to some degree and dealt with as granularly as possible in this MOPR.

Question 11: In my prior life, I was a pipeline attorney, and I think that disconnect is, if I recall, you can't build new pipeline capacity without at least 10 year contracts, I believe. And to me, that seemed to be one of the fundamental disconnects. How can a generator commit to building new generation when they have the pipeline contracts for 10 years, and they only can get a year worth of capacity?

Speaker 3: And again, our goal is not to reconcile it. Our goal is to let the market reconcile it. If there's enough of the supply who is losing out on these revenues for a long enough period of time, they will have the momentum to build more capacity in the lines. Otherwise, their only other choice would be to build their own backup capacity or to forego these revenues.

Questioner: But I don't know how somebody is going to invest in a generator that's going to pay for a contract on a gas pipeline for 10 years when they don't have ten years of revenue

guaranteed. I don't know how investors can invest in that.

Speaker 1: PSEG owns natural gas fired generation, and we continue to develop it, and we've developed and put into service new gas fire generation just this year. And the idea of that you have to have a long-term contract for a firm transportation supply is a very regional question. In PJM, we don't have the same challenges with gas supply. There are many gas pipelines, and they're building a new one, and there seem to be an abundance of options. There's a group of competitive entities that will also package gas supply options for you. There are people out there who are willing to put together products for generators or other buyers of gas that can be used instead of having to make a long-term firm contract. It can be a combination of storage. It can be a combination of some peak supplies that this marketer might have available. So maybe it is a challenge in New England. It seems like they do have some issues in New England on gas availability. But when you look at a region like PJM, we just don't see, as a generator or as a company that distributes gas for gas heating and other purposes, those same issues.

Session Two.

Seeking Standards Through a Proactive Compliance Initiative

The principles and protocols that determine electricity market manipulation are in flux. Changes in enforcement practices have created concerns for market participants. In some instances enforcement actions imply restrictions that threaten the very structure of efficient electricity market design. What is the theoretical framework defining market manipulation? How do market manipulation analyses differ for real-time and day-ahead transactions? What defines safe harbors for transactions and conduct? How can the system provide transparency while deterring and detecting market manipulation? What can be done to support efficient market design and mitigate market manipulation? Would a proactive policy by industry participants help reduce uncertainty about enforcement and improve market operations? For example, should there be a voluntary industry subscription service to: Define voluntary compliance regime. Establish framework identifying market manipulation practices. Define code of conduct for market participants. Develop model(s) of “best practice” compliance regime(s). Offer enforcement litigation insurance. Provide legal support for subscribers meeting compliance standards. Identify market design problems that implicate market manipulation. Establish benchmarks for empirical analysis. Analyze compatible regulatory remedies. The purposes would be to bring greater transparency to distinguish manipulation from efficient market activities, reduce uncertainty for market participants, and hedge the litigation costs of enforcement actions. The deterrence effect of fines and penalties would remain.

Moderator: Now that you all have sorted out all the issues with the capacity markets, we are going to turn to the simple and straightforward topic of market manipulation and solve that in the next three hours.

Just to set the stage here, as we all know, nearly two-thirds of the citizens in the United States are served by parts of the country that rely on competitive markets to attract investment from resources to serve them. And one of the responsibilities of the Federal Energy Regulatory Commission is to contribute to making sure that those markets work efficiently, effectively, and fairly, to make sure that the rates are just and reasonable and that the resources are available to keep the lights on. FERC tries to do that through numerous means, of which enforcement is only one, by dealing with tariff filings, complaints by parties that work in the market, rule-makings to address issues generically and enforcement under the Energy

Policy Act of 2005. As you all know, the law was passed in the wake of Enron, and invested FERC with broad authority to prohibit market manipulation and other fraudulent conduct and assess penalties of up to a million dollars a day. And shortly after the law was passed, the Commission issued regulations in Order 670 that set out what it would do, prohibiting the use of device scare, artifice to defraud, the making of any untrue statement of material fact, and engaging in any act or practice to operate as a fraud or deceive.

Since that time, the Commission has really worked hard to build up its enforcement work and the capacity to ensure that the markets operate fairly through increased surveillance and analytics, a hotline, and strong relationships with the independent market monitors. And there are a number of ways that FERC tries to inform about its views of market manipulation through orders, on settlements and show cause orders, through transparency notices of pending

investigations, and through the annual enforcement report that coincidentally just came out a couple weeks ago this year.

In the past several months, the Commission has announced settlements of enforcement actions against Constellation Energy Commodities Group and Gila River Power, and also issued show cause orders against Deutsche Bank and Barclay's. Three of those cases related to allegations of unprofitable and manipulative trading in energy markets to benefit financial positions. Gila River related to allegedly manipulative wheeling strategies to manipulate transmission prices. These settlements and show cause orders have generated considerable controversy and national attention. Both Deutsche Bank and Barclays, whose cases are still pending, have been quoted in the press as sharply critical of FERC's theory of market manipulation and have indicated their seeking *de novo* judicial review.

So with that as background, today we're going to be talking about the evolving principles and protocols that determine market manipulation, how the system can best provide transparency to deter instances of manipulation, and how market participants can best prepare themselves by developing proactive policies. We have a very expert panel to dive into these topics. I just want to pose two specific questions to the panelists and then a caveat. I'm interested in hearing what each panelist thinks constitutes market manipulation and where they think FERC should be targeting its efforts, not just what they think FERC is doing wrong, although that's fair game as well, but what you think FERC should be doing more of or what you think Congress intended in the law that FERC should be doing.

And secondly, I'm interested in any suggestions as to how the Commission should clarify its enforcement policies or priorities beyond the ways that it has tried to inform the market participants that I mentioned. We have a very expert group here who deal in these matters. I

welcome the thought as to what might be helpful. The caveat is that we want to keep the topics as much as possible to a general policy level. While the cases that are closed, Constellation and Gila River, are fair game to dissect and discuss as examples, we have to be careful about hearing discussion of specific issues in pending cases because Deutsche Bank and Barclay's are still before FERC. And in that regard, one part of Speaker 1's charts discusses some of the theories underlying Deutsche Bank, so members of the FERC decisional staff are going to briefly sit out, step out, and then come back in after that, and if there are other times when that comes up, because we don't want to shield people's questions, please bear with us. We're just trying to do the right thing here.

Speaker 1.

Thank you. I emphasize again, I only speak on behalf of myself here and not anyone else, and what I want to try to do today is to raise a couple of issues and then talk about some ideas that address the moderator's questions about what we should do going forward and how it interacts with questions of electricity market design, which is something that you know is a continuing concern and interest of mine.

I won't go through all the details of some of these early charts, because most of you have seen this before, but just to set the stage, I'm trying to step back and talk about the fact that these matters of market design, trading, and market manipulation are all inter-related and we have to think about how they fit together and the implications of one for the other. They cannot be analyzed in isolation. It's a complicated problem. That's what this chart says. And there are a lot of factors that we have to look at that you are familiar with and I won't talk to you about them again.

The message of this cartoon is that it is very hard to get to where we are. We've gone through lots of experimentation and different paths on

the road to market design. And we've ended up in the organized markets with a framework built around the notion of bid-based security constrained economic dispatch with locational prices. We tried almost everything else, almost everywhere else, and the other things we tried didn't work, but this model does. It is robust. It doesn't solve all problems. We heard about the missing money problem earlier today, for example, but it does address many of them. So it's a critical part of the story of electricity restructuring.

This is just not an incidental thing. This market design is actually something that's both very important and that we can easily screw it up and get wrong, as we've demonstrated by experience, and that can be quite expensive. And the basic structure of that market design has gone through lots of transformations, but it hasn't changed the core principles as captured in these graphics (which again you're familiar with). What I want to emphasize here is the connection between bid-based, security constrained economic dispatch with locational prices and financial transmission rights, which are part of the design. And financial transmission rights are contracts, in effect, to collect congestion revenues between different locations. As the name suggests, they're financial instruments, and they were designed on purpose in order to provide a mechanism for people who were trading in the market and scheduling in the physical market where the LMP's would apply to protect themselves and hedge against changing congestion conditions, so that everybody could have long-term contracts, which is central to the design and being able to actually do that kind of contracting and deal with the congestion part. And this isn't just an incidental part of the design. It's actually critical to the whole system, because it provides the economic solution to the problem that we don't know how to provide physical transmission rights that we can honor in the future (this is the contract path debate, and all that stuff that I won't rehearse).

But these pieces actually fit together in a very important way and the physical market affects the prices. The prices affect the congestion. The congestion affects the value of the financial transmission rights. You marry them, and now you've got a hedge for a long-term contract, and that's the solution to a very important and hard problem that we don't want to overlook.

We're not done in all of this process. There continue to be problems that we have to deal with, but I would argue that this market, which has now been adopted across the organized markets in this country, is, as the International Energy Agency said, the textbook model of how to do it and how to go forward. And we want to make sure we're thinking about what could be done here.

And that brings us up to these questions in addressing the issues associated with the market manipulation. And there's a lot that goes under this heading. And our moderator asked us how do we define market manipulation. Well, I'm going to skip a whole bunch of stuff, because it just takes too much time to get into all of those things. And I have a list here of things that I'm not going to talk about. So I'm setting aside for now related but different problems of market manipulation such as fraud and misrepresentation--lying about what you're doing; price index manipulation in bilateral markets; collusion amongst market participants; capacity auctions in organized markets, which we heard this morning are amenable to being manipulated, and all of the problems associated with that; and demand response mandates, which actually have a similar effect of manipulating markets. These are all important problems. I've talked about them elsewhere, and many other people have talked about them, and we have to deal with them. That's not what I want to talk about.

What I want to do is turn to this question of the issues in market manipulation that come up that

implicate the market design and, in particular, this interaction between, for example, financial transmission rights and the LMP prices. We're talking about a competitive market context. We want to have workably competitive markets, and workably competitive markets are thought of as a reasonable approximation of perfectly competitive markets. We don't have perfectly competitive markets anywhere, so we can't set that as the standard, but we might get reasonably close. And the attributes of workably competitive markets that I would emphasize and will be thinking about is that, taking the prices as fixed, transactions are profit maximizing. And here I mean in the most general sense of the expected value and all the other things dealing with uncertainty. But the critical part of that definition is *taking prices as fixed*. So if you take the prices, and you say, "Given those prices, I think the transaction is profitable," then that's what you're supposed to be doing in a competitive market. You're supposed to do that. If you don't do that in certain context, we worry about you as actually withholding so that you can exercise market power, and so on. And second, that the prices clear the market satisfying various "no arbitrage" conditions. That's an important part of the definition.

As I say, we don't have perfect markets but we have pretty good approximations in these bid-based security constrained economic dispatch design. And I'm thinking about this design as having implications for the definition of what's market manipulation and what isn't, which is one of the questions that we were talking about. When I was first doing this, I was looking back at some earlier submissions I had made at FERC, and I extracted them there just to show that this is not a new point of view here. So these are from the list of top 10 challenges in dealing with market power and mitigation for something that I submitted in 2004, but it said things like, "Scarcity pricing is good, withholding is bad." And so high prices are not the problem; it's high prices that are caused by market manipulation where you're not taking

advantage of competitive opportunities because of the effect on the value of something else that are the problem. "Electricity markets make control of real time generation, transmission or load essential in exercising market power." That's something I said then, and I still think it's probably true, although it's something that I think we ought to be investigating and understanding better about exactly how one could exercise market power in the absence of being able to control real time markets. "Monopsony is a problem as well as monopoly." So we spent the morning talking about that. That's the reason for MOPRs, the monopsony problem.

These problems of market manipulation are not brand new, and the views expressed here, I think, are consistent with what we've talked about in the past. I'm going to just summarize the different ways of mitigating market power here, but we all know about offer caps and why that is consistent with competitive markets and why it mitigates market power on the supply side and we see offer caps all over the place and various ways to implement them. So I think conceptually it's quite possible that you could have market power, and then you can mitigate it, and then it's not a serious problem.

So in the organized markets where they have offer caps in real time, in particular, you can't withhold, and therefore, the prices can go high because of scarcity if we do the scarcity pricing right. But you can't necessarily exercise market power. So it's not that there isn't any opportunity for market power or market manipulation, but there are opportunities that are constrained either by policy or by the implications of policy in one market for what effects what you can do in the other. And that's the concern.

The possibility of market interactions raises some of the concerns that I have here. The point of this chart is to summarize the broad points that I was making, which is that there are very

strong market interactions. So, financial contracts interact with energy trading. Forward markets interact with real-time trading. You have to examine both of them to see what's actually happening. Market hedges are going to be imperfect, so they're never going to be balanced exactly right. The barriers to entry differ in physical and financial markets. Prices clear the market under economic dispatch with bids and offers. And all of those things are important in thinking about how the market works, and I've provided a little table here which tries to look at some of these interactions, in this case between real time physical transactions and forward financial transactions, real time prices and forward prices. And I won't go through each one of them, because you can read them yourself, but an example of a limit on manipulation is that given real time market power mitigation, forward transactions don't create physical real time energy withholding, and therefore, you cannot sustain manipulation of forward prices in the organized markets. And that's because you can always settle out of the contracts in real time, and that makes, I think, a presumption that forward and financial markets are competitive. If you can't manipulate the real time market, then you can't sustain manipulation of the forward market. Or at least if there's a model for explaining it, we haven't talked about it yet.

There are a lot of theoretical issues that I've talked about before and what I want to do now is to try to cite why I'm worried about what's actually happening as we try to confront these theoretical issues, talking about some other topics.

So I've said before, and I'll say again that I was very heavily involved in the California debate, running up to the implementation of the California market back in the 90's. And I testified. I wrote papers. I had private conversations. I went around every place to stakeholder meetings. I said, "Don't do this, don't do this, don't do this, don't do this. This is

a mistake. This isn't going to work. Don't do this!" In California they, of course, ignored me, kicked me out of the state, and took away my passport so I couldn't come back. And then when the California market did blow up, my regret in subsequent years was that in the earlier discussions I had been insufficiently hysterical. I hadn't said how bad this really could be, even though I said that it could be really bad. So I'm trying now to be sufficiently hysterical. [LAUGHTER]

What I'm worried about here is the development of what's happening in these market manipulation cases that have been coming out recently, some of which I'm involved in and some I'm not involved in. And part of the fact that I'm involved is just a fact, and it's discussed in these charts that you see here. But, as I explain in this next chart here and go through, it appears to me that the mere fact that a physical transaction can affect prices to some degree and thereby influence the price of related financial contracts is being treated as a per se definition of price manipulation. And I'm arguing that cannot be allowed to stand. For reasons that I just went through, the whole structure of the restructured electricity market design involves financial transactions and physical transactions that interact with each other. And that's recognized. And the structure of the financial contracts and FTRs is to allow people to hedge for it and to put those two things together. And when you do a physical transaction, you're going to affect the price of the financial contract. That's just unavoidable. Everybody knows that, and it cannot be the case that simply having the the financial position and the physical position and then implementing a transaction is market manipulation. If that's the definition, then the whole system is going to unravel.

So was that sufficiently hysterical? This is really, really dangerous and it's really bad. But there's a way to deal with it, and the way I thought it was always to be dealt with, and there's a very happy citation here from the HQ

Energy case that the FERC decided a while back. And basically the idea is what they were looking at is that if you have a physical position and a financial position and you do something in the physical position which is stand alone profitable, or expected to be profitable, if you have an economic interest in it, and it also effects the financial contract, that's not a problem. It's when you take the position in the physical market where you expect to lose money but you want to affect the price of the financial contract and you're going to make it up in the financial. That's a problem. OK. I agree. That's a problem. So that would be part of my definition of manipulation.

But what's going on, and what I see happening in these cases, is that this is not consistent with the decisions that are being made. And here I emphasize again this HQ Energy case, where they found that it "*did not* use a combination of market power and trading activity to act against its economic interest." And that's the critical idea. And they were just acting as a price taker, and it was taking prices as fixed. They were implementing transactions which were profitable on either side, stand alone, and that was OK. It's only when you are losing money on one hand in order to make up more on the other that it's a problem, and that's the same problem as withholding and market power and all the other things we've always said is a problem and is an example of market power.

There's a little bit of discussion here, which I'm not going to spend time on, about what prices apply, and the fixed prices, and how do you deal with technical conditions like degeneracy. But that's not what's important. What's important here is this notion that everything in the market affects everything else. And knowing that everything affects everything else is hard to avoid. Now the standard for market manipulation, the scienter part of it, was that you knew that it was going to effect the other transaction. And I think that's an important component of the definition of market

manipulation, but I think it's a necessary condition. I think it is not a sufficient condition, because if it's a sufficient condition, we can shut down the market, because everything affects everything else and everybody knows it. So if you knew that, and that's all it took, then utilities that are doing trades and physical transactions couldn't do financial.

So turning to the recently decided Gila River Power contract, I'm going to make a point, using the settlement decision that was published by the Federal Energy Regulatory Commission, which is at the core of the argument that I'm concerned about. And I've quoted what I consider to be the relevant factors here for the general point, which is, first it's acknowledged in the settlement that the Gila River Power traders knew that their wheeling transaction could benefit other transactions by affecting the price. So this is a contract they want or a transaction in one place that affects the value of something else. And they said that was, they knew that was true. Secondly, they said the strategies were profitable. And I just summarized what the numbers were. And then there is a reference, the only reference, that speaks to what I talked about, the HQ Energy standards. It is provided without support or explanation, but it says that "Gila River's Wheeling Through transactions done in conjunction with its Adjustment Wheel strategy were undertaken with the intent to increase the revenues for its imports sourced from the Gila River plant and were *not based on market fundamentals*." Now this may be the critical phrase in the whole document as far as my point is concerned, but it doesn't elaborate on what it means by "market fundamentals."

And so the point I would make about the settlement is that I don't know whether it is consistent with what my definition of market manipulation would be, which is consistent with the HQ Energy standards that the FERC has talked about and the chairman has talked about, that you're losing money and intending to lose money in one transaction or make more money

on the other. And I don't think anybody who wasn't party to the decision knows either, because you can't tell from reading the document. It could be that the separate transactions were profitable on a standalone basis, in which case then it wouldn't pass the test of being market manipulation, or were the individual transactions "against economic interest" absent in the impact on prices and other transactions? Or is trading with the knowledge and intent to affect prices all that is required? If that's the case, if trading, knowing that one thing affects the other, is enough to make market manipulation, then we're in serious trouble, because everything affects everything else in the market design. It's not almost not possible to participate in a market without having transactions in one part affecting other parts of contracts that people hold, and that they know that that's the case. So is the Gila River Power settlement consistent with or opposed to the HQ Energy standards? I would like to know the answer, and what concerns me about the process is you can't tell by reading the document as to whether or not it is. And that's, I think a very serious problem.

So this raises a lot of questions about what to do going forward seeking standards, and I listed some of them here. What is the theoretical framework defining market manipulation? I think the HQ Energy standards are clear, and if that were what it is, then that would be good to know. If that's not what it is, and we're changing the standard, then that would be good to know, and it would have major implications as to what people could actually do. How do market manipulation analyses differ for real-time and day-ahead transactions? As I've argued before, these are very different circumstances, and you have to look at the interaction of the two. What defines safe harbors? How do these confidential enforcement settlements affect policy and precedent? How can the system provide transparency while deterring and detecting market manipulation? And what can be done to support efficient market design and

mitigate market manipulation? And what I'm worried about here is throwing the baby out with the bath water--that we're undermining the electricity market design if we're changing the policy on market manipulation.

One idea that I have described as the program on steroids, the energy compliance network, would be to have an industry group that got together on a voluntary basis to work together to do things like define a voluntary compliance regime, establish this framework for identifying market manipulation practices, define a code of conduct for market participants, and develop models of best practice compliance regimes, and to offer enforcement litigation insurance. One of the big costs here is just going through the settlement process, and if people are settling in order to avoid that cost and they're changing the fundamentals of the market in the process, that's a problem. And I would like to avoid that problem. But on the other hand, I don't want to provide protection for people who are manipulating the market. So we shouldn't be protecting them from the fines and penalties if they're actually found to have done so. And then the same group could identify and support improvements of electricity market design. If they are features of the market design that are causing the problem, we should change those features of the market design.

So I think there's a real problem here in terms of knowing what the rules are and making sure that the rules for market manipulation, while well-intended, are also consistent with the broader market design. And until recently, I thought that was the case. Now, I'm not so sure, and so I'm trying to think about how we can find out and then how to deal with it in order to preserve efficient electricity market.

Question: You said during your presentation, Speaker 1, that you thought (and maybe your position on this has changed) that you needed to have real time generation in order to exercise market power. Do you also feel that you need to

have real time generation to manipulate the markets? Do you have a distinction between market power and market manipulation in your definition of that?

Speaker 1: Well, the short answer is that there's a whole list of things you could do in the day-ahead market that I excluded from my discussion. So fraud, misrepresentation, banging the close, doing all the stuff that people do in order to get their prices to be misrepresented somehow in that marketplace. I was interested in the case of whether there is something where I could do what appears to be a perfectly legitimate transaction--I'm not misrepresenting what I'm doing, I'm taking the consequences, I'm trying to make money with it. Is there a way that I can materially and consistently change and profit from the prices of the day-ahead market if I can't also manipulate the real-time market? And in certain circumstances, it's easy to answer that question, if you assume away a lot of hard parts of the problem. So if you assume away liquidity constraints, and assume away risks and uncertainty and all that kind of stuff, and allow for entry, the answer is no, because you can't get the price to deviate between the two. It creates an arbitrage between the two, and then people will enter and take it away, so you can't do it. Now, the real market isn't like that. So now we have to think about that. But what I was talking about before was the case where if you can't manipulate what's happening in the real-time market so that the price in the real-time market is independent of what you do, then what can you do in the day ahead market in order to manipulate the price if the price is going to converge to the real-time price? Because you can't change it.

Question: What is this insurance that you're talking about? Is it like country risk insurance? I don't understand the concept.

Speaker 1: Well, it's an idea in progress, a work in progress. What I discussed with other people in various different contexts is that people in the

market who are trading and are worried about this problem would get together and they would try to develop standards and practices and do all this kind of thing and they would also contribute to a fund that would deal with the litigation costs while you were trying to go through the settlement process or the enforcement process. Now, if you lose, you have to pay the penalties. But you don't have this problem of people settling all the time in order to avoid the litigation costs and, in the process, settling on things which have big impacts on the rest of the market where they wouldn't have settled if they internalized the cost of the impacts on the rest of the market.

Question: I'm going to ask this one as a yes or a no question, and it follows up on the previous question because I didn't catch the answer, because I couldn't follow it. So if I have an unconstrained market, a spot market, and I have one generator who happens to be constrained in that market, and if he bids basically at the unconstrained market price, he'll get the constrained market price, but if he bids below the unconstrained market price, he'll be constrained and get his bid. If he does something to manage that, such as taking his generation off cost dispatch and self-scheduling at a lower amount or bidding towards the market price, so he's not constrained down, is that, I would think that that's some degree of market power. Is that market manipulation?

Speaker 1: It's a good question. My short answer is yes. And the longer answer is that I'm assuming that problem away, in the sense that in real time you can't manipulate the market. Now, if you can't manipulate the real time market, what implications does that have for the forward market? Can you manipulate that? And that was what I was trying to answer.

Question: I just want to be clear. I don't want to be clear, but I'd like to get a clear answer because it certainly sounds like you have no faith in enforcement and that some of these

cases are questionable and are only being settled because the expense of contesting the allegations is greater than the potential penalties--the parties saw that settling was less expensive than actually the cost of litigating.

Speaker 1: Well, in order to avoid any difficulties here, let me reference the Constellation settlement, which is now behind us. I think paragraph 42 in the Constellation settlement says (I don't know the exact words but I'll paraphrase it) this settlement does not apply if the Commission does not approve the merger between Constellation and Exelon that's going to happen later today, basically. [LAUGHTER] So do I think that the settlement was agreed to for reasons that had nothing to do in part with the particular issues of market manipulation there? The answer is yes. And I think they wanted the merge, and it was worth a lot to them, and they were prepared to pay a lot of money, and they might have done something different if they could have separated those issues and gone forward. And so I think that's an example. Whether or not they would have won or lost if they'd gone forward is another issue. It's very hard to tell by reading the settlement, because it doesn't reveal all the facts in a way that allows you to discriminate, so I don't know. But I think there's no doubt that there is a lot more going on here than the merits of that particular case.

Speaker 2.

Thank you. I think my role here today is to be the historian, if you will. I am speaking of my personal recollections of the early days of enforcement at FERC. And what I hope I can do is provide some insight here about how you can be proactive, identifying some of the risks

So I want to review how the current enforcement situation evolved. I think that has some insight here. Of course, I speak only for myself and not for our clients. And I will also be going into some examples of proactive compliance,

because just through some quirks of the things we had to work through, I've seen how some of that works and how some of it doesn't, and then I'll walk you through some examples, because I think the examples will be useful for the discussion later because, as was said earlier, it's not clear what we're talking about here, and I think some of these examples can help.

So, basically, before 2000, enforcement was really in its infancy. We had the Energy Policy Act of 1992. It started to unleash some of these market forces. But there wasn't a group within the Commission outside the general counsel's office worrying about policing markets or whatever. Then in 2000, and through, I'd say, 2002, I'm calling it "the crisis." We had Enron. We had California. All sorts of bad things were happening. But there was a loss of confidence in regulation of this transition and there's no doubt of what Speaker 1 said, that there were warnings about this ahead of time. FERC, as I heard it, had issues with the California approach, but, as I understand it, the California delegation unanimously said, "Do it. We've already cut the political compromises. It's this or nothing, and we want this," and I think the Commission reached the opinion that, "Well it's got to be better than nothing," and sometimes nothing's better. So that crisis was underway, and from 2002 through the end of Chairman Pat Wood's chairmanship, FERC moved to set up oversight.

Pat based this on an office that he had in the Texas Commission, where he had been Chair before. The idea was to have analytic capability to watch the markets, to notice anomalies and problematic trends, and to provide support to the lawyers involved in investigations. And so this was a first marriage of analysis and the investigations. And it was pretty helpful, and we made a fair amount of progress. Our emphasis was on collegiality, if you will. Everyone said, "We've got to do this differently." The state regulators, same thing. We are going to be really watching what you're doing because it's important that this happens correctly. And so the

whole idea was outward focused. We were going to be skeptical, which wasn't something Pat would have been concerned about. And we're going to be outward focused as opposed to inward and agenda focused. And we specifically wanted to be able to continue to have dialogue because we thought that was the way forward.

After Pat left (and Pat's strong and unending support of standard market design meant when he left he had some enemies), Chairman Kelleher came in, and in his confirmation had the promise to do things noticeably different than the prior chairman. And among those distinctions that he chose to pursue was he was going to take a law and order approach to enforcement and he planned that change in terms. There was less interest in the analytics side and more in the enforcement of the statutes. And it was a difficult period for the staff in the office. I actually had times where I felt like I was functioning as a camp counselor, not at the camp any longer, but people were saying, "I don't want to be trying to put heads on pikes or do show trials," and those terms were being used in the discussions. So it was a period of transition.

Before 2005, we didn't have the Energy Policy Act of 2005. There was no million dollar per day per violation penalty authority. So we had to be much more creative to kind of get people to agree to change how they were doing things. Although there was one "show cause" order that lead to removal of market based rate authority for Enron. But that was the least of their problems at that point. [LAUGHTER] So then, in 2008, I think we began this new period, and I characterize it here as 2009 to the present, where we had this crisis of confidence, not in the regulators as much as in the business side, right, and I think as we have this discussion, we have to take account of that. That there is a crisis of confidence about the performance of business. Ten years ago, everybody thought capitalism won. Business could really help deal with all the problems. There's a lot of skepticism around

that again. I think a lot of it is ill founded but I think we have to recognize it.

And so with yet another change in chairman, we got a shift and a new director of enforcement who was a professional prosecutor and a law professor. I think there was immediate upgrade on the prosecutorial side and they have been able to track a lot of legal talent into the shop. And then the analytics side was rebuilt as well. And one of the interesting developments here which I don't think we'll get into much is that the CFTC raided a lot of the analytic and even some of the legal talent at FERC during that '05 to '08 period and a lot of the people who looked at power markets for FERC are now looking at them for CFTC. And that will complicate this problem for compliance as well I think.

So we've got this successful prosecutor and a large increase in the investigation staff. I think that aggressive regulatory postures in this new period and in this political environment is encouraged and I think we see that, and I think there's a real difference in perspective between the staff positions today and attitude today and not that long ago.

I've got a few pie charts here just to show you a sense of the attitude of industry on FERC compliance, and you've got it in your packets, if you want to look. So I included a few questions. One was on the frequency of compliance reports to boards. And I thought it was interesting that about half of the respondents said it's quarterly. So I take that as indicating they are taking it pretty seriously at the highest levels. Then we asked about their compliance budget and the outlook for change, and more than half had no change in that. So that suggested people aren't too worried about how they're dealing with FERC compliance matters at the moment. On the compliance training metric, I included that because more than three quarters of the folks say attendance is what they take. So I just take that you're doing attendance rather than a test on whether you learned the material. So do you

really know that your traders know what they're supposed to do? People don't seem worried about that at the moment. And then we asked, "What your biggest compliance risk concern?" It's NERC. So I thought that was interesting.

We asked if they find FERC regulations clear and understandable, and it's only about a quarter that disagree with that. Half are neutral. The other half are neutral or agree. And then, what about the new enforcement measures at FERC? Now, this was last summer. The group that affirmatively said it's a problem was pretty small--like 20%. But "remains to be seen" was the biggest answer. And then, on the biggest concern at FERC, enforcement showed up as a good chunk, but not the overwhelming concern. So again, reliability seemed to be a bigger concern. So I think that gives a sense of the attitude from several dozen companies involved in this stuff pretty heavily. And I just think that's illuminating.

So let me turn to the pro-active compliance initiatives, because I don't have that much more time. Some examples: NERC. NERC was a self-regulatory agency at first. After the big blackout of 2003, it turned out that most of the NERC standards were being treated as suggestions rather than standards, and that's a big part of what happened. People were aware of that and were planning to address that already, but it got addressed in EPLRA 2005. There are still problems there, and we hear a lot of angst about the issue of inconsistencies among the regions.

One compliance initiative that I think is very relevant to this idea of insurance is the Nuclear Energy Institute, which was a post Three Mile Island (TMI) institution. After TMI, the nuclear industry said, "Our weakest link created problems for all of us. So we actually need standards that are stronger than the federal standards." How often do you hear that? And I've been told by several lawyers involved in the nuclear industry, but I couldn't find it on any NEI site, that if you do follow the NEI

standards, it gives you access to different and preferred types of liability insurance. So they do have standards. They are enforced primarily through peer pressure. I don't know if there's a certification, but I imagine that if any insurance companies are giving a break, that it is verifying that you're following the standards.

Another interesting compliance initiative goes way back: The American Society for Mechanical Engineering (ASME). Anybody who works in energy efficiency has heard of these standards. It began with the Polytechnic Club that was dealing with issues around boiler explosions, and there, too, the issue was insurance. And if you followed the ASME standards, you could get insurance against boiler explosions. So this concept is not pulled out of the sky, if you will.

Another compliance initiative is the Gas Price Reporting Coalition/SafeHarbor Response, right? So, gas price reporting after Enron was getting a lot of people in trouble for false reporting. It turned out there are all sorts of crazy reasons for that. We can talk about that later. But so what was the proactive response to this? Gas price reporting was voluntary. If I report falsely, I'm going to get in trouble. No brainer. The proactive solution was to stop reporting. So members of industry came to the Commission and said, "We need that price discovery." And we had a series of technical conferences on the subject. And an industry coalition formed and came up with a process that involved independence of the reporting entity, audit of the reporting trail, and agreements with the index publishers. It was all done in the private sector. The market oversight staff was at the negotiating table. And I occasionally got rolled into the meetings, sometimes basically when they reached an impasse. Sometimes with the impasse, I came up with an idea that moved it along. Sometimes I didn't and I'd say, "OK, I guess we'll just have to have FERC take one on." And I never said

that and didn't have a solution proposed the next morning.

Another example of a pro-active compliance initiative is on Dodd-Frank. The notional value calculation is critical there, figuring out the amount of activity. You may have heard about the \$8 billion threshold. It's based on notional value. The calculation industry went and asked CFTC, "Well, how do you want us to calculate?" And they said, "We don't know. You've been talking about notional value. Don't you know how to calculate it? Apply the industry standard." So they're like a voluntary coalition trying to come up with some standardized approaches to that.

The last point I have here refers to a speech I gave for the World Energy Council on reliability compliance, and it drills a little deeper on some of these insurance ideas. You may want to look at that. But I do want to say, I'm not the source of Speaker 1's insurance idea.

So how do companies keep out of trouble? One approach to company-level pro-active compliance is to look at the cases, try to build screens that will give you a red flag if you're doing something like something that has led to an enforcement action already. As Speaker 1 has said, a lot of that is not clear. There are some cases that are and others that are not. The compliance culture is critical, and I think FERC's gone to excruciating efforts to try to give detail on that. And within the compliance guidelines, there's a lot of information about that. But I was actually shocked because I had to revisit it. I had a client who said, "You talk about the compliance culture, but when I look at the scorekeeping system for the penalty guidelines, it doesn't mention the culture of compliance specifically. It includes a lot of the actions."

I think that the aspects of the Constellation settlement that Speaker 1 discussed are certainly important. And it's what's created a lot of the

uncertainty for, if you will, the bystanders to this case about what do we make of this? And I've never seen a case like this where both sides have such total confidence that they are in the right on it. Usually one side knows their story's weak. I don't see that in this. I've never seen anything like that before. But in the settlement, there's a line in which Constellation agrees that they will record trader communications. That is a really important takeaway for anyone about what to be doing proactively. If you want credit for your compliance culture, you almost surely need to be recording.

Safe harbors. We talked a little bit about the Safe harbors. If you look at what came out in that gas price reporting case, you get insight. Another way is "no action" letters. But sometimes people talk about "no action" letters as "no help" letters, right, because if the Commission's going to say it first, the first thing it says is, "This is staff and it doesn't bind the Commission." The second thing about "no action" letters is that the staff is like, "Well, why should I get in trouble? I'm going to hedge what I'm saying here as well." So the more important it is, the less clear the guidance in that will be. Sometimes it can be helpful, but don't view that as a silver bullet.

And then I want to make one point here. There are proactive compliance measures you can take that are acceptable and then there are others that may not be acceptable. My examples go to driving, right? So one approach is that you're going to avoid speeding tickets by leaving your car in the garage. Another proactive measure is to obey the speed limits. Another one is to have a radar detector, right? That's proactive on your part. If you drive across the bridge right outside the hotel, you'll get to a sign that says, "Welcome to Virginia. Radar detectors are illegal." And I think it says the state bird, too. [LAUGHTER] But it's right up there on the sign.

With respect to cooperative compliance initiatives, I think around FERC and around Dodd-Frank, we're hearing all the time, "What is everyone else doing?" People want to stay in the herd here. It's like, "At least I can have that protection. If I don't happen to be out on the outside, at least I'll know when the attack is coming," sort of thing.

And there are issues around whether you do this formally or informally. There are a lot of groups huddling on this. Associations are involved. There are other coalitions and things that are ad hoc. I think formal is probably a better way to go. And then you're going with leading practices or common practices.

So that's it. I think that trying to figure out whether these approaches can work or not is trying to address a big uncertainty. The uncertainty is causing hesitancy on market participants parts, and I think that's a problem, and I hope we can talk about that more in the discussion. Thanks.

Speaker 3.

"What is market manipulation?" is the first slide that I have. I'm not going to go over it. I reproduced FERC's Anti-Manipulation Rule here. I think the important part of this to takeaway is that it's an SEC 10B-based regulation, which means it's fraud-based. It's not specifically written in terms of market power, and yet it is often applied to market power cases. So it has been described a little bit as a problem of fitting a round peg in a square hole or vice versa. And a number of the findings, including what Speaker 1 talked about earlier, would say, well, is it consistent with market fundamentals? And it's not necessarily clear that something that may not be consistent with market fundamentals at all points is necessarily a fraud. And this may be the beginning of where we are getting into the market participants thinking that there is a lack of clarity--that the

regulation might be the start of that problem, I guess, is the takeaway.

Then we have some examples of the regulation as applied. The first being from *Cargill v. Hardin*, "We think the test of manipulation must largely be a practical one...The methods and techniques of manipulation are limited only by the ingenuity of man." And what does that get us? It gets us to almost like the pornography standard. We'll know it when we see it. And the answer there is also not very satisfactory to market participants, because you want to know in advance what you can do, not to have someone judging after the fact, "I know it because I saw it." So that is another part of the problem. There are not clearly defined borders on manipulative activity. The Anti-Manipulation Rule was intentionally framed broadly to allow FERC latitude, and while that may be good, the flip side to that equation is that market participants are potentially unclear as to what they can and cannot do. FERC has also stated that it's unwilling to be limited to "textbook" economic analysis but wants to account for the practical realities of how markets work. And for that, too, I think on the one hand, you've got the benefit of it, and on the other, for a market participant, what do you have to go against other than textbook economic analysis? And if that's not necessarily going to be used, there's another aspect of lack of clarity there.

And in the historical construct of it all, and this may be changing given the recent Hunter case, which is now initiating the litigation stage, and Deutsche Bank's announced intention to litigate, but there have been a lot of settlements in this space. And you might hear only one side of the story in a settlement, which is not to say that settlements aren't good and shouldn't be pursued. But I think the industry feels, when they read the settlement orders, that not everything that they need to know is in them. So our moderator started this off by saying, "What can FERC do a little bit differently?" and maybe it's a matter of the impressions of the industry

that there's a little bit of information in those orders but it might not be everything that we need in order to make decisions about what kinds of practices are acceptable going forward. So we've got shades of gray (back to our pornography discussion from earlier), not black and white. [LAUGHTER] FERC has historically recognized that its anti-market manipulation rules may present interpretation challenges and it's of interest that it said that back in 2005. But I think the industry perception more and more is that FERC may think that it's really clear and that we all know what we're supposed to be doing.

And now we pair this market perception of uncertainty with increasing enforcement tools, which may be also increasing the trepidation of market participants. FERC has announced its new Division of Analytics and Surveillance. We've got Order 760 now, which is requiring RTO's electronically within seven days of creation to deliver all sorts of new information to FERC. And then on the electric side, at least in Electric Quarterly Reports, market participants are going to be asked to be reporting more and more information. So FERC's tools are increasing, and I think part of the point of this panel is can we also somehow work together and roll up our sleeves to get not only those tools to be improved, but also to get information to market participants that's vastly better in quality than what we have today?

So going over some FERC guidance. In the Hunter case, FERC stated that the inquiry is fact intensive, and "will depend on the facts and circumstances of each case." It said that fraud includes "any action...for the purpose of impairing, obstructing, or defeating a well-functioning market." We have that statement in Order 670, and then we've seen more recent orders suggesting that anything that is not consistent with market fundamentals may be manipulative, and that trades that are "not in accordance with the normal interplay of supply and demand," but are intended to benefit

financial positions as violating the Anti-Market Manipulation Rule also coming out of the Hunter case. So there's some guidance that we have out there.

And then in response to the Constellation order, Chairman Wellinghoff issued a statement, and I think the first one here may be the clearest rule that market participants have. First, do not trade uneconomically on one position in order to benefit the value of another. And I think my proposition here is that we may need more of that. We may need more meat on the bones of that sort of statement. Wellinghoff's statement also covered senior management being held accountable, and emphasized the need to tell the truth, the whole truth, and nothing but the truth when questioned. And we've seen various enforcement actions where the underlying activity was actually exonerated, as maybe not necessarily being OK, but not being wrong, but there have been fines imposed for the conduct of the investigation, the market participants' cooperation with FERC, and so forth. And then Wellinghoff stated that, finally, the Commission will be vigorous in using its anti-market manipulation authority to protect consumers.

So that now that we have kind of a fundamental of the background, we can move forward and perhaps discuss a little bit more the question of, "Well, what is the problem?" The problem being that the law surrounding manipulation is complex and uncertain and the contours of the regulatory landscape seem to be constantly changing. The distinctions between activity that may be manipulative and legitimate trading activities are largely nuanced and subtle and conflicting legal authorities exist. We've got the specter of ever-increasing civil penalties. Constellation's at the time seemed to be fairly substantial at \$135 million and a disgorgement of \$110 million, but that's been completely eclipsed now by the Barclay's proposed fine of \$435 million plus almost \$35 million disgorgement. And I'm hearing from market participants, "Well, if you look at the value of

that business line, it is nowhere near \$435 million.”

So what do you do? Do you just like not do that activity? Do you not engage in that kind of beneficial transaction any longer, for fear that something that you may do may expose you to a penalty that is completely out of whack with the value of the business line? So we’ve got the problem that fear may deter market participation, deter liquidity, deter engaging in transactions that otherwise might be very beneficial to the markets.

We also have concepts in flux. I have an example of that. The textbook definition (now, we talked earlier about FERC not wanting to beholden to “textbook” definitions of things), but the textbook definition of market power, at least as I’ve always learned it, is the ability to raise prices above competitive levels for a non-transitory period of time. And there was a recent order that came out involving some activity in California, a California ISO tariff change proposal that introduces this concept of “temporal market power.” It was in the context of California ISO market rules that allowed market participants to change their bids 75 minutes before the hour. And if you know that you’re going to be taken for the next couple of hours, maybe you have an incentive to go in and change your bid to something fairly high, perhaps the bid cap. And an investigation was opened. We’ll see what the results of that are. But here’s a question: if the market rules allow you to do something, is there also a problem to some extent with rules being inappropriate in allowing people to do things that may be profit maximizing, which is at the end of the day pretty much every business’s objective? So I’ll leave that one alone.

So, what are the options for market participants? You can trade conservatively, following the “avoid inquiry” standard. We’re going to lose some beneficial transactions and some liquidity if that’s the approach that many folks in the

market end up taking. You can push the envelope and be prepared to be investigated, and you need to be prepared for the consequences of that. You could document the reasons for your trading activity and hope for the best. That’s one of the other outcomes of the Constellation settlement, which was favorably discussed by the Commission, which is having more contemporaneous documentation of the sorts of trades that might raise an eyebrow later on if you really believe you have a legitimate reason to do it at the time. It’s harder to perhaps prove your explanation after the fact than if you’ve documented it contemporaneously, and that comes up in our compliance training these days a whole lot as well. Or you can await the results of litigation for further clarity, and we may be seeing some of that.

Are any of these the best ways? I would say that of these options that I’ve laid out, probably none of them are completely satisfactory. An additional option (and Speaker 2 approached this earlier), is that you can uptake guidance from FERC through “no action” letters. There is this whole process to get informal advice. Speaker 2 criticized it a little bit. First of all, it’s not necessarily used that often. The staff will say, “Well, this doesn’t bind the Commission.” But do we just throw up our hands and say, “That process is useless,” or can we roll up our sleeves and try to make it better in some way? This may be an avenue that could be considered further. There are limitations on it. You have to use real transactions that you’re planning to do, not hypothetical ones. But perhaps using this construct, market participants can ask various questions in a more hypothetical fashion, and FERC can issue some guidance. That might be another idea of how to have something in place that is helpful to market participants.

So, the problem, (and Speaker 1 has stated this earlier as well) is that physical trades have an effect on financial contracts. We cannot divorce that. And also, from the business standpoint, maximizing profits on a portfolio basis is a goal.

But in some cases, we've seen that that is perceived as manipulative. We also have the problem that sometimes you are trying to pursue maximizing profits, but it doesn't work out that way, and you end up losing money. And can there be an implication there that that was your intent all along? If we all knew how to make money all of the time, we would all be very wealthy. And we have a standard that remains, don't trade uneconomically on one position in order to benefit the value of another.

So I'm going to end my talk with a little bit of an example. This is a simplified example of what the problem may be. In my little picture here, I've got a company that owns two generating units. One's cost is slightly above what the market clearing price is expected to be, and the other is below. However, at one generator, this company has an FTR position, and that FTR position, because running that generator creates congestion, causes it to receive revenues, in my example, of \$3.00. There's no FTR position at generator B. In this example, it would not be economically rational to run generator A on a stand-alone basis. But once the FTR position that pays \$3.00 is thrown into the mix, it is more beneficial to run generator A than generator B. If generator A is run, can XYZ Co. do this, or is this considered manipulative? Is this a fraud? Is this not market fundamentals, if this is done? And I am not certain that if we opened up to a full discussion that we would all be on the same page of the answer. So this may be an example of how we've seen some of the enforcement issuances that come out that seem to be clear on their face that, "Oh, that must be wrong." But there are a lot of other examples that are in gray areas, where we're not so clear right now. And with that, I will end my talk. Thank you.

Question: In this example, are you in a capacity market where you're required to bid?

Speaker 3: Well, I was just trying to throw out a simplified example of the problem without

going into particular market or what the market rules....

Questioner: And what you were trying to do, it just demonstrates the factual issues surrounding these kinds of questions.

Questioner: Just following up on your suggestion to trade conservatively as one of the options. I think one of the real troubling parts is that we've introduced now a gray area. If there's a clear standard of acting against your interest in one market to benefit your other, then I think that you can live with that. If we now have gray area which seems to be looking at the cases that acting in your interest in one market, knowing that it may impact the other, and to Speaker 1's point, we all know that everything impacts everything. How do you suggest that you actually trade conservatively in that environment? Because to me it really has become problematic. How do you ever marry a physical and financial business and meet the trade conservatively standard?

Speaker 3: Right. And I guess I suggested when I threw those out that none of them were really that palatable, and they don't solve the problem, because you never can have that answer. So what the fallout might be is that there are certain beneficial transactions that don't happen at all for fear of what the consequences may be, and that's not where we want to end up, which is why we're all grappling with this problem here today.

Question: Just to connect two parts of your presentation, is your problem here one that you could submit a question to FERC on a "no action" letter process to get informal advance guidance? Or not?

Speaker 3: Right now you could do that only if someone were actually trying to do this. You cannot submit theoretical transactions. As I understand it —

Question: You wouldn't have to be doing it, but you'd have to have these plants and those costs to submit the question?

Speaker 3: I think you have to be intending to do it. You can't just say, "Can I do this or not? But I have no intention of doing it," as I understand the "no action" letter rules as they stand right now, and they have not necessarily been modified since they were issued, so this might be an opportunity to take a new look at them and see if they can expanded to make them more useful.

Question: We don't know?

Speaker 3: No, I think the answer right now is only if you were intending to engage in this transaction could you go to FERC and ask for a "no action" letter. Otherwise, you cannot. The process does not accommodate it.

Comment: And there's no way you'd have the answer in time if you were really planning to do it.

Question: Just a follow-up. I can't remember the rules, but isn't it true that the "no action" letter is not binding, anyway?

Speaker 3: Correct. It's not binding on the Commission.

Speaker 4.

Good afternoon. The perspective I'm bringing to this is a practitioner's perspective for compliance, and I will qualify that by saying I'm not in compliance and I have never been in a compliance role in my career. I've been in different roles, the latest being risk management. But over the last couple of years, the activities in risk management have melded very closely with what's going on in the compliance world and the two have become almost inseparable in many ways, as the compliance schemes and rules have evolved for the energy trading world.

What I want to cover today is extending a strong compliance culture to power and gas trading, and that's going to be in reference to working at an investor-owned utility that has other compliance functions, obviously, associated with it, ways of building a strong trade compliance program, and then talking about what are some of the barriers to doing that, both internal and external barriers, and then trying to develop a proactive compliance culture and program versus one that's reactive.

When you talk about an electric utility, and especially one that's got nuclear generation associated with it, you're talking about an organization that historically has probably had a very strong compliance culture. That culture has evolved over many years, and it's basically because of the multiple layers in areas of regulation that those utilities are subject to. Examples are your FERC and NERC compliance. If you're nuclear, you're regulated by the NRC and INPO. And then you have state PUC regulations and things of that sort. So that utility has been subject to many layers of regulation over many, many years, and typically has evolved a very strong culture of compliance in response to those things.

When you then layer on a trading organization either inside that utility to support the rate base or outside of the utility, as in the case of an energy resources group where it's trading to support our merchant generation and to make money (which I think it's still legal to do), you're subject to a lot more regulation now than you have been in the past. We've talked a lot about the FERC market manipulation and compliance issues here, and I'm going to concentrate mostly on that, but really the new and burgeoning area of growth for lawyers in compliance and for regulatory folks is the CFTC and Dodd-Frank. I spend roughly eight hours a day on that--not on anything commercial, because that would be wrong. [LAUGHTER] I also spend a lot of time on ISO and RTO issues,

and then on a state-by-state level looking at PUC rules for the different areas where we have our merchant generation in addition to our regulated rate base.

So the size and the shape and the scope of the compliance activities is growing pretty quickly in the world of energy trading, be it for either your regulated utility or for your, well, I can't say non-regulated anymore, your merchant activities. When you talk about building a strong compliance program for trading, there are a couple of things that you really need to concentrate on. And the first one is the most important, and that's the company's culture, which really must be steeped in compliance from the CEO on down. I have the benefit of working for an organization that has one of the strongest compliance cultures I've seen. I worked for 10 years at a different utility that had the merchant utility split. I worked for four years at a large investment bank before this, and I have the benefit of working now for an organization that takes compliance more seriously than anywhere else I've been. So that's the most important thing. You really need to make sure that you have that culture in place, and it's not just in one area of operations. It's in all your areas of operation.

And then from there, you have to implement, and implementation is just hard work. It's a lot of hard work. You have to have a compliance/legal/risk group that reads and understands the rules. We have multi-functional teams that go over the rules, interpret the rules, and then translate them into plain language so that our business lines can understand exactly what we think the regulators are talking about. And then you have to train the organization on the rules. So we hold trainings with our traders, with our desk managers, with our risk manager, with our management, so that everyone understands our interpretation of the application of those rules. And going back to your survey, Speaker 2, you mentioned that some people say the majority of them just take attendance at

trainings. We actually do a CBT, a computer based training afterwards to test, and they have to take it over and over again until they actually pass, which for some people is problematic. [LAUGHTER]

So we have to train the organization on the rules and try to come up with real world examples, either from enforcement actions or through situations that you can think of on your own. From there, you have to assign roles and execute responsibility. So we have somewhat of a decentralized approach where we have a high level compliance organization that does a lot of the interpretation and checking and stuff like that, but then the execution responsibilities are decentralized out into the business units, and then they report back. And then the tracking of the execution of those rules needs to be maintained by that compliance organization.

Speaker 2 also talked about the implementation of monitoring programs. So you can look at the trade activity and come up with different algorithms to pick apart what the traders are doing, to flag things like, are you consistently losing money on your day ahead real time trading, to the benefit of perhaps a leveraged financial position or something like that? You can develop that ongoing and real time monitoring, so you're not having to parse through thousands of trades every week. You're able to try to pick things out based on the algorithms that you've developed upfront.

And then the last step that I'll mention is just that the compliance group and your regulatory groups have to monitor at all times for changes in the rules and be in lock step with the regulatory bodies to make sure that you understand the new rules that are going out and you're then again disseminating them into the organization. And you basically have to iterate on all of the above on a regular basis. So this is not something that you do once a year or once every two years. This is an iterative process that's occurring every day.

So what are the barriers to a strong trade compliance program? I think the first one is if you don't have that compliance culture, you're going to get lulled into a false sense of security in times where it's quiet, where maybe the markets are quiet or you don't have any letters coming from any of the agencies, or there are no investigations, or there haven't been a lot of rulings coming out lately, or anything like that. So you can really get lulled into a sense of complacency if you don't have that strong culture and you're not iterating on the things I mentioned on the last slide.

Some of the other external barriers include the difficulty in understanding and interpreting and implementing vague rules, and we've touched on that quite a bit today with the market manipulation rules. You have to be able to develop trainings that take the abstract to the concrete and work through those with your folks to make sure they understand them. And then you have to take it even further and know what to monitor for, and be sure you'll know it when you see it. We talk about that a lot. Every compliance conference I've been to over the last six months has had a reference to it, so I guess that's the in thing. How do you know it when you see it? So that's a challenge for your compliance group and your regulatory folks.

Other challenges include the fact that the ground is shifting underfoot constantly. The markets are evolving. The regulatory landscape is evolving. You have to be able to evolve with those and change. And then one of the things a lot of people find if they do work for a large organization is that there's organizational inertia associated with keeping up with what's going in the market. And if you're on the merchant side, you typically have less of that inertia, but you still have to work through the corporate governance of the organization, and so it can take time to make changes that you think should be made quickly.

So one of the things we want to talk about is what is a proactive approach for building a compliance program? It's difficult. I mean one of the areas we've talked about is trying to get more of that guidance from the FERC in terms of what is allowed and what isn't. And I understand fully the idea that the regulatory bodies don't want to tip their hand. They want to be able to give you principle-based or broad-based rules, but they don't want to say, "This is what you can and can't do," because they know that traders are smart and they're going to figure out ways to work through that and find ways to maybe find those gray areas and live and work in those gray areas.

So I know it's a balance for the regulators to try to give you enough guidance without tipping their hands, but I think we need to err more on the side of saying, "This is what you can or you can't do," just so that people have that clarity. The way I think about it is, I don't know how many of you have worked on a trade floor before, but from my perspective, you take a 20,000 square foot floor. You fill it with a couple hundred kids who have Asperger's. [LAUGHTER] And for those of you who don't know, that's an autism spectrum disorder where they're particularly very high functioning, intelligent people, very rigid and have to live by a very strict set of rules and have to have things explained to them over and over and over again before they can internalize it and understand it. I have a son with Asperger's, so it's like I'm at work and then I'm at home and I'm dealing with the exact same thing. [LAUGHTER] But if I went to my son and I said, "You're not allowed to commit fraud," he would look at me and that would be the beginning of maybe a 20 to 30 hour discussion with him about "What is fraud?" and "Give me examples of fraud." And he would come back day after day asking, "Is this fraud? Well, what if I do this? Is this fraud? Well, how about if I do this? Is this fraud?" Well, that's exactly how it is when you take a lot of these rules and you try to explain them to your traders in trainings, because they are going to be sitting

there thinking about every different possibility as to how you can operate under those rules, and they're going to want to know with certainty what they can and can't do. And at this point, we have a very difficult time answering those questions for them. So I don't know if any of you have ever dealt with a kid with Asperger's, but explaining a lot of these rules is very similar to trying to get my son the guideposts he needs to live his life by. Guys, help me out, because I've got a hard enough time at home. I need some help at work. [LAUGHTER]

So I think that's a big thing. And then what we look for internally is having more standardized approaches for compliance for our different strategies on trading. So we do natural gas. We do power. We do some other things related to the fuels associated with our plants. There are a lot of trading strategies that are employed both for hedging and optimizing our assets and then trying to make money on a proprietary trading basis. And what we try to look for is standardized ways of practicing our compliance across all those different strategies and trading types without having to reinvent the wheel every time. So those are some of the things we try to do from a proactive perspective.

The alternative is kind of more what we're faced with on a day-in day-out basis, which is the reactive approach where you're really building and revamping your compliance function or your compliance activities in response to the case particulars as they come out or perhaps don't come out. So a good example is the Constellation settlement, where we read through that very closely, and we looked at what was required of Constellation, and we figured, well, if this is what FERC's requiring of Constellation, if they come knocking at our door, we need to make sure we're doing the exact same things they're requiring of Constellation for any of these activities that we may undertake, even though we only do them at 1/1000th of the level that Constellation was doing them. We still need to make sure we're

being as conservative as possible in complying. And the analogy I use a lot with the trading organization and the compliance folks is the whole analogy of the bear. It doesn't matter if you're the fastest guy when you're getting chased by the bear. You just don't want to be the slowest. And I think that goes back to the herd analogy as well. You want to be kind of lumped in with everyone else. Conservatively, you don't want to be pushing the envelope. You also don't want to be the slowest, because a bear is going to eat you. [LAUGHTER] So thank you.

General Discussion.

Moderator: I think this has been a great discussion and there's certainly a lot of commonality in what everyone said. And I was really struck by the final chart that Speaker 4 used of the different approaches to this, and one approach was to learn from each case that comes out and apply your training to each case, and then you get the next case and you apply your training to that, and carrying it to its logical conclusion, it could be a long time before every square on the mosaic is filled out and you see the whole pattern, because these markets are complex and evolving and people who are operating in the market are very creative in what they think of.

On the other hand, there's not a secret list, at least that I'm aware of, of everything FERC is ever going to accuse anyone of that's existing that FERC just won't show. It's not the case that it's all written down and FERC just doesn't want to tell anyone because it's better if it doesn't, and it is evolving as we go along. So I'm very interested in if people can flush out more what, if they could have the Commission answer questions, what would those questions be? I'm less interested in whether it's a "no action" letter or a complaint or a rulemaking, but what is the actual thing you're confused about?

Question 1: Say I want to teach my traders not to impair a well functioning market, and I'm

hoping maybe one of you folks can sit and teach me how to do that. Can you help?

Speaker 2: I think that the biggest confusion right now, and I don't have the facts one way or the other on this, is clearly that hedging involves doing things in two different markets that are related, and you're hoping that if one goes down, the other will go up. And that's what it's about. So that cannot be illegal, right? The allegations here are that doing one *makes* the other thing happen. So it's that causal link, and the scienter point is the other one, which is that it's malicious in the intent. And again, scienter is most important in the post EPOA 2005 world. It's not the world I had to operate in.

My sense is that the Commission's staff believes that it has identified scienter-type of intents to manipulate. As to what they've looked at, I'm not seeing that stuff, so I don't know. I might have a different opinion if I were looking at it. I haven't seen it.

The other important element probably is that it sounds like in the public debate that there's leverage going on, right? So if you're going to lose 10 bucks in the physical to make 10 in the financial, I don't think that's going to get attention. But if you're losing \$10 and that helps you make \$1,000, that's probably going to get attention. And again, unfortunately, that kind of information's not in the public domain here.

Speaker 4: I'd be interested in your training program. I think it's important to tell traders to be careful about what they say. Like I've heard one lawyer say, as you're dealing in the Dodd-Frank world, SWAP is a four letter word, OK? Get that in your head. Traders say the darndest things. And I saw that in cases, and I actually had one investigator who said, "I need a day off. I can't listen to anymore of that trash." I mean, in the old days, before digital signal processing screening, you literally had people listening to them all. On the California tapes, that was what was going on.

So I think it's the leverage and it's the intent and having the contemporaneous records. The other thing I think that's gotten some people in trouble is it doesn't look like their compliance staff is empowered, right? If it looks to the Commission like the compliance staff was blown off, that gets you in trouble. And it could look that way and not be true. But again, it's a lot about the deliberations, I think, and building contemporaneous records. Several people have mentioned contemporaneousness. I think in defending, that's important. And we were talking during the break a little bit. It's unfortunate what happened with Constellation, because it probably was a case that could have helped clarify things, but the way it played out, it really has muddied the waters here.

Questioner: Just to clarify. As my hypothetical self, I wasn't assuming that the circumstances I would necessarily be confronted with would only be related markets manipulation cases. You can do other things, presumably. I'm not really sure.

Speaker 2: OK. And I think you go out there and you observe the markets. You get smart about how to make money, and then you make money, right? That's how it should be working if you're going to be supporting a market function. So the question everyone has today is, is that true? Can you do that and stay out of trouble?

Speaker 4: I would echo a lot of what Speaker 2 said. It starts with the culture, and then you have to build the monitoring. So we record all of our traders' phone calls. We also record all of their IMs. We have selected audits of those. We also look at their P&L for each of their individual books every day to see, if someone's consistently losing money, why that's happening. We also talk about leverage a lot in our training. So we make it clear that you can't benefit one transaction by meaning to lose money on another one. And then we talk about what's hedging versus what's leverage. So if

you've got FTR's and SWAP's and you're a day ahead in real time trading and they are all kind of balanced out and it's because your hedging one of our assets, then that's fine. But if your FTR is for 600 megawatts, and you're only trading 200 megawatts or 50 megawatts in the day ahead of real time market or something like that, two different locations, then that's where you run into trouble. So you have to look for all those things that, again, are what you've seen in past cases but then you also have to try to be able to think ahead and to let your traders know these are kind of the precepts that you can't violate, and then you have to monitor for that. It's not easy.

And to the last thing, on whether or not there's any, I guess, backbone in your risk or compliance organization--I mean, in the late 1990's, early 2000's, risk organizations were pretty much a joke, at most merchant trading shops anyway, and a lot of them reported to the commercial people. And then we learned about governance, and it should really work, and things have changed from that perspective. Hopefully, people's risk organizations have a little more backbone than they did in the past.

Speaker 3: Well, having actually given a number of training sessions to traders in my day, I think starting off with the clearest statement of Chairman Wellinghoff, "First, don't trade uneconomically in one position to benefit another," is kind of the cardinal rule to the extent we have a clear rule. And then I like the approach of going through hypothetical situations and then asking questions of the traders. Can you do this? Or what's wrong with that? Can you identify it? Then pulling statute out, going through each step of the statute. Does this constitute a fraud? And seeing what the answers are, and then, I think, the best advice, because so much of this may not be clear, is, "Well, if you're in a situation where you're not really sure, bring it up to your compliance department. Go to the office of general counsel. See if that particular transaction requires

additional documentation, or if you're just told not to do it, so that there's not anything that's done without management's knowledge and sign-off if you're in one of these gray areas." I think that's the best way a company can proceed to protect itself.

Speaker 1: I wouldn't have written a guidance using these words because I don't know exactly what they mean, "impairment of the market." And it's not a concept that I can relate to first principles. But I think easy cases are cases such as we've just talked about, in the HQ Energy case, as long as you don't lose money here in order to make money over there...I think those are the easy cases. The ones I find that worry me are the ones where you make money here and you make money over there and you know it, and then that's counted as manipulation. I think that's the thing that leads to the complete unraveling of the whole market, if that's market manipulation, and that's the problem I'm really worried about. The gray area where I find it more troubling I think really imposes more of an obligation on the people doing market design. This probably ought to be handled in the policy office and not the office of enforcement, if you've got a market design which has got quirk in it, which presents an opportunity for people to do things where they make money in ways that you sort of didn't think about and didn't intend. OK? And now the question is, is the obligation of the market participants to refrain from following the profit maximizing incentives that are presented if it's not violating this HQ Energy kind of principle? And this gets involved in things like uplift and demand response and all the other kinds of things where these issues come up. And I find myself torn, because I don't like it when people are screwing up markets but, on the other hand, I don't think it's the obligation of the market participants to refrain from responding to the incentives that are presented by the market, because it's just so difficult to know in those situations.

And then I think the task is to redesign the market in order to fix the problem. So if you have a crazy market design like, well, let's assume that the price is constant everywhere in PJM, and we'll have a single market clearing price for PJM like we had back in the mid 90's, and then you notice that people are contracting around that in order to take advantage of constrained off generation. Are those people manipulating the market? Well, they certainly impaired the market. The whole thing unraveled, and the ISO ran to FERC and said, "Help, help! We have this crazy market design that we were forced to accept. It creates these incentives. People are contracting around it. It's going to cause the lights to go out." Now, that seems to me like impairment of the market, but I don't think the people who are signing the contracts to go get the constrained off generation were at fault. I think it was the market design that was at fault. And that's the thing to fix. We did fix it. We put in LMP. FERC said, "OK, go ahead. Go do it right now. Remove that crazy incentive." So those are the harder cases, but I think there it's not an enforcement problem. It's a market design problem.

Question 2: The nut clearly that needs to be cracked here is clarity around the market design, the market rules, and what constitutes manipulation. But I think the current Commission is really taking steps to try to bring to light to their enforcement regime and how to work within it and how to set up a compliance program. So I'm just wondering, from practitioners, if some of the recent issuances and events the Commission has held to bring more transparency to its enforcement program have been helpful. So those are things like the annual reports that they issue, the penalty guidelines, policy. I believe pretty much they've held annual conferences on enforcement issues generally to get feedback from participants. Is this helpful, or does it really sort of not matter in light of the understanding that has to come around the market rules and what constitutes manipulation?

Speaker 3: I think it's helpful to some extent. It certainly makes training a whole lot easier, developing your compliance program, and determining whether you need to make changes to it. This idea in some of the orders about, "Well, not everyone was necessarily aware of what the company's compliance program said," that's very helpful. Make sure that you train everyone and they are aware of it. Don't just put the document on the shelf and have your people that actually need to know the rules not be aware of them. Pretty easy to say that's helpful there. But it's also great to have all the examples out there. I think we need to go further, but where we are is that definitely having some examples out there is very helpful from the standpoint of putting some parameters around it. I think we need more, but we don't lack them all together.

Speaker 2: The other place to be looking is the audit findings. I think the audit group worries more about being educational. With a settlement, you've got to get both sides to agree to what's in it. The audits, I think, are much more educational. That's another good place to look. On the guidelines, it's interesting, because the guidelines do provide information and a framework, but I hear from participants in discussions around the penalty guidelines that they become kind of a problem more than a help when you're actually trying to negotiate numbers.

Moderator: I just want to put in a plug, and obviously I'm not in the best position to judge if they're helpful, but for the annual enforcement report, because it includes things like hotline calls that were closed without an investigation and summary numbers of some of the things that are going on in audits and so forth. I have a feeling that a lot of people just read the part on the investigations and don't read all the boring stuff, but in the non-headline part, there's information buried. I'm not suggesting that that means FERC has satisfied all the information

inquiries out there, but a lot of work goes into putting it out and I commend it to folks.

Speaker 2: Yes, I think on that very point, the information on self-reporting has particularly a lot of effort there to convey ideas.

Question 3: Thank you. I just had a question about the overriding theme of fraud, and, Speaker 4, you brought up the idea that explaining what fraud is to your son is a 30-hour process. So there's just very little clarity as to the concept. But when we've talked about market manipulation, and, Speaker 1, I think you were talking about the idea that obviously market power in the traditional sense can cause market manipulations, where somebody has an act, for example, of economic withholding. Outright fraud, such as lying or putting misinformation in the market, is another way of defrauding the market.

But you raised an interesting example of banging the close. And forgive me if I'm mischaracterizing this, but banging the close means that you have a position that's tied to the end of the day price and you're short. And then you go in at the end of the day, toward the end of the trading day, and you sell. Sell, sell, sell, sell, sell. Try to push the price down as much as you can in order to benefit that position that's tied to the price. Is that accurate?

Speaker 1: I've never participated in this. [LAUGHTER]

Questioner: As a theoretical exercise.

Speaker 1: That's what I've heard. [LAUGHTER]

Questioner: And I think it's interesting that you group that type of behavior with fraud because, if you think about it, the trader that's doing that trading isn't communicating any sort of patent fraudulent information in the market. They're just coming in as a price taker and just selling,

selling, selling, trying to push the price down. And obviously, there's an element of intent there, as you all were discussing before. So I guess my question is, when we talk about uneconomic trading (because I know that seems to be a lightning rod, losing money in one position to make money in something else), focusing just on the losses, as you had suggested you do, can simply the placement of price taking bids in volume (For example, as temporal market power), is that something that can be used to manipulate markets?

Speaker 1: Well, if I called banging the close an example of fraud, I probably should restate it, because for the reasons you just said, it's not exactly the same thing as fraud. But it is trying to take advantage of the fact that you don't have clearing in this market, and so if you're in an organized market and you put in a whole bunch of bids like that and other offers there, and then the system operator chooses among them and they get a clearing price that applies to everybody, this problem goes away. But if you're in these bilateral markets where you're reporting for the index and you wait until the last minute before anybody knows what's going on, and then you start, as I understand it, and you just rush in and do a whole bunch of things real quickly before anybody has a chance to respond, as opposed to letting other people put in their alternative prices, and the contracts that didn't get satisfied, and all the other kinds of things, that seems to be a problem. And I haven't spent a lot of time analyzing that, so I'm prepared to be convinced it's not a problem, but I think it is a problem in bilateral markets. But it doesn't come up in these organized markets. I don't think that you can do that, which is one of the advantages of the organized markets.

Questioner: Just in terms of the organized markets where you have a market clearing price, I mean, obviously, this was an issue in the Constellation case, for example, which is settled, so we can talk about it. The idea was that virtuals were being placed to influence the day

ahead prices to the benefit of various financial positions that were tied to those prices. So you had said that this can't be done in the organized markets, but can't somebody come in as essentially a price taker and add bids to increase demand and thus raise prices? Or offers in order to add supply and push down prices?

Speaker 1: Well, this is a good question and you've written on this subject, and lots of other people have written. I think it's an open question. And I'd like to know the answer. But let me suggest that one of the implications, if you're doing that and you don't have control over the real time price, then you're creating a gap between the day ahead price and the real time price that creates an arbitrage opportunity where somebody can then enter and make money against you and close that gap. And what I don't understand is how you can have simultaneously no market power in real time, so the expected price and the real time is not under your control when it's fixed, and exercising market power manipulating the price in a day ahead so it deviates from the expected value of the real time price, and make money and not have anybody enter in order to eliminate the arbitrage position, because one of the things I put in about competitive markets is that there's no arbitrage. So you eliminate those opportunities. That can happen for an hour. It can happen for a short period of time, but I don't see how it can be sustained. And that's the reason I raise this question about how can you actually do this?

Now, maybe there's a way. And maybe it has something to do with we really don't have the potential of entry and we have very strong liquidity constraints, or we have something. I don't know. But it's got to be a more complicated story than just, I arrive and I put in a lot of bids and I move the price. Then you're going to violate the no arbitrage condition or you're going to violate the entry freedom or you're going to violate something. And the real problem is exercising market power in the real

time market, and can we do that? I mean, we know how to do that. That's easy, conceptually, and that's why we have all these mitigation rules for dealing with market power in real time. And I think they work quite well. And so then you say, "OK, we've solved that problem. How can the other problem exist if you can't exercise market power in real time?" That's a question which I think is an open question.

Question 4: I just wanted to speak briefly and raise a couple of issues related to Question 1 in this discussion about being a real-life trainer for power trading organizations, and also to speak to the liquidity issue.

I'm an electric power regulatory attorney who has sat on trade floors. That's all I've done since 1997 when power trading started, and I sat on the trade floors for very large trading organizations. So I've been one of the people who has actually done trader training since the get-go. And first of all, I'd like to say to the moderator that part of our trader training is that we look from our compliance and legal standpoint at the annual reports to look at what's going on. We also provide annual training, for example, for our FERC training, for gas and power, our code of conduct training, we have that on computer. We have testing. And then kind of one off training, which we've had to do a lot of recently, which is based on any time a significant "show cause" order comes out from the Commission. So over the past six months, we've had a number of these where we actually sit down with the relevant traders and try to explain what happened in Deutsche Bank, in Constellation, in Barclay's, and this week in the Gila River case.

And I just want to tell you just this little vignette about what happened in our training this week. I think there's a concern in the marketplace right now about companies perhaps getting out of the market. I've even heard anecdotally from outside counsel saying that some of their clients are considering getting out of the physical power

market, and they're only going to do financial trading. And I think that's pretty bad from the standpoint of liquidity from a corporate standpoint. But I'd also like to raise the issue of what is happening to traders, because of the possibility of very good, very honest traders who've been in this business a long time saying, "I'm getting out of the market because I don't want to participate because I don't know what the rules are and I'm scared." We had a Gila River training this week to our relevant traders, including our real-time desk. And, if you don't know, the real-time desks are typically the least experienced traders. That's where you put your new guys. In our case, I think our real time desk traders are all experienced, but the newest one came about three or four years ago. And we value the fact that we have traders who've been in the business for a long time. And I personally as a FERC regulatory attorney working with these guys, I'd probably walk off the job if I thought any of our traders were liars and cheats, because there's too much downside. But in our training, we went through it. We explained Gila River. Barclay's came up. And part of my job, since 1997, has been to educate and to scare. And that's what I do is try to scare the traders so that they don't do anything wrong. And so we got through with our training and one of these real time guys, they asked questions about the particulars of Gila River because we do FTR training, but at the end, one of the guys said, because I went through Barclay's and, of course, I'm trying to scare him, \$435 million plus \$98 million, and I said plus \$15 million individually against the head trader and one million each against the little traders, the real-time guys. And one of our real time guys said to me (and hopefully I'm not waiving my company's attorney client privilege) but he said, "What if that real time trader doesn't have a million dollars? Does he go bankrupt?" And that just tugged at my heart, not just my legal thoughts as to what do you tell a trader. And I'm really fearful that if we don't get more definition around how to tell traders exactly what they're supposed to do, that we're going to lose really

good traders. And that is really bad for the market, because all the market, including load and everybody else, wants traders to provide liquidity, and you want traders who are honest and experienced. So I just throw that out there.

Speaker 4: I've seen a lot of similar stuff at our shop. We have, one of our traders who trades one of the regions for basis, who now documents his reason for every trade he does, and his boss told him, "You can't do that," because he's missing out on trade opportunities because he's writing down why he's trading while the market's running away from him. But he's so scared about everything he does in the FTR and the basis market, and he wants to make sure he's justifying his reason for every trade. And this guy is trading like 5 megawatts here and 4 megawatts there. And sometimes he'll trade at a node where it does affect the market price. Well, yeah, because that's the only trade that's been done there in two months, right? And he gets all paranoid and comes out, "I think I moved the market here." And I'm like, "Well, yeah, because it hasn't traded since December." I mean they are scared. They're nervous, and there isn't a lot of clarity. We have them sign an acknowledgement once a year on our policies and procedures, and that's been expanded to include civil and criminal penalties and other things. And they look at it and they're like, "Who's protecting me?" because when the proverbial you know hits the fan, the company is going to protect itself, and no one's going to protect the traders. And I just look at them and say, "Yes, that's true."

Moderator: Thank you for sharing that. I don't think there's much risk that it's not making an impression.

Question 5: Thank you. I do want to kind of just turn the conversation a little bit and maybe provide some more cheerful thoughts, but probably not. [LAUGHTER] And that has to do with the CFTC. I've discussed this a little bit at the break. We only mentioned that in passing.

But we go back to the dawning of RTO markets and LMP. Speaker 1 led us through all that. How come financial is better than physical? Obviously, we didn't necessarily agree with that at the time, but that bridge has been crossed. However, because these are now financial markets, all sorts of unintended consequences have ensued with the passage of Dodd-Frank. I've spent a whole lot of time and money in the last two years at the CFTC, trying to convince them that state and local governments that engage in electricity supply did not cause the financial meltdown and should not end up as collateral damage on the road to financial reform. And that's been a very difficult discussion. I've worked with other people in the industry, including many of the people in this room, as a coalition to try and file comments to convince the CFTC that really, we're not so bad. We're just trying to do our business.

But what we're finding is that just getting an exemption for RTO markets, which we figured would be a no brainer because, after all, FERC regulates these markets, has not turned out to be an easy thing. And in order to try to fight off CFTC regulation, the FERC has done a number of things, for example, requiring a central counterparty in all RTO markets. You pull that thread, that presents issues for entities that are not their own members. And that creates all sorts of tax questions for us, going to tax exempt financing, all sorts of other stuff. So the doctrine of unintended consequences has tumbled us way down the hill. So I just note to you that we talk about grand new ideas and theories, but the way these things work out in practice can be very different than the way they work out in theory. So this leads me to my point, which is what can we as an industry do to try and convince the CFTC that FERC regulation of these markets is sufficient, and that they really do not need to be imposing a second layer of regulation on us? Because I don't necessarily see us winning that argument at present.

Speaker 3: I think you might need to lobby Congress, because I'm not sure that FERC and the CFTC are going to work it out. Not to be flippant. But that may be the answer.

Questioner: Well, guess what? We already are. But maybe that's a call to action among this group to join forces to think about that a little harder.

Speaker 2: I'll make three quick observations. One, the people who had special understanding of the financial physical markets at FERC were recruited by the CFTC, right? Secondly, I think your members have a much bigger danger than being regulated by the federal government. Dodd-Frank specifically sought to help your members, and that's your problem, right? The special entities help. It's not that you're being regulated. When I used to walk into an especially tense meeting when I was at FERC, the sure fire way to get off with a laugh first was I'd say, "I am here from FERC and I'm here to help you." And I always brought the house down. So I think that is a real part of the problem for you here, is that that special entity is not viewing that you cause the problem, but they're viewing you as a victim of problem needing their protection.

Questioner: I understand that, but actually, what we've worked on in the larger coalition are things like reporting, what is an option, a trade option, the seven-part test for volumetric optionality....I mean, this stuff just gets so esoteric so fast. I'm quite concerned that it's going to adversely impact the ability of my members to serve their end use customers (end use in the FERC sense, not the CFTC sense, because all words have different meanings over there.) But I really am just quite concerned about it, and want to raise to this group that we're talking about FERC enforcement, but CFTC enforcement could be an issue unless we can work this out.

Question 6: I'll be relatively brief. But my comments are a combination of defensiveness, self-promotion, admonishment, and encouragement. [LAUGHTER] FERC has got a ways to go before we can be more transparent in these orders. And we're somewhat hamstrung, of course, by the nature of what we do. But it's a lot better than it was four years ago. Keep that in mind. Some of us had to fight pretty hard to get annual enforcement reports, to get a lot more details in these orders, and to come up with penalty guidelines, which, although they are not ideal perhaps, at least are a framework, and there was no framework before. So in that sense, things are getting better, I think, from a transparency perspective.

The admonishment comes in that I think the trading industry, and don't take this personally as a reference to any of you as individuals, but I don't think the industry has demonstrated its worth to the Commission in adequate ways. You bring a value to the markets, but you haven't demonstrated it or advocated for it effectively enough. And there's an opportunity there, and that goes to my encouragement. This is the time, actually the time was before now, but the time is now to continue to make your points, to come to the Commission, and express what you bring to the marketplace. The comments expressed today, I think we hear them. We can't solve all the problems all at once.

Speaker 1: I think the point is legitimate, and I agree with it, but I think the situation is worse than that. And I was just discussing this with Speaker 3 here, about people leaving the market and traders leaving the market, and suppose they all exited the market and we didn't have any traders? Well, that would be a problem, and that's the kind of thing you'd want to document. You'd want to understand what greater liquidity is, but the point I'm trying to make is, there's much worse areas than that. And that is, even if you didn't have any financial traders, if you had only load serving entities, and they were municipals, and they were members of APPA,

and so forth--the best kind of people you could have, right? [LAUGHTER] And if the rule has become that if you have a transaction over here, which is profitable, and it affects the price of a financial transmission right, and you know it, and if that's market manipulation, then they can't do it, then that's a real serious problem, because now you can't have people who are physically trading in the market, physically scheduling in the market in order to serve their load, hedging against the price changes that come with the market. So you've undone a critical part of the market design, and the whole thing unravels. That's the logical extension of the argument.

Now, you might say, "Well, we won't go that far. We'll only do it to bad people like financial institutions but not good people who are members of APPA," right? Well, that's just bad public policy. Right? So we should have a rule. We should apply it, and it should apply to the financial institutions, and it should apply to APPA, and it should apply to all of the parties in the market. And it should make sense, and it should be consistent with the basic market design. And what I'm concerned about is that we're in the process of doing things which lead us to the logical extension of the argument, which is to have that whole thing unravel. And now we're back to the question of what do we do instead of the market design, which is the only one we know that works if you want to have open access and nondiscrimination and all the other things? And so this is a very serious issue.

Moderator: I guess it's my time to be defensive a little bit, but I just want to make a couple of comments. The first is, by definition I speak only for myself, but I don't think I do entirely. I don't think that there are bad people. I mean I've been very troubled by the sort of press implication that we have a war on Wall Street and we don't value them but we love public power. I mean, this hasn't been in the press but it perhaps is implied that the meanies are not the

LSE's. They're good. The people who are only financial traders are bad. Actually, they're all participants in a complex ecosystem. And I think that one of the things I really learned a lot in the last two and half years is that there are a lot of players in this ecosystem that I wasn't even aware of and that are increasingly playing. And so the rain falls on the just and the unjust. Enforcement has implicated load serving entities, demand response providers, financial institutions, independent power producers, and so forth. So I realize that's not what you meant, but I just wanted to give that little advertisement.

Secondly, I understand that if you drive this thing to its logical conclusion you said, "Well then, obviously nothing can ever be done in one market that affects another market." But the very market design is so interdependent that things affect each other in the market, so while you could draw the kind of *reductio ad absurdum* that if you don't know what the rule is, it might be all the way, so you can't do anything that ever affects anything else, but then you couldn't do anything, because the markets are interdependent. Things in one market affect another. So I think we can put a stake in the ground that it's not that.

Now where is the rule between there and internal revenue code that's this thick, that says as long as you don't do these 3,000 things, everything else is good? We're quite a ways closer to the general than we are to the specific right now. If you think of when 10B5 was new, and of when 10B5 had been around for six years (I know no one here was around), but how many cases were there? That's where we are.

My question that I'm mulling, I'm not expecting you to answer and do my job, is how can we jumpstart the process and give more guidance than the three or four or five or six cases we have that are all the way through the pipeline? And I think that's something worth thinking about. But I don't think it's all the way to the end, traders are bad. We don't want trading,

things can't depend on each other because that would undercut the whole process. And all of the people who are getting the electricity have a lot invested in the market right now. So we should be looking toward the positive of making them work. End of my sermon.

Question 7: Thanks. I have a clarifying question actually for Speaker 1. You've mentioned some of the areas of concern, but can you articulate a bright line between what could be considered manipulative and what shouldn't be? So is it as simple as when there are a set of money losing transactions to benefit a larger position, that that's manipulative? And if you're actually making money on both transactions, that's never manipulative? Would you say that? Or is it not that simple? And I know a couple of factors that make it a little bit trickier are, of course, that you may lose money inadvertently, right, on the one hand. And then, well, there are so many different kinds of trades, and so I'm wondering if you can develop a rule this simple at all.

Speaker 1: Well, I never say never, except for LMP. Don't do anything else. [LAUGHTER] But I think the HQ Energy statement that the Commission promulgated is a pretty good bright line, and it doesn't say it has to be profitable this hour. It says it has to be in your direct economic interest, so that opens up the possibility of uncertainty, and over time, and all the other kinds of issues that you have to get into the detail. But I think that's a very important line, which is that you're not intentionally losing money over here in order to make money over there. And that would also encompass in the real time market withholding power--are you withholding in order to make more money on the power that you're producing? So it would be consistent with that. And I thought that was the rule, and now I'm not so sure. And that's the thing I'm worried about here.

Questioner: Well, just to clarify. Are there any instances you can think of where there would be two sets of transactions and they're both making

money, or both expected to make money, or intended to make money, where you think maybe that's manipulative, or do you really think the bright line should exclude all of those instances?

Speaker 1: Well, if I had to answer right on the spot, I would say, I don't know of an example. I mean, I think the example I talked about before, where I reached back into the 90's in PJM to get it out of the current context and so forth, where you can have a market design defect which creates a money making opportunity which also benefits other things, and you might say, "That's not really a good thing because what you're doing is taking advantage of the defect in the market design." And I don't like it when those situations exist, and I would fix the market design as fast as I possibly could, but I don't think that it's correct policy to impose on the market participants the obligation to refrain from doing what the market design tells them to do, given the incentives that it provides. And so I might find it a bad thing and deleterious and we should fix it as quickly as we can, but I wouldn't call it market manipulation, because they're just making money because that's what it says to do.

Speaker 2: And closely related to that, so Tim Belden, one of the first MVPs into the hall of infamy, if you will, from Enron, his original charge was exactly that, right? Figure out these weird rules, find the ways to just crank out money, and that was how they started and got on a slippery slope. But I just want to shed a little more light on that. So what we would do when we saw some suspicious behavior is go out. We'd analyze the situation, sit down with the traders and supervisors, not together usually, and say, "Tell us what you were trying to do here. What actually happened? And what's your view of the outcome?" And we're doing the sniff test on it. Did it make sense? And you had kind of three outcomes. One was, "OK, I can understand that," another was, "Let's do some more homework," and another was, "This is perjury."

Question 8: I think I'm going to follow-up on question 7 and get the perspective from the other participants and figure out if Speaker 1 is actually being hysterical or if there's really...

In my company, the compliance program, Speaker 4, that you put up there is very familiar for us. I think we have a very strong culture of compliance, and I think our approach is just to always try to do the right thing. I think to the last question, he was sort of asking, whether profitability is a safe harbor in some of these markets. And so I wanted to give a hypothetical example, and ask you guys to answer as if you were consultants for a trader coming forward with this, asking is this OK or not OK, because Speaker 1 seems to suggest that there's some uncertainty out here as to doing things that actually make sense, are in the market design, are actually being prescribed here.

So say we've got this crackerjack new weather trader named Ed, and he's got this great new model and he's figured out the weather for tomorrow better than the market. The forward market is trading at say \$50.00, and Ed comes and says, "Hey, it's going to be much hotter tomorrow or much colder tomorrow than what the market is. We should buy tomorrow," and so the traders go out and say they buy 1,000 megawatts. And they decide to put half of that into real time through virtual bidding because they think it's undervalued. So they have half their position in the day ahead, half in the real time. The day ahead market comes out at \$85.00. So the traders made a lot of money on their forward transactions, but they're exposed now to real time at \$85. The real time market comes out at \$100.00. So both transactions were profitable. If someone brought this transaction to any of you, is it very clear what the FERC believes should be done? I mean is that clear? You're shaking your head no.

Speaker 4: I don't think so. I don't know.

Speaker 2: I don't think it's perfectly clear, but I would be pretty comfortable in telling that story. I would have confidence that I would get a just outcome, but you don't know, right? I mean I think a lot of parties are stuck in some cases they think are really unfair, and so there's an uncertainty level out there that's --

Questioner: Well, let me just respond, because that's why she's scared and that's why her traders are scared. OK? Because to be able to come to you and have you say, maybe not, that strikes me as problematic. I mean, here the market is actually in real time, \$100, with no manipulation, and yet there's some uncertainty that's been created about whether that's right or wrong. You'd think it's right. It seems like the right thing to do. Right?

Speaker 4: Speculative trading.

Questioner: Speculative trade that worked. But you may be subjecting the real time guy who put that on to a million dollar fine or something like that. So maybe Speaker 1's not so hysterical.

Speaker 3: It seems to me that that transaction involved economic risk. You didn't know that you were going to necessarily make money in the other market. So then if you go to my first slide and look at the statute, is that a scheme or artifice to defraud? Did it involve any untrue statements? It seems to me that that transaction should be OK.

Questioner: But when I talk to my chief compliance officer, he looked at me like, I don't know about that one. Right?

Speaker 2: Well, I think that's a part of what we're discovering and talking about here, is that the uncertainty is causing a hesitancy that is not healthy for the marketplace.

Speaker 4: I was at a conference a couple weeks ago where one of the lawyers presented a somewhat involved case for a natural gas trader

that had a storage position and an IMEX position and presented some different scenarios on how they handled that. And the room was definitely kind of a third, a third, a third on whether it was a clear case of manipulation, whether it was a gray area, whether it was just really good trading. And the room was filled with people from FERC and industry folks and legal folks, and there was no clear consensus across the room as to how that case would come out if it was investigated.

Question 9: I actually want to try and turn this little constructive. And that's really turning it to what can we do about it? And so my question is, how can we integrate the really tough issues of market design and enforcement, because it seems to me that there's a bunch of things that are easy and obvious and we've talked about them, but quite frankly, I think most of the industry has moved past them. The need for compliance programs, not intentionally acting against your interest in one market to benefit the other, where that is black and white and very clear, I think most people understand that. Not relying on leverage to take advantage of a position. Those things I think are given, and I think most of the industry has moved past that.

What I find really troubling is the more complicated issues, where you have this very complicated interface between market design and physical and financial markets, and how do you actually solve those? And what's really troubling is the conversation in the room today. We have some of the brightest and most experienced minds in the industry, and we can't all agree on those things. I'll give a few examples--and I've worked for public utilities; I've worked for big trading companies; I've worked for merchant generators, number two or three big generators; and I now work for a bank. And quite frankly, with respect to the dialogue and the issues, I don't see a lot of difference across any of them. When I was in the other companies, the same dialogue and same issues existed. When I talk to my peers and friends

back in those organizations, they're all dealing with the same issues. And it's really at the issues where it becomes really complicated.

And I'll just add to the last scenario that was given. Puts on exactly the same trade. What happens? And the intent when going into the trade was that we really have a very bullish view. It may happen in the day ahead market. It may happen in the real time market. You're going to diversify. What happens, actually, if after the fact the real time market ended up lower, and he lost money on the real time market? So now all of a sudden in hindsight, it looks like the real time position lost money, but it certainly could have benefited the financial position that settled against the day ahead position. And now all of a sudden in hindsight, you have a problem trying to differentiate between exactly the same set of trades with exactly the same intent, and it's very problematic.

I'll give you a couple other examples. Back at one of the merchants, post-Enron, we had a DC firm come in to talk to us about fraud. And the presenter said, "Well, you know, you're OK as long as you don't impact price." And I said, "We have the marginal generator. Everything we do impacts price." In these markets, if you're at the margin, everything you do is going to impact price. So the question becomes, what is sufficient? What is acceptable impact to price? Does that mean that I have to bid my generator at cost and commit my generator at cost and not make any money? Or can I offer above my cost, and how much above my cost can I do it? And honest people, really struggling to try and figure out how to act, are struggling with the issues.

Capacity markets. I remember when zone J went from being capacity deficient to having excess capacity and in city generators offered their capacity at the cap. Now all of a sudden, it wasn't going to clear at the cap. What could we offer our capacity in that? And we looked at the FERC rule, and the FERC rule clearly said that

you couldn't bid your capacity in such a way that did not get accepted. And we proactively got all the lawyers in the room and the regulatory folks and I said, "Does that mean we have to offer our capacity to zero? Do I have to keep offering my capacity to zero, because if I offer it somewhere above zero and it doesn't get taken, arguably I could have lowered my price and gotten my capacity taken?" And I think that people are really struggling with where is the interface.

Speaking to Speaker 4's description of traders, the problem is traders deal with gray. Every day they have to make a decision, a precise decision, about that interface in the gray. And where is acceptable? How acceptable is it? And how far can you go? And so my question is, how do we deal with that? Should we have a technical conference to help sort out the issues, that brings the policy issues together? Does the industry start an initiative to try and set standards? Speaker 1 talked about that. We've talked about that with a number of folks. How do we get at it? And I think we have to move past the obvious ones, because it's not about having a compliance program. It's not about training. We all know that. It's how do you solve the real difficult, technical questions on the interface between physical markets and financial trading? I don't know, as panelists, whether if you think we should go down the route of a technical conference, how do we make that happen? How do we move the ball?

Speaker 3: Certainly, I think having the audience here today vetting these issues and having people seem to be receptive, at the Commission, from what I've heard, to trying to get some better clarity is a good first step, and your idea of a technical conference is one that I was thinking of earlier as well. Or being able to bring hypotheticals like the one about the weather prediction, and getting a real answer to it rather than, "Yeah I think it's OK, and he thinks it's not OK, and we don't really know," and the compliance officer saying, "No, you can't do

that.” That’s sort of troubling. Because then we’re hearing that the transaction may not be happening. But you can’t control the weather, so it seems to me that one should be clear.

Speaker 2: I think the gas price reporting experience is relevant here, and the industry did kind of frame issues that led to a series of technical conferences that did shed a lot of light, and it was a case where the Commission said, “This should be your responsibility, industry,” and industry then moved forward, and it was an interesting technical conference that actually was conducted as a staff discussion rather than run by the Commissioners. The Commissioners were in the room, but the staff ran the conference. It was distinctive, and it was leaving some distance between the two parties. But everybody got to hear what the issues were, and Commissioners even asked questions of a more, if you will, a clarifying nature. And it did help move the ball forward there. I think most people were pretty comfortable with the outcome of that process.

Moderator: Well, thank you. I think the technical conference format is good for complex situations where there are a lot of hypotheticals, and this is certainly one.

Question 10: Speaker 1 brought up the issue of market design and what constitutes manipulation. And so let me put it, I guess, to the rest of the panelists, and I think Speaker 2 kind of stated an opinion of sorts. But if it’s the market design that’s bad, and legitimately market participants are following the market design as it exists today, should that be considered manipulation? Because they’re just responding to the incentives that are there. And I say that it’s incumbent upon the RTOs. It’s incumbent upon all of us as RTOs to make sure that we get the market design right, and when we find these kinds of flaws, that we get them corrected immediately. But that’s really on us. Is that the fault of the market participants, or is that the fault of the RTOs, really?

That’s the first question, and then the second one is, as we’re getting into this whole gas electric coordination topic here, let me give you an example of, is this market manipulation or not? Suppose that I’m a gas fired generator. I have a day ahead position. In real time, the spot market price makes it such that I can actually make more money by just selling the gas rather than burning it for power. I’ll take a loss in my day ahead position because the real time market price is higher than the day ahead price, so I’m losing money in that one market, and I’m selling the gas because it’s more profitable. Is that market manipulation? Or is the opposite market manipulation? If I don’t actually sell the gas, and it leads to curtailments and even higher prices in the gas market, and I go ahead and burn the gas, is that market manipulation of the gas market, even though I’m a power generator?

Speaker 1: I think my answers are no, yes. There are two different examples at the end. The first case didn’t sound to me like market manipulation and the second one did, it also had other gas sales. If you’re not making money on other gas sales, then I would say no. But if you’re causing the gas to burn for less than economic reasons, then I would say yes. You’re spilling the water in order to raise the price of the other stuff, and so on.

Speaker 3: And as to your very first question, it seems to me that there are various cases pending before the Commission that involve those fact patterns, so it’s probably better for us not to get into that. But we’re going to see answers, I think. And those will be very interesting to see.

Speaker 2: On your market design flaw, what I would think about doing is I might communicate to either the RTO and/or the Commission the flaw. And then I’d start to trade on it. Say, “There’s a problem here and you can make a lot of money because there’s a problem here,” and so you’re not doing it any nefarious hidden way.

You've pointed it out. But then do your arbitrage.

Question 11: I want to just to go back to the very first point the moderator raised. What can the Commission do? And it seems to me you hit on a very important point that would be very helpful, which is you made the point that it took a long time for the case law under the 10B5 standard to develop. As you know, the Commission did not want that standard as its market manipulation standard. A number of people and I begged the Congress not to use a disclosure statute on top of a market rule.

So I start with the proposition that you are sort of dealt a hand that the Commission didn't want in the first place, which is a disclosure statute for a market form of regulation. OK. That was a bad hand. But that's the hand you've been dealt. So the question becomes, you've said in the initial series of rulemaking, 745, that you're going to rely on the 10B5 case law. I think a very significant chunk of the uncertainty, not necessarily the related position issues, but the rest of the uncertainty, comes from when the Commission strays from that. And that gets directly into the earlier question of what does "impairing a well-functioning market" mean? I think if the Commission did nothing else but say, "We're going to really rely on the case law under 10B5 and go back to what is fraudulent conduct and what is fraudulent intent," and then said that's the main body of law we're going to rely on, and then either abandoned the well-functioning market test or at least tried to give it some definition, those two steps in and of themselves, which are directly contrary to the interest of my daughter's 529 college fund, but those steps alone I think would be very positive. Just those two. We're going to rely on the fraud based case law, and when we stray from it and go into this impairment of the market test, whatever that means, we're going to try to give that some definition. I think if the Commission did nothing else but those two things (and that's a lot easier said than done), I think everyone in

this room would think that was a big step in the right direction. And so from my point of view, that's my answer to your first question. And I'd hope the Commission would give that some serious thought.

Moderator: Well, thank you. I think that's a very productive answer and one of the rules I try to live by is don't play in the statute. Don't whine that we don't have a good enough statute here or there or whatever. It is what it is.

Question 12: As this discussion has gone on, it's kind of struck me that there are kind of two issues going along. And one is the temporal issue, which is concerning a lot of the trading desks, in particular, that there is now this regulatory risk that wasn't there before. And so my question to you is, to what extent, in the kind of near term, while this works itself through the precedent process, is this a mitigable risk--can you insure your traders the way my dad who's a doctor has malpractice insurance? Are there ways in the near term to mitigate this? And so that's one question.

The other question that I think Speaker 1 raises is that depending upon which way those precedents go, you work towards a way that either the markets continue to work, or you don't. And so my question to Speaker 1 is, can you imagine a standard that is different than the one you propose (of kind if it's a transaction that benefits in both places), can you imagine there being some other bright line where the markets potentially do work as long as it's a clear bright line? Is the issue that there's a clear, bright line and that perpetual indefinite uncertainty is going to bring the market down, or are there going to be bright lines that are going to preclude transactions that are going to allow the hedging to work and the interactions to work the way they need to?

Speaker 1: I think that's a very important principle, the bright line that's the HQ Energy story. And I would like to see that preserved.

And if we're going to replace it with something else, I don't know exactly what it would be. And I'd especially like to know if we're replacing it. And where I am at the moment is I'm concerned that we're replacing it but not saying we're replacing it. And I think the Gila River case makes that point as clearly as I could, and I did it in the slide that I presented, which is, is this consistent with the HQ Energy case? And the answer is that I can't tell by reading the settlement.

Speaker 3: You asked about the analogy of your father having malpractice insurance. I understand that recently there was a potential proposal where traders would have licensing requirements, and I don't know if some benefit would come such that if you're licensed then the worst that can happen to you is you lose your license, and not that you get fined a million dollars. I don't know how that plays out, if that ends up coming into play.

Question 13: I just wanted to clarify something related to what Speaker 3 just said. I can tell you that if our traders found a flaw in the market and they came to me and we called the Commission or the ISO's to tell them about the flaw in the market, I would absolutely tell them, do not play around with that. So I would say do not exploit the flaw in the market.

Speaker 3: I was just giving my personal opinion and that's all I think it is. The issue goes along with your earlier point about people are afraid.

Speaker 4: That goes back to insuring your traders, the earlier comment about how you kind of all huddle together and the market doesn't advance because everyone's afraid to do anything that may get them outside of that herd.

Comment: But remember, the case law in the Commission. And I'm not saying anything that hasn't been said publicly. The case law of the Commission is if you identify a flaw in the market and you trade around that arbitrage opportunity, the Commission has said consistently that the way we address that is not to prosecute people for market manipulation but to fix the rule, which is what Speaker 1 has been saying for how many years now? And I think this gets back to the moderator's original question, how do we fix the rules requirement? I mean, the Commission has consistently said, for market flaws, to change the rules, not to prosecute the market manipulation. And now the reason why your traders are scared of that is because now it's moving beyond that. And that's the problem.

Moderator: Well, it goes back to what I said at the top of the hour, which was that this is just one of the tools that we use. There are cases in which the markets are being redesigned, and those continue to happen. None of these are standing still, as well as more significant rulemakings, and then enforcement as a subset of what we do. I guess we're going to wrap this up. I feel like probably less than usual we have given you a lot of good guidance. But it is absolutely a work in progress, and for that reason, I've tried to be even more careful than normal and not to prejudge things that might be coming. But I think the questions that you've raised, and particularly the observations of the folks who do compliance trading with the traders about the misapprehensions that they have and the concerns and what that might mean for the market have had a big impact.

Session Three.

Our Annual “Hundred Year” Storms: How Much Electricity Infrastructure and Reliability Should We Be Planning For and Investing In?

Hurricane Sandy devastated the East Coast of the U.S., which has been hit by two “hundred year” storms in the last two years. Japan was attacked by an earthquake, the severity of which exceeded the planning parameters of energy planners and system designers. The Netherlands calls for dikes to withstand a thousand year storm. There is always a delicate balance between what is to be planned for and how much investment is affordable. How have those balances been struck historically? To what extent have recent experiences and climate change considerations altered prevailing thinking? What influences on planners are ratemaking considerations, the availability and costs of insurance products, and the availability of public funds? How, if at all, has the growth of competition in the industry affected our ability to make and enforce understandings on the level of reliability we need to plan and invest for? Both underground and above ground wires seemed vulnerable to Hurricane Sandy’s wrath, so what investments ought we to be making? What are the appropriate risk allocations between utilities, consumers, and government in the case of natural disasters, and what implications arise from the various ways in which risks might be allocated?

Moderator: Good morning everybody. I don’t have much to open this with other than just, I’ve been asking people as I had breakfast this morning, and in conversations yesterday in preparation for this, is this just a cycle? Are we just going through a cycle now? We’ve had a number of storms, high-impact incidents, and so everyone’s talking about it, largely because, in my mind, every time you have one, it ultimately ends up with some politician needing to blame somebody publicly, rather than explain, really, what this is all about, because it’s much too complicated for anybody to try and explain in 30-second TV sound bites.

So then you have the cycle that that all starts with. Blaming somebody, what do we do, let’s have a discussion about how do we make sure that we limit the impacts, or prevent outages as a result of these cataclysmic events. Or are we truly ready, state by state, as a nation, to have a new analysis, if you will, of what it’s worth to protect against outages? There’s certainly a different state of need today for reliability, with the increasing dependence upon electricity that drives so many facets of our life. So does that call for a recalculation, or do we just let this cycle ride out, and we kind of stay in the pattern

we’ve been in for a number of years? That’s what I think about when I think of this topic and the choices before us.

Speaker 1.

Thank you. Some of the best parts of yesterday were give and take and responding to questions. So what I thought I’d do is just pick some of the themes in this paragraph that we had and give you some thoughts about them, and then we can talk.

The saying in my state, in Connecticut, for this past storm, was that it was preceded by two major storms, and that had a big effect. In 2011, we had both a hurricane, which turned out to be Tropical Storm Irene. And then we had that Halloween snowstorm that occurred, with a lot of wet snow while the leaves were still on the trees. Electricity was out for well over a week. Utilities not fully prepared. It was a surprise and caught everybody unawares.

So you had two storms, and there’s always a certain amount of complacency. If you hadn’t had an emergency in this period of time,

obviously you're not thinking about it as acutely as if you just had one.

We had an emergency drill for four days at the end of July last summer over a weekend when everybody would rather not be at the armory, but at the beach or somewhere. A four day drill going through this just because in Connecticut we know we're going to get a hurricane or an ice storm or a flood or something. We have also had, since then, a docket that my authority presided over, which found that the utilities' performance was deficient, and presented a rebuttal of presumption there would be penalties in the next case, and in their ability to recover costs from it. So I just put that on the record.

We also did a standards docket--what standards should we be held accountable for? And that needed to have further definition, so it has it now. And we've launched one right now, it's what I've called a "best practices" docket, because I wanted to know what utilities perform best across the country. Which ones do the best job, and what are the reasons for it? How about public utility regulatory authorities? Which ones do the best job and why?

And finally, how about the municipalities, because the municipalities are absolutely critical to the utilities' ability to perform, and they have to work together, they have to communicate. And I need to make the caveat that my authority will be doing a review of the performance of the Connecticut utilities on this Sandy Storm. So that limits my ability to be too specific about performance in Sandy.

When you got Sandy, following those two other storms that we had, now, do they stretch or expand the new category of demand for ensuring reliability service? I don't know, but the public does. As far as they're concerned, when you get three huge storms that they hadn't seen in the last 10, 12 years, something's going on. And so whether it is a real change or not, there is a public reality that they think it is, and if they

think it is, that affects the politicians, the utilities, and my agency.

You know, the world is increasing its dependence on electricity. I spent a lot of my time in third-world settings, working for the World Bank and for other organizations. And when you see a village or town or area get electricity, it just changes everything. And in the United States, we've gone far beyond, you know, lights and that sort of thing. And now our entire lives depend on this electricity. And, therefore, the patience for its restoration is getting shorter all the time. So it may well be that the dependence on electricity is colliding with global warming.

So the question is, what's the fair and reasonable expectation for preparation and restoration cost? We had the statement, there's a delicate balance between what should be planned for and how much investment is "affordable." Have those balances been struck, historically?

Well, from the regulator's perspective, the utility comes to the authority with a plan for infrastructure investment, it's a rate case. And the plan reflects those initiatives that the utility believes are necessary to sustain or improve reliability. The regulatory authority may modify them, and almost always the modification is a reduction. I've never heard of a modified increase, but the point is, it is reviewed.

Well, the term "affordable" is not in our statutes. So that's just not a concept that we have. And it's hard to calculate what an individual customer household can afford. So, you know, that isn't there, but the impact a rate increase would have on the economy, particularly during economic downturns, is relevant in how much a rate case would be fair and reasonable. In my state we have three of the poorest cities in the United States, Hartford, Bridgeport, New Haven, parts of Waterbury, parts of New London. I mean, Connecticut is thought of as a wealthy area, and some of it really is. I mean, you go

through some areas, and there's astounding wealth. And then you go 10, 12 miles down the road and you have remarkable poverty.

So the point is, the rate base. Who pays? That's a very, very real question, because it's not a homogenous population. To what extent have recent experience and climate change considerations altered prevailing thinking about this? Well, I think there's been a recognition that the soft economic environment in recent years, especially the 2001 and 2008 recessions, have led to reduced electric spending on infrastructure, particularly tree-trimming. And this reduced spending may have worsened the impact that Sandy had on electric infrastructure.

The prevailing thinking has not directly engaged the issue. There are two emotional issues at play here. One is tree trimming. And the other is not having electricity. And believe me, you hear really angry voices about both. And they call the utilities and complain, and our public utilities rank their authority as a consumer service that takes calls from the public. And both of them can present, I guess outrage is the clinical term, just absolute outrage that this tree that, you know, my grandfather planted, and whatever, you took it down. Or, I haven't had electricity, it's four or five days, six days, you know, and my aunt is on a respirator.

You all know about this stuff. And there's very little patience. There is a conflict between the two, obviously. I mean, if the tree didn't come down, you may lose electricity. So you balance that, and that hardens you a little bit to a rational discourse in a situation which is not given to rational exchange.

The public's conclusion, though, is that if we are going to have these storms...and they would say that, "Yeah, this is three within the past 18 months that we haven't had in the past dozen years, yes, there's a change going on. And if that's the case, then the system, we don't care who the system is, it's the governor, the public

utilities regulatory authority, the utilities, somebody, the system has got to adjust to manage it, because electricity is critical to living."

What are the influences on planners regarding rate-making considerations, the availability and cost of insurance products, and the availability of public funds? Well, the basic fact is that utilities are in a world of rate of return on capital investment, not on expenses. So they tend to choose investment over expenses whenever there's a choice.

But they're almost always concerned that regulators will not approve a rate increase out there. So they want to tie critical programs, critical expenses, as directly as they can to a rate case. And you're more likely to see a program expense justified when a rate case is near or pending. But it's less a matter of time that is of direct tie.

How has the growth of competition in the industry affected our ability to make and enforce understandings of the level of reliability we need to plan and invest more? Well, I don't know, maybe I'm being a strict constructionist here, but reliability is very much a function of the electric distribution companies and not the producers. I mean, when it goes out, when there's a tree across the lines, it's coming into my house, and somebody's got to come fix the wires. It's not a production question. We haven't seen an effect from competition. We discussed that yesterday, competition among suppliers and what that all means. But when you're in the armory and you're managing this day over day, you're dealing always with the local distribution companies.

You know, there was one case during Sandy. Dominion is a provider, and has a nuclear plant called Millstone. And they cut back from 75% production to 70% at one point, because there was debris in the water in Long Island Sound, and their protocol called for cutting back intake

a little bit just to make sure you didn't get logs or other floating stuff in there. And so there was somewhat of a reduction, and then you know, ISO New England adjusted to that and carried through. But that was minor. So I haven't seen an effect on the suppliers. But daily, all the time, intensely, the electric distribution companies are thoroughly involved.

Both underground and above-ground wires seemed vulnerable to Hurricane Sandy, so what investments ought we to be making? Well, let me just start by saying that there was no model for Sandy in Connecticut, at least. And the weather forecasters were there, everybody tries to figure, all right, what can we expect? We have models for ice storms. We have models for your basic hurricane. But this thing, there was nothing like it. It came up the coast and intensified.

When a hurricane intensifies, it gets smaller, the winds at the center become stronger, at the exterior they become weaker, and it turned left and went into our friends in New Jersey and New York, hitting them directly and us peripherally. We still had 600,000 outages. We had lives lost. I mean, it was a serious storm, just not as serious as it was in New York and New Jersey. But one of the effects was that coastal flooding was more destructive than the wind. And as I said, we didn't have a model for this.

So if you can just picture that Long Island Sound, the wind just blew the water in there. So high tide went up, and low tide couldn't get out. So the high tide comes back in with more wind, and it's got to go somewhere. Well, we didn't have models for it. We didn't know where it was going to go. And it turns out it found Greenwich and Stamford and Norwalk, and it just kept pushing it down toward New York City, and when it tried to get out past the Race Point and Fisher's Island and that area, it couldn't do it.

So we had flooding that we hadn't seen before. About 12 sub-stations--this is brand new for the electric distribution companies--were in danger

of flooding. And they had sandbags up, and they actually did new concrete walls and everything. So we had a brand new challenge based on something that we had not seen before, the threat of seawater incursion.

Now, obviously, aggressive tree trimming is also a priority. During major storms like this, aside from the flooding, about 89% of the outages are caused by trees. And when you go out, and I did, and talk to the crews out there working, they laugh at the term, "tree trimming." They said, "You're not 'trimming,' it's not a branch that does it, it's the damn tree, the whole tree falls over." All right, I got it. But in some areas, only radical surgery is going to reduce the risks of outages.

I'll just tell you a story. I went down to one of the wealthy suburbs in Fairfield County, and there was a street that had eight houses on it, and there were six trees down across the wires on that one street. And it had taken crew, they'd come in from Nova Scotia and Boston and Kansas. Crews with four or five big trucks, it had taken them most of the day. They had to drill in, put in six new poles, cut the wires, you know, everything to restore the power.

And you're looking around, and there were six trees that had come across. There were maybe 20 trees that had come down. And this is one of the famous wealthy neighborhoods down there. Now, you look around, there were maybe 400 or 500 trees that could have come down. And I'm talking about trees 150 feet high that are in somebody's yard. They're 50 feet back. And you just look at it, and the crew says, "Well, they'll come down next time." I mean, this is not a matter of tree trimming. If you have 400 or 500 trees on a street with eight houses on it, and 20 of them came down this time, that leaves hundreds vulnerable to come down the next time, and they will.

And that town, Greenwich, Connecticut, that town might have just tens of thousands, some

say 40,000 or 50,000 such trees, 150 feet high, that are susceptible of coming down. Now, what are you going to do? Are you going to take down 40,000, 50,000 trees? I mean, you know... And they're on private property. And you know, they're way in. So I mean, people like to talk about tree trimming as a way of, you know, alleviating this thing. Hell no, it's complete eradication if you want to be completely safe. And so we won't. You can't. And so, therefore, trees falling on wires is just going to be part of what we do in the future.

How do you pay for that? Well, in Greenwich, there was a proposal to put the wires underground, and the electric company said, "Fine, we'll do that. It will cost you about \$200 million."

"What? We can't pay for that."

"Well, who should?"

"Well, you should."

"Well, that goes in the rate base. So the poor family in Bridgeport pays so that you can put your lines underground?"

"Well, someone should."

"Well, it's going to be you."

I mean, this is, that's the argument you have.

I've got some more things to say about infrastructure, but the point is that length of outage intensifies the value of electricity. The longer it's out, the more value electricity has. The greater the area of the outage, the greater the value of electricity. And the loss of service in some entities is more destructive than others. Hospitals, gasoline stations, grocery stores, more than a barber shop or a fitness center, for example.

I would say that the question of reliability is now a political issue. It affects elected officials and all of us. The expectation is that we will make it work. The recent storms enhanced the public expectation that the utilities, the regulators, and the government will make restoration a priority. And that challenge is not fully engaged. The complexity of it and the inevitability of future outages is there. We're learning about each other, but the key is going to be communication. We've made a lot of progress on that, and I think we have the strange advantage of having had three storms to help us get there. So I'm going to stop there and let my colleagues proceed.

Question: Right up front you said, how do you calculate affordability? And certainly one of my pet peeves in this sector, we always talk about affordable rates. Is that something just out of the equation for you in terms of this analysis? Is it strictly a net value?

Speaker 1: Well, that term, "affordability," isn't in there. "Just and reasonable" is. And everything in Connecticut is expensive. We frequently are the most expensive state in the United States in electricity. We have even beaten Hawaii, where you have to ship oil to each island to generate electricity. And it's a serious problem. I mean, I don't think we're number one right now, but we're in the top five.

So, yes, it gets to jobs. We have a comprehensive energy strategy coming up now as to how much you use shale and what should that do the generation of electricity? So cost is huge. And when you want to make these changes, yes you do, but, historically, we're a strong manufacturing state. Our manufacturers are at a disadvantage because of the cost of energy, and therefore both to the economy of the state and to the individual rate payer, the "burden of that cost" is probably the language that we would use, and it's obviously very relevant.

Question: So I'm speaking from the heart, because we were out for 11 days with Sandy. And the reaction that we had was, well, this is never going to happen again, we're just going to buy a generator and have it be a whole-house generator, run on natural gas, and that will be that. In Connecticut, essentially the whole town of Greenwich, I assume, is thinking the exact same thing, but obviously the people in Bridgeport aren't going to be able to have that option? So I wonder if there are discussions about that kind of a divide?

Speaker 1: Yes. Let me just state that when you hold a drill, you have to postulate a storm. We postulated a direct-hit by a category 3 hurricane hitting New Haven and going right up straight through Massachusetts and Vermont. A direct hit by a category 3 hurricane would mean that 80 to 90% of all trees in the state would be down. So your generator doesn't mean a damn thing, because nobody can get to your house. And so a generator can last for a while, but very soon, your cell phone will go out. And you can't go to your neighbor's, you can't go to work, you can't go to school, emergency medical service can't reach you.

And so yes, there is a dichotomy between the two...We had a very ugly situation in which the mayor of Bridgeport accused a utility of favoring the wealthy suburbs in restoration over the city of Bridgeport, which led to people coming out and throwing rocks at the utility ground crews, rocks, eggs, and you know, just getting into fights with them. While they're there, some natives of the city of Bridgeport, to try to restore the power.

Well, you know, first of all, they just adamantly and with great passion say, "It is not true." And they presented, right there at the Armory, at the emergency operations center, evidence that in fact they had done everything possible to restore electricity to the city of Bridgeport, no matter who lives there. But yes, this was a have's, have-

nots situation that resulted in physical violence. So unfortunately it's a serious issue.

I lived in various parts of Africa and lived through some very tumultuous times in which law and order was gone and you feared for your life. And I start to see elements of that when people do get desperate like that. I mean, human behavior is the same, whatever the setting. And you began to see the kind of absolutely raw, I've got mine, I will do whatever it needs to take to get what I need to have, kind of behavior. In which case, you have to work with the National Guard and the state police.

Well, they had to deploy the National Guard to prevent looting in some areas where they had had evacuations. And some of the generators they installed to keep the cell phones going were stolen. You know, up in a pickup truck and gone the very next morning. So, yes, the social compact is challenged by this kind of event.

Speaker 2.

Speaker 1 and I did not plan this, but the first topic on my list is "expectations." What I'm going to try and do is give you a little bit of my perspective, coming from a safety regulatory perspective. And from a safety regulatory perspective, looking at nuclear power plants, a lot of these questions and issues, to some extent, were answered, maybe not necessarily well, but nuclear power plants, for example, have to be designed to deal with floods, hurricanes, tornados, all the kinds of natural disasters that can happen. So there are always arguments about whether you've done it well and done it right, but the model has always been there to do that, and it's always been a basic element of what you have to do.

So I'm going to try and talk a little bit about what that framework is like, and see where it's applicable here and how it could work. But the first thing is, you have to understand what expectations are. And maybe you should even

put it as a zero here instead of a number one. It's really the framework of what you need to do in this kind of a setting.

If you're dealing with natural hazards, with things that can make whatever system you're dealing with not function, you have to know what the public expectations are. And I would certainly agree, I think, with Speaker 1 and some of the other comments, that expectations have changed, I think, a lot. Electricity is now much more dominant and much more of a basic necessity, almost, or perceived to be that way. And I think that creates a greater expectation for reliability.

So ultimately, I think that once you understand those expectations, you then have to design and implement a system that meets people's expectations, or you've got to do a lot of communicating to change the expectations, to get expectations in line with what your capabilities really are. That's not to say that that's easy.

You know, as I said, nuclear power plants have been designed to deal with floods and hurricanes for years. I wouldn't say that even at this point, after decades of that, that we have alignment on expectations and capabilities. So I'm not trying to say that any of these things are easy, but ultimately that's the basic equation.

You've got to figure out what the public expects. Is it, you know, no outages? Here are some examples of expectations: "Nuclear power plants should never have accidents." There certainly is a segment of the population that has that expectation for nuclear power plants. That's unrealistic to actually implement. But it's an expectation out there. I don't think it's the majority expectation or anything like that.

Another expectation: "Nuclear power plants will have accidents, but my family will be safe even if they do." OK, that's an expectation I think you can get to with some dialogue, with some

communication, and ultimately put your expectations more in line with what your capabilities are.

I'm not an expert in electricity transmission and distribution, so I threw down some expectations there which are just based on personal experience. And I'm pleased to say that one of the questions just now hit one of them almost exactly. They run the gamut from, "My electricity should never go out during a hurricane." There probably are people who are now saying that, you know, "This is unacceptable. Why is that happening, you know, in the modern area?" Another possible expectation: "My electricity should only go out if there's a greater than category 1 storm." OK, what does that mean? As I've said, you have to postulate a storm, you have to figure out some kind of storm.

And then, here's the last sample expectation: "I'm OK if the electricity goes out, because I've got a portable generator." But then that raises questions of fairness and equity, and whether that is something you as a homeowner should go out and provide, a portable generator, or whether that is an obligation of the utility. If you get to a level in which the expectation is that you need to be able to survive this kind of a natural hazard, then is there an obligation for the utility to provide that kind of element as part of the system? And then that starts getting into maybe a whole new way and a whole new model for how we look at electricity generation.

In case anyone is going into this conversation without thinking that these things are real, I just pulled up some statistics. There was a Congressional Research Service report that was done in August. They published a report, and in there they said there are about \$20 to \$50 billion dollars annually in costs from storm-related outages.

And I actually just did a Google search when I was putting these slides together, it was about

two or three days ago, and I Googled “storm-related outages.” And I had no idea about a lot of things that were going on, but there were a bunch of storms in the Midwest that had produced outages. There were a bunch of storms in San Francisco at the time that were producing significant outages. You know, we here on the East Coast have been focusing a lot on Sandy, but these things happen on a routine basis and occur quite frequently. So these kinds of natural hazards are out there, and they do have impacts.

Of course, the incident which I’m most familiar with is the accident at the Fukushima reactors in Japan, which was really triggered by a natural hazard, something beyond a hurricane, but an earthquake in a region that is known to have earthquakes. But what you had, in many ways, was something that was unexpected. It was an earthquake followed by a tsunami. And I’ll talk, if I have time, a little bit about this idea of probabilities and the frequencies of these kinds of events, and why that’s not necessarily a useful metric.

But bottom line here, there have been some cost estimates right now, and they’re preliminary, and no one may ever really be able to say how much that accident cost. But one estimate coming from the American Society of Mechanical Engineers was about \$500 billion, half a trillion dollars, as a result of the nuclear accident as a result of that earthquake and tsunami.

And that was done earlier this year, before Japan had made some announcements about moving away from nuclear power generation completely. And if they do that, as that estimate says, that that’s not even included in that. And if you were to include those costs, or that change in the way that they operate, you’re looking at substantial increases, trillions of dollars, potentially, of cost increases.

So I put that out there because one of the issues of dealing with these areas is that often you’re

talking about hypotheticals. And it’s very easy to dismiss a hypothetical. You know, if you’re planning for a storm and planning for that storm which may happen, which comes from the imagination of some people who look at these things, and your practical actual cost is to go and take down a tree that’s been there for 150 years, people can appreciate the immediate concern of that tree.

It’s hard for people to appreciate a once-in-100-year, or even a once-in-10,000 year, storm. So it’s important, I think, to appreciate that when these bad things do happen, they can have really significant consequences. And as I said in the previous slide, the estimates the costs of power outages are \$20 to \$50 billion dollars annually.

Now, it’s not a large, one-time event, it’s multiple events adding up to this kind of cost. So if you take anything away from that, I think that one, often the worst kinds of natural hazards are the combination events. It was Hurricane Sandy with this frontal system that gave you this big storm surge. I mean, it was a just a category 1 storm without really strong winds. So it’s those combined events. In Japan, it was the earthquake followed by the tsunami. People had planned for the earthquake; they hadn’t really thought about the tsunami following the earthquake in the right way. So to some extent you need really good imagination to think about these things if you want to tackle the challenges of addressing them. And then, as I said, the economic costs can be staggering, let alone the daily life disruption, the intangible kinds of facts that are very hard to categorize.

I’m not in the government anymore, so I don’t have to deal with the realities, I can deal with the impractical. So I’m going to go through a whole discussion here, assuming an infinite amount of money and an infinite amount of resources, and then kind of work back on how you go back from there. And the punch line is, it’s really not that easy, bottom line.

But if you've got infinite resources, the answer to this question is fairly simple. You redesign, replace, and upgrade all the transmission, distribution, and generation to ensure that your design and implementation are commensurate with the expectations of customers for natural hazard situations. I mean, that's the answer in a nutshell.

I put a phrase like that up there because, previously, Congress gave us a similarly wonderful phrase that we had to then try and implement, and bottom line is, it's not easy. In the nuclear world, it's "reasonable assurance of adequate protection of public health and safety," which sounds great and perfect. Implementing that is not really easy. But, bottom line, this is all you need to do. If you have infinite resources and infinite money, that's all you need.

So what does it mean? Basically I would say there are three things you need to do. First, you design your systems to prevent whatever damage state you want. So if it's electricity distribution, it's no loss of electricity. So the first step is, you want to design your system to prevent the loss of electricity, and then you go and you build that.

So what do you have to do to do that? You have to characterize the hazards, and you have to be creative. You have to go and look at, what are the things that could happen, not just the things that have happened. Because invariably what's going to cause you the problem is something you haven't seen before, it's something new. So you have to be creative and you have to think about the combination of a category 1 hurricane with some type of other event that can give you a large storm surge, and the tide just happens to be perfect.

Then you design solutions to address those hazards, whatever that particular answer may be. And you implement that design without any mistakes. So, again, this is the ideal world.

Now I have a good robust system. You don't stop there, because you do know that your imagination may not be perfect, and that there may be something you haven't thought about.

And so all those systems that were designed to deal with all the hazards that you thought about may not exactly work, because you're going to get thrown something you didn't anticipate. So your next kind of level of defense is to develop mitigating strategies to deal with that outcome. So, in the electricity world, as a simple idea of what this means, it would be the ideal portable generators.

So you would design your system to ensure that category 1 hurricanes don't topple power lines or utility poles, but as your mitigation strategy, then, you would perhaps either outfit every home with some type of portable generator that has the ability to provide power for 48 hours, something like that. So that's the model and idea of what this next level is. You've designed this system, and then you take a step back and say, "OK, well, what if everything fails? What do we do next?" And then you add those extra layers of protection.

The last step then is, if all that stuff doesn't work, you go to one more level. And that's some type of emergency response. It's some type of usually government or other maybe utility-sector-wide effort to then mitigate and help deal with that. And that's something that's done today. Utilities get together, they provide resources, they provide personnel to help do recovery and to help deal with the event. But it's all part of the comprehensive system that looks at these things in a holistic way, and each of these layers is built one upon the other to get your solution.

So that's the easy part. Now you've got the real world. And how do you do it? Well, you know, as I said, I think in the end it's a balance between what you're able to do and what people think you're able to do. So, with limited

resources, you really have two options. One, you have to spend some resources trying to address the issues. If you can completely address, you know, an issue, then you do that to the extent that your resources will allow.

Alternatively, you've got to address expectations. At a certain point, if the expectation for people is that we are not going to lose power after storms, and the cost of doing that is just impossible, at a certain point the political leadership, the regulatory leadership, the utility leadership, and the public interest community has to come to some kind of agreement about what is realistic and what we can actually do. And ultimately, then, you've got to figure out a way to choose among all these different alternatives.

And one thing that I want to stress is that sometimes it's not just money that's the problem. Sometimes it's technological know-how. It's imagination, it's creativity, it's properly understanding what kinds of storms, what kind of events, can actually happen. I think there are probably a few people who had anticipated this kind of significant storm surge that you actually saw in the New York metropolitan area. The hardest part is believing people when they come up with these kind of crazy ideas for storms, because you sit back and you say, "Well, that's never really going to happen. You're never really going to have an earthquake of that magnitude and a tsunami that's that big, that high. It's just not going to happen, and here's why, because we've never seen it, or we don't remember it, or we didn't record it in history." So the hardest part is sometimes just believing these people, because sometimes they're the people who kind of look like quacks. And that's the reality. But sometimes that's what you need to think about.

Sometimes it's just simply a technological skill set. I mean, 30 years ago, you couldn't really have designed systems to deal with hurricanes in the way we see them now, because the modeling

capability simply wasn't there. You just couldn't do it. Today we can do a lot better, which also raises the expectations that we can plan for these things, because we can model them now in a way that we couldn't before. And then sometimes, quite frankly, it's just lack of imagination in thinking about the kind of thing that could go wrong.

So here's the bad news. There's really no easy way to do this, fundamentally. You get put in the regulatory position, you have to make difficult decisions. In the nuclear world, we've tried probabilistic risk analysis. That is ultimately a flawed model for a lot of reasons. It's not an un-useful tool, but it's not going to give you a definitive answer. The basic reason is that it's ultimately hard to appreciate that something that has a probability of once in a million years, you can't take that off the table.

But the fundamental problem is that just because something's a once-in-a-million event doesn't mean it won't happen tomorrow. And once it happens, then it's something that happened, and you can't sit back as the regulator and say, "Well, that was our one-in-a-million probability event," because you either look really, really bad because you didn't predict it, or you look really insensitive. And that's not really effective for any government official of answer questions that way.

So I'm not a big proponent of cost-benefit kinds of things, because in the NRC world, in the safety space, cost-benefit comes down to ultimately putting a price on, on usually human life. And in nuclear speak, the cost equation is that figure there. It's \$2,000 per person REM. REM is a measure of radiation exposure. You know, I always find it fascinating that nature just happened to be such that, you know, the equivalence between radiation exposure and cost is an even \$2,000, and it's not \$2,001.37.

So, you know, the cost-benefit analysis hides what is ultimately still a subjective

determination about where you place the value of that kind of bridge between the cost and the human interaction. And that's just as subjective as any other kind of model, but you create that number, and then you can do a bunch of math, and it makes it look objective. But in the end, you've still got very, very subjective decisions about where you place that value. So that's the bad news.

The good news is that ultimately I think you can do a lot with communication. You can do a lot to raise awareness of these issues proactively. I think it's much, much better. And you know, I think these couple of storms that have happened have given people an opportunity to start talking about these things to really get a sense of what's realistic, and what utilities can really do that's within the realm of our finite resources, and get better alignment between the expectations and the actual capabilities. But it requires tremendous collaboration and a tremendous amount of communication. And that needs to happen best in times when there isn't a storm, but before the storm.

And the last slide I'll throw up there is just to maybe think about. Sometimes what you need is a paradigm shift. Sometimes what you're really talking about are solutions that are a complete shift away from what you've talked about. I mean, I read a report studying ways to make utility poles stronger. At a certain point, you maybe have to step back and say, is this utility pole the right model? And the obvious answer, the simplest answer, is, well, OK, bury lines. But when you bury lines, then you're dealing with underground effects. Potential flooding, these kinds of things. So there's a certain point where you have to just take a step back, brainstorm, and say, is the model right? Maybe there's a better model completely. And so I just threw up there, as almost a hypothesis, "Is smaller, modular, and distributed better?" Is that really the right answer?

And then you start to think, instead of trying to retrofit the system, can we move to a new model that's going to be built in to deal with these kinds of issues in a way that the current system just is not able to do? So you should be able to make that conclusion for yourself, and I'll stop there.

Question: On the previous slide, what's a small modular nuclear facility? Is that a hypothetical? Or is that real?

Speaker 2: That's a thing that people are doing right now, and I put that up there, again, because it relates to this idea of changing the paradigm. If you look at large nuclear power plants, the problem, from a safety perspective, with large nuclear power plants is not really the plant operation, it's what's called decay heat removal. It's basically after you shut the plant down, you've still got a lot of energy in the system, and that's where you run into problems, if you can't cool the plant after you shut it down.

So if you've had those accidents, and it's a large plant, you take the example of Fukushima, you have a lot of radioactive material in that reactor. So from a lot of perspectives, having a smaller reactor is better. You've just got less nuclear material. Say it's about a tenth of the size, you're not going to be able to contaminate as large of an area as you did in the Japan if your reactor is smaller. I mean, it's just simple physics. It's simple math.

So it's a totally different way of thinking about the problem, and it also gets you some advantages from a cost perspective, because you don't have to front \$10 billion in capital to build a plant that's going to take you five years, and that capital is doing very little for you during that process. If you have smaller, modular facilities, you can build these kinds of reactors, potentially in a factory. So it's a very different cost model.

And so I throw that up there, not necessarily to endorse the technology, but to say that in a sense, it is a complete paradigm shift from what is now part of the traditional electricity model, which is that you need a large, essentially gigawatt nuclear reactor to make sense. But when you start to look at the accidents, and then the things you have to do to make that plant safe, adding on safety feature after safety feature, it's really fundamentally there's a flaw in the design, which is that you've got too much radioactive material in that reactor, so that if everything goes wrong, you're going to contaminate a large area. But if you have a small reactor, invariably, you're not going to do that. It's just a very different model.

Question: I always thought of the small modular reactors as something you would put together in a group anyway, but I'm hearing you say that you would actually separate them. Don't the same rules apply, or maybe there need to be new rules about the radius and all the very costly requirements that a nuclear plant owner and operator has to address about the area for evacuation and testing. Wouldn't all those things still apply?

Speaker 2: Yes, in principle, you would change the rules, because quite frankly you don't have the material to do that. So that would be the idea. But again, it's there more as an example of just a rethinking of the model and of the paradigm of what a nuclear plant really is and what it means.

Question: Could you just refresh our memory on Price-Anderson Act liability limits? I don't remember what they are now. Relative to your Japan numbers, I think it's pretty, probably shocking.

Speaker 2: Price-Anderson limits liability essentially in the tens of billions range, in terms of what the utilities would be responsible for. And Price-Anderson says that after that, Congress would allocate resources as Congress

decides to deal with anything larger than that value.

Speaker 3.

I want to try to talk about a little bit of reality, looking at some of the options, starting mostly with the distribution system and then talking, a little bit about the bulk power system.

I appreciate the discussion about the need for imagination. I think another thing we need to talk about is institutional memory. There was a hurricane in I think it was 1938 that killed lots of people in Long Island. I suppose most of the people living in Long Island, and I don't mean them ill, had forgotten about that. In the 1800s, there was an earthquake at the New Madrid fault. Most of the people on the East Coast and very few people in the Midwest know where that is, but it could topple Chicago if it was a really bad earthquake.

And I understand that in Japan, in the area where the tsunami hit, there were plaques on the ground showing how high the water had gone in the 13th or 14th or 16th century. So it wasn't like people didn't know about that. It has to do with people reliving their current experiences, and tending to forget. And there have been books written on that.

The term "derecho" did not come into the dictionary in the summer of 2012 when the storm hit the East Coast. We in the Midwest have been living with bow wave storms for decades. And just to show you, this was a radar picture, of a storm coming into the Chicago area in July of 2011. And as you all know, red is bad, and purple is worse. And this event, within a period of maybe a half hour, took out the distribution system for about a million customers and took complete restoration in the order of five to seven days, and we learned some lessons.

This picture shows 700,000-volt-class transmission towers that were crushed by an ice storm. It's the towers, not the wires. It wasn't the trees, it wasn't the wires--this is pretty amazing. So the forces of nature that we have to deal with are pretty rough, and whatever you postulate, there's probably something bigger out there, as we've seen.

So now I want to get to the heart of this. What can we do? And this is going to be like a playbook, or a menu. There are options. And there's no one solution, nor is there any great solution. So, undergrounding, we've all heard about it, since the trees aren't going to fall on it and the wind isn't going to take it down. The first and foremost thing about undergrounding, as I'm sure everyone here knows, is cost. It costs a lot of money to put stuff underground. Restoration time. We're talking about undergrounding during an extreme event, but the power system operates 24/7, and things go wrong. You get water, you get faults in the manufacturing, you get varmints who tend to like to eat some of this stuff. You get contractors digging.

And when you have a problem on an underground system, the first thing is finding out where the problem is. If it's on the overhead system, you use the Mark I Eyeball. It's pretty simple to find out where it is. Or a helicopter with the Mark I Eyeball. Underground, it's not. You've got to find it. It is complex to fix it. This is just the reality. It takes a long time. It's also subject to flooding.

So when we in the industry started talking about this after Irene, the people in Florida said, "We don't underground because of the high water table. It doesn't work for Florida." And then there's simply the time that it would take to switch your entire system, or parts of the system, from overhead to underground. It is not an easy task.

I'll get back to cost. Speaker 2 raised this issue of, who should pay? And different states have different rules. For example, in Illinois, we have a statute that if a municipality wants to change the standard design, that's OK. The remedy is that the customers in that municipality will pay the incremental cost. Now, that has been used mostly because people don't want to look at lines, so they'll say, "Well, you know, underground this and we'll pay for it." But to some extent, that is an answer to the Bridgeport Fairfield County issue, but not necessarily the best answer or the only answer, because then the rich people get it underground and the poor people who can't afford it don't.

Higher design, loading, and construction standards--this was just raised. This was one of the solutions that was looked at in Florida after the spate of hurricanes that came through in the 1990s. And we've forgotten about all of those, right? This solution particularly works well in certain areas in Florida, where undergrounding's not a good solution. And guess what? They don't have a lot of trees. So strengthening the construction standards tends to work.

Inspection and maintenance. That does help you. It may not help you for an extreme event. But I'm sure everyone's had the experience of driving somewhere and seeing a pole that's 30, 40 degrees, ready to fall down, or a tree that's just about ready to go. A comment that was made earlier, and it's something we observed in Illinois in 2011, where we had a really bad storm before the derecho. A lot of trees came down, there was a lot of rain, and anybody with any knowledge of history knows that the next one is going to take all those trees that were weakened by the storm, and the ground that was saturated, they're so much more vulnerable to going down.

Tree trimming and removal. It's controversial. I sometimes, kind of as a bad joke, say, "If you want to deal with the trees (I'm going to show my age) the solution is Agent Orange." I mean, that's the tree destruction. I will give you an

example. Last year, on a line we had in Illinois, in this case transmission right-of-way, we had people in one of our more wealthy suburbs start yelling and screaming that we were using herbicides under the right-of-way. And they got the TV crews out there, and we got our communication folks out there and calmly explained to the TV crews that it was in fact our property. The TV crews very nicely went away and said, "What's the big deal?" We had people yelling about us doing stuff on our own property.

So imagine when you're talking about going on someone else's property and taking the dear old 150 year old oak? There was an article this week in the New York Times, I think it was, talking about this issue. And some people said, "I want to get rid of that tree, I don't want it to fall on my house." And they said, "No way no how. We need these trees."

So it's a very controversial issue. And while tree trimming probably works for moderate storms, the normal kind of storms you're going to see year-in and year-out, as Speaker 2 said, and I've seen this in 2011 walking to the train, it's not a big branch, it's a big old whole tree that's been blown over. And you don't trim that.

Technology. One of the things that has a lot of promise, at least for anything but extreme storms, is circuit auto-configuration. I live at the end of a feeder, so during the 2011 derecho, I was out, and I just want you to know that since it was a feeder and there were only 58 customers on that feeder, I was appropriately down toward the end of the list to be restored. As it should be.

But had there been, and there will be in the future, circuit auto-configuration, the rest of the feeder could have been restored without sending crews out. Now, it was restored relatively quickly by pulling the disconnects and getting most of it back. But with reconfiguration, you could have opened those disconnects automatically and gotten 90% or whatever

people back. That has a lot of promise. It doesn't work so good if the whole distribution system's down. But, again, you've got a range of storms you have to deal with.

And then there's the issue of micro grids that has been brought up. And then there are cost issues. There are issues of how well is it going to work? You know if it's a factory, you don't need any distribution system. If it's, you know, a neighborhood, it still leaves the distribution system to get from the source to the rest of the houses. And it's, as I said, expensive.

So there's no perfect solution, and you have to look at these possible solutions and say, which of them may work where?

Now, there's prevention. You know, stopping the terrorist attack. These are not going to be natural events. Stop the cyber attack. Stop this and stop that. And yet some of these things may happen because you haven't figured things out. That virus to your computer may get through because someone got a day-zero virus.

So how do you recover? These are issues, again, that are being talked about. You can increase local labor forces. Of course that costs money. You have people sitting around for normal operations. But is this part of the answer? You can have a stand-by supply of equipment and restoration materials. And I want to differentiate between the two. The equipment are things like line trucks--I'm sure some of you read during Hurricane Sandy that line trucks were airlifted in by the Air Force from California into airports north of New York City and then driven down, because of the time they would take to bring them there. Our line trucks from Illinois were driven to the East Coast. The issue is time, there. The time to get that equipment. You can fly people easily, but you need the Air Force or the Air National Guard, who have planes that can take main battle tanks, to bring these things in. Or do you have extra supply of this equipment

so you can just fly the line crews in? That costs money.

Materials. For these large-scale geographic, extreme events, you start running out of materials. Again, what do you stock for? I mean, it's simple things like cross-arms, poles, wires, connectors, the kind of stuff that is not sexy, nobody really cares about it, but that will help you.

Enhanced communications, planning, and coordination. This is probably a good lesson learned about doing these drills that were just talked about. Think of the movie Apollo 13. You see in the beginning they go in their simulator and somebody, you know, throws a couple of switches and something really, really, really goes wrong. As was said, you know, you've got this restoration drill, and oh by the way, the road is flooded so you can't get your trucks there. So what are you going to do? So one of the things is more planning, more coordination.

One of the lessons learned from Sandy, we brought cable crews into New York City, qualified cable splicers. Unfortunately, there was no place for them to stay because the people who were driven out of their homes were staying in the places. I mean, Con-Ed did a wonderful job in arranging these things, but it is thinking of these things, planning, drilling, having a plan to go through them, I think, that is another area of improvement in getting the restoration quicker.

Communications. Apparently a lot of cell companies don't have long-term emergency backup on their repeaters. Your cell phone may have power, but you can't do anything with it. Satellite phones. Another thing that was learned by the industry, voice mailboxes got full. Not necessarily something you think about. The analogy was, we learned this in '77 on the bulk power system after the Con-Ed blackout. The alarms overloaded with minor alarms. The solution was to suppress the minor alarms. So

here we have to have a solution of special numbers or something like that.

And then I've talked a little bit about technology, the auto circuit configuration, smart grid, the identification of the outages. Right? The current technology is to rely on people to call and say, "I'm out." We have some algorithm, and we figure out where you're out and who's out. Well, if all your land phone lines are down and the cell towers aren't working or overloaded, it's hard to find that out. But if you've got the proprietary system, you'll know who's out. And then I don't know that this is new technology, but airborne damage assessment is another thing.

OK. We need to talk about cost recovery. It's expensive. These things are expensive. How should they be paid for? I'm not going to beat this to death. There are different ways to recover the costs. The issue of rolled-in rates, obviously that's an issue. As part of a rate case, what level should everyone pay? I've mentioned the municipalities paying for their own non-standard installations.

The way rate-making is done, with test year issues, you go through and then you go before the commission and someone says, "Well this wasn't a normal storm year, so these costs shouldn't be in." And it gets very difficult, and there really needs to be a conversation as to what's reasonable for the material and the investment that you're stocking for the storm. In some places, I believe in Florida, they've used securitization, probably a bad word these days--but essentially issuing low-interest bonds to pay for this.

This is the distribution system I've talked about. We all know from Fukushima, there were serious issues (serious issues is an understatement) with the event. And the issues become flooding and loss of off-site power. The NRC in this country is going through a review, and there's a recognition that there needs to be a

review. One is the reexamining of the licensing basis. Is the original design robust enough? What is the design basis of the event?

But one thing that is being done, and it's a lesson learned, is to get additional emergency equipment in place that's near but not there. So if you need to get in big, emergency generators, you don't put them at the same place where you're going to need them, but you get them so they can get there very quickly, so hopefully the geographic diversity will spare you. This, by the way, is an issue that people are facing for recovery from terrorist attacks. Where do you put the spare equipment?

I want to talk very briefly about bulk power system issues, because the bulk power system generally has not affected the service to customers. I want to talk about three things. First is, and it was referred to yesterday, the extreme cold weather event in February 2010. Do you need standards? Is this a market response? Or is dropping load once in 20 years acceptable, and the generators can get their incentives through being paid for or not?

The Halloween snow storm was mentioned. There was a review by FERC and NERC on this. And one of the recommendations was off-right-of-way tree management. OK? This is a recommendation to the industry. Off-right-of-way means it's property we don't own. Now, as I just told you, we were getting people beating on us for using herbicide on property we do own. So it's difficult.

And the last thing is something that I don't know how many of you have heard of, it is space weather. Yes, space weather may be a threat to the electricity supply. And what you're seeing there on the screen is something called a coronal mass ejection from the sun, where the ionized particles will interact with the magnetic field that protects the Earth, and can cause induced currents in the system, and it can or may cause large-scale outages.

I refer you to a rule-making docket by FERC. The answers are due December 24th. I'm not sure how that date came up. I think it was coincidence, just 60 days from when it was published in the federal register. There's going to be a lot written, you're going to hear about the apocalypse, and you're going to hear that there's nothing wrong.

The point I'm trying to make is, there are lots of other events, and this is an event. How often will this occur and what are the consequences? So these are some of the things we can do, we may do--they need intelligent discussion. And I think it's great that Bill and Ashley put this on the agenda because this is a place you can have this calmer discussion without the people out there, you know, ready to shoot the linemen who are out there trying to help them. It's like shooting at the firemen who come to put out the fire. So thank you very much.

Speaker 4.

What I'd like to do is to take the topics that the previous speakers talked about around measurement, cost-benefit, probability, affordability, and specific potential actions and kind of put that in a framework and try to measure the impact of these hazards, and put a fact base out there so we can have at least a starting discussion as a society, as rate payers, as utilities, and as commissioners and commission staff, on what are the costs of expected hazards, climate hazards, and how are these hazards changing in terms of profile? How much more damage did we expect, and how do we share the cost of those damages? So that's really what I'll talk about. And I'll whiz through a few pages on the framework we've put together, and I'll go through the case study we've done at the Gulf Coast as an illustration.

At a high level, if I just summarize the page, we do see an increase in hazards. The data shows that. And, of course, things happened in the

1800s and the 1700s, but the magnitude of these events has increased in terms of damage. If you look at the Gulf Coast, of course the Northeast, even if you look at California, and you think about the fires and the incidence of fires and the magnitude of the fires and the damage associated with those fires, that has also increased in the last three decades. So it's certainly wide-spread, this issue of hazard.

What we did was, we worked with SwissRe. You've got to run a million probabilities to really understand what is the probability of an event happening tomorrow versus 500 years from now. And what SwissRe has is a large database that looks at events. You can model the events and then you can link the events back to damage. So I'll talk a little bit about that.

And what we did with Entergy and with the weapons foundation, with the Louisiana governor's office and other folks, is kind of set up a discussion, at least the framework for the discussion, about which standards do you put in place, what utility measures do you put in place, and how do you share those costs, and where's your affordability glass ceiling, and how do you translate that expense into rate-payer increases? That's the discussion that is happening right now. So I'll take the Gulf Coast example and walk you through a little bit of that.

Before I do that, on page two, if you look at, you know, at the top line, on number of natural catastrophes, you see victim numbers and you see insured loss. This is global data. You can cut it for the US, you can cut it for specific events, and the trend is relatively clear. It is increasing in terms of magnitude.

So the approach we have taken is to say, you know, there are really three elements to this. One is, you define the hazard. Is it rain increase? Is it a sea surge? Or increase in sea surface temperature which then pushes hurricanes to be stronger? Is it the fire linked to the wind? Define the hazard and model the hazard. You lay the

hazard onto the area that you think the damage is going to happen across, so you can get into a fair amount of detail, you can go down to the hospital level, specific parts of the electric infrastructure. And then you apply probabilities. You say, in the past, when these things have happened, what's the damage that's occurred? And in the future, as I increase the incidence and magnitude of this damage, how does that then affect the assets at risk? So that's the vulnerability module. So that's sort of the high-level framing.

So on to the Gulf Coast example, what we did was to try to create the fact base behind this. We looked at 23 different asset classes (and I'll talk a little bit about how the utilities fit into that), in 800 zip codes across 77 counties. The map down there is the area we looked at. And we also modeled a number of adaptation measures--system hardening, changing a class one to a class five pole, changing the design standards of a cross-arm... For oil and gas folks that are affected, it's moving from a fixed platform off-shore to a floating platform off-shore.

And we had a pretty wide stakeholder group that was involved, down to parish-level NGOs that obviously had a voice in this and were the impatees of the events. And of course all of this was triggered by Katrina, right, this is post-Katrina interest, and pre-Sandy.

So this is what it looks like in terms of baseline. The shaded areas were the zip codes we looked at, the counties we looked at. And on the left-hand side, the darker the shading, the more GDP at stake. So there are lots of discussions you have to have around this. You know, you look at societal value.

How do you measure societal value? In this case, we've done several cuts. This is grounded in GDP. And GDP is then broken down by assets in different categories: utilities, oil and gas, residential structures, commercial infrastructure. And you see those categories on

the right-hand side summarized, and the shading you see there is 2010 values, and then what the replacement values would be in 2030. Because we know these hazards are increasing over time, and the time frames we looked at were today to measure the baseline, to look at 2030, we looked at 2050, we also looked at 2100. You can't predict anything by 2100, so I'll focus on 2030. So what you see there is 2010 and then 2030--how do those asset bases grow if you assume growth at a normal rate, you know 2% GDP or 1.5% GDP based on a specific sector?

The hazards we modeled, in the case of the Gulf Coast, were three. We looked at wind, we looked at sea-level rise (and the specific situation on the Gulf there is, you've got subsidence happening so that the ground is actually sinking, which has been monitored and measured by NASA and others, so there's a lot of data availability there), and we looked at storm surge. So it's not just the wind that carries the storm over across 70 miles, but at the shoreline you have immediate surge, and how do you measure that as a separate hazard? So those were the three hazards we modeled.

And if I just take the infrastructure cut for the Gulf Coast, what you see here is a map of obviously the highlighted counties we looked at and the specific subsectors and infrastructures. Chemical plants, refineries, LNG facilities. You see in the orange there the transmission and distribution assets for Entergy and for the other utilities, AP, Center Point, other munis in the area. These are all asset values. So the objective was to see what the damage would be against these assets.

And just to cut to the chase, you know, really the tagline for me that came out as we looked at the analysis is, if you look at Katrina and the expectation on Katrina as an event that happens once in three generations, I think what the data shows is, it's an event that's going to happen once every generation. That's really how the hazard patterns have changed. And the way to

look at that is, if you look at this chart, on the X axis, you have the return period. So how frequently does a storm happen? One in 100 years? One in 50 years? And then what's the magnitude of damage, on the Y axis?

Today's scenario is the 2010 scenario, the first bar. And then what you see is three different climate scenarios mapped out. So what we did here is we mapped it to IPCC scenarios, and we're getting to that. But even if you're not a believer in climate change, you can map it just using hazard data, and look at the increases in losses. Basically what we saw was, between 2010 and 2030, you could interpret the change in two ways.

You could say, number one, that a one-in-100-year storm that was creating \$150 billion in damage is now going to create \$200 billion in damage in 2030. So you could focus on just the magnitude of that same event going up. Or you could look at it as a one-in-100-year event that is now going to happen every forty years. And when you think about the Gulf Coast and you think about the amount of damage Katrina caused, \$120 billion, this obviously becomes quite significant.

Now, in terms of analysis, on this chart, what we mapped is average annual loss in 2010. So \$14 billion a year is actually what the Gulf Coast is paying in terms of hazard loss. It's lumpy. So when you have Katrina, it's \$120 billion. It's not \$14 billion every year. But that's really what it comes out to be. And if you look at the right-hand bar, in 2030, that number goes up to \$23 billion per annum. So that's the increase.

And what accounts for the increase? What the modeling shows us is that actually a large part of it, about 40% of it, has to do with asset growth. It's just purely growth in the region. You've got more people, you've got more assets at risk, you're building more hospitals, you're building more bridges, so it's just more assets. More people living there.

A very small part of it is due to subsidence in the Gulf Coast, and this does not apply to other regions. But the sea floor is essentially sinking at the coast line, and that's the \$0.7 billion that you see of increased annual losses. And then the climate hazards, so the hazards themselves and the nature of those hazards, account for the remaining 40 to 50% of increase.

What this does, of course, is it raises all sorts of questions which came up post-Katrina, which are things like where do you situation growth? It becomes a very political discussion. Do you tax people for certain areas of living? So you can imagine all of the issues that creates.

Now, I talked about mitigation measures. On the previous page I talked about damage and the increase in hazards. What this chart is showing is how we modeled the 50-year sort of adaptation measures I talked about. Now you get into all issues of subjective value. Right? The cost-benefit you do is an objective measurement of, I'm going to spend this much money on a measure.

And a measure is sandbags, right? Sandbag costs me \$50 a sandbag. For every square mile of damaged area, I need X many sandbags. So you can figure out what the cost is. The way you measure the benefit is, in the vulnerability modeling. Then you say, my resilience has gone up. I run the model and I say, OK, how much reduction in losses do I then see? And that differential is the benefit.

Now, you get into all sorts of subjective issues. So you can imagine on the Gulf Coast, wetlands restoration. When you have a cost-benefit ratio, which is on the Y axis above one, and anything environmental in the Gulf Coast is over 1--it's very expensive to restore the coastline, to restore reefs, to restore the byways. How do you justify that? Because there's intrinsic value in that that's not reflected in the cost-benefit.

So the way we thought about it is, at least you can put the framework and then start having the discussion with the right stakeholders. So we had, with certain parishes, with the Wetlands Foundation, with some of the commission staff, discussion around, what do you do around the wetlands?

Now, in this, one thing I'd like to point out, in this sort of gamut of adaptation measures, embedded here are utility measures. So if you look at this one, for example, new distribution, this is saying that any new growth that I'm going to have, and new distribution circuit miles that I'm going to build, that I will change my design standards, you know, back to some of the things Speaker 3 was talking about. How do I design my cross-arms so they're more resilient? What kind of class of poles do I use? Do I underground? If I'm doing distribution automation as part of the auto-reconfig, I situate that? So embedded in here are the utility aspects, but this is really a societal look at all the different measures you could have in the Gulf Coast.

Now, taking the lens of the utility, what we did do was model a set of utility-specific measures which we agreed to with the utilities, but also with the commission staff, governor's office, etc. And what this chart is just saying is, you've got the measures here listed, and they're buckets of measures. Within these, there are specific initiatives. So, for example, distribution hardening. Within that hardening, a lot of it is undergrounding, but some of it is actually stronger structures at the base, stronger cross-arms. So you could get into more details as you measure these out. But what we've got is, over the 20 year period, from 2010 to 2030, what's the capital required for each of the initiatives? And then when you run it through and assess the benefit, what's the loss averted? So this is a 20 year cumulative loss aversion analysis.

So for example, for distribution hardening, it's \$1.1 billion of loss reduction if you did that

measure. And then you've got the cost-benefit ratio. So you can imagine this then sets up the debate with some facts to say, well, is that measure worth doing? And then you also get into, obviously, the discussion of, well, how do you measure? But the idea is to put the structure around that.

And then you can get as detailed as you would want, and you know, we I think did it at a pretty high level. But I know some of the utilities have picked it up in the region, they're going deeper. So you know, you can take specific voltage levels on transmission and look at the replacement values by circuit, and put some value against those.

Overall, for the 2030 scenario, from a utility perspective, this is what you see. You see a total loss over the 20 years between 2010 and 2030 of a billion dollars just for utility assets, right, and then you see the distribution between flood losses and wind losses.

One of the types of losses I've got there is business interruption. There's a lot of heated discussion around how you measure that. Is it value of lost load? What kind of measure or metric do you put around that? And there's no firm answer. I think it's a consensus-based answer, and that's certainly what we used here, a specific methodology for the region.

And then you can map back the assets. I think this is where it's helpful, with the Commission and utility discussions, to map back where the damage is going to be by zip code, by county, and that's just a snapshot of that. The darker shading is higher losses in that area.

I just talked about the utility piece. But, you know, this is a societal discussion. It's not just about utility losses, but also other parts of the economy, other parts of society. So there are a set of other areas of risk. In the Gulf Coast, 40% of the oil and gas infrastructure in the US is coming from there. So it's important. You also

get into residential and commercial, and you can break it down into hospitals, etc., but there's a set of discussions that are happening separately around the treatment of those damages, and what sort of changes do you need to have happen, whether it's design standards or it's moving certain neighborhoods into other areas. Anyway, I wanted to just show you this, that it's beyond the electric space as well, it's broader societal risk.

Question: I had a question on the frequency assumption on the weather impacts. It looks like you were just taking kind of a straight-line extrapolation from, you know, the early 70s out through, I guess, 30 years, forward to 2040. And if you think about maybe some of the climate change skeptics who talk about more climatic cyclical effects versus, you know, just things getting worse over time, did you look at any other scenarios where you looked at a longer term, and whether kind of that straight-line extrapolation was appropriate, or whether you could actually level it off or bring it down within that time period?

Speaker 4: Great question. Yes, we did. The way the SwissRe modeling, or the insurance modeling, works is, it's not just a linear relationship. So you have to look at, for example, sea surface temperature increase. We know the sea surface temperature has increased. How do you link that to the frequency and magnitude of hurricanes? So, IPCC has published some results, and there are studies that have been done. So we tried to use sort of the average of studies, and it's certainly not a linear relationship. So that's kind of just one point I want to throw out there.

Now, in terms of cyclicity, in the weather models that not just SwissRe, but other insurers in other companies, and some of the larger banks that are looking at catastrophic loss have used, you're able to model not just kind of the linear belief that this thing is going to go on for the next 200 years, but you can model 40 year, 30

year cycles. So we looked at both scenarios. We had way too many scenarios, but yes, you can run that, and you can then simulate, say, if there's a 40 year mean reversion of certain elements of that storm.

Question: Where as your run, here, was it a stochastic process, then, where you took all of that into account? Or was it more of just, you chose one of those scenarios and ran it?

Speaker 4: What we showed here is an average of three scenarios. So we picked a path. We said, it's not a mean-reverting set of storms, so it's not cyclical. It's going to continue to be bad. And we attached it to the IPCC scenarios. So if you think of A1, A2, B1, the different parts-per-million scenarios, in this work, it was focused on attaching it to that, because that's what the stakeholders of the project wanted to do. And now you could say, "Well, we're not going to attach it to that, we're going to believe in cyclicity and run it that way." Does that answer your question?

Question: Yeah, thank you.

Question: Have you run this study for any other areas other than the Gulf Coast?

Speaker 4: We have done it for the Florida Coast. And we did a global study looking at things like in India, if you have the same issue, how does that affect farmer income? So we did eight case studies globally trying to test this methodology, and one of the case studies was Florida, to be specific, it was really the Miami Coast. So it wasn't the full Gulf Coast. And what you find there is sandbags and beachfront extension is the cheapest mitigation approach, and it's a big part of the curve. So you can actually do a lot of mitigation with a lot cheaper measures versus the Gulf Coast.

Question: What's beachfront extension?

Speaker 4: Essentially trucking in sand.

Question: I think that's a very good analysis. One thing that is striking is that with all of the cost of abatement, all those measures you have in there, I don't see any market-based measures like a cap-and-trade program, or something which could be used to avoid these disasters.

Speaker 4: It's a good point. We did not measure that. If I go back to the numbers I was showing you earlier, \$14 billion in average annual loss, this curve, not to get too technical, gets to \$10.5 billion of potential losses averted. So there's a residual risk of things that you just cannot mitigate. So then you get into discussions of, if you put a cap and trade program in, or you have some more structural changes, you change the model. I think you can measure some of those, you can apply those and model those out. But we didn't go to that extent.

General Discussion.

Question 1: First, a thanks to the panelists. That was very interesting, and I think it's important. Can we get page ten from Speaker 4's presentation, that marginal cost curve? So I was thinking about this question as we were talking along, and I want to make sure I'm reading this graph correctly so that we can pose the question. The thing which puzzled me was the two over here under where it says, "average annual loss is \$21.5 billion," and then there's an arrow with a two next to it on the right-hand side, and a dash line going across. What does that mean?

Speaker 4: So "1" would be where you would say your cost to benefit ratio is one to one. So everything below the line, you'd say you do. So the compromise with the stakeholders was that there are some things that you are not capturing intrinsic value for, and drawing a line at two was an attempt to suggest that--you could draw it at four, you could draw it at one.

Questioner: OK. I thought it might be something like that. So the nice thing about this curve is

how it highlights the difference between this total loss, the total reliability, the total problem, and the total cost of undergrounding everything and so on, and actually the fact that there are a whole lot of incremental steps, and you know, it's the classic marginal cost, marginal benefit story which this picture tells us.

And if you don't use the two and you use the one, just to make the point here...but two gives you qualitatively a similar story. In Speaker 2's framework it says that it looks like it's probably worth adjusting your standards to get about one third of the way to meeting people's expectations. And it looks like about two thirds of the problem is changing people's expectations so they understand they have to live with it, because it just isn't worth the cost of actually doing it. Is that a consistent interpretation of what's going on here?

Speaker 4: Yeah, that's a great way to paraphrase it.

Moderator: All right, there you go, problem solved. [LAUGHTER]

Questioner: No, I don't think the problem's solved at all. I think it's extremely difficult to change the people's expectations about this directly.

Speaker 2: Can I follow up? Can I ask you, how hard was it to get from, say, one to two in your discussions?

Speaker 4: The reality is, two was what was presented in the broad stakeholder report out. Now, when the parishes met with the governor's office, met with, you know, Entergy and other folks, the negotiations on what actually came out didn't always follow the curve. So you could say, "Well, you know, wetlands restoration is, has a nine-to-one ratio, but it's critical for the legacy of the Gulf Coast," and then the tertiary effects come in—"Well, it's going to support this part of the economy, and there's a

multiplying factor we're missing..." So the two is, on this page, arbitrary. The reality is in the discussions, depending on what measure and which party you're talking about, I think it gets very subjective.

Now, for the utilities side of it, though, because you're talking about rate payer impacts on cost, the cost benefit measures are relatively straightforward, as much as they can be, and you can have a discussion around them. So for a utility commission discussion, it's fine. For a social issue, it's not that fine.

Question 2: Well, now that we know that it's down to a third of what we need to do, each of you has talked about five important things, communications being key, decreased risk tolerance, risk reduction, preparedness, and improved response, none of which are free. Could each of you talk a little bit about how you see getting public consensus, public policy around the fact that this is going to cost more and who should pay for it?

Speaker 3: Well, I think that started, to some extent, at least on the electric side, with some of the state commissions trying to put aside the state legislators' outrage and such. For example, you have a paper in the package of some EEI testimony, for the Maryland commission, which is an open inquiry, to try to lay out the issue. That there are solutions that can help, not necessarily solve the problem entirely. That they cost money. That there's a menu. And that all pieces have to be considered at the same time.

And it really becomes a public policy decision as to how much you're going to try to do in prevention, how much you're going to try to do in restoration, and how much you will do with the communication. I think that, at least at the distribution level, that clearly is within the purview of the states.

At the other end, at the FERC level, I don't think we've had that conversation. We've been having

the conversation on risk, we're not having the conversation (and I think FERC will see this in comments) on the cost of some of these very low-frequency but very high-impact events, what that may cost, and the bill is going to come from someone, because the equipment will not be delivered on December 24th just for free.

So it's in those settings, where at least they can be relatively calm and have those debates, put facts on the record and have those discussions. The real question, I think, is after you have those discussions. These are not one or two year decisions, because these are not things that will take one or two years, they will take decades.

And I'm not the probability expert, but you may not have another northern hurricane for 30 years, or you may have one next year. And if you don't have one for another generation, will the memory forget about it and be concentrated more toward the cost? So I think the state commissions are having those conversations. That's a good place to do it, where it is done, you know, through logical and intelligent discourse.

Speaker 1: Divide the response into two parts. One is this normal storm response. We've got some Texans here. I lived in Houston for a few years. And every so often, every couple of years in Houston, it gets down to 28, 29 degrees, and you might get a half an inch of snow or something. And you don't want to be out there. I mean, these guys haven't got a clue how to drive.

And I remember my neighbor coming down and, oh my Lord, she said, and she's screaming... I mean, you know, the sort of thing that would be any given day between now and March one up in New England. But I mean, if you don't have snow a lot and it hits, you're better off just closing down the city for that day than trying to have --

So I mean, what is your expectation? That's my point. And for that same woman, if she were from New Hampshire, you know, eight inches of snowfall is, OK, the expectation is, you might be a little late getting to school or getting to work that day, but by eight, nine, ten o'clock in the morning, it ought to be plowed, and so it's a matter of expectation.

Now, where we've come to on hurricanes--I mentioned the Halloween storm and Irene, and the utilities in Connecticut did not have foreign crews in place, they did not have them on extended shifts, they had a whole bunch of things that my organization found that they were deficient in responding to. And we had emergency drills over the summer, and we talked about all this stuff. And before this last storm came, what are the expectations? Well, we just had a drill on that.

So I called them up and talked to them about it a couple days ahead of time. The governor, who obviously has a hell of a lot more clout than I did, brought in the CEOs and said, "I want the foreign crews, I want answers right now about what you are doing." And they could see he was serious. Clearly, we were serious, we drilled for this thing. And there's going to be an exam. You know what the question is. And you don't have to get an A, but you better not fail it. And you know what you're supposed to do.

So this time, one of the utilities had more foreign crews in place, safety-trained and deployed, before the storm hit, than they did at the peak of the prior storms. Both utilities had a brand new thing of embedding at least one tree crew and one line crew in every city and town in Connecticut, and some had more, the bigger ones. So my point is, what are the expectations?

Well, here it is. The storm's coming. This is the *Hartford Current*, the headline says, "Utilities Face Test." OK? Well, it's like last time. The public knows it, we know it, the governor knows it, the TV stations know it, and you know you're

facing a test. And so you better get ready, and what's the reasonable expectation, living in a place which deals with hurricanes? So, there, I think the answer is, it goes to the rate base, doesn't it? I mean, the reasonable accommodations to get ready for these kinds of things--I mean, you know what's going to happen. Reliability is critical to having electricity. I mean, they'll come before us and pose that question. But my guess is that there certainly is a case to be made for that being a reasonable expectation.

The second one, though, I think is a little trickier. Are we undergoing climate change? Should there be special hardening for certain facilities? Do we have micro grids? Should the utilities be obliged to pre-position generators for warming shelters, for gasoline stations? How about the cell towers--you know, this was a huge thing. People were used to being without electricity for two or three days in a hurricane, but to go a couple days without being able to talk on your cell phone led to an urgency and a level of outrage that surpassed not having electricity.

So what should you do? I guess the question of normal restoration as we know it is a set of stated expectations communicated regularly. And we've all mentioned communication. I mean, we had daily, twice a day, press conferences in which the representatives of the utilities would go out, and I'd be kind of working on the side in case I was needed, and the governor would be there. We'd answer the press about what the restoration process was.

And you know, the public knew what to expect. You're having a test. How are you doing? And the utilities were on the line. The previous storm, they had predicted 90% return of power by Sunday night. Sunday night came, and they were at about 50%. Well, you know, one of the senior executives lost his job. I mean, it was a complete meltdown, lack of credibility. And we

had municipal phone calls with all cities and towns twice a day.

So that massive communication as to how are we doing, where are the bottlenecks, had been rehearsed. And the expectation is that that's part of being in the power business today. You can't prevent a hurricane, but when it comes, you ought to have done all the preparation you can, and you should make a special priority of returning power. And that incurs expenses.

Speaker 2: Speaking as a former regulator, I think some of the challenge with some of these issues is that sometimes these things fall to the regulator, and I think in many ways they're really issues that are better handled by the political bodies. Because in the end, they really are more societal discussions.

And, you know, something like deciding whether to require new standards lends itself more to a legislative process. Because it's at that level, I think, that you can then begin having the dialogue that makes determinations about who is going to bear the burden of paying for that. I think sometimes it's difficult for the regulatory bodies to do that, because they have fairly narrowly defined responsibilities, and those narrowly defined responsibilities don't always allow for the flexibility to deal with some type of unique event.

And so I think in the end, that's the right forum, and that gets you the kind of dialogue that you need with all the right parties. Because there's no simple answer to these questions.

But going back to this idea of expectations the expectations are increasing that these issues will happen less. And probably my most vivid image from Hurricane Sandy was that there were some shots of people huddled around outlets in New York City, I mean, going place to place, plugging in their cell phones, you know, wherever they could find an outlet.

And you know, you go to the airport on a normal day and you see people sitting on the floor of the airport, which is probably one of the dirtiest things you can ever sit on, just because it's near an outlet and they can plug in their cell phones. And I would probably be in the same case. So I think that expectation has just increased. I think people will expect more in these kinds of events, and they're going to happen again. I mean, there's no way they won't.

Question 3: A comment, or an observation, and then a question, both of which are unrelated. So, first, a comment. On the cost recovery, it seems like we need a new paradigm in the state distribution rate recovery context. I don't think it's an issue at FERC, with formula rates, and even companies like Entergy and some of the Southern Company distribution companies already have formulaic rates that get updated every year. But for the most part, most states, including New Jersey and Connecticut, have traditional rate cases where for these O&M costs, unless it's in a test year, you have to go in for a full rate case in order to recover them. And it can be a huge burden from a cash perspective as well as an earnings perspective to the company. And it does create a disincentive, in some respects.

So I think that is something that, as an industry, we need to look at. And, you know, maybe there are some performance tests. Maybe you need to make sure that the utility did what it was supposed to do before it's able to recover those costs. But just putting the burden on the utility to wait until its next base rate case, is a huge burden for utilities.

And a question. Something that we've seen, and I don't think this is unique to New Jersey, is that customers are reacting to these storms. After Storm Irene last year, a lot of people went out and bought their own generators. Some people spent \$500, \$800. I know people that spent \$10,000 to get generators that automatically come on when the power goes out. We're seeing

just a tremendous increase in these behind-the-meter home generators.

And I'm curious what the panelists think about how that should be included or not included when we look at the total costs. Because customers are just going off and doing this, and \$10,000, or even \$800 per customer in getting this done so they can deal with what they view as a lack of reliability, or a lack of trust in the system, doesn't seem to be part of the dialogue when we're talking about the cost of these storms.

Speaker 3: Well, I've got a friend who went out and did just that. And he knows it was not logical, but he said, "I'm going to make sure I have power." I don't know how you take that into account. I will make one comment, and this is something all the utility people know. People putting the generators in themselves is a safety hazard. It is a safety hazard to our people. It's something we have to worry about.

For those that don't understand, if you don't have an automatic throw over switch, you are back-feeding power into the line. And when a line crew goes out there to repair that line, if that line is not isolated, they could get hurt or killed. And we have to deal with that. I know that's tangential, but it is a real, real concern to many of us.

Because one of the things, and I'm getting on a little tangent, is that when we get into these situations, whether it's an extreme storm or any storm, everything has to be done safely. People don't go up during 90-mile-an-hour winds. They need to get sleep. And so when people start yelling they're not seeing crews at certain times, "Why aren't you working 24 hours a day?" for example? It is because you can't. It is not safe.

But to answer your question, I don't know how you do that. People are going to vote. I mean, it is a cost. It is an externality. But people are not going to necessarily react logically as far as

money is concerned; they're going to react emotionally. And you know, maybe in the end when you use enough generators there, it may change your plan. I don't know. I think it comes in spurts. And again, you also have this issue of, who's going to put the generators in? It's going to be the wealthier areas, and who spoke about the theft of generators? I'm not quite sure how to deal with it, but I did want to really mention the safety issue that concerns all of us.

Speaker 1: Speaker 3 made the comment about the political system, the legislature and others. And when you kicked it off, you talked about the potential blame to political people in power. And it's also the other way around. If you are in a state which deals with this on a fairly regular basis, it's considered part of your job evaluation. In my state, one of the great events that everybody refers back to was the flood of '55.

And there was a governor named Abe Ribicoff who was there the morning of recovery, and directed the recovery and became a folk hero, and it helped, you know, launch and enhance his career. Ella Grasso was photographed riding on a bulldozer, clearing the streets of Hartford. Another governor was in New Hampshire at the time of an ice storm skiing with his family. He came back, decided that the emergency crews were doing everything they could, and so he went back to New Hampshire. He never recovered from it. So how you manage this and what you do is considered part of your job. You can suffer blame, and you can also have an opportunity. So this is part of what you do as an elected official.

I spoke about the real discrepancy between wealth and poverty in a very, very small state. And you're absolutely right. People are quite aware of the fact that in some of the wealthier communities, households are getting generators. I mean, this is a huge issue of how it's connected. It's got to be done by a certified electrician. But you can see them humming all over the place.

Well, if that's the case, and a mile or two down the road you've got apartment buildings in the inner city which don't have anything, what do you do? That's a political issue. What have you done as a municipal leader for a warming center? For all the kinds of things you need to do? But the dichotomy between how a wealthy community survives, thrives, lives through a major storm, and an inner city, especially when they're a mile or two from each other, and it's all on television, is a very, very serious social issue.

Speaker 2: Well, I think that's probably one of the most important points about the generator issue, the dichotomy. And I look at it as a signal that there is a different expectation, when people do go out on their own initiative and spend \$5,000 or \$10,000 for a generator. I actually had a friend here in Washington who had a problem with his basement flooding because he lost his power and his sump pump stopped working. He said, "That's it, it's the last time it's happening for me, I'm getting a generator."

And you know, that would send a signal to me that there probably does need to be better reliability. I mean, that that, somehow if it's possible, you need to try and tackle that. And it's probably more efficient to have a more holistic approach to doing that than having the individual home owner go to Home Depot, for safety and reliability reasons, and for all the impacts that you may have with these different systems.

But it also leads me to start to think that that may be also telling us that there is a different model out there which is more of the micro-grid model. Because maybe you start to get into a situation where if you set this up correctly, those generators can become your primary power source, and you're in a more of a micro-grid environment.

And so that's a more efficient expenditure than just going out and supplementing the grid with these generators. I did a quick calculation and I think I read an article that said that about 10,000 generators were sold after or around Sandy at about \$5,000 a pop. I mean, that's \$50 million that, you know, people have spent. It's probably not the most efficient, you know --

Comment: That's pretty expensive for a generator. My generator was \$800.

Spaker 2: It's a number, it's out there. Is that the most efficient way to do that? And you know, that's the question that I would ask.

Speaker 4: Just a couple of comments. I think when you talk about getting behind the meter from a utility perspective, you get into all these equity issues. So maybe \$50 million is not the right investment, but those are private decisions that have been made. When you do it from a rate payer perspective, you get into the red line issues about where you put those generators. So I think behind the meter for a utility is a disaster area to get into, from my perspective.

Just one other thing I'll say is that I think utilities have been terrible at understanding customer experience, and only in the last two years am I seeing, in the industry, some push to really modernize the way customer experience is thought of. And the only reason I say that is, you know, if you look historically, most of the attention was on generation, and then T&D.

I mean, those are the bulk of the capital expenditure areas for utilities. Even if you're talking just about a distribution utility, it's going to be the system that gets the attention. And customer service tends to be an O&M-only and the least part of the budget. So not a lot of attention is paid as to what do customers really want?

And when I think about this in the context of post-Sandy, I think when you think about

customer experience and expectation-setting, if you are going to rate-base a set of measures, and I agree with you that you have to think creatively about trackers in there, O&M versus Cap expenditures, how do you incentive some of those expenses? But if you are doing that, I think a quid pro quo is a set of best practices that utilities, regardless of which geography, or if you're muni or co-op, you have to do. You have to give an expected time of restoration, and you know, 75%, your target should be something like 75% of meeting that ETR.

You should be able to give people statusing. So you said six hours. Two hours in, I can call and find out where you are. Even if my cell phone is not available or I don't have that connection, is there a way I can get on the internet or that I can ask someone, a neighbor or a relative to check for me? But you should have a way of statusing. So I think there is a set of things around expectation-setting that can be hardened as the quid pro quo for rate basing some of those investments.

Question 4: The discussion this morning has taken me back to yesterday, to the discussion about resource adequacy. And we were talking about the one-in-ten reliability/resource adequacy target. And what I'm sort of struck with today is that there are two issues that are now sort of involved with that standard. And one is, is one in ten the correct target based on current customer expectations? It sounds as if expectations have changed. And so I don't know if that means there needs to be some examination of the formal reliability standard one in ten.

And then also, is a one in ten standard today the same one-in-ten from 2005 or 1995 or 1985? This gets to Speaker 4's issues around climate change and how often these events actually occur, and the fact that a one-in-100 event could be really a one-in-forty event. And so I'm wondering with these impacts and possible changes to the reliability standard, where does

the responsibility or the ability to deal with those changes lie? Is it with regulators? Is it something that companies are looking at? Is this something which gets discussed or should be discussed at NERC? That's sort of my question. Because it seems like it's actually a shifting target. I'm wondering whether that's being dealt with, or if it's being dealt with?

Speaker 3: Well, as far as NERC, the answer is no, it's outside their jurisdiction to deal with capacity. And many of us would prefer to leave it like that. I mean, it's really within the province of either the states or the markets. And there are active discussions going on, and it's been kind of interesting. A few years ago, for example, in PJM, there were a number of people saying, "Well, one-in-ten is too strict. You should allow greater interruptions." And there are other people who are saying, "One-in-ten isn't good enough." I think in the end, you know, it's always good to step back and review your assumptions.

I think in 1998, so this is ancient history, when our nuclear plants were not running very well, in May we had to go to a public appeal to get through the early hot weather. And the absolute outrage by the city and state politicians that we even had to ask people to cut back was amazing. And it has convinced me that the actual LOLE standard, in practice, is zero: "You may never run out of power."

We understand natural events can cause interruptions, right? We understand that wind storms take lines out. We don't understand, as a political matter, and I'm not saying any particular state, this is just my wide experience, we don't understand that you haven't planned well enough to serve the customer. No one discussed the costs, no one discussed the fact that this whole thing is probabilistic and can happen, but you're never allowed to run out of power.

Maybe getting a little bit back to expectations, one of the things we seem to have seen, and it may be early, is that when you have severe weather, people are pretty understanding. They do not generally have the expectation, "I will never lose power." However, after two to three days, that appears to be the break point where people get increasingly upset.

And one of the reasons EEI in particular started forming a group on restoration and resiliency is, how do we deal with this paradigm shift of big storms and getting restoration in this amount of time and reducing the number of outages, to dealing with the bigger events and what those expectations are?

So in a way, I'm glad the expectations appear not to be, "I will never lose electricity." Again, there's a curve. Those people are out there. But, and I don't know what the experience in Connecticut is, or other places, but we've seen, at least on the East Coast, it's two to three days that seems to be, right now, the break point for most people.

And I think the generation issue is a different issue. It's, "You may not run out of power." Just look at the reaction to the ERCOT event, which happened once in twenty years, which dropped load for a few hours at most, compared to what people were suffering on Long Island and other places in the East. If you step back, it's nothing, right? But it's very important there, and so each event, I think ends up being its own little story.

Question 5: I have two sets of questions going in somewhat different directions. The first follows what the last questioner was talking about, whether we need to rethink how we do rate treatment after disasters. But there are a couple things, I guess, that I'd want to know that sort of get fed into that. One is, I had this image in my mind of Curt Hebert, with tears running down his cheeks in Congress, asking for Entergy to be subsidized, and the question he was asked

was, “Well, what insurance protection did you buy?”

And the answer was, none. And the Bush administration said, “that’s it, that was your decision. You get nothing.” I don’t know what products are even available. So one issue I had is, what sort of products are actually out there that utilities can buy to deal with the obvious need to spend a lot of money in a very short time? And secondly, related to that, is what sort of FEMA policies and other federal policies exist about reimbursements, and how do they influence utility behavior in preparation and in response to storms, particularly when they spend money, how they spend money, and so forth?

The other issue which is not really related to that, but it’s a separate question, is this. After one of the storms in Massachusetts, the Boston Globe did a survey looking at how small municipal distribution companies compared with the large IOUs in terms of restoring service after a major storm. And the answer is, the large IOUs did quite poorly. I mean, the average outage in small muni systems was relatively short, and it was much lengthier in IOU systems.

And I understand there was a similar study in Connecticut that showed, had similar results. I don’t know how scientific these studies were. But I’m curious as to whether, in terms of storm response, whether the old notions about economies of scale and distribution aren’t true anymore? Maybe we’re benefitted by maybe much smaller systems that can respond more quickly to local circumstances. So those are two separate sets of questions, but I’d like to hear the panel’s reaction.

Speaker 3: Actually, given the last couple of years on the East Coast, there maybe have to be some rethinking of insurance. You know, most large companies tend to self-insure against these events. And in general, while events may be severe, they may not be the catastrophic type events that have been seen. History doesn’t

always repeat itself. Hurricanes on the Gulf and the southeast coast had been the big events. And not really reached the rest of the country.

I don’t know how to answer the second question. I think it is very utility-specific. It has to do with their geography, it has to do with rate pressure, to keep the number of crews down. That’s why one of the possible solutions is to increase the crews. I think it has to be looked at. Is there a better way to restore Power? But that’s going to be part of the regulatory discussions. Not only how do we recover from a specific event, but the bigger question of the preparation for the event, and it may take more crews on hand.

I want to get to something Speaker 1 said about, in the drills, having the crews there. That works great for a hurricane. It doesn’t not work very well for tornados or large windstorms. And that’s not a criticism. Again, there are different events. It may not even work for an ice storm, because sometimes the ice storm is really unexpected. So that’s why this is so complex, and I think we need to look at this big menu of things, and we have to have those discussions about recovery, and what’s reasonable in the rate base, and what’s reasonable when a disaster happens, and should it be insured?

And of course, the insurance itself needs to be prudent, because that needs to be a cost you recover from. So I don’t think there’s any one answer. I do think that for the issue with the municipal recovery versus the IOU recovery, I’d like a bigger statistical sample. I’m not questioning it, it needs to be looked at, and if it’s broadly true, why are the municipals able to recover quicker than the larger utilities? What’s the root cause? I doubt it’s the model. It gets down to whether it’s equipment, whether it’s crews, whether it’s geography, those things. You have to get to the root cause of that.

With respect to insurance, in Connecticut, we grow jet engines, we grow insurance in Hartford, and so forth, and obviously we like the insurance

industry because it's one of our main industries. But I've been on the job six months, the question of insurance has never come across my desk. So let me just plead ignorance rather than proceed. And you're right, you've got to be specific to the challenge. You get these derechos out there and these tornados out in Chicago, we get hurricanes and ice storms, and so yes. You prepare a little differently.

But there's something to this, because of the two ways in which the public judges us. One is, how prepared were you, and did you make a reasonable effort? And you're on television all the time, they know how you prepared, they know whether you brought in crews, whether you are seen to be out there, whether the crews are working 16 hour days as they're supposed to be doing? All of that. And they judge it against the storm. I mean, at least in New England we know it's going to snow and we know you're going to get hurricanes. It's going to happen. The point is, do you manage it reasonably, and did you prepare, and are you doing everything you possibly can?

But there is a secondary phenomenon, which is this decentralization. The fuel cell industry is a big industry in Connecticut. Well, facilities have fuel cells. And just as some wealthy families and everything else have their own generators, some institutions, hospitals, have their own fuel cell. And so when the power goes out, another question is who else has power?

And there is a tendency now to look to the municipalities. I mean, in 2011, you had high schools with 1,000 or 2,000 cots set up with people living in them for 10 days. Or you'd go down and take a shower and then go home and be cold in your home all day. But the municipalities were looked on as having the obligation to have main facilities covered by generators or a fuel cell or something.

And that's debated in things like town hall meetings in New England, where there might be

a motion to have the police station and the fire station and the high school set up with generators so that this can be taken care of. So I do think there's a decentralization, and people do not look just to their utilities for the example of it. The state and local authorities are also responsible for adjusting interim until the power comes back on.

Question 6: I have a question I'll direct to Speaker 3, but I'd welcome comments from any others who care to. We've been talking about whether planning for the one-in-100-year event is worth doing, and I want to assume for purposes of this question that it is worth doing in the sense that it passes some cost-benefit test. I've been into a lot of meetings over the last six months where there have been a lot of things that are worth doing that pass the cost-benefit test.

I tried to write down just a quick list of hardening the grid, cyber security investment, distribution, modernization, Smart Grid investments that can cost half a trillion dollars nationally, advanced metering, nuclear waste storage improvements, electric vehicle infrastructure development, meeting new NERC requirements, new EPA requirements, as well as the traditional way of utilities making money by building new power plants and building new green field transmission lines.

So the question is, I hear capital is scarce, there's not an infinite amount of it, you have to allocate it. So if in the corporate board room, if you've got a whole bunch of things that pass a cost-benefit test, how do you go about prioritizing? Is it greatest return to shareholder? Absolute regulatory requirements, which you have to do? (You know, there may be regulatory urging, but you don't have to do it.) Public outrage? How do you go about sorting out among dozens of good ideas, and I'll bet I left off main ones that are worrying you at home, all of which take a lot of capital, and you don't have enough capital to do it all?

Speaker 3: That is the question. And, you know, one of the concerns is additional regulatory requirements being thrown at you that you question whether they should be done. So the first thing is, the projects that are necessary, let's say, on the T&D system, to maintain reliability within the existing standards must be done. That's our obligation. We're now talking about expanding that obligation by what I'll call "hardening the grid" or "increasing resiliency."

That will, as I said earlier, that really needs to be worked out, that's a state matter, really needs to be worked out in the state. Because in order to do it, you need more revenue. And in order to get that revenue, the customers pay for it. It's, at least or in large part. If the revenue is not there, it's going to be very hard to do it. I don't see people doing it for nothing, and I don't see the government doing it.

I think it's a very difficult question, because as you say, at the same time, we're dealing with the regular reliability stuff, new technology such as Smart Grid automation, and we are now being asked (and this is an expectation from Congress) to protect the grid against national security threats. And I don't know any other way to say that. We are being asked to make the grid secure against a cyber attack by a nation-state. Not by a hacker, but--let's call it what it is--by China, the Soviet Union, and some other countries which have terrific capabilities. We're being asked to protect the grid against a simultaneous physical attack by enemies of the country.

And these are soft targets. We're being asked to protect the grid from portable electromagnetic weapons--I mean, I almost jokingly say, watch Ocean's 11. And you know, they run around in a truck. But there are these devices...

And so there has to be the revenue. And I think the answer is that many of these, while we can debate them at the state level, some of them have to be intelligently debated at the national

level as to which of these things are done and who does it.

Just to show you the length this can get to, there is a phenomenon known as electromagnetic pulses that can be set off by a high-altitude explosion of a nuclear weapon that has the potential to send us back to the 17th century. And there are people in Congress, some very specific congressmen, who say that we have not done enough and we must do something. And to me, that is a public policy decision. And if that is our job and we're expected to do it, then, A, we better figure out the technology to do it; and, B, there's got to be a whole lot of money; and C, the Department of Defense (which in my view has the primary job of making sure this doesn't happen) ought to be involved.

So the short answer is, we have to have these intelligent debates in the state and in the federal government as to what the electric industry really should be doing. What is in our national and state interests? Understanding that all these things have costs, and the threats, whether they be natural, whether they be space, whether they be man-made threats, will continue to increase. And what's our job?

And then the last part is, how much is prevention and how much is recovery? Sometimes prevention costs a whole lot more than recovery. So it's not an easy answer, but we cannot do everything.

Speaker 3: It strikes me that the questioner has really brought up a very large and very serious problem, and I totally agree with everything that you just said. First of all, the unforeseen. At the state level, you've got your tools. You don't know what's going to happen. But you have the National Guard, you've got state police, you've got the transportation department, you've got medical resources, you've got all this stuff.

You don't know what it's going to be yet, but the point is, you do the best you possibly can

with what happens. And while that's taking place, as I say, municipalities are demanding that the hospital be kept open, that there be something, so that across the board from the state, you don't know what's going to happen, but they want to know that government is at least worrying about these things, hardening and preparing.

Before I came here, I was in the intelligence community, and I was on a combat support intelligence operation with the Defense Department. Cyber Security is a huge problem. I think everything that Speaker 3 said is true. States cannot prepare for this. The federal government is doing everything it possibly can to stay up to speed with the complexity and level of sophistication in this area. To expect that to be understood, replicated, and defended against at the state level is not possible.

And so, yes, there is a myriad of things, not just electricity--banks, air traffic control, transportation systems--the probes take place all the time. There is no way to defend completely against it, and the vector by which a probe and attack could take place is hard to predict, and the states are not prepared to do it. I mean, they try, and they kind of do everything possible, but the range of threats is so large and so complex that it's not something that could be managed without the kind of national response that you just referred to.

So we've got to live with a certain amount of these threats. Everything you just said is true. And we could run around, and we could suspend the United States Constitution and make it much safer to prevent a terrorist attack from happening in the United States, you know, but we want to live our lives according to our culture and our laws, and that means that you don't get frisked every time you get on a subway.

It means that you have to recognize liberties. And it's the same thing with this. You're absolutely right. Those threats are massive. And,

no, states cannot prepare for them adequately, it just can't be done. But you have to at least look for the most probable threats, and use the tools you can in the most reasonable way you can, and communicate about them.

Question 7: Thank you. This is a question for Speaker 1, and your comments made a lot of sense on storm preparedness and response. But just to add to some of the complexities that Speaker 3 mentioned about unpredictable events, I'd argue that the effects of almost all major storms are quite hard to predict. And so just for example, I think there are some examples where 100,000 customers were predicted to be out, but then it turned out that it was more than a million, because the storm took a different turn--if it was snow, for example, it froze. And so something happened that maybe had only a 5% chance of happening.

And so the question is how conservative to be and how proactive to be about calling the distant crews. Because that's when you incur a lot of the expenses, by calling the crews. And it also takes a while for them to get there. So, you know, just waiting until after the damage occurs, that's what gives rise to some of the very long-term outages like Connecticut experienced. And so I think there are some difficult policy choices to make about how conservative to be, given the uncertainty of a storm's effects. And how do you think about that?

Speaker 1: Well, the public, the politicians, and the regulatory agencies will make that decision. Let me take two cases of an extreme event, just to illustrate. In 1938 on Long Island, there's this true story of a guy who bought a barometer and thought it was broken, because it was clearly pointing to a level of low pressure which was not possible. It turns out, the hurricane was right off the coast, and it was working. And we didn't know it was coming. We couldn't predict hurricanes then.

Now, as soon as there's a squall off the Azores, for crying out loud, you know, you track it, and it's got a name, and it comes up. Well, if you have five days in which this thing is tracked up, and you know it's coming, you call in the crews. It's simple. You have a warning, you know what path they may take. They tend to come up and they tend to curve up, and you can figure out whether they are going to be a Nor'easter or not, and whatever. So for that kind of thing, you have to bring the crews in.

Now, Speaker 3 used the example of an ice storm. That can happen more quickly, if you get an arctic clipper that comes down, sweeps in in a very fast fashion, and happens to freeze everything, and then you've got a warm front that comes up, and you've got water on the wires. And within a day or two, you can have an ice storm that knocks down everything that was not predicted. OK, what are you going to do? I mean, you do the best you can, given the intelligence you have of what's coming.

So I don't know what to say other than that the public is dependent on electricity, and it looks to us and the politicians to do everything they possibly can to keep their electricity on. At least in our part of the world, they know these things are going to happen. But you're right. Two, three days is understandable. After that, I'm beginning to lose my sense of humor over this whole thing, and I want to tell you about it. So what is a reasonable degree of preparation given what you knew and when you knew it? And the public is going to be very, very demanding. And it's up to the regulators, the politicians, and the utilities companies to know that and to do everything they possibly can to be ready.

Speaker 3: I just want to add, for tornados and those kind of storms, it's, even though they come quickly, it's not like the utilities don't do anything. We have weather predictions. And when you have predictions of severe weather, the first thing you do is you don't have the crews go home, or you call in your own crews, so

they're available. Now, that takes a toll on the people, and sometimes it doesn't happen, and sometimes it does. And we've found that erring on the side of having the crews at their reporting centers is better than not having them there.

I do think one of the things to seriously look at is to preposition equipment such as bucket trucks. Remember, a crew can get there on an airplane fairly quickly, within a day. For bucket trucks, you need the National Guard or the Air Force to get them there.

So that may be one of the selective things that people can do--to have excess equipment, if everyone agrees, "Look, the incremental cost of an extra 100 bucket trucks is very small compared to the return you can get in response." Because they can only move at 60 miles an hour. The physical crews can come in on planes. But it really means digging down into the details. Because, as I think everyone said here, there's no infinite money, and there's no easy solution to everything. And smart people are thinking of these things, and I think the two years of extreme storms has gotten people thinking as to looking at maybe some out of the box alternatives.

Speaker 1: I talked to so many people, five, six, seven days into the storm without electricity, and you go out as it's being restored, and they'd come out. And they said, "Yeah, we've been tracking it, we've been listening to the radio. And we know all about this, we knew about the people who came down from Nova Scotia or Quebec or flew in, and we've seen them come by, and thank goodness, yeah, it came one today, they did a great job."

I mean, the degree of communication is vital, and the resilience of the population is reassuring, quite honestly. I mean, if it appears that competent people are really doing everything they can, you have the good will of the population out there. It's when you start getting tricky with it or cutting corners or not doing

something which prudently should have been done, then you know, God bless you, you deserve to be in trouble for it.

Speaker 2: We've talked about these things as isolated events. But sometimes there may be one solution that addresses multiple issues, you know--the terrorist or intentional acts against the transmission and distribution may have solutions that also deal with natural phenomenon, with weather, with these kinds of things.

So it's not as if all of these problems are independent and need different solutions. Sometimes there are common solutions that can address them. So that minimizes them, and sometimes that's a good factor in terms of what you choose to solve and how you choose to solve it--the thing that maybe can capture a lot of different issues. And if it's just having more robust recovery programs so that you can deal with recovery regardless of what the initiating event is that caused damage to your system, then that may be one of the most effective things you can do.

Moderator: Thank you to the panelists. Thanks everybody for being here. I guess you're entitled to at least a final answer here on this, so I'll give you the final conclusion. My perspective on this is that things are going to evolve. The weather pattern's going to evolve, the infrastructure's going to evolve as we replace the infrastructure. the technology's going to evolve as it enables us to be better at hardening and having resilience. If you're in the utility industry, my best advice is, manage expectations.

And managing expectations is understanding what they are so you can respond to them, and you can respond to them either through maintenance, through resiliency, through hardening your assets, or through communication to political leaders and PUCs about what's realistic. And I think the pivotal thing here that should drive the effort is the management of expectations, both understanding and deployment of how you respond to that understanding. So there you go. You all got an answer to conclude this. Thank you very much. [APPLAUSE]