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Rapporteur's Summary*

Session One.
Cyber Security and Electricity Market Policy: Allies or Antagonists?

Cyber security is in the news, and it is important. The transformational benefits of digital innovation create a valuable target for cyber threats. In the electricity sector, the obvious importance of the interconnected grid, power plants, and the growing internet of things is self-evident. Greater reliance on digital communication is all but inevitable. Other things being equal, everyone wants a more secure system. We are willing to pay a great deal to implement, monitor, and improve cyber protections. Evolving electricity systems and markets will continue to place great demands on the protection of the command and control systems. Work is proceeding apace to address cyber standards, equipment, and procedures to stay ahead in the cyber security arms race. In principle, the cyber threat could be reduced through greater balkanization of the grid, a return to manual analog controls, and foregoing the benefits of the digital revolution. However, the trends are strongly in the other direction. In this context, what are the implications of the cyber threats for electricity policy, markets, and regulation? Is the directional influence all one-way: electricity systems and markets evolve and cyber protections adapt? Or do the demands of cyber security have implications for electricity system design and markets? Are the two problems -- efficient markets and cyber protection -- separable? Or are there important dimensions where they interact? Other than seeing that we pay the bills for cyber security, how should electricity policy design adapt to the risks of the cyber threats?

Moderator.
Good morning everybody. It's great to be back at HEPG. I see a lot of friendly faces, and we have a lot of good discussion ahead of us. Our first panel is a topic that obviously is wide ranging, but growing in importance, and one that we probably, at least in the electricity industry, probably don't talk about enough, given its sensitive nature. But this panel will be a terrific wide-ranging discussion where. We'll start out kind of with the larger national security view, and move into a discussion of potentially an alternate network to deal with these issues. We'll talk to the premiere

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regulator on these issues in the United States, [LAUGHTER] and then talk to somebody who is regulated by her. So, we will begin with our first speaker, who's well-known in this space of protecting the homeland.

Speaker 1.
I want to give you my bottom line upfront. Nobody ever designed a wholesale electricity market in order to be able to defend the United States against all-out attack by China or Russia. This is a classic example of a nonmarket objective. But for reasons I'm going to describe today, the electric power grid is ground zero for potential attacks against the United States. And there are opportunities to redesign markets, to improve upon markets, in ways that add terrific value to national security. I'm going to give you some examples in my brief remarks this morning.

But first, since I'm going first, and our moderator asked me to do this, I want to talk about the scope and severity of the threat, so we can have a shared understanding of what we need markets to be able to handle. Some of you remember my old friend, General Curtis LeMay, and he said a wonderful thing. He said, "If you can take care of the cats, you can take care of the kittens." That was true in the Cold War for nuclear annihilation, and it's true today in the cyber world.

So, we ought to be prepared for an all-out attack by PLA3, the Third People's Liberation Army, which recently combined its operational capabilities for cyberattack and information warfare, for reasons I'll talk about a little bit later. We need to be able to make sure that we can have market support and national security against China and Russia. I don't care about terrorism. And neither does the Department of Homeland Security, up to a point. Kristjen Nielsen, the Secretary said the other day, and I completely agree with it, "Yes, we understand 9/11 drove the creation of DHS in response to terrorism. Now, we need to be ready for the long term, strategical competition with Russia and China."

What kinds of attacks would we potentially suffer? I like to follow the GridEx assessments and assumptions about the threat. Number one, we'll have combined cyber and physical attacks. They'll hit us both ways at once, because you can achieve synergistic effects on a transmission system with kinetic attacks on transformers and substations in general, along with cyberattacks that produce much longer duration outages than would otherwise be the case. So, let's assume that we're going to have simultaneous cyber and physical attacks.

Second, adversaries are going to strike multiple infrastructure sectors at the same time. Now, if they're going to expose themselves to retaliation by US forces, they'd be fools just to attack one sector of critical infrastructure. They'll go after communications. They'll go after the oil and natural gas subsector. They'll go after everything that has important interdependencies with the electricity subsector, in order to magnify the effects of their attack.

And then, finally, we should assume that cyberattacks will come in conjunction with information warfare. Why are they going to be attacking the United States power grid? It's not to cause blackouts. It's to achieve political effects. What Clausewitz said about the purpose of war being political, that applies to the cyber realm, so information operations are part of the challenge that all of us need to face.

Let me talk now about some of the things that markets might be able to achieve against this threat. Well, we can bolster protection against attack and make sure that investments in cyber resilience get their costs recovered…blah, blah, blah.

Protection is important. Let's keep protecting. But I'm going to advocate today that markets can help do more than that. I think we need to start thinking about cyberattacks, not just before, but during and after. We need to make sure that if adversaries attack the power grid, we can sustain the flow of power to absolutely critical customers. So, US Cyber Command, Strategic Air Command…we need the folks who are responsible to have the ability and the authority to make sure that prioritized load-shedding goes forward; that we sustain power to critical national security facilities, critical regional hospitals, major water system—we should make a list of where we need to be able to sustain loads while we're under attack.

And then, second, as best we can, we need to sustain adequate levels of responsibility. I hate uncontrolled separation. I do not like cascading power failures. So, at the same time that we're preventing the adversary from cutting off power to absolutely vital national security facilities, let's do what we can to maintain ALR (adequate level of reliability).

So, we've got the "before." We're in pretty good shape with that. Have we got the "during?" No. We're not in good shape for that. And then we've got "after." And we're really not in good shape for after. We've got terrific capabilities to restore power in the aftermath of hurricanes and other natural hazards. We've got now a terrific new cyber mutual assistance system that tries to leverage the ability of utilities to assist each other in cyberattacks. But what we haven't been thinking enough about, and what I want to focus on during our conversation today, is restoration under fire. If you think that Russia is going to launch an attack that is one and done--that is, they'll launch a cyberattack and they'll sit back and admire their handiwork—then move to California where the strong stuff is now legal. Because you're smoking it. We need to assume that the adversaries will be conducting a sustained campaign, and that power restoration in MISO and every other market is going to go forward under fire, with sustained re-attacks on the assets and the capabilities, including, above all, black start necessary for restoration. Black start will be preferentially targeted for physical and cyber attack.

So, I've got a little study on this. I apologize for the length of it. Some of you may have at least glanced at the executive summary. I lay out how we can leverage the ability of the Department of Energy to issue mandatory emergency orders to BPS (bulk power system) entities; how we can leverage this development of emergency orders in order to accomplish the objectives I've just been talking about.

But let me conclude by talking about what I think organized markets can do. They're already doing an excellent job of helping enable on the protection side, and I love what Cheryl LaFleur said a few months ago. She said, "It's an urban legend that transmission companies can't recover their costs." Well, that's B.S. They're doing a good job of recovering their costs including a wide variety of emerging hazards. But it's too soon to declare victory.

Let me give you a prime example of where I think market redesign can help. As I mentioned earlier, we have to assume that adversaries will attack the power grid and the oil and natural gas subsector simultaneously. Because, of course, we increasingly rely on the flow of natural gas in order to generate power. So, they'll attack the grid, but they'll also go after the flow of fuel on which power generation depends. And, as all of you know, there are zero mandatory standards for cybersecurity or physical security of the oil and natural gas subsector, both for natural gas and for the supply of diesel for dual fuel generators. Now, there are ways in which natural gas generation can be resilient. If you site your generator on top of a wellhead, or right next to a salt cavern filled with easily extracted gas, I'd say you're resilient. So, it isn't about the type of fuel, although I do think that fuel type is something to consider.

In the work that I've done to support Exelon, I've identified three things that I think we ought to be doing. First of all, we need to identify the attributes of resilience. What makes for energy sector resilience? Second, let's develop a Design Basis Threat. I offered some initial thoughts on what I think the threat would look like. Let's do that in a way that reflects all the contributions to electric grid resilience from the other energy subsectors, so we can assess the risks that fuel interruptions pose to electricity. And then, finally, most important, let's think about how MISO, PJM, and other organized markets can price power generation in a way that reflects the resilience of that power and its value for national security. There are a lot of discussions going on about that now. I think that's one of many examples of where we might be able to use markets. I have additional ideas on what markets might be able to do for black start, which in my humble view is in deep trouble in a contested environment, and also on what maybe emerging threats, especially supply chain risk management. And with that I'll turn it over to my other colleagues.

Speaker 2.
There's an idea that's been kicking around the cyber community for over a decade. It's the idea that we should take critical infrastructure off of the public internet and create a separate network for it. It gets brought up in every task force report for every new presidential administration. It's never been fully vetted. It's never been fully explored. And so, what I'm doing this year is to try and figure out, is this actually a feasible idea? And one of the main challenges on the feasibility, if you can figure out the technical challenges, is how you would knit together all the disparate elements that make up critical infrastructure onto one network. And then, how would you pay for it?

That's where I think the market question comes in. How do you create a massive infusion of money into critical infrastructure? So, for this study, because it's the most interconnected of the critical infrastructure sectors, barring communication, we decided we'd focus on the electric power sector. So, the way I like to break this issue down is as three interrelated problems. The first is weak information sharing. This is often talked about in cybersecurity. The notion is that you want to be able to share information among partners. If one detects a threat, they want to be able to share it with the other people within their industry and with government, and you also want to have government be able to share information back to industry. The second problem is the issue of restoration. This comes up mostly in the communications context for the major internet service providers. If the internet went down, how would you restore it? But, talking to people in the electric industry, the question of communications restoration has been a major topic. And then the final issue is basically protection. How do you assure communications? How do you know that you have confidentiality, integrity, and availability of your communications?

The notion that has been put out is that we should have a single network for it. To break this down, the information sharing piece is probably the easiest piece of this to address. What we've been able to do over the years is take unclassified information sharing as far as we possibly can. Now we're at a point where the US government is declassifying everything that they possibly can, getting beyond issues of protecting sources and methods. They've often found that there are still things that they cannot share.

The other side of it is the issue of coordinating response. If the US government is going to work closely with the private sector on responding to a cyber incident, say by (the new term) "defending forward" in cyberspace, that is, using offense to protect critical infrastructure, that coordination isn't going to happen over unclassified phones. It's not going to happen over email servers that may be already compromised, that probably are already compromised. It's going to require some kind of a shared communication between government and between government partners.

The second piece of this is redundant communications. In 2003, in the Bush administration after 9/11, they created something called CIWIN, the Critical Infrastructure Warning Information Network. CIWIN existed until 2013. It connected many different vectors of critical infrastructure. In 2013, during budget cuts, the Department of Homeland Security decided to end funding for the program, and it went away. There were questions about how reliable the network would have been, given the layer it was operating on. It was operating over internet infrastructure, but on a separate channel, and so it might not have been truly out of band, but we no longer have that capability.

And then, finally, there is the issue of point defense for critical infrastructure. What I have here is a US-CERT (United States Computer Emergency Readiness Team) bulletin, and these bulletins say something terrible happened. In this case, we know that an advanced persistent threat actor, I think this was a Chinese actor, was targeting energy and other critical infrastructure sectors. And they describe the threats, and at the bottom of each of these reports they always put in the same very long list of several hundred controls that critical infrastructure operators should implement to thwart the attacks. They're always the same recommendations, and they usually go unimplemented. And the reason for that is, it's not always possible to do protection the way that we do it for IT networks for OT (operational technology) networks. You can often not take these systems down to patch them. You can often not put the kind of security in place over the top. And so, for that reason, it may make sense to think about how you would create a separate network.

This is the 2018 Defense Department's cyber strategy. The White House put out a new cyber strategy which was largely the same as previous strategies, but this DOD strategy actually goes far beyond what any other administration had said. Where they're essentially saying is, "Look, we will use our offensive capability to protect critical infrastructure." The issue, of course, is, how is that coordination going to happen? How are you going to use classified capabilities to protect critical infrastructure if you don't know what is hitting critical infrastructure? The only way that you're going to have that kind of communication is if you're essentially bringing critical infrastructure companies inside the information sharing loop and the coordination loop with the Department of Defense. And, again, that's not going to happen over an unclassified network.

This is an idea that's been out there for a long time, but a big push for it came last August from the NIAC, the National Infrastructure Advisory Council. They essentially said that government has to study and should look at launching a pilot on using dark fiber and microwave in order to create separate networks for critical infrastructure. It's a very provocative recommendation. The Department of Homeland Security essentially has done nothing with it so far. So, we're essentially doing the basic homework for them to figure out whether it is in fact feasible. And there're many challenges with it. We're about a month into this study. I think we can say that, at the end of the year, we're going to recommend the idea that we can certainly extend classified information sharing to the private sector. It won't be cheap, but it won't be expensive. There is a longstanding effort within the defense industrial base, companies like Lockheed Martin, Northrop Grumman, where they have a classified network where they share information with each other and with the defense cybercrime center at a classified level. I worked on a paper that looked at this idea within the financial sector almost two years ago now. It's a very feasible concept. It would not require that much to do. I'll get into that a little bit in one minute.

On the idea of, well, how would you actually take operational technology and bring it off the internet onto a separate network, it is really, really difficult to conceive of how you might do it. The end of our study may very well be that it is just not feasible technically, and it may not be feasible financially. The benefit would certainly be there. Classified networks are much better protected, because they're simply not accessible from the public internet. In order to do that, you've got to figure out, what's the data? Where is it? Where does it need to move to? What layer of communication would you create this network on? Are you talking about connecting out the OT networks at generation plants, but not the IT networks at those plants? So, we're looking at this issue. It is not easy to actually conceive, when you start thinking about where you would lay fiber and what you would connect. It's not at all clear to us at this point. So, we're working on that piece of it.

What we're proposing early on is, there certainly is a minimally viable concept on information sharing. And the reason I include these slides here is, I think it helps people understand what we're talking about. What you have up in the corner of that slide there, the picture of the conference room, is what would be called a vault. It's a room that is highly secured within a facility. It's protected. It's got levels of hardening, so information cannot leak out of it. And then what you would need inside of that is essentially a secure phone with an encryption card, and then a secure laptop with an encryption card. So, you're talking about a fairly basic setup to extend out to critical infrastructure. And then, for the secret level classification, communication over the internet could take place, but on a secured channel. So, we think this is feasible.

I think I've talked about most of this already, but the basic point here is that if you want to have a coordinated defense with government, you've got to be inside the intelligence cycle. You cannot simply be consuming intelligence. You've got to be shaping how intelligence is collected. You've got to be getting the requirements into the process, and you've got to be part of that feedback loop. The only way to do that is, of course, if you can actually communicate at the right level of clearance.

On the operational network piece of this, we'll put out a paper, probably by mid-spring next year, looking at the technical feasibility and talking about what the security value of that would be.

The real reason I was interested in coming to this group is to figure out, how would you fund something like this? You're talking about a need for a massive infusion of capital to build out a network and then to operate it. So, it would be a very different kind of model, much more unified in certain ways, I think, than the current market. And you'd need to sustain that funding over time.

The last point I would make here is that if this idea proves to be infeasible, and we need to continue with these sort of point protection solutions that we see today, doing that will require also a massive infusion of capital upfront, followed by continued funding over the long term, I think at a much higher level than we currently have.

Speaker 3.
It's nice to be here. I always value coming to this group. I've already learned something, and it's wonderful to be here. Obligatory disclaimer: I speak only for myself, not for the commission and cannot discuss pending adjudicated dockets.

What I thought I would do is give a very brief introduction to FERC's work in this area, which is probably mostly well-known to this audience, but it sets a baseline to address some of these issues, and then comment on the market/cyber interface that Speaker 1 has talked about and others have spoken on.

So, obviously, FERC is not a solo player in most things and not in this. Protecting the electric grid, the critical infrastructure, against cybersecurity threats relies on a complicated ecosystem of the federal government, state governments, and public and private entities with different responsibilities for different parts of the system. And FERC has a role to play, but we work with DOE, DHS, the states, NERC, the industry, and others.

Basically FERC's work is in two areas. Since the Energy Policy Act of 2005, we have been charged with overseeing and enforcing a mandatory set of standards in that expressly include protection against a cybersecurity incidents. So, that was foreseen in the Act itself, and that sets a baseline of, hopefully, good practice that applies to everyone who operates on the bulk electric system. It supports cost recovery and consistent action. It's a baseline. It is not everything they're doing.

And then, secondly, FERC is involved with a plethora of other alphabet agencies on voluntary and collaborative efforts, in part to help address threats and vulnerabilities in cyber and other areas that are rapidly emerging--emerging too quickly to throw a standard at them. When you have an attack, you don't say, "Well, my goodness, let's vote out a Notice of Proposed Rulemaking, and that will solve this." Sometimes faster action is needed. I think over the past 12 years we made a lot of progress in qualifying good practice on this and other fronts.

I would say, if you look at the broad sweep of FERC's reliability work, we started more in the bread and butter stuff with some of the things that contributed to the 2003 outage. You know, tree trimming and relay controls and so forth. And increasingly over the last several years we've been more focused on manmade threats such as cyber security and physical security, GMD (geomagnetic disturbance), EMP (electromagnetic pulse), and other macro threats to the system (not all of these are manmade) and how you can build in some resilience, if I can use that word, in the system to meet those threats.

A few trends that have informed our work: the first is trying (all of us--FERC, NERC, and the industry that work on this) to learn from experience and adapt to new threats. I used to quip that our Critical Infrastructure Protection standards, our CIP standards, were like the iPhone. Just when you thought you had gotten your kids the best and the fastest, a new one would come, and you'd have to do it all over again. And we were numbering at one time: CIP1, CIP2, CIP3…but, unlike the iPhone, people did not stand in line at 888 First Street and long for that next edition, so we've gotten rid of that nomenclature. Now we're just using CIP5 as the baseline, but we keep updating for new threats, and right now, a lot of work is going on related to how to build some security into the supply chain network that supports the electric group.

Secondly, FERC and NERC have been trying to use a risk-based approach, to address the biggest risks. That seems to make sense in life generally. We have created a tiered system of high, medium and low impact assets, ranked by how much damage a cyberattack would do to the bulk electric system. So, an ISO control center would obviously be the highest of the high. Critical substations, and so forth, and things that are at high voltage but are radial, and would not affect a lot of other people, would be in the lower category.

Just to pick up on something Speaker 1 said, I certainly agree that people who run the grid, whether in an ISO, in a company, at all levels of the system, should be aware of where their most critical assets are. As long ago as 20 years ago, when I ran a distribution company, we knew where the water company was, the gas compressor station, the two military bases we served, and what kind of backup they had, what kind of fuel they had. We knew where the hospitals were. We even had a map of customers on life support on each feeder. That is part of running the grid. And so, obviously, the notion that you should know where your military bases are and how they're served is baseline. If that's not being done, someone's not doing their job, because that's part of running the electric grid.

The final trend is increasing mechanisms for self-assessment on the part of grid owners. Rather than us going out and saying what the most critical subs are, we try to oversee standards, so this grid operators can do their own assessment and figure out where to put their dollars to best protect the grid, and we audit it.

So that's what we've been trying to do. I want to turn to my personal views on this intersection of cyber risk, or security risk, and electricity market policy. "Cybersecurity" is a word I don't think I heard 25 years ago. I don't even know when it came into locution, but I certainly didn't study it in college. I mean, not so long ago, people just lived 10 miles from where they were born and didn't go all over the place and weren't in touch with people, other than with the landline. It's a reality of life in all aspects of our work, and the electric grid is one of them. The technological improvements that we are seeing, whether it's in transportation, in digitized apps like Lyft and Uber and GPS and all the things that people use, bring with them a reliance on digitization in networks that brings a cyber threat, but is bringing so many benefits to customers that customers are voting with their fingers, and, similarly, in the electric world, the technologies are also bringing, and have brought, substantial benefits to customers, but bring with them the inevitability of dealing with cyber issues.

In my mind, there are two big trends that are shaping what's going on in electricity right now. One is the increased regionalization of how we get our power, driven by location constraints, renewable resources, and the desire to connect over broader geography to run the system more efficiently and share resources. The West, right now, is a very important example of this. Then the second trend, which is equally strong, in my mind, is the increased miniaturization and localization of resources, with people looking at things behind the meter and micro grids and so forth, and looking at things that are small and that they can control in the small scale with their own devices. Both of those trends, which are in tension and sort of pulling on us in different ways, require increased digitalization to serve customers. Both doing things broader and using the smaller things and aggregating them requires the network.

My concern (and it's not new, but it's certainly been loud lately) is with the use of cybersecurity risks as a rhetorical mechanism to attack change, defend the old way of doing things, and try to fend off technological progress or evolution. When I was first at FERC, we were talking a lot about the smart grid. And there was this notion that, if you let people be connected, a toaster could take down the North American grid. I mean, I remember a toaster being invoked at a tech conference. And, of course, I thought, even at that time, that if we write our standards right, even if something goes up, it won't go across. That's what is a cascading outage is. But the notion that we'd better not do that rooftop solar and all that, because it would cause all kinds of cyber damage to the grid, was partly founded in reality, but very largely founded in the commercial interests of the people who were making the argument against those technologies. Now, that battle has been lost. The distributed technologies have achieved critical scale and somehow been integrated into our lives, although that's a work that has to continue.

The most recent thing is, with the tremendous growth of domestic natural gas, there is the notion that reliance on gas for electricity must have a cyber risk, that there are these pipelines that are so vulnerable. What keys me to thinking that somebody's thinking of this problem for different reasons is if the solution isn't, "Therefore let's improve the cybersecurity of the pipeline," but, "Therefore let's pay people for having 90 days of coal," or something else. If that's the solution, and it's in response, supposedly, to a cyber risk, I'm quite concerned. If we're going to require people to do something on the grid, or alter the way the markets operate, it has to be fact based, based on a sober and independent assessment of the risk. That's our job as regulators and government policy makers--to try to untangle the spaghetti on the plate. How are people's commercial interests, and the technical interests, and the security interests, all tangled together, and our job is to try to do the most fact based work that we can. And I think it's bad for security if we go the other way, because when people are using it as a fake reason for something, to you risk people thinking it's not even a thing, when it actually is a thing that we have to address.

And there actually may be fuel security risk in certain places. As long ago as 2012, I asked whether we should change our transmission planning standards to address loss of a fuel asset, and people at that time, asked, "Why would you do that?" Now they actually have a committee looking at that. So, there's no question that looking at attributes makes sense, and looking at black start makes sense, but this kind of macro sense that it's all so scary so we better go back to the old way, I do not think makes sense.

I do think we need to maintain some redundancy in the planning system to de-risk the assets, and I know that's something a lot of the grid operators have been looking at. How do you make sure you have redundancy? It's good practice anyway.

Senator King and Senator Risch had a bill that I called "the horse and buggy bill," but I don't think that's what it was called. It was a bill to study analog solutions, or whatever. I think, if you're taking out your Hertz radio for…I know that's not the right word, but the one we used to have in the trucks…if you're taking it out, it might be a good time to think, "Hey, should I get rid of this? Should I keep this as a backup?" But to now start putting in old fashioned solutions…I mean it reminds me of the people who said, "Someday I might own a car, but I'm obviously not going to get rid of my horse. Because what if I go out and I can't get my gasoline? So, clearly I still need to keep the horse, right?" [LAUGHTER] So, I just think we have to be a little careful with that notion.

I think our care should reach its zenith when we're changing market rules. Because now we're, with a stroke of a pen, potentially changing who gets paid what in ways that contribute to the reliability and efficiency and protection of customers. And I think that we should be careful, if we identify attributes, that they're fuel neutral and based on fact, and not based on listening to the concerns of people who are being hurt in the current market realities.

Obviously, it's axiomatic that we need sustained cooperation with other agencies in other parts of the government. I saw that the DOE is starting a new initiative that was announced in *Politico* this morning between the Oil and Natural Gas Subsector Coordinating Council and the DOE and the DHS and the TSA to look at gas pipeline security. That makes sense. I think it would be lovely if Congress decided to have mandatory standards for gas pipelines. I'm not holding my breath, but I think that, with whoever they give it to, that would make sense. But, in the meantime, we can't say, "There are no standards, so we won't have security." I think it's great that there's an effort. I think we need to work across sectors. All of those things are important.

I know there are State regulators and former State regulators in the room. I want to say just a bit about the distribution system. On the distribution system, obviously, if there's an outage, it can't cascade as much, but if there were a widespread attack on the communications networks of the distribution system, that could potentially cause, although not connected problems, decentralized problems. So, I think that it's important that state regulators keep an eye on what their companies are doing and make sure they're keeping up. I'd love to see a model code or something about how state regulators look at cybersecurity, but I think, at FERC, we're doing our job if we try to make sure that the high voltage end of the system does not cascade. And then we'll let the state regulators, working together, do their job on their piece of the system. And if I've forgotten anything, I'm sure people will ask questions. Thank you very much.

Speaker 4.
Thanks for the invitation to participate on this panel. Thank you, I think, because I consider myself mostly a markets and operations expert. At best, I'm a cybersecurity enthusiast. But after listening to Speaker 1's presentation, I'm convinced that I'm in favor of it. [LAUGHTER]

So, I'm here today to present MISO's perspectives on how best to align our market rules and market systems to meet the ever increasing cybersecurity threat. At MISO, we've certainly already seen changes in the industry that have led to a transition of our traditional generation fleet. We've seen a significant growth in renewables. We've started to see the addition of distributed generation resources on our system. We have the expectation of the ever increasing digitization of the power system. All of this points to the ongoing challenge we face on how to ensure ongoing security of the system.

So, let me start with just a quick overview of MISO. I'm sure most of you are familiar with the company. MISO is an RTO serving 15 states in the Central and Western portions of the Eastern Interconnect. Our region is geographically diverse, as you can see. And our customer base is also very diverse, to include members that are relatively small, such as public power entities, communities and co-ops. And we have a nice mix of large vertically-integrated utilities as well, such as Entergy, in the southern part of our footprint, Ameren in the central region, and Xcel up in the northern region. Our load and supply diversity has really created substantial reliability and economic benefits and value for our membership. Each year, we complete what we call our value proposition. It's a set of calculations to try and estimate the net value delivered to the membership. For 2017, the net value delivered is approximately $3.5 billion. We've been making this calculation for the last

10 years, and we've estimated almost $20 billion of benefits returned back to the membership.

So, as we look at the drivers of change in the industry and the implications for MISO, we see our role remaining largely the same. We're focused primarily on ensuring the reliability of the bulk power system, and we're also focused mainly on maintaining and operating efficient power markets, which certainly support the FERC's objective, as well. We face significant challenges from the evolving resource mix, and also from the evolving relationship that MISO has with customers and suppliers on the distribution system. In recent years, we've responded to many of these changes by making several market design element changes, trying to keep up with the pace of change, including the addition of a ramp product in our day-ahead and real-time energy markets intended to value and compensate resources that are providing ramp flexibility in those periods of rapid load change. We've made enhancements to our pricing construct under our ELMP methodology, designed to reflect the value and create incentives for flexibility in both unit commitment and dispatch. We've made significant enhancements in our ability to monitor and dispatch intermittent resources, primarily wind, which has been a large advantage both from an operation perspective and a market outcome perspective.

In addition to those kind of functional market changes, we've been keeping pace with some nonfunctional changes as well, primarily focused at performance, as we continue to increase the complexity of our market optimization solutions, which taxes the ability of the systems to keep performing, and solving those problems at a pace that makes sense for the market. And there has been no small effort in changes implemented to our current market systems in the area of security enhancements. What we've seen, through implementing those updates, functional and nonfunctional, in our current legacy market systems, is that those systems are really starting to show their age, in terms the headroom required to continue to maintain the required levels of solution performance. We believe that headroom is running thin. Even our ability to continue to keep up with the pace of change required on the security front is a concern. So, about a year ago, we started an effort to completely redesign and replace our market systems over the upcoming few years.

DERs. Distributed resources. The cat's out of the bag, as they say, or the genie is certainly out of the bottle, from our perspective. Currently, we don't have a substantial amount of distributed generation connected to the distribution systems within MISO. We have seen growth in that area. States like Illinois and Minnesota are pursuing policies that are designed to increase penetration of DERs, so a continuing slow, steady growth of those types of resources connected to the distribution system is our expectation for the region.

As you continue to add generation to the distribution system, naturally that makes those systems more dynamic. A more dynamic distribution systems is another significant driver of needed change on MISO's system. Our systems will need to be updated and continue to evolve to deal with much more dynamic distribution systems in the future.

I mentioned earlier that we don't think our current legacy market systems will be able to keep pace for the extended future, especially in the areas of needed performance and security. The system architecture that underpins our current market systems stems from designs form the early 1990's, a period of time, as Speaker 3 mentioned, when the term "cybersecurity" wasn't in existence. So, those systems were not built with the need of keeping pace with an ever expanding cybersecurity threat landscape increasing the way that it has been. Those systems just weren't built to accommodate those changes.

So, as I mentioned, we've begun the process of redesigning our market systems from the ground up. These systems will need to be flexible, adaptable, and upgradable. Key design requirements not only include those functional requirements needed to serve our future markets, but also the essential nonfunctional requirements, the best example of which is the need for flexibility and adaptability in the area of security, so that we can implement more easily and more quickly needed security adjustments in those systems as the threat landscape continues to evolve.

So, one of the questions posed for the panel (Speaker 3 touched on this as well) asked if we should consider re-balkanizing the grid, returning to more analog control systems, all in the name of managing and controlling the expansion of the cyber threat to the power system. To be honest with you, at MISO we really have not given this question much thought. All signs are still pointing to continued regionalization of the power system, continuing growth of renewable resources and distributed resources, and continuing digitization of devices and control systems.

So, how are we approaching that reality in our market design? Well, we're approaching new market system design with the expectation that cybersecurity threats will be an ever present and ever increasing concern. A new market system would be better able to cope with this reality, but, as much as we think that we can build into this new system in terms of protections, we're still only able to design for what we know. The unknown unknowns are still a concern, and the best that we think we can do at this point is design systems that are agile, flexible, and adaptable, able to easily and quickly be changed as you become aware of those new requirements going forward.

So, this slide gives an overview of how we're looking at the threat landscape. We know we can't control everything, as I mentioned before, so we're trying to identify and harden those areas of our systems that matter the most. We're moving beyond a simple compliance mindset to a true security focus. We continuously engage, for example, with third party security vendors with extensive testing and monitoring capabilities. Our own internal threat hunting team is constantly improving our security operations and, in real time, making strategic decisions around cyber threats and how best to position MISO to be secure.

These are just a couple of examples of steps we're taking to protect MISO and MISO systems, but, again, we can't do it alone, and we know that this isn't sufficient.

So, from a policy perspective, we've got two extremes here. How do we manage the need for rules that promote security, while allowing for the needed flexibility to encourage innovation? We know that that's going to be the requirement. We think that having some floor in cybersecurity standards makes a lot of sense, but, again, the goal is security and not just compliance, so we always have to keep our eye on the goal.

We all will be challenged to continue to think out of the box in creative ways to address this ongoing challenge. One area that we should examine is expanding the use of cloud computing in this space. We've got sophisticated providers out there today, such as Amazon and Microsoft, that are offering highly secured cloud computing solutions, including to various state and federal government entities. These services are among the most cyber secured available, being supported by resources in the area of cybersecurity that no individual entity in this industry can really bring to bear on their own. CIP standards currently do not support these type of cloud tools. Fortunately, NERC is taking a look at this and exploring the future potential use of cloud computing capabilities for CIP compliance, and we certainly support these efforts.

So, as policy makers in industry, the key, really, is how do we bring the different actors with different interests in this space together to work on this very difficult problem and create effective solutions? As the complexity of the grid and the nature of security threats continues to evolve, how well we continue to work together to address this common need, to support this common interest, ultimately is going to determine how successful we can be.

General discussion.

Question 1**:** There are a couple issues I'd like to raise, or pose, and see what your responses are. One is the issue of moral hazard. I had a colleague who worked in Puerto Rico in 2013, 2014, and his comment last year was that it was known it was going to happen. So, you've got a potential issue with systems where there are no sanctions in place to require compliance, and you might get better compliance from some entities and very poor compliance from others. Of course, it's the poor compliance places that turn out to be the weak points in the chain. What does this planning and thinking do about that situation?

And the second observation that I'd like you to comment on is this. Back in 1956, '57, our family, in the suburbs of New York, was instructed to build a civil defense shelter. It's a concept of self-insurance. We're talking about costs being imposed from above. What about teaching digital hygiene to a generation that is completely oblivious to it? As well as kind of the expectation that individuals can self-insure to some extent with generators, or some other systems, in their homes? Or, just be aware of weak links and their habits, so that you've got a bottom up approach to cost management, not just a top down?

Respondent 1: Let me take a quick whack. In terms of moral hazard and the risk that low performers, for example, will be targeted in order to create cascading failures across the bulk power system, that's why we have CIP standards. I like the way Speaker 3 framed it. They don't do everything. They can't keep pace with fast moving threats, but it sets a floor. It sets a minimum basis for both physical and cyber security. And I think that model is very worthwhile to deal, in part, with the problem that you face.

In terms of the equivalent of self-insurance. I think that's important, and how much should we expect power companies to do? Nobody ever brought stock in ITC in order to defend the nation against Russian attack. IOUs, and I think we extend that to munis and, yes, RTOs, are not in business to defend the nation. Yet, that's where we find ourselves. So, think about what's equitable and what's fair in terms of what rate payers should be charged and what we think self-insurance ought to entail, given the scale of these threats.

Respondent 2: I'll just chime in on a couple things. On the question about the sanctions for people who ignore the risks, I think that is where it's important that we have some sort of baseline, and that we actually enforce it. Now, Puerto Rico's a special case in many circumstances, but in the part of the infrastructure that FERC regulates, even a small entity that ignores the standards can have significant consequences, and that's as it should be. But I think, equally important, the statute had it right when it talks about cascading outages and uncontrolled separation. If FERC is doing its job, and NERC is doing its job, then even if somebody is out of compliance it can't spread and infect their neighbors, because it will be stopped at the high voltage level, and that's how it's supposed to work. So, both of those have to be in place.

I also think there increasingly have to be business consequences of doing this wrong, not just regulatory consequences, because that's what companies surely listen to. Facebook is not logging me out of all my devices because some regulator told them to. They realize that if they're not perceived as doing this right, it's a threat to their very business model, and I think that's what ultimately makes companies change their culture. And, speaking of culture, I do agree with you on the self-insurance. I really think we need a cultural change. I will acknowledge that I, myself, I mean, I propound cyber standards, then I go home and I want to do email or load my granddaughters' pictures, and I click through all the warnings and keep simple passwords, so I can get on my system sooner. (Actually, I've upgraded my passwords. I've done that much hygiene, [LAUGHTER] so they're not simple). But, I mean, people have to feel that their thing they do on their own devices, on their own time, with nobody watching, is part of keeping the country safe. Sort of a stupid analogy is when seat belts first came out. I remember people saying, "They're uncomfortable, and I don't like them. I'm not a bad driver. Those are for bad drivers." But now we've kind of changed the culture, where you feel ridiculous if you drive without a seat belt, or you would never let your kids do it. And we need to feel that same way about this less well-understood challenge.

Respondent 3: I would just comment on the point that we tend to be more aware of good cyber practices at work than at home. I bet many of your companies' cyber teams test that. For example, we'll send out controlled fishing emails to see who within the company will click on those. So, if you ever get a chance to talk to your cyber team about the results of those tests, my guess is it would be quite interesting. So, there's definitely still work for us to do, just within our own companies. And, as you say, it's not only the right thing to do, it's critical to our business models, to the extent that there's an event and it's traced to carelessness on behalf of folks that work in the industry. That would be certainly concerning.

Respondent 4: I have kind of a different take on the issue of cyber hygiene. I don't think national security can depend on teenagers making good decisions. I think that's probably a bad approach. [LAUGHTER] Security is not something that is done by default in most places. If you take your home operating system, if you're really bored one night, you can go and download a guide on how to secure your Mac or PC laptop, and six or seven hours later you will be in a Linux operation environment, typing in obscure commands. That's not something that we should expect most people to do. But we do have examples of security by default. I mean, if you want to secure a cell phone, it pretty much comes secure by default. There's not much you need to do to it. That's, I think, where we want to get to. I think there's a major role within industrial control systems for regulators to require security by default--getting rid of things like hardcode passwords, getting rid of things like passwords that cannot be changed, and using basic security, so that, out of the box, things are secure.

Question 2: We have largely, in this discussion, been talking about the bulk power system. But can you elaborate a little bit your thoughts on distribution-level security? Because, for the many NARUC members that I know, this is an area of anxiety. At the Commission, everyone has clearances at the highest levels. You can at least have access to those briefings when knowledge is disseminated. But, at the distribution level, our state regulators typically don't have the clearances, or the staff with clearances, to deal with this, and, yes, it is the distribution level, but we see roughly two million devices a day being added to the grid of the internet of things with unique internet addresses, 70 percent of which, apparently, Speaker 2, referencing you, come with default passwords. And the combination of malware and bad intent is…we've seen it with the baby monitors. We've seen it with the cable top boxes. There's a wider threat vector there, and I'd like each of you, if you have thoughts on distribution level cybersecurity, to share them now.

Respondent 1: Well, I strongly support the idea of expanded clearances for industry members and all, but I don't think not getting the briefings is what's causing the greater vulnerability on the distribution system. I think distribution systems tend to be older. They tend to be run to failure, because they're so ubiquitous, with low usage in a lot of places. They're not managed the same way that transmission systems are. At least, when I ran a distribution system, we didn't do a lot of replacing the transformers on the poles just because they were old. We waited until we had a storm and they blew. I mean, distribution systems are run differently. And there's never enough money to do all the things you want to do. And I think that these are some of the bigger drivers of why there has been probably less technological progress in building in security.

I think one answer, not the be-all and end-all, is, as we invest in distribution systems with two-way metering infrastructure (I mean, we're way past the first generation of automatic meter readers to far more sophisticated infrastructure with behind the meter devices), money is going into those systems, and so we have an opportunity to make them far more secure and build in cybersecurity. But the underlying outage management systems, and so forth, have not seen the kind of investment that we've seen in other parts of the grid. And I think that is the bigger issue. And, yeah, I try to be mindful of it at FERC, that every time we require something on the transmission system we're taking capital money that is coming away from some other part. But it's hard to be mindful of it when you're being charged to keep this part in good shape, is the honest truth.

Respondent 2: I'm very focused on knowing what you might do to secure the bulk power system. If you do that, the remaining risk will be this sort of death by a thousand cuts problem. The focus in the cyber security industry right now is that you have vulnerabilities in connected devices that can demand huge amounts of power: air conditioners, hot water heaters, things like that. You could compromise thousands, hundreds of thousands, of devices and then ramp up their demand all of a sudden at an unexpected time. What would that do to the grid? That's a very real risk. The only way to protect against that is to have better device security. Currently there is nobody in the United States with the authority to regulate those devices for security. California is moving in that direction.

Respondent 3: In the realm of solutions, what we probably need, particularly with more DER penetration, is just a lot more visibility in the distribution level, somewhat similar to what we have at the bulk power system level, maybe not that extensive, but I think certainly we're seeing, with the high penetration, that in order to assure system reliability they need more vision into the system, and that's going to take some investment, but I think it's well worth it.

Respondent 1: I'm going to tell a war story that I forgot when I gave my talk, because I completely stopped looking at my notes. Distribution systems now mostly have SCADA. There was a time when a high percentage of the distribution network didn't even have the SCADA to look at what was on and off, and they all had outage management systems of various vintages. When I was doing distribution, we lost the outage management system during a major storm in the City of Providence and had to put the lights back on without the benefit of the system, and we did it. We called in all the old people who used to work for the company and knew how to do it the old way. We made everyone work dead. We went on the radio in Providence and said that we had to kill big parts of the system and put it back up slowly, and we did it. And we got the lights back on, but it's nobody's plan A. I think of that whenever I hear these, "Let's go back to analog" comments. So, yes, distribution automation has to be more of a priority than it is now, and companies need to prioritize investment in those systems in a way that has not always been prioritized, because either they made more money in generation or they had more hanging on the transmission, literally and figuratively.

Question 3: I very much appreciate the panelists and their contributions here, because I think this is a challenging subject for all the reasons that you have suggested. Let me give you an example of a question which I find myself on the wrong side of here that is related to this issue. So, we have all these distributed energy resources that are coming, and they're going to be out there in the system. And I see lots of advantages in that, and that's terrific. And we can have all different kinds of ways to handle these transactions, and so on.

Then, if you go to the debate that happened in New York about Reforming the Energy Vision, one of the main points is this: you're not going to get any benefit out of these distributed energy systems, if you don't send them the signals that reflect what you actually want to do, which is the real-time price. Otherwise, you don't get the efficiency gains. And I think that's a very important argument, and people are working on trying to figure out ways to do that.

And then I think about that in the context of this situation, and I say, you know, that might make me a little nervous, for the reasons that Speaker 2 was talking about. We're sending out all of these real time signals to all these devices, and then we can tell them all to do bad things, if we send out the wrong real time signals. And that might actually be dangerous, as a matter of market design, for everybody. And then I step back and I think, you know, there's a kind of near analog system that we could do, which is called time of use rates. OK? So, now we put together time of use rates, and then people go and they program their devices to follow the clock, so you'd have to, I guess, take over the clocks in order to sabotage that, I suppose. But customers are not going to be responding to price signals that are being mischaracterized. And then we won't have the same kind of catastrophic failure stemming from people sending the wrong time signals.

However, we know that there's a big gap between real-time pricing and time of use rates. As a matter of fact, there's a paper out of Berkeley about a week or so ago which went through a very careful documentation of this. There's a big gap between the variation in the real time prices and the time of use rates. And then you say, how much of the benefit of real-time pricing can you capture by going to the time of use rates? The answer is 20 percent. You get 20 percent of the potential benefit of having good rate design by going to time of use rates. So I say, "Time of use rates are not a good idea. They'd only capture 20 percent of the potential benefit, and we should go all the way to real time prices and get it right." But I'm thinking about this panel now, and I'm saying, "Maybe I'm on the wrong side of this argument."

So, should we be looking for these sort of partial analog solutions along the way in order to prevent the bad things that are going to happen out there?

Or should we go all the way to I and others would recommend for economic efficiency reasons?

Respondent 1: Well, I would say it would be big progress to go to time of use rates. We might send the wrong signal once in a while, but primary reasons that we don't have time of use rates in more parts of the country are political, having to do with concern about exposing people to those rates. And if it was an unprotected real time price, I think the political issues would be even more acute. I know that in New England, every time we have a spike because we run out of gas or something, the urban legend appears (I've even heard FERC Commissioners say it) that prices in New England are higher than anywhere on the face of the earth. Yes, that was true for one minute, in one winter. But it becomes, like, the new thing with every spike. So, I think time of use rates would be more politically acceptable, and that might be a reason to go to them first, in some parts of the country, before you go to the real time rates. But if there were the political will to do it right, I can't focus on the cyber risk as a reason not to. Because what would be the wrong thing that might happen? You'd get a signal saying that this is a good time to use your device, and it actually wouldn't be a good time, and you'd pay more money. But the rest of the time, when the signal is right, it would be good for mankind.

Respondent 2: Let me be Doctor Doom here and scale up your question to the bulk power system and wholesale markets. I've heard from a couple people in DOE that there is almost certainty that adversaries will seek to manipulate wholesale markets, especially same-day markets, as a means of creating disturbances on the operational side. Knowing that, of course, you've been building barriers to that happening. But they'll still try to do it. So, in the Secretary of Energy's back, back pocket, he ought to be prepared to issue orders, under Section 215a of the Federal Power Act, to halt market operations and have electricity sold at a fixed price. That's the kind of back up thinking against an emerging threat that maybe we need to think about.

But I'm so grateful for the work that MISO and all the other markets are doing in order to make sure their operations are not vulnerable to attack and manipulation, because, of course, adversaries will seek to create Enron-type disturbances, if they can. That will be one of the attack vectors. So, thanks for what you're investing in your new design to prevent that from happening.

Respondent 1: I strongly agree that we should have executive orders drafted for emergencies. Noah built the ark before it started raining, or whatever the expression is. Yes, we need all those things in our back pocket. I just think we need to have a clear understanding of what an emergency is. And I think the misuse of that word has hurt the effort of responding to real emergencies.

Respondent 3: MISO has over 50 distribution systems connected to our low power system, and what we think we can count on is that there will be many solutions adopted among those distribution operators--everything from doing nothing, assuming that they operate systems that are not dynamic or controlled in any way today, all the way up through potentially, at some point in the future, election to implement distribution markets. So, there are questions on who operates those markets, and what those interfaces are. But from MISO's perspective, we're engaging our members, the operators of those distribution systems, in most cases, to make sure that we're part of that conversation, so we can help them with their decision making, with the goal of being able to integrate those multiple distribution-level solutions into a communications and operations and market system at the wholesale level that still works--still works for them, and still works for the region. I think that's the point I was trying to make.

Respondent 1: One thing we haven't touched on that I think is significant is the fact that, even though we have 50 distribution systems and seven RTOs, the number of software purveyors is a lot lower. All of the RTOs, I think, use OT software in some part of their system to run the market. There's only so many. There's GE, and ABB…and I've lost touch, but there's only a few that all the distribution systems use. If we can build more security into some of those systems at the supply chain level and make the supply chain better, then it gets to when Speaker 1 picked up his phone and said that for phone security, somebody has done it for us, because that will cross a lot of the industry, I believe. I'm not an expert, but I think there's only a few suppliers of the core software.

Respondent 4: I think this is a question that's going to be talked about for a while. My concern would be, I guess, less about false market signals being sent, than about somebody figuring out a way to hack 10,000 ovens and turn them on at the wrong time when people aren't home. But that's an aspect of what we have to be paying attention to.

Question 4: First of all I really appreciated the panel. Speaker 1, I appreciated your report. I thought it was very helpful. I want to ask a question that builds off something that you said, because I think it's a critical question that I don't know how to answer. And that is this question of, what does it really mean to have a system that is more resilient to security threats? Now, typically, when I think about resilience, I think about making a system that can operate in multiple ways, so that if one way is attacked and goes down, there are other ways to operate the system. So, a system that could have both centralized or cloud computing and distributed computing. It could have a grid that could operate regionally, but also fractally, so that there would be parts of the system that could operate independently, even if the RTO went down. But you raised a question of how to value that resilience. And I don't know whether I have the right way of thinking about this, and I'm not sure how I would go about valuing resilience in the market. And I'm wondering if you or other panelists have thoughts about exactly what that means, and where we should be looking for low hanging fruit about how to make the system more flexible, more resilient in other ways. Because one of the things I don't necessarily want is simply to harden the system and create a brittle system, which may be hard against lots of attacks, but a system where the attack that gets through takes us down for months.

Respondent 1: I'll take an initial whack, but I'm sure my colleagues will have their own views. I think you hit on one of the attributes for resilience, and that is getting away from single mode failures. To have diversity in what we need for energy, and especially electricity resilience, is a virtue. So, let me give you an example. I think it's great to have diverse fuel or resources, and I love it that we have so many generators with dual capabilities, so that if for some reason gas is interrupted, they can run on diesel. But that also gets to the point of, I call it, "fakey" resilience. Because, unless we do fact based analysis of the sort that Speaker 3 called for on the ability of diesel or suppliers to conduct resupply operations for dual fuel generators in a severely disrupted environment, we've got fakey resilience. And the ability just in time diesel delivery systems to provide that resupply when transportation systems are severely disrupted due to loss of electricity is unknown, although New England ISO has done some interesting work on what they call the Great Unknown. So, I think you're on to something. That's why I like a mix of fuel resources, and I think each of them can be made more resilient. But we have to avoid fakey assumptions about resilience and do the analysis of the sort that Speaker 3 suggests is essential.

Respondent 2: I think resilience, at bottom, means the ability to keep on going if something bad happens. That's what we mean when we say, "my kid is resilient," or, "the Red Sox are resilient," or whatever. That's what that word usually means. And we certainly want our electric grid to be able to keep on going if something bad happens. I agree that diversity, not just fuel diversity (of which we have more on the grid than we did a few years ago, actually, when some big parts of the country were like 86 percent coal), but diversity of all types is good, and I think, in general, since we've had the regional networks, we have far more diversity of transmission options to serve customers than when each company was its own little beast with an extension cord here and there to each other. And so, diversity is good.

I think the issue is, when you say you want to keep going if something bad happens, you have to figure out what the bad thing is that you're worried about. Most everyone has medical insurance, because everybody knows, pretty much, that at some time in their life they will get sick, because every human being who's ever lived has gotten sick and died eventually. So, pretty much, medical insurance is a necessity. So, every utility trims their trees because it's universal that they grow. I mean, that's not in debate. Everyone has storms of different types in different places. So, those are the baseline things that you know will happen. What's hard is balancing them with the low probability, high impact things like an EMP attack, or whatever, that you know will happen, but you don't know when or where, and what kind of resources you're going to put into the system for what type of resilience. I think that some of the work that Alison Silverstein and others have done to look at the broad picture of what other types of threats to the grid exist, and where we should be making investments, is important. Not to endorse any specific thing, but that kind of analysis is important, because we won't just singularly focus on one element, which is fuel.

Respondent 3: To me, resilience is just the ability of a given system to absorb abnormal inputs and still produce outputs within spec. So, that sounds simple enough, but you have to determine what system you're talking about. And I have a little bit of experience, just working with our stakeholders, when we define the systems as the control center operations across MISO. So, traditionally, resilience in that space comes in the form of redundant systems backup, emergency operating procedures, emergency communication channels, and certainly MISO was built and designed to have those kinds of redundancies in this system control center system space. We put most of that stuff in place within the first four or five years of our operations. And then we sat for about five years and thought that it worked pretty well. And then our members started asking questions around, what, really, does business continuity capability look like in that space?

One of the challenges of creating an assessment of the value of additional resiliency, I think, generally, is that you have to make a lot of assumptions about the future, including probabilities of events and outcomes. We're currently working with stakeholders and a stakeholder group to explore these questions. We created a model that kind of says, "Given a certain set of possible future operating events impacting control centers, what is the ability of the MISO control center system today to be able to ride through those events?" We're trying to create models where we can explain and discuss with our members what the value of additional redundancy and additional resilience would be, and we're trying to just create a conversation with our stakeholders around that question, on what additional business continuity of control center operations they would be willing to invest in. If the system is the entire bulk electric system, or the integrated bulk electric system and distribution system, then, obviously, the models get more complicated and the questions get a lot harder. But that was one example of how we approached that in that area of control center business continuity.

Respondent 4: So, your question was really about how to value resilience. I'm not sure we've necessarily given you a distinct answer on that, but I think this overall topic has obviously piqued a lot of interest, so perhaps there'll be some discussions in the future on it.

Respondent 5: Yes, I think it's an important question, and resilience is not just operating within spec, but what happens when the system is out of spec, and how can you be resilient in that situation?

Respondent 4: So, there are a couple things that I think it's important for everybody at least be aware of. First, the North American Transmission Forum is undertaking a supplemental operating strategies approach, which is, if there's a catastrophic attack, how do we get the system operating minimally so that society can maintain its stability, even if it's for a few hours a day? And there are references to going back to an analog system, at least conceptually, so that effort is ongoing. Similarly, the Cyber Mutual Assistance Program (CMA) is one that's only been around a couple of years. We started is at EEI (the Edison Electric Institute). We opened it up to APPA, NRCA, the RTOs, the gas industry… Now the water industry is interested. It's totally voluntary, but its premise is, let's assume there's a successful cyber-attack, what do we do? And so, key IT people, cybersecurity people, from I think we're up to 139 entities now, meet regularly. They go through exercises. They have a playbook. We probably don't talk about it enough, but it's a very proactive effort to deal with the response to a successful attack.

Respondent 1: CMA is great. I love everything about it. But there are a lot of opportunities for growth. I'll be very candid here. I think that, when it comes to the ability of utilities to assist each other in the face of a cyber attack, too much thinking thus far has assumed the equivalent of a blue sky day, and not one in which transportation and communications between utilities are severely degraded. I'm confident in the ability of big utilities to conduct communications inside of their own operations. They're going to be able to get to all the substations they need and have good backup communications. When it comes to the ability of the utilities to talk to each other on a nationwide basis, or even get NERC alerts... Geez, this stuff is sent out on public switch phone networks, or the internet. Well, none of that's going to be available, and if you think satellite phones are going to work against major powers--outer space is maybe the first place that the shooting starts. Again, stop smoking the strong stuff. Satellite communications are going to be at risk for sure.

So, thinking about what is survivable in order for the CMA system to operate effectively and be able to transport people in a disrupted environment…I think that we've got a great foundation now in which to move forward. Also, as far as I know, CMA has not tackled the question of black start. What would resilience look like in terms of black start? And we need that ability, because, again, the adversaries are going to seek to create interconnection wide outages. It's tough to do, but, with physical attacks, maybe they can get there. So, we need to be able to do inside-out restoration as well as traditional outside-in. How do companies support each other in that?

Question 5: So, my question sort of really stems from some initial comments that Speaker 1 made that got me thinking about referencing Curtis LeMay and some of the early thinking around nuclear warfare and the focus on national actors as potential instigators of a cyber-attack, as opposed to some hackers. And, in that framework, I wonder if there are actions that the community as a whole, or particular actors within the electricity sector, could take to spur more thinking about deterrence as an option. This conversation sort of makes me imagine a similar conversation in the 1950's occurring in the United States about missile defense, and how we just need better missile defense, and then we'll be OK. And that was not the solution. The solution was to ban missile defense and create plate glass windows and greater certainty about attribution of an attack, so the consequences of being an attacker became so severe that no one would consider it. Is there some analog for cybersecurity? Now, admittedly, we're not in a position right now to be negotiating with the Chinese government and the Russian government about these issues, but that doesn't mean we won't be there at some point in the future. Is there a conversation that can be happening within the power sector about what types of strategic actions we could take to create an explainable framework of deterrence that can become something that we share with some of our potential opponents? Thanks.

Respondent 1: Thousands of pages have been written on trying to apply the Cold War concepts of deterrence to cyber warfare. And I think it has mostly proven difficult to replicate the concepts. You're dealing with very different kinds of weapons and very different political realities. In the first place, there's a basic question. If Russia finds it in their geopolitical interest to try and destabilize US power systems, if there is some kind of shooting war going on, how would we deter that in that context? Would Vladimir Putin care if the United States was able to place at risk the power supply to his population the same way that the US government would? I think that the answer is probably no. So, I think deterrence has its limits.

The other piece of the problem with the deterrence model is that we're so much more reliant on information technology than other countries are that we're going to remain so much more vulnerable. China, Russia have both greater control as well as fewer vulnerabilities in their critical systems. That may change over time, but right now I think the risk is that we might not be able to deter an adversary under the right context, if it's something like China attempting to deter us from engaging in support of Taiwan, for instance, in a cross-straits conflict. In that kind of scenario we could very well see them preempt with a kind of cyber-attack as a warning shot, and I'm not sure we would be able to deter that.

Respondent 2: I guess I thought mutual deterrence for cyber was more around the United States as a nation state developing offensive capabilities to kind of negotiate with other countries, and I honestly didn't think that was something the power industry would have a role in. So, if there's a role we should be having, I don't think it's happening now. I thought it was more a role for DOD or other intelligence agencies.

Respondent 3: I think deterrence is exactly like nuclear deterrence in the Cold War in one respect, and completely different in another. And the way it's different, that's where all of you come in. That's where RTOs come in. The way it's similar is, we need to be able to deter attacks on MISO by threatening to impose unacceptable costs on the adversary. So, we need to convince Putin or Xi Jinping that if they attack the power grid, we're going to thwack them in ways they'll find unacceptable. And that requires those of you who have power feeds to critical defense installations to make sure those feeds stay up and running, so that our deep strike capabilities are all going to work and our power projection capabilities are going to work. So, it looks a little bit like the Cold War. In fact, quite a bit. Cost imposition. The way in which deterrents are completely different is that we can do something today we could never do in the nuclear area. And that is, we can do deterrence by denial. In a nuclear war, both sides are going to get thwacked, in part because we abandoned ballistic missile defenses. But now we have a chance to strengthen the resilience of the power grid, thanks to what you're doing, so effectively that adversaries will doubt whether they can achieve their objectives. They know they're going to be thwacked if they try.

So, this deterrent by denial is where power companies come in. Where you come in. At FERC, and EEI, and with all the other folks here, we can do something so we live less in a glass house, and if we can do that, thanks to your work, then maybe we can do extended deterrence. The Trump administration, now, saying to the NATO allies that if Russia messes with you we'll come to your assistance. Well, Speaker 2, you've been in the Sit Room, and so have I. The President's first question is going to be, "OK, if we actually help out Lithuania, what happens to our own citizens when they attack our grid?" I want to be able to say, "Well, thanks to what MISO has been doing, we're going to get through this OK," and so we can defend our allies. This is really on the electricity industry to play a role that is very different in deterrence, and for which I think the subsector deserves some credit that they don't get. So, all praise to the national security benefits of the investments that you're making in security so that we can make conflict less likely, and that's always got to be the goal, right? To make conflict less likely.

Respondent 2: Your comment picked up on something that Speaker 2 said about the states. The mandatory standards that we have now do not cover Hawaii or Alaska. Even I know there's a lot of critical defense and missile defense systems there. So, that's, I think, a place where we have to be willing to work with the states, because they may just not be part of the bulk electric system, but they are sure part of the critical defense system, if we want to have deterrence by denial.

Question 6: I wanted to make a quick observation and then have that lead into two specific questions for you all on the broader theme of resilience. Representing a more consumer and even a kind of tax payer perspective here, the conversation on cybersecurity and grid resilience has become very paternalistic. And when we're looking at this, going forward, there are things that do pose serious risks to consumers and, perhaps, national security. And so we recognize that those are some very tangible benefits that may be there out there, but how tangible, we don't know. I like the earlier framing about how we don't really know the probability, and we're trying to assign probability to what are essentially very fat tail events, which gets us into the point of a lot of the issues that you brought up on system redundancies on restoration service protocols and assets, et cetera. These are all things that can easily lead to billions of dollars in added costs for very speculative benefits. So, how do we make sure that our institutions and the way we proceed going forward maintain that economic discipline, where the benefits are going to outweigh the costs, especially when the benefits are very difficult to quantify? And then, part B is, how do you determine cost allocation of some of these costs for consumers, and, if this is also a shared national security issue, what's the tax payer burden versus the consumer burden?

Respondent 1: Just one comment that I sort of struggled with. A lot of people I've spoken to have said, this is really a national security risk. The burden should be borne by government, not by rate payers. I get confused by that argument, because I think that if you did a Venn diagram of rate payers [LAUGHTER] and tax payers, [LAUGHTER] it would largely be the same. [LAUGHTER] And so, from that perspective, I think it probably does make sense to say, "OK, if more money needs to be spent on the grid for national security purposes, that should probably be as an equal share by rate payers on some percentage basis." I think that probably makes more sense than saying, "Let's just take this out of the national security budget and come up with very convoluted way in which we would provide credits or tax credits or direct payment from government to the utility industry." So, that's just my thought on that.

Respondent 2: Well, there's a porous line, and there always has been, between what we put on people's electric bills and what we put in their tax bill. It's often determined by politics, because the people who set the taxes are facing elective office, and the people who set the electric bills are frequently appointed. So I would aver there are lots of things on electric bills, like low income rates and various environmental initiatives, that you could well have argued should be funded by the state, but the state has chosen to fund them through electricity customers, and we take that for granted. So, I don't necessarily have a feeling that we need to make this line very clear in this case when it's so porous in so many other ways. But I think the allocation issue of making sure that if you charge a whole region it really has a regional benefit, as opposed to benefitting only commercial interests, and so forth, is important.

Respondent 3: I want to answer a different part of your question, and that is about how to maintain cost discipline. Because, clearly, we could waste the GDP of the United States on investments against these events. You can correct me if I'm wrong, because I'm not any good at this. There is no Monte Carlo or probabilistic approach that can quantify the likelihood that Kim Jong-un is going to wake up on the wrong side of the bed and launch an EMP attack. You can't do it. And if you try to do it, it's garbage in and garbage out. So, event probability, if you're doing risk-based investment decisions, washes out a little bit for these manmade events, and instead you need to look at vulnerability, and especially consequence, and think hard about whether there are defensible ways that you can talk to tax payers and rate payers about why, for example, you want to invest in something like EMP hardening, even though there's no way to quantify the likelihood. There are some very sensible targeted investments in control centers that you could make that don't take the GDP. You can select a couple systems that you really care about. Protective relays for cyber, for example. Let's start investing in things that have the biggest benefit for our consequences, when you can't assess probability of an event. Am I getting it wrong? Do you think there is a methodologically defensible way of assessing manmade risks?

Respondent 4: I think your point about sort of doing a cost efficiency metric system would be really beneficial. Where can we get the most bang for our buck is a great way to start ranking some of these things, but, ultimately, we still have to decide what's worth it. And that's a tricky benefit-cost analysis. And there are different ways to approach it, and maybe the probabilistic approach is just going to be very difficult, and you do a few sensitivity analyses on it, but we need to come up with some type of approach, I think, to decide what's going to be in and what's going to be out.

Question 7: Thank you. My question takes off from some of the others, but I want to bring it back to the issue of markets. In ISO NE, we're grappling now with how we try to build more resiliency into our winter fleet, which is right now supplied by gas, but gas-constrained on very cold days. And the issue is how we can make sure there's enough inventory, and we're going to be building market systems to cope with that.

Speaker 1 seems to have a certain degree of optimism that we can design market structures to ensure resilience. And I get that when the market that we're asking to respond sees a certain probability of the event happening, but the less likely and the more catastrophic the possible event, the harder I think it is for markets to grapple effectively with it. And so, I can imagine that we'll have responsiveness from generators who are concerned about cold winters and feel they're going to happen once in every three or four years, and we'll build a stronger supply chain. I have a very hard time seeing them figuring out what they need to do to protect against Kim Jong-un getting up on the wrong side of the bed. In terms of cyber security, I have a very hard time seeing how markets could work, frankly, very well at all in that context, in combination with the other things that you have labeled as part of an active war. And I would have thought that the answer there has to fall back on regulation or something that's determined from the top, because you're not going to see individual generators picking up on that, in terms of putting that very slim probability into their own risk assessment and letting it influence how they invest their money.

Respondent 1: That's one of the hardest questions we've received this morning. I'm not going to pretend to know, at this point, for example, how we would redesign capacity markets in order to deal with these challenges, or have carve outs in a way that helps resilience, although I think this is worth pursuing.

Let me first start by thanking you for the excellence of the New England ISO study on reliability. It came out earlier this year. It's really good. It does focus, however, on weather, because that's more of a bounded problem, and is really the wolf closest to the sled in your region, which is so gas dependent.

I believe that the first step for building a market system that will value resilience and price resilience into the cost of electricity is to identify the attributes of resilience. So, what kinds of characteristics in the energy sector as a whole produce reliable and resilient power? And then, going back to, let's say, a fuel neutral approach to understanding what kinds of sources of generation are going to be most resilient. And then trying to incentivize generators, for example, to match those attributes of resilience. That's where I think we would start.

So, again, although I understand that, in the context of the administration's proposal for protecting coal and nuclear, this looks like a biased approach, and I think the administration, is frankly open to that criticism, there really is a "there" there. There is a problem of fuel resilience that we need to think about in a way that isn't biased or isn't predetermined, and I think starting with one of the attributes of resilience and thinking about how all fuel supplies might be able to achieve those levels of resilience against a design basis threat has got to be the starting point, and that's what I believe might help in many regions of the United States.

However, New England is a special case, because of its overwhelming dependence on natural gas. So, how do we help that system, that natural gas system, become more resilient? That's what I would like to open up for discussion, and then reward resilient gas generators and the gas suppliers on which they depend for having investments in resilience. That's the 40,000 foot level answer. But you're on to a tough, tough question.

Respondent 2: Well, of course I agree that New England is special, oh so special. [LAUGHTER] I think there was a sentence in there where you said that we have to make sure that our markets reward reliability and keep the lights on and all. I would have said, "That is their day job. That is what they were set up to do. That's what markets do." Now, if there's a new threat that comes along, or a new circumstance that is challenging that reliability, then maybe markets have to say, "Whoa." Just like MISO did with its ramping rating, CAISO did with its ramping rating, and others. "Wow. Reliability means something different than we thought. There's a new element we need to consider and put that in our lens of reliability and resilience."

ISO New England undertook a study that was premised, first of all, on the idea that if you're going to make yourself more resilient, you have to know what you're making yourself more resilient against, and what is the threat. EMP requires a different thing than running out of gas, than a cyber-attack on a pipeline, and so forth and so on. ISO New England had a clear sense of what it was studying, which was limitations on gas capacity into the region in the winter months when a lot of the gas is used for heating, and so forth, and did a study, and is now, as I understand it, doing the work to figure out how to value that. We'll obviously take a very hard look at that when it comes in.

Back when we started looking at gas-electric, we had regional meetings in all regions of the country, and one thing we learned is that the situation was a lot different. So, taking any kind of leap from that and saying, "Wow, there's a winter gas issue in New England, therefore we need to figure out that there's a fuel issue everywhere and pay different kinds of generation differently…." You'd have to take a really hard look at that, because, I mean, PJM is sitting on the Marcellus, and has 21 pipelines or something. And there's various issues in different places. I mean, California might be facing the issue of, how do you integrate very large amounts of renewables in a certain way, and what elements or what attributes do we need? How are we going to pay for that? So, I think it has to be very much based on fact.

Question 8: I first want to say, great panel. Really interesting set of issues, and a lot of questions come to mind. I've done work in the past on some other high-risk industries. For example, the oil and gas industry, where the issue of safety there is really important. And I kind of want to break down what I see there.

If you're drilling a well, say in the Gulf of Mexico, and you're going really, really deep, you have a really complex problem to get that well down there safely and to design it. Some have described it as just as complex as sending a man to the moon. And so, today I'm hearing a lot about the hardening the systems and resiliency. What I'm hearing less about, though, are two other aspects that were really important in the context of the oil and gas industry. One is, just what I'm going to call safety culture. That is, do people in the industry behave in a way that is completely consistent with compliance, consistent with the norms? If you're with a person from BP, and you're walking down the stairs with them, their hand is on the rail. And if your hand isn't, they're telling you to. And the question is whether or not this industry…linemen need to wear hardhats and such, and so that's always been a part of it. But I'm not sure I'm hearing that that part of it has translated over into the cyber area. When we hear about the disruptions in the Ukraine, it's because of simple stupid fishing and lack the kind of double redundancy, good passwords, et cetera. And so, I'm just going to leave it at that. It seems that that's a really important dimension of the problem. Where are we, as an industry, with respect to that kind of vigilance?

The second aspect of that problem is that, obviously, in that industry that there is real direct liability for the consequences of accidents. And, obviously, it's a little bit simpler to assign liability in that context, because there is typically one or a core set of responsible parties. Within an integrated network, where we both have disruptions that can flow to other areas and we have systems that are mediated, that occur across multiple systems, such as the dryers that could be triggered and that could be located in NYISO, ISO New England, PJM all at the same time, this obviously gets more complicated, but I'm wondering where we are in terms of really thinking about assigning liability in a constructive way, but also recognizing the degree to which this is insurable for a given company probably is vastly insufficient, relative to the potential magnitudes of the kinds of consequences we're talking about.

Respondent 1: I'll start, because this is something I've thought a lot about. I've had employees die on my watch. I spent three years of my life trying to work with DuPont to start a new safety culture from the bottom up, and I would say that I believe the electric industry does have a focus on safety culture at least equal to oil and gas when it comes to electrical risks, which are paramount. We worked hard on some of the less frightening risks, like a car accident, or a slip and fall, which were by far the biggest issues our employees faced. But it comes down to everything you said. Personal responsibility, correcting someone else, and making it a part of the job. I don't think we're there, but we need to have that kind of a cultural ownership when it comes to cyber, where if I use the simplest password I can and leave it on so I don't have to re-enter when I come back from the meeting, that is just like not holding that handrail or not putting on my rubber gloves, because I'm exposing my coworkers to risks from that. I don't think we're there yet, because I don't think the problem is as well understood by people.

As far as the liability, this is not a complete answer, but I know Speaker 4 said they do fishing tests and all that. I think good companies do that to try to make sure people understand that little things can have a big consequence, as with safety. And, as with safety, if something goes wrong, it's usually multiple things that contribute to it, and you have to have multiple safeguards. I think that, in terms of liability, this is not the complete answer, but that's where the liability standards come in. If the company that let the fishing attack in is the one that it is spread from, there would be consequences--although that would be thought of well after we thought of putting the lights back on.

Question 9: This has actually been a very fascinating panel. In fact, I propose that we call this the "Doctor Strangelove" panel, given the doomsday scenarios that we've been hearing. I never thought I would actually come to an HEPG meeting and hear Clausewitz, Rumsfeld, Curtis LeMay, mutually assured destruction, the Cold War and a reference obliquely made to NATO Article 5 within the context of electricity policy. It makes me feel like I'm doing my undergrad all over again in military and diplomatic history.

With that being said, the previous questioner who wanted real-time pricing (not time of day pricing) is on the right side of history. I think that if we are afraid to extend pricing and control signals down to the distribution level (full disclosure, I've written a lot about this back in the day), we're just giving up. In fact, we're going to economically bomb ourselves back into the Stone Age, in reference to Curtis LeMay.

The question that I have is, how do we go from a cyber physical security issue on the transmission and distribution network, and somehow get to fuel security? I just don't understand that, especially given that most of the outages are on the distribution system, and the US military actually acknowledges that this is not a generation issue, it's a distribution issue. That's the first question.

The second question has to do with a question that was asked earlier about DERs. From a security standpoint, why don't DERs work? I mean, they're distributed. They're much more difficult to attack in unison. They're much harder to hit, and, if I think about the issue, going back to fuel security again, we're putting all of our eggs in a really large basket, which is almost akin to what General Short and General MacArthur worried about om December of 1941, when they worried about sabotage and lining up their aircraft so easily to be hit by the Japanese, during their respective attacks at Pearl Harbor and the Philippines. That just seems kind of crazy to me.

The third question that I have is, if we're talking about separate networks, have we thought about the interaction between avoiding a cyber or physical attack and the cost associated with restoration should something happen? What I have in mind here is my experience working in Florida in 2004, 2005, after the hurricane season. We got hit by seven storms in two years. Everybody thought undergrounding was going to prevent this stuff from happening. A funny thing happened on the way to that. We had so much rain, and, in a lot of the underground systems, when trees got uprooted, it took the power lines with them. When storms surge came in, it popped the vaults right out of the ground from the pressure. What survived? Old overhead systems. And if they didn't survive, they were much quicker and easier to restore than the underground systems. Have we thought about that interaction? You can try to prevent stuff, but if it does go down, now the restoration time is a heck of a lot longer. The same is probably true with cyberattacks, as well.

Respondent 1: From a restoration capacity perspective, if you built a separate network, and somehow it went down, you probably still want to have some kind of minimally viable backup system that is probably, from talking to people, going to be wireless. It's going to be limited in the amount of data that can move across it. It's going to require having on-site power backup. You still want to have that kind of redundancy, in the event that you lose your main operating capacity. So, I think that probably makes sense as an approach.

Can we go back to your first question? [LAUGHTER] That was a long time ago.

Questioner: I'm sorry. I do pontificate. [LAUGHTER] How do we go from cyber and physical security attacks to saying, fuel security is an answer, or the answer? That's one I don't understand. Because if there's no delivery mechanism, I don't care how much coal you've got sitting in the yard. I can sit on that coal pile and watch the darkness.

Respondent 1: I think it's a fair question. You're saying we got off topic a little bit. How we got there I think is understandable, as well. Cyber security is a sub issue of the real desired outcome, which is security of the power system. Fuel security is also a sub issue to that main topic. So, having a conversation about the real goal of ensuring a reliable power system includes both those topics. But your point is well made that fuel security is maybe outside the topic for this panel.

Respondent 2: Well, I'm going to politely disagree with you. I think there are a lot of ways in which we can deal with fuel security as a contributor to overall grid reliability against these emerging threats, and you heard my pitch. But I completely agree with you that if T&D system goes down, having reliable fuel and generation is of no value. We've got to work all of these issues simultaneously.

It's your second question that I wanted to focus on, and that is about DERs. You said something about how they're harder to attack in unison, because they're distributed. I partly agree with that, except when it comes to the realm of common mode failures. That is, if all of these systems rely on components that are provided by a small number of vendors, and if adversaries go after those widely distributed assets, you can have a lot of things, even if widely distributed, go down simultaneously. So, there are people in this room that know more about it than I do, but to the best of my very limited, primitive knowledge, every smart inverter for solar is made in China or depends on a majority of its components manufactured in China. What could possibly go wrong? [LAUGHTER]

Question 10: I want to go back to regional differences for a moment. It's come up a couple times, with the mention of Puerto Rico and then the discussion just a bit ago about New England. And so, my question is, how much regional variation can or should be built into developing systems and standards? Because what's needed in Puerto Rico or Hawaii is not necessarily what's needed in the MISO region. So, we talked about different metrics so far. We talked about the large scale bulk power system. We talked about smaller scale distribution systems. We talked about different fuel types. So, these are clearly metrics that people are focusing on. But is there another metric we need to consider up front in terms of regional variations? I'd love the panel's thoughts on that.

Respondent 1: In terms of the reliability standards for the bulk electric system, first of all, they don't cover Hawaii, Alaska, or Puerto Rico, or any other island territories, because they're premised on cascading transmission outages. And I think what's happened is, as we've moved more into using the reliability standards as a defense against manmade threats like cybersecurity threats, you get into areas where those other regions are just as vulnerable. In the standards area, I'm in favor of certainly as much standardization as we can have. And there is a regional standard need. For example, the Western Interconnection is considering a regional standard to deal with changes in the reliability coordination out there. It has to be premised on a really factual difference between the regions that you can readily explain. Now, when it comes to the bigger picture of resilience and reliability beyond reliability standards for cyber security, different regions have substantial differences based on policy choices that are being made at the state level, geography that affords access to certain fuels or fuel storage, and just geography--how remote they are, how widely distributed their loads are, how much is underground, and so forth. I think the example that came up before of New England looking at winter natural gas constraints is premised on an actual factual circumstance there of some winter days running out of gas that does not exist in other regions, but there might be other things that exist there that don't exist in New England.

And so, as you decide against which threats you're going to harden your system, it has to be based on fact, and there undoubtedly will be some regional variation. For example, right now there's a lot of climate adaptation money being spent at the coast. In the interior sections, different adaptation might be needed.

Respondent 2: I don't have much more to add to that. Again, the goal is security, not compliance, so, to the extent that there are regional issues that are relevant, those need to be addressed and put on the table. But I agree that, in a lot of cases, standardization does make sense in this space as well. So, standardize where appropriate, but real issues have to be brought forward, or you're not going to be able to say that you're focusing on security over compliance.

Question 11: I'd like to come back a little bit to the DER topic. As Speaker 4 noted earlier, the genie is out of the bottle. We're seeing, even in the Midwest, the beginnings of significant amounts of DER penetration into the markets, and the Commission is thinking about ways to potentially further encourage DERs to participate directly in the wholesale markets, either through aggregators or individually. I think the point was made earlier that DERs may be distributing the risk, but is there also consideration of the potential increased risk, maybe not from a nation state, but through hacking or other cybersecurity threats that may be imposed on the wholesale system as a result of this increased participation in wholesale markets at the DER level, notwithstanding some of the efforts that are being put in place by the RTOs to protect their systems? How is the Commission thinking about that? How should NERC be thinking about that? How should the state commissions be thinking about those potential increased cyber risks?

Respondent 1: Well, the term DER covers a wealth of things. I mean, a generator that you keep in the garage with a can of gas is distributed, and not even hooked into anything, for more resilience of your household. As I said in my remarks, I think that, as with many things, there's an element of truth. As you get more aggregation of deployed distributed resources, there's more vulnerability to cyber weaknesses, because that digital network is carrying the responsibility for aggregating potentially a lot of power over a vast network. On the other hand, I think a lot of hysteria has developed around the issue because people whose business models would be hurt by less reliance on the central station resources have a tendency to puff up the risks of the distributed resources. Yes, I think that there may be places in which either standards have to change or RTOs have to do something different. But I think aggregation of those resources has a lot more benefits than the risks they bring in the long term.

Question 12: Working at ARPA-E previously has showed me that technology is way further ahead than any of us here in industry are assuming, and that going to a more distributed system entails choices that maybe we're not making. So, for example, in terms of having something that doesn't have too many common mode failures or isn't too vulnerable to somebody hijacking the price, how would you design a more distributed architecture to be cyber secure if you have autonomous controls, and if you have distributed sensing that's far more advanced even than what utilities are using for very low cost? What if you have reconfigurable feeders, what if you have protection systems that are also power flow controllers? If you start tapping into all of that technology, what are the cyber risks that remain, and how can we design a system like that to be as cyber secure as possible?

Last time we were here in DC for HEPG, we had a really interesting conversation about reliability. There was somebody from NERC, and something that emerged that I thought was really interesting is that NERC actually does not account for backup and on site generation in their calculations. Professor Hogan did a really interesting analysis that found that the one in 10 standard for transmission reliability equates to a value of lost load of $100 per megawatt hour. At that cost, for the transmission and generation system, any backup generation is basically in the money with today's state of technology, and technology continues to improve. Meanwhile, the vast majority of outages happen in the distribution system. One of the panelists mentioned that they could see a lot of the capital that we're putting in the bulk system being put in the distribution system, in various ways. So, how would you see reliability standards essentially evolving so that we can put more of an emphasis on local resilience and tapping into, by the way, American-developed technologies that are unfortunately underutilized in this country?

Respondent 1: A lot of the issues with new technology is their availability to access by malicious actors. You can go online and get what I think is still a free account. There's a search engine for industrial control systems and IOT devices called Showdown. And what you can do with that is search by device. You will find all kinds of distributed power generation that is not only internet accessible, but directly internet accessible. And oftentimes those devices have default passwords. In fact, one of the scarier developments over the last couple years is that an enterprising young fellow decided to match up Showdown with Metasploit, which is a framework for carrying out cyberattacks, and he created Autosploit. So, with a click of a button you can say, "Oh, I see this Siemens device. It's publicly accessible. It has a known vulnerability. Let me press a button, see if the vulnerability has been patched, and exploit it." So, I think that the first answer to your question is, if you want to deploy this new technology, it needs to be deployed in a way where it's not easily accessible for adversaries to target it. You want to limit who can communicate with those devices, wherever they're deployed, and make it so they're not easily accessible. I think the basic lesson here is if you could force an adversary to carry out some of these sort of scarier scenarios that Speaker 1 is talking about, where you need to combine a cyber and physical attack, that's actually where we want to be. That's a much better world to be in than one in which somebody can sit in Kiev and carry out an attack in the United States.

Respondent 2: I'll take a stab at the second part of your question. I think that, to the extent we become, as a nation, more dependent on distributed resources that collectively operate as central station resources do to contribute to both reliability, potentially black start, and other parts of keeping the lights on, it's essential that the Energy Information Administration, FERC, NERC, and RTOs have a better accounting of what's out there, so that we make sure we don't overbuild other parts of the system. On the other hand, NERC is a highly trusted, engineering based, well-staffed organization that works on reliability, but they don't have jurisdiction over anything other than the bulk electric system. So, as much as we might want to lean on them to figure this all out, that's not the way the Federal Power Act is written. So, we're going to have to continue to work with NARUC in the states and people who can control the spend of money and so forth on the distribution system. NERC, although they might have a lot of smart people and all that, that's just not what is in their jurisdictional responsibility, at least at this time, so it's going to require reliance on the deployed network of regulators that oversee that part of the system.

As to your other question of, how do we take into account the distribution money needs, it partly goes to making sure that any transmission requirements we put on are thoughtfully imposed and proportionate to the risk, so transmission doesn't suck more capital than it needs to, but it's going to require the distribution regulators, the state regulators, to demand the spending on the distribution network, not just FERC leaving money on the table, which might just go in shareholders' pockets. I mean, it's not necessarily clear that if FERC lightens up on the transition requirements, people will invest that money in more cybersecurity for distribution. That's going to require push, as well as the availability of the money.

Question 13: This has been a terrific panel. One of the issues that makes this topic a little different is, how does all this work with competition? We're hearing a lot of talk about planning, collaboration, and all the things that any advocate of competition would find abhorrent. So, the question is, how do we maintain the kinds of security, that things that we're talking about, without, in fact, ultimately upsetting the competitive nature of the market?

Respondent 1: I think financial services has done a pretty good job of figuring out how to maintain competition within an industry while collaborating on cyber security. And they've taken that, I think, almost to an art form in terms of information sharing and in terms of backup and redundancy. It becomes something that they don't want to compete on and don't see value in competing, and they want to ensure the trust and reliability of the US financial system. They realize that if one company goes down, everybody may doubt the viability of that system. I think that analogy carries over fairly directly to the power system. I think it's in everyone's interest to maintain the power system, probably even more so than in the financial industry.

Questioner: I think that's true. The question is, how is it they do that without actually sort of transgressing the bounds within which we want competition to function?

Respondent 1: Maybe you're kind of getting at an anti-trust issue?

Questioner: That's certainly one of the issues, yes.

Respondent 1: I think that Congress, the Department of Justice, and the Federal Trade Commission have all taken action on this to make it clear that cybersecurity cooperation falls outside the bounds of anti-trust concerns. There's now a law that has codified those prior opinions to take away that risk.

Respondent 2: There is a tension. If there were a true emergency, for example, if the industry implemented cyber mutual assistance, if the biggest expert on doing something was in AEP, we wouldn't want to be saying, "Oh, my gosh, we can't let him into the National Grid control room, because he might know where the transmission was flowing. I guess we'll just leave the lights off." That might be a case for one of those emergency orders that had to be issued to allow that kind of sharing. But I do think, in the day to day, when it's a non-emergency, the financial services model is a good one of how businesses operate.

Respondent 3: I think it's a very good question. Most of us realize that markets remain workable only in the presence of certain preexisting conditions. "Workable" is a fungible word, so we get to talk about what we think that means, but workable in most cases does allow for a certain amount of regulation, or counter market constraints that have to be applied on the execution of that market. But I think it's very important that we continue to have the conversation about additional regulations. How far does it go when you cross a line of non-workable competition? I think that's an important conversation to have, and then you would need to go into the conversation about priorities. Which is more important? Do we want to maintain conditions to support workable competition because of the benefits that brings? If the answer is no, then I think we need to have a sober conversation about reconsidering the use of markets to solve certain problems. The adherence to the value of markets really is a choice. So, at some point, you might want to choose non-market based solutions if the risks are high enough.

Respondent 4: I think one of the aspects of the financial industry is that the portal for information sharing is very robust. We're getting there. But I think the financial sector is seen as, again, the model for being out front on this sooner than others. There is a renewed effort, or a new effort, at the ESCC (Electricity Subsector Coordinating Council) level to get the comp sector, the finance sector, and the electricity sector working more closely together. I think the portal plays into it.

Respondent 5: Let me make your question harder and more pointed. I think everybody understands how we get cost recovery for investments in cybersecurity that help us stay complaint with CIP standards. Same for physical. It's those voluntary measures that are necessary to keep pace against the evolving threat where I think we need to think about how can, in a competitive environment, ensure that a T&D company and a merchant generator get the cost recovery that they need to go above and beyond CIP standards, and why it doesn't look like collusion. And here, the burden is really on State PUCs, FERC, and NERC in order to have realistic standards of prudence.

It goes back to the probability question a little bit, too. What, above and beyond CIP standards, are you going to allow cost recovery for? For example, what about measures against EMP, where there are not yet standards? And I think that's the hardest part of your question. What makes sense on a voluntary basis, and how do we incentivize investments to go above and beyond standards in a way that allows markets to be further designed in order to provide these incentives, in a voluntary realm, not only in compliance with CIP standards?

Respondent 2: As I said, there's a little bit of urban legend mixed in with some truth. If there is a transmission company that has tried to put cyber security protections in its FERC formula rates and has been denied, I would like to hear from them. I have said that at least 20 times, and no one has ever spoken to me.

Now, merchant generation is a different thing, but the main people who have told me that merchant generation isn't spending enough are vendors trying to sell them things. I have not had a merchant generator say, "Something I was trying to spend. I couldn't put in my bid," but if there is such a thing, I would like to hear from them, because that's not a situation we want to have, where our rate structures are discouraging this investment. And I've also asked gas pipelines, because, in an earlier administration of FERC, we had an idea of putting out something to the gas pipelines. Norman Bay wanted to reassure them that they could get cyber investments and I met with INGAA (the Interstate Natural Gas Association of America) and a whole bunch of pipelines and said, "Are you having trouble getting your cyber paid for? Would this help you?" And they said, "It's not a problem we think we have." So if somebody is having that problem, I would like to hear from them, because that is not a situation we want.

Respondent 5: And let me add that that's also true for nuclear generation, where the Nuclear Regulatory Commission is responsible for such issues as extremely rigorous standards for supply chain, risk management, everything else that nuclear power plants have to do, including physical security that goes way beyond what's required for other components of the energy subsector. They get their costs recovered for that, too, although maybe not in a way that is going to prevent premature retirements of nuclear power plants, because they can't compete against gas fired generation under current market rules.

Respondent 2: That's because the gas is cheaper, not primarily because they're spending too much on cyber, I think. [LAUGHTER]

Question 14: First, I have to correct a factually incorrect statement. There are economic nuclear plants throughout the United States, but the government wants to shut them down in New York, and they are economic in New Jersey and Pennsylvania.

Let's put that one aside. If I were a crazy terrorist (I probably would be a bad one, and I'd probably be a bad unstable world leader) I would not be going to bomb a gas pipeline and take out one line of generation. I would be going to bomb a nuclear plant, where money and communications can't do anything about it. And I'm going to bomb the transmission system. And so, this discussion about fuel security is interesting, when really, I don't know, maybe I'm a bad terrorist, but it doesn't make sense to me.

Back in the blackout of I forget when, interestingly enough, First Energy's stock did not go down. I think it actually went up after the blackout. And so, it's not like Facebook, where their stock goes down if they do something stupid. So, I go back to your thoughts on transmission incentives and penalties. And, two, more importantly, I worry that there's always so much focus on the RTOs. But there can be attacks on facilities outside RTOs, as well. What's the coordination nationally, and with these other transmission systems? Thank you.

Respondent 1: OK. I didn't think there was anything scarier than Kim Jong-un waking up on the wrong side of the bed. [LAUGHTER] But the questioner being a crazy terrorist [LAUGHTER] definitely is scarier.

First of all, I did not mean to imply in any way, shape, or form that all nuclear units are uneconomic. That could not be farther from the truth. Many of them are economic. So, I stand corrected if my comment implied that.

I don't remember the first part of your question.

Questioner: My concern is about the focus on the market. First of all, it's unusual that the idea of making markets for transmission investment didn't come up until the very end of this discussion, when you've got Order 1000 out there. So, one, there is merchant transmission that might make investments relevant to security.

And, second, my concern is, we focus so much on the RTOs. What's the coordination outside the RTOs with other utilities? I know it's not FERC's jurisdiction, necessarily, but there's got to be something going on.

Respondent 1: Well, transmission investment is another way to add resilience and redundancy to the system, because you have different paths that can serve a region or serve a metropolitan area. And we have not seen incentive applications saying, "We need this to help with security," or whatever, but I would certainly entertain them, including if there are issues of confidentiality. We talked a little bit with PJM about it, because they're starting to do some work on redundancy and de-risking their system. You don't want to file an application at FERC that says, "We need to build this second line because X, Y, Z is so vulnerable," so how do you handle that? But we would certainly want to encourage people to make those investments.

To your second question, the reliability standards of course apply to not just the transmission owners and operators and generation owners and so forth, and the RTOs, but those throughout the bulk electric system, both the mandatory standards as well as the information sharing. I believe the last time I went to an Electricity Subsector Coordinating Committee (ESCC) meeting, Tom Fanning of Southern was the head of it. And so, those other regions are very much in the conversation and spending the money. We're not just worried about RTOs in those regions. Southern, I believe, is its own balancing authority, its own reliability coordinator. It has all those same responsibilities and cyber expectations as would MISO or someone else.

Respondent 2: Yes, there's extensive industry involvement, and at the ESCC level, it's the CEOs of EEI, NRECA, PPA… So, as with any other aspect of this industry, the cyber people meet regularly, either through that avenue or through forums that EEI puts together. It's extensive. We could probably spend a whole session on that. But, again, our focus was more on the market side of this.

Respondent 3: A brief observation on your observation. This is why we need a Design Basis Threat. Yes, a single terrorist group, sure. One pipeline. Russia and China…what are the number of assets in any part of the energy sector we should assume are going to suffer simultaneous attacks? Four teams, as in 9/11? A big old truck bomb pulling up to a critical compression station? We remember what Timothy McVeigh was able to do. And then, in the cyber realm, what are the standards? We ought to mutually agree on what standards should be applied, knowing, as was pointed out, that every region is going to need its own solution set, but there should be a shared understanding of the threat. We're not there, and we should get there.

Session Two.
Can Electricity Markets Meet the Challenge of Meeting Non-Market Objectives?

Restructured electricity markets arose as an alternative approach to meeting the societal objectives for economically efficient operation, innovation, and investment. Reliability mandates constrained market design. Adapting the abstract theory of markets to recognize the special requirements of electric power was important and difficult. Now growing and conflicting pressures for change to address environmental and other social objectives, interacting with changing technology, could undermine successful electricity markets and recreate the very problems that precipitated the restructuring reforms. Furthermore, fundamental differences in national, state, and regional policies do not map well into natural market configurations. The decarbonized-clean-renewable energy nexus is a case in point. Can market design adapt to address the conflicting requirements, or will non-market mandates and subsidies return us to government direction of most procurement and operating decisions? Is the death of markets imminent, or can markets adapt to address the broader objectives? How much economic efficiency is lost in trying to accommodate diverse policy preferences? How much do such conflicts impact the roles and comparative importance of capacity and energy markets? How does the existence of carbon trading or some form of carbon pricing, in some states and not others, affect the apparent conflict? How should market operators respond to these challenges? Resistance, surrender, or adaptation? What is the proper mix of policies? Most important, what would adaptation mean for electricity market design?

Moderator.
Good afternoon everyone. Let me just give a very brief introduction. Obviously, we are in very interesting times. We're seeing a fairly rapid turnover in our fleet, some of which has been driven by market fundamentals such as low cost gas, but some has been driven by state policies such as renewable portfolio standards. The challenging thing is, it's happening at a time of very low load growth, so this is more disruptive than it might otherwise be on the incumbent folks.

Now, some folks are really liking the change, and others want to slow it down. We've heard from DOE that they're worried about resilience as we see this turnover. We've heard from NERC that they are seeing the need to ensure that we have sufficient essential reliability services as we switch over the grid. Some companies are worried about what happens to their investment-backed expectations, their stranded costs. When we had a giant change in the industry, with Order 888, we had stranded cost payments that sort of smoothed that changeover. We're having a changeover now, but we're not discussing that issue. We're talking about other ways to support resources.

On the other hand, some states and stakeholders want to go faster. I'm seeing a lot of state pushes right now for offshore wind, for example, and more talk about carbon. Obviously, there's tension between markets in the states, and we also have the other player out there that I have to mention. We have the traditional load serving entities who are getting caught in the crossfire between the states and the markets, who just want to get left alone.

So, the question is, given these conflicting interests--the market interests, the participant interests, the load interest, the state policy interests--can markets be designed, whether they're the RTO markets, bilateral markets, or attribute-specific markets, to meet all of these interests? Which market designs can be best? Do we need to blow things up and start over? Or, are there marginal changes that we can make in the market designs in order to meet all these needs? And, of course, our panelists have all of the answers. So, with that let me turn it over to Speaker 1.

Speaker 1.
I'm going to focus on the questions of improvements in market design. There's a lot going on. We all know about the context of this discussion--the Trump analyses that came out of the Department of Energy, and the response of the FERC. A lot of that was focused on topics that are related to this subject here today on improving markets and price formation. A reference was made to the PJM paper on the subject and the efforts that are underway on those matters and then the continuing discussion in front of various press conferences, and so on. So, there's a lot going on, and everything is in turmoil, and that's pretty familiar.

A lot of this, but not all of it, is because of the challenges of integrating increasing levels of renewables. There's a large literature on this subject. I just copied here an example of one of these studies, not the only one. The questions always come up, are renewables fundamentally different? How do we handle the problems of investment in an industry where you have zero marginal costs of supply, and more intermittency? Do we need a fundamentally different approach for electricity market design? And then, the final question that this panel is trying to address, what's wrong with the existing market design fundamentals? So, that's kind of the motivation for my comments.

The growing use of subsidies is an important part of that story. Renewable portfolio standards, renewable energy credits, production tax credits, investment tax credits, demand response, and zero energy credits…my favorite was the anonymous quip that soon we're going to get DECs, which is dirty energy credits. [LAUGHTER]

We're all familiar with Joe Bowring's great contribution to the literature, which is that "Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies." I think he's the first one to say it in such a pithy way. And, of course, many people, myself and others, have picked up on that. And then we have some of these comments about the challenges, such as the comment from Norman Bay in a prior FERC proceeding about the "idealized vision of markets free from the influence of public policies," and then asking how can we reconcile that with the fact that we do have all these public policies and what to do about it. So, that is the context and a part of my motivation for this.

I like to refer back to this extract from the National Academy of Sciences study. You have a copy of this in front of you. It was written by Bill Nordhaus at the time of the study. But the essence of it is that the problem with these competing subsidies is that what they end up doing is undermining each other, so you end up with total cost going up, but the supposed policy effects that you're trying to compensate for not being addressed. In this case, he's talking about carbon, and his observation and that study's observation was that the net effect of all of the subsidies taken together was effectively zero. He meant zero in terms of the impact on carbon emissions, not zero in terms of the cost. So, the costs were all going up. So, in the end, it is much more effective to penalize carbon emissions than to subsidize everything else. Obviously, that's also my own view, and I think that's a real problem.

There are many other problems that are associated with this, not the least of which is that subsidies tend to be such that they suppress the prices that the demand side sees, so you only get half the market response to it, and you don't get all the other advantages of competition.

So this is a serious problem and something that we should worry about. What I'm going to focus here is on what FERC should do. And, not surprisingly, first, my answers are generic, so they don't have anything to do with any continuing proceedings in front of the Federal Energy Regulatory Commission, so I don't have to worry about that. And then, second, to get the prices right, FERC should address the problems of market manipulation and support consistent infrastructure expansions.

So, what do I mean by that? This is sort of an outline of what the talk that I would give if the moderator would give me enough time. [LAUGHTER] So, this is a summary, and I'm going to try to make several of these points, but I'm only going to expand on a couple of them.

The first point is about deference to markets. We go through all these conversations about market failure. I've always cited the most dangerous definition of market failure is, "The market fails to do what the central planner wants." And when we get into that mode, and then we reinsert the central planners into making the decisions, it's not hard to see where this goes, because basically most investments would be left back to the purview of regulators and central planners, who operate a better collection agency. And that's going to undermine all of the hope that we have for the advantages of markets. And I think we need a deference to markets rather than the opposite, and that's a real problem, because of all the issues that we're talking about.

Another market design improvement is pricing externalities such as carbon emissions. This is absolutely critical in terms of internalizing the costs. One of the advantages of pricing carbon and the social cost of carbon is that it provides a guide for how much is enough, whereas the quantity mandates, such as the Fuel Use Act (just to pick one that's a long time ago), don't do that, and they do not balance costs and benefits. So, we can go into the why. It's hard to set the price and it's hard to set the quantity. It's much harder to set the quantity, for theoretical reasons, and I can go through why that's the problem. So, setting the price is what we should be focused on.

I'm going to talk about scarcity pricing, because it's part of my mission in life to talk about scarcity pricing at every opportunity. And I'm going to talk about the ERCOT experience and the Operating Reserve Demand Curve.

Another topic that I don't have time to go through today, but it comes up in a lot of these kinds of things, is a little bit wonky, but it's multi-period pricing. In the short run, operating a system, the theory of the economic dispatch and locational pricing was always developed implicitly with the notion that it was a multi-period story. And if you have multi-period pricing, and you calculate the locational prices, then you automatically take care of ramping and flexibility issues, and you don't have to go around and define new products in order to provide payments for people for reliability, ramping, and flexibility. In most of the ISOs, we don't have a very good representation of that. I think that's one of the latent issues which we should be paying a lot more attention to, because I think it's going to become much more important.

Transmission investment. We need hybrid systems that integrate costs, benefits, merchant investment, and regulated investment. And this is the Order 1000 fiasco, just to put a mild editorial comment on it. And I'm happy to get into that, but we don't have time. But I just point to the New York ISO Tariff, which provides the closest example. I underline the word "tariff." I don't say the New York ISO practice, but the tariff has got the right theory.

And, finally, price manipulation, which is actually the hard part of all of this, and I'm going to talk about seller and buyer price manipulation.

We should all be humble about what we know about what's going to happen in the future, and the central planning story. So, these are two examples of surprises. The one on the left is a bad surprise, and the one on the right is a good surprise, so this is not biased in one direction or the other. The one on the left is the nuclear power plant, the Bellefonte plant. They had $6 billion that had been pumped into the plant, and they offered it for auction, and the minimum asking price was $36.4 million. Now, I think they got a little more than that, but they didn't get anything near $6 billion for that. So, that was obviously a mistake to go into that. Maybe not *ex ante*, but certainly *ex post*. And it's the kind of thing that motivated electricity restructuring in the first place, making mistakes like this, and we have lots of examples. Shoreham's another good example.

On the right we have the US shale miracle. I don't think we have a shale performance standard. We don't have mandatory purchases of natural gas from shale. We did do a lot of R&D, and it turns out that introducing new technologies in the energy sector is not hard, as long as they're better and cheaper. What's hard is to introduce technologies which are not as good and more expensive. There are all kinds of market barriers to that. And so here we had a good outcome, and the projections are even further, and it's going to go on and on. I don't need to elaborate on that, but it should give us humility about our ability to pick technology. So, with the kinds of things you heard this morning about technology neutrality, this is what's behind it. That kind of a story.

And then we have continuing discussions about what we should be doing, and I was very happy to see that former Commissioner Norman Bay endorsed the ERCOT market design, and talked about the advantages of the energy-only market, and all the things that might be considered.

The final quote here is to try to focus the attention. This is not, as sometimes you'll see in the press, a debate between markets and central planning and regulatory control. That's a false characterization of where we are and what the problem is, and I quote one of my fellow panelists on this subject, saying that we don't want to go back to the years, the time before open access. We like wholesale competition--the operational values that RTOs and ISOs provide, and so forth. Which I endorse, and I'm accepting,

The fundamental structure of the market is the other chart that I have to show every time I speak at the Harvard Electricity Policy Group, which is bid-based, security constrained economic dispatch with locational prices, where we've had this long history of discussing and debating it. But this is the only model that can meet the test of open access and nondiscrimination, so, when I'm talking about deference to markets and deference to design, I'm trying to always put it into this framework, and particularly the real time economic dispatch framework. And you'll see some examples of that coming up.

So, the first part is that if you look at what's happening in short run spot markets, because of all the things that are happening with subsidies and mandates and everything else, the trend is actually in the opposite direction of being against markets. It's actually for markets. The best evidence of that is not only is that the existing organized all use that basic structure, but you see what's going on in the West. The Western Energy Imbalance Market (EIM) is expanding rapidly. And this is in an environment where the politics all go in the opposite direction, because they don't like FERC, and the EIM is under FERC jurisdiction, by way of being operated by CAISO. But it's actually happening, and it's happening in a big way, and that's a good thing. And it's happening precisely because of the pressures that are being put on this system because of renewables and entry and all these other kinds of things.

So, it's not the short run spot coordination wholesale market that's the problem, it's the investment story, going forward, and that's not going to change. That basic model that we talked about, about economic dispatch and price clearing, is basic economics. And then I asked the question (and there's a paper in your folder about this), suppose, as a thought experiment, we changed the electricity supply curve--so we got rid of that blue supply curve with lots of different plants, and we had only green technology with zero marginal costs up to its capacity. So, that's the green supply curve line that you see on this picture. And then the question is, what changes in the fundamental analysis of how you should run the short-term market? And the answer is, nothing. You do economic dispatch. You charge the market clearing price. Lots of times it's zero. And then sometimes it's not zero, and it's high when you get into constrained situations. The big difference, of course, is that in that kind of a theoretical, hypothetical market (we're not going to get there) all of the high prices come from scarcity pricing only, it's not because you have increasing variable cost of operations. But you still have market-clearing prices—everything is the same.

The problem is getting the scarcity price into the system, and we haven't done a good job of that, and there's a whole literature on this. But, basically, we didn't have demand-side bidding participating in the real-time market enough. We didn't have the mechanisms, and what we really needed was to do a better job of pricing operating reserves, as one avenue for solving this problem. And the basic Operating Reserve Demand Curve, for which the theoretical version that's sketched out on this picture here, is a way of dealing with that problem. And I can expand on that, but just to say it has now gone from a theoretical conversation to having been implemented. It's been running now for four years in Texas. They're having continuing evaluations, but my short-term summary of the situation is that the problem continues to be in Texas that we anticipate scarcity problems in the future, but we have too much capacity now. And that just keeps happening. But this is a straightforward way of addressing the scarcity problem, and it handles the pay for performance problem because it provides real-time penalties if you're not there. It can be locationally…it's terrific. I can explain how to do all of this.

And, just by way of comparison, this is a superposition of the graph of the ERCOT Operating Reserve Demand Curve on the PJM Operating Reserve Demand Curve. And it's not scaled for size. PJM's actually much bigger. So, the existing scarcity pricing mechanisms in the real time systems outside of ERCOT need a lot of work. That would be an important recommendation, and, happily, they're looking at it very closely. If you go to back to that PJM study that I mentioned before, and extracted one of the pictures from there, of a "Demand Curve for Operating Reserves with Minimum Reserve Requirement," you will see a certain similarity between that picture and the picture that you just saw. So, of course, I'm sure that there will be some things that are different and have to be analyzed, and so forth, but they're recognizing that's a high-priority problem. I think it should be more of a high priority than we're now discussing. But getting scarcity pricing right is going to help in all these other things.

Then we get into energy, looking at other kinds of problems, and I've been thinking about this and trying to describe it from the perspective of an energy-only market, because not only do I hope that people move in that direction, but also it helps in thinking about things. It clarifies and gets a lot of the clutter out of the way. There are lots of things which affect energy market prices. As Norman Bays said, an idealized vision of markets free from influence of public policies, this doesn't exist, and it's impossible to imagine it will get there. A challenge is to internalize the cost of market and nonmarket actions.

So, there are a lot of things that happen that are conditions that are addressed in markets and don't require regulatory intervention, I would argue.

So, related costs. We have power plants that are not just in the energy business, but they're providing cogeneration and other things, and that interacts and affects their costs, or they are hydro facilities, and they're interacting with lots of other…there are all kinds of things that are going on. As long as they are playing by the general rules, the fact that they have related costs or related benefits that affect what they're doing, that doesn't disturb us, and we think that's just natural and they include it in the market in a natural way.

Exogenous shocks. The U.S. shale miracle, that I showed before, we don't view it to be the case that the job of regulators is to restore prices as though we didn't have the shale miracle. That's not our problem. We just accept that, and we go forward with it, even though it has tremendous impacts on different companies.

Optimistic expectations. I've got Panda Power here, but I should have put a question mark after Panda Power, because I don't know enough about what they actually did. But this is this company in Texas that invested in a lot of natural gas plants, and a lot of people were scratching their heads about, "What are they doing? Prices are too low. They can't make money in this market," but they had a different view, and then they entered, and now running, and they're having their own problems, but it's not a problem for the regulator. So, some people are spending their own money, and they're making investments, and then we shouldn't be intervening.

And there are the externalities, like carbon pricing. If we price carbon, or any of the other kinds of emissions or problems we want to deal with, we would say, "That's good. That's better. That helps the market," but we don't have to intervene to undo the effect of carbon pricing.

The harder set of problems is problems arising in markets requiring a regulatory response. And the two principle problems that I think of are seller-side market power and price manipulation and buyer-side market power and price manipulation. Establishing the difference between a condition and a problem is easier said than done, but the critical frame of reference is, would a price-taker accept the transaction, or is price manipulation essential to the strategy?

And the way we think about seller-side market power is just that it is economic or physical withholding, and then that raises prices, and they make it up on volume, and it reduces the efficiency in the system, and regulators intervene because they don't like that. And how do they intervene? Well, the best method of intervening is with offer caps for these people who have market power, because that integrates well with the market and gives deference to markets, and you get the efficient outcome with offer caps, because we still have market clearing prices. We just don't allow people to withhold their capacity. And we don't let them retire their capacity, necessarily, because that would be another way of dealing with physical withholding. I don't think these arguments are particularly controversial. We're already doing that.

Where it gets harder in this energy-only market context is thinking about what to do if you face buyer-side market power. But everything is symmetric, and it just flips the other way. So, now you lower demand artificially in order to depress the price. You have all these rent transfers, and that creates the same kind of inefficiency, and then you can say, what would we do? Well, the analogy to what we just saw is that we'd have bid floors. So, you can't shift your demand curve. You have to bid it in in some way that reflects your underlying costs. Boy, that's easier said than done. And we have to deal with the investment solution, because you can accomplish most of these things by shifting the demand curve, or by adding generation, I think, which would effectively shift the net demand curve for everybody else. And there we want to make sure that it somehow isn't affecting the market in such a way that it's only because of the price manipulation that you're doing it, it's not because of the other externalities. I think that's a really big challenge, but what I would come back to all the time is that it's the price manipulation that benefits the person who, or the group who is manipulating the prices and that the strategy wouldn't go forward without the price manipulation. That's the guide that I would carry of what we're looking for. I think it's extremely difficult, though, to implement that, and I'm sure others would have thoughts about this as we go along.

I didn't put it in my outline because we don't have time, but if you think that what we were just talking about is hard, once we get down into the distributed energy resources, we're back to what we were talking about this morning, and all those other problems. And the challenge of getting the prices right at the wholesale level is easy by comparison to this problem down at the distributed energy resources level. But I don't have time, so I won't talk about that. Thank you.

Speaker 2.

Thanks, Ashley and Bill, for asking me to speak here. While you just got the intellectual framing of this problem from the heights, I'm going to give you a view from the trenches in New York. When we started markets in the late '90s, I don't think environmental stewardship was foremost in our minds. Reliability and costs were the two overriding considerations. But, given a competitive market and its drive towards efficiencies, we have seen in New York, and I'm sure it's true for other markets, that just cost and the market efficiencies have brought about a lot of improvements in the fleet in terms of environmental factors like SO2, SOx, NOx, and carbon. Over the last 20 years, the environmental footprint of the fleet has steadily improved.

However, in states like New York and California, the emphasis is front and center on environmental stewardship, going to a cleaner and sustainable future. So, in New York, the bar is being raised consistently higher. We started in 2004 with the renewable portfolio standard, with the goal of getting to 25 percent renewables by 2013. Fast forward to 2015, our goal is 50 percent by 2030. In between, we had the REV initiative that Audrey Zibelman the New York Public Service

Commission Chair, launched, which was moving towards distributed assets, and this year we have a target from the Governor to put 1500 megawatts of new storage in by 2025. So, we certainly are on the road to a cleaner, greener, and more sustainable future.

Our challenge in NYISO and in similar initiatives in other regions to make these public policy initiatives compatible with the wholesale markets. I will look at the challenge in a more general framework before delving into New York. The way we look at it is that the first principles are (being true to the theory that Speaker 1 espoused), first of all, you've got to make the investment signals right. We had the markets. One of the biggest drivers of competitive markets was that investments should be through competitive means. The revenues for investment decisions should be based on market revenues. And when we had the 50 percent renewables by 2030 goal, one of the stakeholders came to me and said, "OK. If you get 50 percent renewables, which is going to be subsidized, would you guys be running a 50 percent market?" Our goal is not to run a 50 percent market. Our goal is to run a 100 percent market. So, our aspiration is that all the resources, whether they're subsidized or market, are getting the revenues from the competitive market framework. And the subsidies shouldn't be pure subsidies. They should be market compatible, as much as possible, if not within the market.

The second part of the approach is that, besides the investment signals, we need to have operating signals, operating signals for response in real time to balance the intermittency. If you have 50 percent renewable with just solar and wind, you need to balance things second by second, literally, so that the system frequency stays at 60 Hz. So, in the context of what Speaker 1 talked about in terms of shortage pricing, in the future, maybe the main entrée's not the energy price, but the ancillary services price. The ancillary services becomes, not ancillary anymore, but the main event. So, things like shortage pricing, five minute settlement, become important. You have to have reserves, regulation, these kinds of things, which all can be incorporated within shortage pricing. Those are important.

Our neighboring ISOs have emphasized the capacity market. We in New York have been truer to the energy market. We believe the first place to give better, real signals is the energy market, to get real time response. If this is not sufficient, we will look at performance components in the capacity market.

So, in terms of looking at the incorporation of public policy into markets, the Lexicon of the FERC technical conference of last year looked at "achieve" versus "accommodate." "Achieving" is when you achieve the public policy outcomes within the market. And "accommodate" refers to, if you're not successful in that, what you can do to, first, preserve price signals for the resources which are competitive and, second, get the real-time response to the intermittency that you need.

Going to "achieve," there are two things I want to emphasize. One is that your signals for the public policy resources have to be market compatible. Ideally, they should be within the markets. Your public policy objectives are achieved through the markets. If not, you have to make it as compatible with the wholesale markets as possible. And the way we look at this is through a spectrum. There are many degrees of achievement. Carbon pricing is probably the purest form of achievement. What New York State came up with is the RECs and ZECs, which are the Renewable Energy Credits and Zero Emission Credits. Now, they are somewhere, in our view, in the middle of the pack between pure market and full regulation. Maybe a little bit towards right of the middle (closer to full regulation). The RECs and ZECs ultimately still leave a significant portion of the revenues for investment decisions, as well as short-term operating decisions, to what's happening in the market. So, we believe it is market-compatible meddling. We would ideally go to carbon pricing, but there's a spectrum. There's certainly a spectrum.

The way we look at it is, we look at achievement and accommodation as two axes, and you have to ratchet up the level of accommodation, depending on the level of achievement you reach in the market. So, ideally, if have something very market compatible, such as carbon pricing, the only thing you need to do in the accommodate sphere is get the response to balance the intermittency. If you have a very low degree of achievement, and you want to preserve the investment signals for the merchant assets, you would have to ratchet up the level of accommodation to preserve the market signals, which can led to conflict, especially if you go in the MOPR (Minimum Offer Price Rule) sphere. As you put more and more faith in MOPR to keep the prices up, what you get is a setup for a conflict between the federal and the state regulators, which can then lead to market failure, because the state can say, "OK, we're going to put a lot of resources into contracts." And then your markets, your price formation, gets compromised. Your investment decisions, a large portion of your fleet, is out of the market.

In one of the scenarios where you race to the bottom, you race to a short-term market, where the investment signals are out of the market. The markets do not disappear. The markets become a purely short-term optimization exercise. I personally view that as a market failure, and I would like to keep as much of the investment decisions in the market as possible.

Another problem is when you have a conflict between a high, excessive MOPR, a high level of accommodation, and a low level of achievement. In that case, you increase costs, because you increase costs to the consumer.

The more you can go towards the "achieve" axis, the more you can get into the zone of harmony, so that you can harmonize your wholesale markets to public policy. It's not black and white. There are degrees of harmonization you can get. And that's where you can get to the compatibility with the wholesale markets.

Going back to the spectrum, there is a region where harmony or effective accommodation are possible, and then, if you get lower and lower in the "achieve" segment, you get more and more into conflict and ultimately into market failure.

So, that's the kind of conceptual framework through which we look at the markets in New York. And we are doing things so that we move our wholesale markets to become compatible with the state policy and preserve the market signals. So, the first line of action that we're doing is looking at carbon pricing in the market. To their credit, our public service commission has given us the go-ahead. They are very involved with it. They are saying, "Go study this. See if this works." And what we are doing is, we are comparing the costs to the consumer of putting a carbon price in the market, compared to the RECs and ZECs. So, if you put a price of carbon in the market (that price of carbon is tied to what the state used for the ZEC program, which is based on the Obama administration projection of the social cost of carbon), the LMP's go up, but then the penalty from the generators are returned to this loads, to the consumers, and then the other consequences are that for the RECs and ZECs, there are savings, because the RECs and ZECs are largely not needed anymore. The ZECs disappear completely in our analysis. The RECs become very small, and then there are other dynamic effects.

So, in essence, what we've seen is that the cost of implementing carbon pricing in New York is close to zero, compared to RECs and ZECs. So, this is what we're going through in the stakeholder process right now. And this is something we will work through and come up with a proposal by end of this year, or early next year.

The other thing to know is that we're not saying that we do not need RECs and that ZECs will go away. The RECs and ZECs can still be in place, but what's needed for the RECs and ZECs becomes very low. In fact, the state is looking at offshore RECs. So, if the cost of RECs today is 25 and the old RECs is 50, the RECs become close to zero. The old RECs might drop from 50 to 25. So, we have not taken anything away from the state, but I think we are keeping things market compatible, so it's not compromising the integrity of the wholesale market signals.

The other thing we are looking at is what we see as the "accommodate" dimension. Now, if we are successful with carbon pricing, then the degree of accommodation we need to pursue and implement is only to balance the intermittency. Things like price formation, shortage pricing, ramping, fast start. If you do not get carbon pricing, and we revert back to RECs and ZECs, we have to ratchet up the level of accommodation and be more aggressive on shortage pricing, more aggressive in moving more revenues into the ancillary services market, and we would probably also have to look at effective mitigation measures for the buyer-side mitigation issues. So, that's where we are, and how we look at this in New York, and what we're doing in New York. Thanks.

Speaker 3.
Good afternoon. It's great to see all of you, and thank you to Bill and Ashley and Jo-Ann for inviting me. I did not see Speaker 2's slides when I put together this title. But I think it is interesting that we both use the same word, "harmony." That's what we're all going for here. I think that would be an ideal outcome, and I think this panel hopefully will be a good way for us to talk about some ways to get there.

I'd like to just start with, from our perspective, what the big picture is. It is certainly true that we need to reduce carbon emissions from the transportation sector and from the building sector, if we're going to reach our climate goals. But it's often overlooked that we do have a long way to go in the electric sector as well, and this is really what, from my perspective, is animating a number of the discussions that are occurring at the state level and hopefully at the federal level and at the ISO level.

So, the green on this chart is where emissions from the U.S. electric sector need to get by 2050 in order for us to prevent a two degree Celsius warming in the atmosphere. And the red is where we're headed. So, yes, we are seeing a reduction in carbon emissions as a result of natural gas prices that naturally flow through the market without us needing incentivize the switchover to gas. It's happening because of price, as we all know, but even with that dynamic, and even with RPS programs that have proliferated in 30 states, we are still nowhere near where we need to get to for the electric sector. In fact, according to the EIA projection, we will exhaust our carbon budget by about 2034.

Effecting that achievement of the carbon emissions target requires a continued operation of the nuclear stations in the U.S., providing 20 percent of our power. This is a Platts picture of the stations at risk, already retired stations, and announced retirements. And it shows a few blue circles, which are planned nuclear additions in the U.S. And overlaid on this map is where some of the states are in terms of addressing what is occurring as a result of market design that does not reflect the cost of carbon pollution and is pushing these stations out of the competitive markets. What's interesting is what's happening in Arizona (which is, of course, not in a formal competitive market), the activity at the state level surrounding Palo Verde and whether the state should have a clean energy standard versus an increased renewable portfolio standard. This is something to watch, in that even in a regulated market there is acknowledgement that, to the extent these clean energy policies do not include all sources of clean energy, we're potentially having stations at risk.

You're well aware that there are four states that have taken action as a result of the dynamics I just discussed to broaden their clean energy policies, and I think the question they've had to ask is, in a carbon constrained world, are customers better off with these stations in the market or not in the market? And, of course, they have to ask the question about cost--if it's a cost-effective carbon abatement tool, relative to the cost of replacing that amount of generation with new sources. And if they can answer those questions in the affirmative, then they have chosen to broaden their clean energy policies to include nuclear generation. The two states depicted at the bottom, of course, have not yet chosen to take that path and it's of course not clear whether they will or not. But the example set by the states that have acted, I think, is instructive, in that they have chosen to largely follow the REC model and have a production-based payment for clean generation.

And now, clearly, when you're talking about incumbents, you have an issue of market power that you need to address, from the perspective of ensuring the customers are not overpaying for the attribute that they're getting, and so, in the case of all the states here except for Connecticut, the legislature set the price themselves, and they essentially said, "This is what a megawatt hour of carbon free power is worth to us." That value is fixed. It cannot go up. If prices in the market go down, it cannot go up. If costs at the site go up, it is capped, and it can only go in one direction, which is downward, to the extent that carbon is reflected in the market or some other change occurs that obviates the need for state support.

Focusing on Pennsylvania and Ohio, one of the stations that has announced retirement happens to be owned by my company, but others are owned by First Energy. Those stations are about 40 terawatt hours of carbon free electricity every year. Even looking at all the renewables ever built in PJM as a result of state RPS policies, or built outside of PJM as a result of RPS policies in PJM, that gets you about 30 terawatt hours of carbon free electricity. So, if you think about the billions of dollars that have been spent to develop those resources and the carbon abatement they provide being wiped out with a couple of nuclear retirements, I think this is certainly not lost on anyone who has that carbon picture in their mind.

And, of course, the question, as I mentioned, is, well, what does it cost? What is the cost of keeping those stations operating? And what are we paying for new clean generation? This is just giving some samples across both the states that have acted in terms of expanding their clean energy programs to include nuclear, but also some other examples in 2018, of prices of what, between federal and state subsidies, we're paying to replace lost zero-carbon generation, or to increase our amount of zero-carbon generation. And, clearly, the states that have acted have concluded that it's cost effective for customers to keep the existing nuclear on the system.

What's interesting about this is, why are we paying such divergent prices for carbon abatement, and is that a market-friendly, and is that the best solution that we could possibly achieve, for both our climate goals and for our duty to care about costs for customers? Probably not. But I think the question we're all trying to grapple with is, is this better than nothing? Because, subject to what Speaker 2 is able to do in New York, what we have is nothing, and I think there are plenty of economists, maybe none in this room, but there are some who would say that it's better to try to internalize the cost of pollution, at least somewhat, through programs like this, than to not do it at all.

So, as I said, the basic framework is a production-based payment through the ZEC, similar to the RECs, for a megawatt hour of carbon-free electricity. We've had a lot of litigation about this concept, and we've now had four courts look at this issue. All four of them have concluded that acting in this manner is a legitimate exercise of state authority and not inconsistent with the Constitution.

Now, clearly, that does not answer the question that is going on in the ISOs, which is, what, if anything, needs to be done as a result of the state policies to address their impact on the market? And that's where, of course, at least in PJM, we do have some guidance from FERC, as a result of an Order in June declaring that the capacity construct is not just and reasonable if there are assets in that market that are receiving out-of-market support. So, I think what FERC tried to do in this Order is to get us into some zone of harmony by making the finding that FERC made, but also saying, "Well, we have our view about what we should do about that," and introducing a new two-part construct that would allow states that want to continue to support assets (in this case, clean energy resources) to carve those resources out of the capacity market and compensate them directly. And in doing so, the FERC would (not to be too cheeky) inoculate the residual market from the pollution of subsidies. So, we would have a market that was completely free of subsidies, capable of clearing based on the bid prices of assets that are solely relying on market prices to operate. And then, if the states want to continue to support certain resources, they do that themselves through a separate construct, and that amount of load is pulled out of the residual market.

So, we're in the process of having a paper hearing on this matter. Comments went in Tuesday. I break them, although I haven't read all of them, into sort of three buckets. There is a coalition of stakeholders that is in favor of this attempt to reach some harmony and thinks this construct could work for states to continue to achieve their clean energy goals on their own, without any support from the market, but directly through contracting with resources that they think meet their state policies. There's a group that is opposed to this construct entirely, and think it's a terrible idea and should go back in whatever drawer it got pulled out of, or it should be heavily conditioned so that it is more difficult to take advantage of. And then there is an interesting, at least from my perspective, couple of sets of comments asking FERC to just move directly to where the New York ISO is going with respect to the PJM market and put a price on carbon in the market across the footprint. Eastern Generation made that filing. They submitted a legal analysis as well as a technical analysis of why that makes sense, which is interesting because it's an entirely fossil-based company asking for FERC to just move right to that solution and bypass this attempt that they've made to try to reach an accommodation.

This is the group that's supporting what's called the Resource Specific FRR (Fixed Resource Requirement), and I won't delve into what all that means, but this is the bifurcated capacity construct, where the states can support resources separately and pull that same amount of load out of the capacity market. It's been described in press reports as a set of odd bedfellows, which, I have to admit, it is. But it represents a number of stakeholders who believe that there's a way forward to implement what FERC has put forward in their June order, and recommending that PJM go ahead and put it in the tariff as FERC envisioned it.

There are many market design issues associated with this, but there is one market design issue that I want to focus on a little bit, because I think it deserves a fair amount of attention, and it is this. To the extent that the residual market, the resources and load that are remaining in the PJM capacity market, is affected by the fact that a number of resources and load has been pulled out, what, if anything, should be done about that? That's where this concept of repricing has been introduced into this docket. And we're going to have some folks step out, but, sorry about that. I do think it's an interesting conversation about what does the academic and economist community think is a reasonable outcome here, where you have an attempt to try to give the states authority to act, but the consequence of that, having a market that is free of the pollution of subsidies, may not look the same as the market today.

And so, there have been a couple of different ways of describing what should happen. I thought I'd just depict them on here so we can distinguish between them. In the top left, we have no repricing. We have the market as it stands today. We're looking at a fictional market that's 60 gigawatts, with six equally sized units (which of course, do not exist in the real world). A, B and C are receiving subsidies. And if they're not repriced the market clears, for example, at $160 in this example, per megawatt-day. Proposed that it had gone into FERC from PJM would say well, one way we can handle this problem is we can take A, B and C and put them in the stack at the price they would have been at, or some analog of the price they would have been at, had they not received state support. So, we back out the state support, or federal support, of course, that the units are receiving, and we put them in the market at a value that replicates what they would have been otherwise, and we clear the market that way. And this is what FERC rejected in the June 29th Order. And there are a number of reasons for that, which I won't go into, but when they went back to the drawing board and said, "We like this bifurcated construct," that was sort of left out of the picture.

Well, what's come back in the picture, with PJM's filing on Tuesday night, is a new version of repricing, and what they're doing here, again, in this stylized market, is they're assuming A, B and C are now supported directly from the state, through a clean energy procurement at the state level. They are in the FRR model, so they are capacity resources. They are meeting the capacity performance requirements, and they are available to customers. They are providing capacity, but PJM will pretend like they still need to procure the same amount of capacity again, the 60 gigawatts, but that those three assets have disappeared. They're no longer available. They don't show up in the stack, and so, by definition, the zone is short. And so, what that will do is, that will drive the price to the cap. I mean, theoretically, it'd go to infinity. And this is sort of the concept that is now on the table, as a consequence of a state taking action to use the FRR mechanism and separately procure capacity. This will be the outcome for the balance of the load.

So, this is among, as I said, many market design issues that will need to get addressed in the docket, but it is certainly one that I think lots of folks would say is not at all accommodating, not at all achieving harmony. It's more of a, I assume, deterrent concept. But with that, I'll stop and look forward to questions.

Moderator: Thank you. Let me ask the panel, from this point on, can we speak about things at a theoretical level so we can invite our FERC friends back in? OK. All right.

So, we won't talk any more about very specific dockets. So, thank you for going out and letting our FERC friends back in. I think we can still talk about these concepts. We just can't talk about it in connection to the specific proceeding.

Speaker 3.
Thank you for having me here. I'm really excited to be a part of this panel and to talk about this. I really do think we're kind of at a place in the history of our industry where we have a lot of challenges, a lot of change going on, but also a lot of opportunity to really make some big advances in what markets can do for us. And I think in my talk you'll hear me echo a lot of what Speaker 2 has said about the need to use markets to help achieve policy goals. If we're going to maintain the relevance of markets, we really do need to see it as the role of markets to achieve the traditional objectives of reliability and cost effectiveness, but also bring in this other big objective of environmental stewardship. If we don't have that as part of our mix, we're missing 80 percent of our story. If we're going to go 80 percent green, as Speaker 3 mentioned, if we're going to get rid of 80 percent of our emissions, that's almost everything we do. Every operating decision that we make in the industry, almost every investment

decision needs to be 80 percent driven by this objective. I do not think we can ignore it. I don't think we can accommodate it, but I do think we can achieve it by 2050.

I am going to focus more on a different path from what Speaker 2 talked about. Speaker 2 talked about carbon pricing as the first best path, and you will hear me say the same thing--that carbon pricing, fully integrated into the electricity markets, is a first best solution to use the markets to really get what we're trying to achieve here. Knowing that he likely would talk about this, I'm focusing more on a different approach to that same end of using clean energy markets. So, let me just put a hypothesis out to you. The hypothesis is that competitive clean energy markets are a really big missing link to get us to that next stage of our evolution in this industry. We have many components of our industry that we have kind of gone through and developed as we moved from an integrated planning type of approach to operating this sector. We unbundled the energy component and created these great energy markets. Then we unbundled ancillary services and capacity markets into their separate products, which, as long as we're actually not talking about the carbon objective, have really shown us a lot of benefits. And I think earlier today we heard about some of those huge benefits, I can't remember what the number was, but let's say 300 billion a year, just from MISO, because of these markets operating together. Resource adequacy, energy, ancillary services--having a good definition of what the need is and then operating that whole system efficiently with that standard market design, energy and ancillary services, and capacity.

But in the next phase we need one more. We need something to represent the demand for carbon abatement, because otherwise that 80 percent of carbon emissions is not going to disappear on its own. We have to do something. And one path is this carbon pricing and another path is clean energy.

The other thing we've got to keep in mind here is that this move to clean energy is happening with or without markets. If you just take a look at the retirements that we've seen over the past five to 10 years, we're seeing a lot of retirement of traditional generation. A lot of it is coal--other types as well, but a lot of it is coal. When it comes to the new developments, some of it is just market based. There's a lot of investment in gas, of course. A lot of it is economically driven, both by utilities, but also by a lot of merchant players, because that's what the market tells us is the cheapest thing to do to meet reliability. That's the most competitive technology, if you're only looking at market signals.

But then there's another whole half of the story of solar and wind, and demand response, and increasingly we're going to see a lot more storage coming in. This is all driven by something else. And it's driven by a number of things. It's driven by lower technology costs. It's driven by innovative players in the industry. It's driven by policy, and it's driven by large C&I customers. I mean, if you see people like the Renewable Energy Buyers Association, that's a bunch of big players getting together saying "We're going to by 50 gigawatts of clean energy in the next X years." That's huge. That's a big demand from corporate players, and also, increasingly, from residential. There's a big demand out there to go green, despite the fact that these are not the resources that would be brought in by the market alone. So, this is what's already happening today, and it is getting out in front of us. And it's happening through bilateral contracts. It's happening through state mandates. And it's happening through just customers getting together with suppliers. And what's that if it's not a market? Somebody demands something, somebody has something to sell, and they're getting together and they're making a deal. The only thing that's not happening is, it's just not happening in a way that's integrated into, or compatible with, our wholesale market design, which I think is a little bit unfortunate.

So, let's assume (and I believe) that the states, as well as many of the customers that are just out there operating on their own, and obviously the states on behalf of their constituents, want to go green. And they're going to do that with or without markets, because this is based on, basically, their commitment to sustainability. So, we can kind of get there in two ways. The path that we're on, in many places (not every place, that's not what New York is doing) is to decarbonize outside of the markets through bilateral deals—which, of course, is a kind of market. It's just not part of the centralized market. There are also a wide variety of state policies, and we've just seen from Speaker 3 how oftentimes these policies end up paying different amounts to different resources. Sometimes they're done in competitive fashion. Sometimes they're not. And there's a big spectrum there. But, at the end of the day, they're going to do it by bypassing the wholesale markets. A different and better path is to use markets.

One way to get that pricing signal and that pricing incentive is to adopt a carbon price. That's really first-best. Of course, it's first-best with many caveats. It's first-best if it's an economy-wide price. Of course, it's first-best if there's no regulatory risk that the carbon price is going to be there and then disappear, so that creates financeability concerns. But if you can address those, it's really our first best solution.

That being said, I am going to spend the rest of this talking about a different path, which is using clean energy attribute markets, which I think, if it's done right, can be close to first-best as well. The other thing that's great about using clean energy attributes is that it's a more general solution. One of the things I think we know about carbon pricing is that it's not an easy thing to adopt anywhere. It's a challenge in New York. It's a challenge internationally, where it's been done. But one thing that makes it more feasible in New York is that it's one jurisdiction. You have one state that can set the price, and then the ISO can accommodate that, or can help to reflect that in its operations. But when you look at every other RTO that's a multi-state regional entity, it becomes more challenging. You do have seams issues. You are going to have different states with different policies, and even beyond that, there are even differences within the state, because there are many segments of customers, some of which have an appetite to go green and others of which don't. So, one of the things I do like about clean energy markets is that a clean energy market is a more general solution. You can use a clean energy market to meet a variety of different states' different levels of demand for clean energy, as well as a variety of different customers who may voluntarily participate in this sort of a thing.

So, what if we stay on the current path of basically going for 80 percent decarbonization? I think what we saw from Speaker 3's figures is that, if we just stay on our current path, our trajectory is that we're pretty much going to flatten out on carbon emissions. And so, to get that 80 percent reduction, you'd have to do it despite the markets. You'd have to do something to incentivize a resource mix that is just not the mix that the market would do alone. If the market's going to focus on gas plants being developed, you have to come up with a different fleet somehow. So, it's going to be despite the market signals, and the bigger your carbon objective, or your clean energy objective, the more of the money is going to be outside of the market. Most of the money today is in the energy market. A very significant proportion is also in the capacity market, and there's a little bit of money in the REC markets as well as ancillary services. These are small. But the path we're going on is to eat away at those markets. They're going to shrink, and by the time we're at something close to 80 percent carbon, most of the sector is going to be dominated by out-of-market payments. There's not going to be much of a role left for the market. The energy market will be lower, which makes sense, because we will have a fleet that's mostly fixed costs and no variable costs, so the variable costs is reflected by the energy market, which has now gone to something very small, and the fixed cost is all being done through these out-of-market mechanisms.

So, in this scenario (following the path we're on right now) we will have done a couple of things, looking to the future. Number one, probably, customer costs have increased significantly, because we've been using a variety of mechanisms, not all of which are perhaps the most cost-effective mechanisms that can be used to achieve your carbon objective. Two, we've basically reduced the role of markets to some small residual value. It can be maintaining reliability, but you've lost a very large fraction of the three billion dollars a year of benefits that it can offer to society. You've lost much of that. You've lost the benefits you get out of the creative and innovative potential of market players fighting each other to come up with a better way to get carbon emissions avoided cheaper, if you don't use markets. So, this is the path that we're on right now.

But I think we can get on a different path, and I think the path that we can get on is to use markets. And, again, the two kind of main tracks are carbon pricing and clean energy markets. If we use those, not only will we maintain the relevance of the markets, but also the very large majority of the total fixed and investment and operating costs of the system will be governed by markets. In terms of how you can achieve that, again, one piece is through carbon pricing and the energy market. That will maintain at least a portion of the incentives in the energy market. But if that's low, or too low to fully achieve the customer's demand and the state's demand to decarbonize, on top of that you can introduce these clean energy markets. And these are order of magnitude calculations as to what the total mix of costs in the marketplace would be if you introduced these markets. But it's probably about right. And if we do introduce these markets, they would more or less entirely displace the need for out-of-market mechanisms and subsidies. You could have a centralized platform for customers and states to put in their demand for clean attributes, and then the suppliers could come in and compete on that. Meanwhile, they would also be competing on the capacity and energy value that they provide to the system. So, we really would have, then, all the markets kind of working in concert together, for resources, for suppliers, to figure out, what new technology can I come up with that's going to have some big enough value proposition to provide energy, flexibility, value and carbon abatement? And folks would be competing in a very competitive landscape.

What could these clean energy markets look like? I have worked with a coalition of stakeholders in the New England context to come up with a proposal for clean energy markets. With partners in National Grid, NextEra, Conservation Law Foundation, and Brookfield Energy, together we worked as part, of the Integrating Markets and Public Policy Initiative to come up with a design proposal that we really do think would meet all of these needs. And it was a very iterative and very collaborative process. I think it was a very healthy process, because many, many players got together and offered their ideas, and then the states gave them feedback. And a lot of the feedback that came from the states was, we'll just put it as "constructive." It took several tries to get something that was in alignment with what the states think that they could use.

Some of the things that I think could and should be integrated into a really great clean energy market design are pretty much the same, regardless of who takes that leadership role to make sure this thing can happen. And I think that could be a coalition of states. It could be one state in particular that really wants to use markets to meet its needs, or it could be an RTO.

In any case, I think you want to use all of these kind of best practices, which are somewhat obvious, but often violated. One is having a product definition that really matches what you want. And here, what we're trying to do is we're trying to displace carbon. That's a first principle, and so the definition of what we're buying should help us achieve that objective. A second best practice is unbundling the attributes. Again, this is something that is often not done, especially by commercial buyers, and so on. They bundle the energy and the clean attribute and the capacity value all into one basket of product, which makes it harder for people to compete in all the different markets. But unbundling it really separates and distinguishes the value and the need for the carbon abatement. The other best practice relates to the fact that, at the end of the day, we're here to serve customers. You have to have customers being able to specify what it is they want to buy. If you define a product that just isn't attractive, because their definition of clean doesn't match your definition of clean, then they're just not going to participate in this market. So, it needs to really be customer oriented. It should be technology neutral--we're going to maximize competition if we allow that innovation, and allow people to compete across different technologies. Regional competition-- the more regional we are in this, the more competition we'll have. There should be mechanisms to mitigate regulatory risk. I think this is really key. How do we share the risks inherent in any investment decision? And I think a general guideline that you can use is that all the fundamental risks that are out there in the marketplace, most of those should be on the suppliers. That's what it means to be in a market. But to the extent we're talking about regulatory risks and policy risks, it's healthy to have that more borne by the customer or their representatives. And then, you should have alignment with our existing markets. And I think if you follow these other principles you're pretty much there. As long as you're really following these best practices, we will have alignment with our existing energy, ancillary, and capacity markets.

To say a little bit more about just taking that first principle of make sure that you're buying what you really want, that's product definition. When we thought about how to apply that in the context of the dynamic clean energy market that we developed for New England, at the end of the day, what we took as the objective is, the states are trying to decarbonize. Therefore, it makes sense that what people get paid should be representative of their carbon abatement value. So, one of the challenges with traditional renewable energy credits, is that they kind of pay the same dollars per megawatt hour, no matter when you output your energy. It doesn't matter where. It doesn't matter when. So, if you are someone who is developing a wind project in Maine, where perhaps the transmission systems are already oversaturated, and by developing that incremental wind resource, all that's happening is you're curtailing other wind, because there's not enough transmission to support both of you, well, you're not achieving any carbon objective. You're just kind of injecting more energy to just have more curtailed, so it's really not helping the carbon objective. Meanwhile, a different resource that maybe costs 10 percent more (because a solar resource in Massachusetts maybe costs 10 percent more) won't be selected, but it will abate 50 percent more carbon. So, shouldn't they get paid 50 percent more? So, the definition of this product that we proposed is to have a kind of a target payment that would be paid out for an expected level of carbon abatement, but the payments would actually scale in proportion to the marginal carbon price, or the marginal carbon abatement in that time and place. So, it will be kind of an additional payment on top of locational marginal pricing. And it would almost mimic the exact payment you'd get if you had a carbon price. That's one of the reasons we like it. It really kind of mimics the payment you'd get under a carbon price.

One other thing about this dynamic clean energy product is that, if you start following these first principles, you really do start to see how you can enable competition and innovation in a completely new way. This is just an example showing how a product like this, that's defined according to what we really want, which is carbon abatement, can help enable a different sort of competition. In this case, we're talking about storage. So, traditionally if we're talking about procuring storage, people understand that storage is going to have a big role to play if we're going to really decarbonize the grid, because we need it to shift around wind that might be curtailed to displace on-peak power. We understand that, but we actually don't have a mechanism for a head to head competition between storage and wind, or between storage and solar. But under this product definition, storage actually can compete on a 100 percent head to head basis. And how it would work is, when storage is charging, say in these off peak hours, it would have to pay the energy price, as it does now, plus, on top of that, it would have to pay for any carbon emissions that it's causing to be produced by its demand. So, it would have to pay this amount. And, of course, if it's charging up using wind that would otherwise be curtailed, they don't have to pay anything. Then they get paid back in the middle of the day. They get paid back when they're discharging, paid for their energy that they discharge, plus, on top of that, they get paid for their carbon displacement. So, between these two signals, we then pay that storage resource, not only for its energy value, but also for its carbon abatement value. So, you can see how now, all of a sudden, we have a storage resource that's able to compete with a solar resource to see which of these two is really giving the most carbon abatement value, and then the market will decide at what point in our evolution are we going to move from wind as the most optimal technology to solar and eventually probably to storage as the cheapest way to decarbonize the grid.

A couple of takeaways. I more and more see that if we're really going to this place of 80 percent decarbonization (or even something less than that), there's a really big missing piece of the picture in the markets today. One way to kind of fill in that gap is much higher carbon pricing, but if that's not feasible, I think a more general solution can be these clean energy markets that are really customer-driven and reflective of what customers want to buy.

Clarifying Questions.

Clarifying Question 1: Speaker 4, on your slide eight, given that the zero emissions sources of generation are really renewables and nuclear, and wind and solar are not controllable, and nuclear is at 100 percent, unless it's refueling, how are you realistically going to incent changes in generation output in response to price other than, I understand, through storage? In other words, is there any other way other than storage to do that?

Respondent 1: I really like that question, because I think it is exactly the role of markets to figure that out. I think the role of market design is that you define what you need, and then the market players have to figure out the cheapest way to meet it. To answer your question, yes, it will probably be storage. It will probably be some controllable demand response. It will be even renewables that are intermittent, but that can be controllable to some extent. At the end of the day, I think that if we were doing integrated planning, we would have to answer that, because we'd have to guess what the best technology is, and we'd probably guess wrong, and we'd probably do something expensive. But when we leave it to the market, I think all we have to do is define what we really need, and then let it rip. Let those creative people out there figure it out.

Clarifying Question 2: I enjoyed your presentation. Just one simple question. You made the assumption that, if your clean energy market were established, there wouldn't be any need for out-of-market payments. Do you really trust regulators that much? There are some regulators that will never accept market outcomes and will always second guess them, and they will think, "Well, if the market gives me Y, why not have more payments outside the market, and I'll get twice Y as a result?"

Respondent 1: I trust every regulator. [LAUGHTER] No, I see my role in this as to say what markets can do, and not to talk about all the mistakes that someone could also make. I don't need to do that.

Clarifying Question 3: Is the money that you're projecting coming out of the clean energy market? Is it an add-on to the energy price in the jurisdictions that want to participate, or is it some other market? And is it administered by the ISO, or something else?

Respondent 1: It would be additive to the energy market. It would be basically the same as a Renewable Energy Credit. So, it's a product that's created by the fact that you're a green resource, so you get paid separately for the brown power, just out of the energy market, and you get paid for it being green, out of this market. So, it is an adder. In terms of the administration, I would like to be open minded about that. I think it's a very natural role for an ISO to take on, simply because of the task of calculating locational marginal carbon abatement every five minutes, which is what I hope this would do. That's a role that at a minimum the ISO needs to be involved in, and would naturally do the settlements around. But if you also combine it with kind of a forward auction to set the base price against which it fluctuates, that could readily be administered by a state entity, or a utility, or a group of states, or an entity like Once you get to the settlements, I think the RTO is probably the natural entity to do that.

Clarifying Question 4: A quick question for Speaker 3. At the end of your presentation, you seemed to suggest that if you do the carbon pricing, there will be some ancillary services or other operational savings in the market, beyond the sort of big items that you were talking about earlier. I was wondering, did I catch that right and what did you have in mind?

Respondent 1: With carbon pricing, it's more compatible with markets; however, you might still need certain other mechanisms, like shortage pricing which will incent more real time response, so that you can balance the intermittency. Maybe I wasn't clear enough. So, even with carbon pricing, you might still need certain enhanced services to make the real time operations work better.

General Discussion.

Question 1: I have one question for the panelists, because I think we were a little bit safe. The question is, can electricity markets meet the challenge of meeting nonmarket objectives, plural. We talked almost exclusively about carbon. What happens when the states have objectives for specific technologies like offshore wind, or they're worried about fuel assurance, or they're worried about what do we do for cybersecurity resilience? To the extent that states have other policies besides carbo, do the suggestions that you offered earlier still apply? Are there still ways to make the markets work?

Respondent 1: I think you've got to take each of those objectives one at a time, and evaluate them individually. The reason that I specifically focused just on carbon is because it is just too big and too central to every single thing that we do in this sector to ignore. I do not think that we should put it on a list along with every other objective, many of which are much smaller. I mean, the impact of these is very, very small individually.

That being said, many of these other objectives can also be met with markets. Fuel security is a really good example of that. I mean, this can be defined in reliability terms as something that we need. We can implement changes to the ancillary service markets and the energy markets to represent those needs. Potentially there could be something more like a forward construct.

There are also other objectives that really aren't amenable to being met through markets. There are lots of those examples, too. And at the end of the days those are, I would say, more around the edges. Policy makers will consider them, but they don't need to be built into the core of the market design, necessarily.

Respondent 2: Of the items you listed, I would say most of them can be integrated into the market. I mean, we're talking about fuel security. We have efforts underway already at the New England ISO to address that question, and PJM's doing some work on it as well. We have rules at the wholesale level that address cybersecurity. That's more of a command and control type of approach, but, again, it can be done in a consistent way at the federal level. So, I guess from my perspective the things that we care about as stakeholders and that the government cares about on behalf of people, I think we're working on trying to address in the market. I think most of the things that you addressed, we can address through the market.

Respondent 3: I think theoretically, yes. If you can state a policy in terms of an unbundled technology-neutral attribute, you can attempt to put it in the market. But if you say, "I want to keep that coal plant open because it has 2,000 workers," it's very hard to put that in the market.

Respondent 4: My view is very similar to Respondent 3's. What Speaker 4 is proposing is very attractive for many reasons, because of improvements of efficiency in doing things and so forth. But I don't think I agree with the notion that the fact that customers and other people want to contract for clean energy or something like that is necessarily a problem, and they're doing it outside the market. They're just doing it, and in my taxonomy, I'd put that under the heading of a "condition." So, if the Watergate Hotel wants to contract with a renewable energy producer in Illinois and sign a piece of paper and exchange money, it's between them. They internalize those costs. I don't worry about that very much. And I don't think the Watergate Hotel is going to be sitting around thinking about how they're going to depress the price in Washington, because they signed a contract with these folks in Illinois, and that's not why they're doing it, so I don't care.

Where it becomes problematic is when states do it and governments do it, because this notion of separating price manipulation and the benefits associated with that from the other attributes that you're talking about is what's really hard to do in practice. Now, in theory, you could do it. You could say, "Jobs in New Jersey are worth this much. This is the willingness to pay per job," and then they can subsidize that much for the willingness to pay per job, and then they would go ahead with this plant anyhow. We don't have to worry about it. But, in the case in New Jersey, where they actually put it in the draft law that the reason that they were doing it was because they were going to depress the price in the market and make it up on volume over their other purchases in the marketplace (eventually they got a smarter lawyer and took that out of the law), it revealed what the fundamental problem was. Buyer-side market manipulation is very difficult to do for the vast majority of buyers. The important category of buyers, or representatives of buyers, where it is easy to do are called states. And that's where their problem gets much harder. And I think, in theory, you could make that distinction, but I don't think it's easy to do in practice. And I'm not worried about what Google does in this context, or what the Watergate Hotel does.

Questioner: So, Respondent 4, would you put a cooperative or a municipal utility in the same category as the Watergate?

Respondent 4: It's a scale question, so, again, that's an empirical question. Are they in a position of depressing the market prices so that they can capture the benefit on all the other purchases, as in classic buyer side market power? We can go through the analysis, and then we would say, if that's a problem, then it seems to me it's a completely symmetric story to seller side market power. So, when generators are exercising market power, the regulators think they should intervene, and I don't see a principled answer to the question which says that if you're doing it on the buyer's side it's OK, but you can't do it on the seller's side. I think the same principle should apply. But it's much harder to do on the buyer's side, because of the nature of some of those buyers.

Question 2. In this overall debate about whether market design accommodates environmental policy, the thing that I don't really get is the way that the economics community frames environmental policy as either targeting emissions directly, either through a taxable mechanism, or an indirect pricing, or as getting into a more command and control approach. But a lot of this conversation is on compensating resources for what they don't provide, and the underlying market failure is not the overpricing of clean energy, it's the underpricing of pollution externalities. And so, looking at this more broadly, we never had this conversation on redesigning markets to address RGGI compliance, or to address 1990 Clean Air Act Amendments, or to address the MATS rule, any of this. In fact, markets have driven down compliance costs for all those. And so, really, we're dealing with this era of green industrial policy. Where do we kind of draw the line between what's a fundamentally incompatible form of intervention vs. what is something that influences market entry and exit mechanisms, but doesn't fundamentally undermine market performance? If there's any elaboration on that, I'd be curious.

Respondent 1: I can chime in. I think you make a good point. If the consequence of some of the state clean energy policies is that emitting generation earns less, then it's less apt to stick around. That's not just sort of a byproduct. That's sort of the point, if they're trying to decarbonize. And so, the question is, is that an inconsistent outcome, either with the policy or with what you would expect to happen? I think the answer's no.

Respondent 2: I think part of the questioner's point is what Bill Nordhaus was talking about. So, we subsidize electric cars, but we don't subsidize bicycles in the same way. And what we really should be doing is taxing carbon and targeting emissions. And I think the problem is most severe, and it doesn't send the right signals to the consumers and the demand side. So, there are all the other things that you could do in energy efficiency and buildings and dynamic control of buildings and all that kind of thing that would be beneficial if we were actually sending those price signals in real time, that we don't get to do. So, then we have to have mandates to undo the false pricing signals, so then we're back into demand response payments and overpaying for that, so it's just a compounding…You get a bad rule, and then you need another bad rule to undo the effect of the bad rule, then you need another one to undo the effect of that bad rule. Instead, well, why don't you just stop? And then go back and tax carbon, if that's what you want to do?

Question 3: This is really a great discussion. I have a two part question. One is, how do we actually solve that problem? It is very easy for me to justify going and hiring a bunch of economists, and spending a lot of money to file testimony that's due tomorrow. But gosh forbid if we ever spend any money on figuring out, how do we actually do this in the future market? And then the second question is, we talk about energy market carbon pricing on sort of a real-time basis. And I actually wonder whether we're sending the investment signal in the right time horizon. I would really love to have a forward capacity market structure, whatever that may look like, that says, "OK, you're a carbon emitting resource. We're going to take your wedge of carbon for that year, and we're going to incorporate it into your bid on the forward timeframe. And if you're a renewable resource, we're going to, obviously, give you a payment for that carbon free quality. But the idea would be to shift that investment time horizon from the real-time energy markets into something on a forward basis, when the investment decisions are actually being made. And all the better if we can come out of that with a project financeable contract of some sort, or (really, I hate the term "contract") more like a commitment that's in market. And I wonder if you can sort of talk about those two aspects.

Respondent 1: The question you mentioned about finance-ability, and making sure that these things are done in the investment timeframe, for the regions that have a forward capacity market, I think it makes complete sense that the investment decision for meeting your clean energy needs as well as your capacity needs would be made at the same time. And, therefore, it makes a lot of sense for the commitment to earn basically a clean energy payment to happen in the exact same timeframe. That is what we proposed in our New England design. And then the other thing about finance-ability, especially in the early years of any market (this was true at the beginning of the capacity markets as well) there will be that investor uncertainty, and, depending on the politics of the states involved, there will still be regulatory uncertainty. Therefore, I think there is a very significant justification for having a commitment term that you'd clear in this forward market. You'd get your capacity payments, which maybe people believe in more, and then you get a commitment for a stream, a forward stream of the clean energy payments. So, I do think insuring that that regulatory risk is handled is a really central part.

Respondent 2: As an investor, you would like to have financeability and predictability of your revenues. But we don't believe that's a necessary condition. We believe that the pure market is closer to an energy market. A capacity market is at heart a construct. It's not that related to the physics of minute to minute operation. It's based on a reliability assessment, which is done offline. So, when the emphasis goes more towards managing intermittency, we believe the energy market is much closer to where it should be, and as the prices evolve more towards shortage pricing and more in the ancillary services than in the energy market, I believe there will be sufficient revenues that can be created for investment decisions.

I know that our neighboring ISOs, New England and PJM, have gone to performance-based capacity markets, which in essence bring energy market characteristics within the capacity market format. Ideally, you would only have an energy market, just as Texas is attempting to do. And if you make your shortage prices high enough, you will attract the investments.

It's difficult to fix the capacity market, because, in the first place, it shouldn't exist. Ideally, there should be only the energy market. The reliability-based construct is open to so many interpretations and constructs and arguments. We will keep a capacity market, but incremental revenues will be, in our mind, more in the energy market, where it gives a purer signal for performance in the real time.

Respondent: I've got to say one more thing on this. Why are you focusing on the short term? Obviously, there's a commercial interest at play, and you absolutely have to look at your immediate commercial interest. There are a lot of incumbent players in the markets, and people care about their investments that they've already made. That's where I also think we do need people who can be champions and leaders. We need people with vision, and I see that coming out of New York ISO. It is a big uphill battle to achieve something like this sort of a carbon price. It's not easy, but I think that's the leadership and the vision that they're bringing to the table. And I think there are many other organizations that can do that. I don't think it would have to necessarily be the ISO. I think it can be people who are policy makers. They have to be at a certain level, obviously, to really champion this sort of thing. But I also think players who care about the future of markets and having competitive markets can do the same thing. I think that lots of people can take some of that vision.

Respondent 3: The last thing we should be doing is finding ways to impose more burdens onto capacity markets. We should be trying to make capacity markets less important, irrelevant, or make them disappear, is my recommendation. That's a long and complicated story, but it's not something that you do instead of fixing the real-time markets. And so, the first thing you need is somebody who demonstrates it actually can be done, and it's not just a theoretical conversation. And we have somebody who's demonstrated that it can be done and it's not just a theoretical conversation, and that's Texas. And the next thing we need to do is to get the right rates. We not only have FERC and many of the other RTOs thinking about this and how to do better scarcity pricing and shortage pricing, but it requires relentless repetition. That's the story. To keep coming back to it and keep coming back to it, to go back to the first principles and try to get that right. Because if you don't get that right, you're not going to solve any of these problems through capacity markets. Now, you may keep the capacity market and fix the shortage pricing, but then the capacity market will be less important. And then you won't have to worry about it so much. But what you don't want to do is keep trying to fine tune something which is completely artificial in the first place.

Respondent 4: I took the question to be not just about getting the prices right, and scarcity pricing, and making sure that we have good fundamental market design, but, to the extent we want to solve the environmental problem, why are we working on things that are just sending us into extreme levels of conflict, instead of towards something that we all, in this room, understand is a better market design outcome, and that, even in the stakeholder community, I think people are starting to think is better for market participants Even over the last five years, the conversation has changed a whole lot in the direction of that type of outcome. And one of the reasons I think it's good to sort of move beyond the litigation and the hiring of experts and the hiring of lawyers, and towards a more collaborative approach, is because then the thought leadership that Speaker 4 mentioned will come out of that, and we will hopefully get some traction solving what is essentially a political problem, and getting governments, both federal and state, onboard with the fact that markets can be adapted in this way.

Respondent 5: Let me build off of this question. If one party wants low carbon resources, and the other party wants investment certainty, and they want to be protected from the regulatory risk, can't they both solve that problem in the bilateral market?

Respondent 2: Yes. And our capacity market allows bilateral contracts.

Respondent 1: Yes, they can do that, and they should do that, that's great. But, at the same time, there's a reason we need a short-term energy market, despite the fact that lots of people do bilateral contracts for energy. It's because it creates the price signal that is actually representing the true need against which everybody can do really good bilateral deals. Today, we don't have a price signal that really reflects what people really want. And, therefore, the contracts that people are signing are just inefficient. And it's going to come bite them. I mean, it turns into litigation. It turns into negative pricing. It turns into issues in the queue. People don't have interconnection rights. I mean, it turns into all kinds of problems when you don't have that well-designed spot market, if you will, against which everybody can sign a good contract that really reflects what they need.

Respondent 2: So, if you have good price formation, it facilitates buyer-side bilateral contracting. But the ISO should not be the party who's doing the contracting. It should be between buyers and sellers.

Question 4: A very interesting panel, but there's something about the whole discussion about trying to build a price of emissions into the market, rather than the market just reflecting emissions as an input, reflecting the use of the environmental services through the means of pollution in the same way that we use natural gas or coal as an input price. And so, I think really what we're talking about is having something that can be reflected easily in the market, rather than building this into the market design. Because there are clearly some jurisdictional issues here.

New York is very unique, in the sense that it's a single state RTO. But how can the ISOs and the RTOs actually build anything like what New York's doing into the market design, when there are so many different states in PJM or MISO that have so many different environmental regulators? It is their jurisdiction. It is not jurisdictional under the Federal Power Act. So, it works for single states. How exactly is that going to work in a multi-state RTO, number one?

Number two, coming back to something that came up in an earlier question, I'll kind of rephrase it as, why have we lost faith in environmental markets? The evolution of environmental policy over the last nearly 50 years has been from command and control, to tradeable permits, to offsets, to the SO2 Trading Program, and in each step of the way we've seen innovations that we didn't even expect. It's like what Speaker 1 mentioned about the Marcellus shale. You get this wonderful surprise, this innovative surprise that reduces costs. And yet, why is that falling out of favor? It's worked so well for us in the past.

Respondent 1: I'm just going to respond on the single state versus multi-state question. I think you're spot on. That's one reason that carbon pricing is really hard. I do think first-best is to have a carbon price, economy wide, that people really believe in. And I think we shouldn't assume that that can't be done among many states. It has been done at least once, with RGGI. It can be done again. And I think that there is opportunity to have two different carbon prices in one dispatch. California does that with the EIM. One carbon price inside, and no carbon price outside. Lots of challenges there. We shouldn't minimize the challenges there. It's hard to get it right. But I think that's actually one of the exact reasons that going the clean energy markets route is a more general solution. Because you don't have to agree. The states don't have to agree on what quantity. They don't have to agree on how much they want to decarbonize. You can have one state get a thousand megawatts, and another getting 500, and another getting zero. And the person who wants the clean energy pays for it. And I think that's a way to accommodate different parties' appetites for clean energy. And I think it's fair to say that that's not perfect, but I think it does match one objective, which is that customers get what they want and what they're willing to pay for.

Respondent 2: I agree that markets for environmental attributes can work. RGGI is an example. The RGGI price of carbon is under $10. If that were sufficient, we would not be talking about carbon pricing. In fact, when we apply a social cost of carbon, we take out the RGGI price before we put it in the market. Now, if by some miracle, RGGI tightens up their procurement targets so that carbon prices rise to what it needs, then you would not need a carbon pricing proposal in New York. But when you have a state which wants to build 50 percent renewables by 2030, and the RGGI prices are under $10, we are building a carbon price which is net of RGGI. And to the idea that environmental RECs can work, as long as the RECs are for technology neutral and unbundled attributes, that's a very high bar. We will see if we could agree to that. And even as far as the price of carbon goes, if regionally you could address what the social cost of carbon is going to be, you could address it that way, or you could use unbundled technology neutral attributes. They're equally effective.

Questioner: Could I make just one quick observation on that? What you just said about New York wanting to build so many renewables, and at least trying to get the price higher, makes some sense, because the lesson from the SO2 Trading Program is all these capital intensive FGDs (flue-gas desulfurization technologies) ended up actually driving the price of allowances down, rather than up, even though it was a much more expensive option. So I'm at least heartened to hear that the story is actually going in the right direction.

Respondent 3: I was just going to address the point about jurisdiction, because the premise of both your questions, really, is that there is no authority at the state level to incorporate pollution. And I think you would agree that certainly Congress has the authority to enact a new law, and that would preempt the states. And the question remains, without that, what is the legacy authority under the Federal Power Act? And you concluded that there is none. There are a number of lawyers, some of whom have spoken at this event, who disagree, and who think there is some authority, and I guess we'll find out, if Speaker 3's proposal makes it to the Commission, because even though it's a single state, it's still going in the federal tariff. So, that question is going to need to be answered, and if it's answered one way in New York, then it's just a political question as to whether you would exercise that authority in a jurisdiction that has more than one state.

Respondent 2: There's no certainty that this New York carbon pricing proposal gets a blessing from the state, goes to FERC, and gets approved. So, the fallback is RECs and ZECs. You have to choose the best of the bad. RECs and ZECs are not that bad. They're better than feed-in tariffs, and better than PPAs. That's why I said you have to kind of calibrate your degree of accommodation to meet your level of achievement.

Question 5: Speaker 1, you started off with a definition of market failure, and it made me think of a textbook definition which is pretty simple: markets fail when the outcome fails to be efficient. And then the textbook example is typically an externality, of pollution. And then, if you have an externality, your market is failing. And so, when we think about what we've heard from the panel today, everybody kind of recognizes that we really ought to put a price on carbon that would get rid of the externality, and then the markets could work well. When I think about a \$43 a ton social cost of carbon charge in a place like PJM, where most of the time a gas fired generator is setting the price, that adds about \$17 a megawatt hour to their incremental costs. And that's in a market that's been clearing on average \$29 a megawatt hour last year. So, I look at this, and I think, we've got a big market failure here on our hands, because of this externality. And that's aggravated by your Nordhaus example, Speaker 1, of subsidies being inefficient. You wouldn't need flexibility payments if we got these price signals right, which probably means we wouldn't need all these RMR (reliability must-run) contracts. Speaker 3, you pointed out all these disparate CO_2 reduction costs that are a source of inefficiency. If we can't get the wholesale price right, we're not getting the retail price right, which leads to the point about underinvestment and efficiency. We've got suppressed wholesale prices that are affecting retirement decisions, and it's not the right price signal. So, my question to the panel is, how bad is the status quo? Because there's an awful lot of people that seem to think, "Oh, markets are working pretty well. We just need to price flexibility in this attribute and that attribute." But my question is, if you have to grade it on an A through F, how bad is this inefficiency we've got from the failures we're seeing in wholesale markets right now?

Respondent 1: I would say that (outside of California) this is more a prospective problem than a current problem, because of the growth of these things that is coming--in Massachusetts as well as elsewhere. I actually think we've had enormous success with markets. The point that was made this morning about how even non-market entities are happy with many of the aspects of the market, and they're expanding, is true. It's these programs with these big numbers in 2050, and whatever... I always come back to Spain and Germany when I think about this. They started out with very aggressive, very inefficient, very expensive feed-in tariffs. And after a little while, a couple of years, the way I would characterize the Spanish response was "*No mas*. This was a mistake. It's too expensive. The first thing we're going to do is, we're going to renege on all the contracts we just signed with these renewable people, because we're giving them too much money. We don't want to do it again, and we're not going to do it again." And that's the kind of reaction which I think is actually harmful in the long run, because we're trying to deal with these problems. The Germans seem to have more persistence in being willing to accept numbers that would boggle the mind in this country, in terms of the amount of money that people are paying through their electricity rates. The charge in Germany for the retail customers that are paying for these subsidies through the feed-in tariffs is larger than the amount that they're paying for the actual energy they're getting from the energy market. And that only goes to a small fraction of the market. I'm expecting even the German system to unravel. And it's starting to happen. And the system is entirely driven by the greens and their power in parliament. When that goes away, you're going to see a big reaction to it. And that's the long-run problem that I would worry about.

So, I don't think the war is over yet. I think the success we've had so far is pretty good. There are a few places where it's a serious problem. California's an obvious example, because they've got so much penetration, and negative prices, and the marginal value of solar is very low, and all those kinds of things. But I think it's the growth of those problems, and not being able to deal with it, that we're facing now. And I don't think the battle is over. So, I think we should keep fighting.

Respondent 2: I'm going to give it an A+, just because I think, like Respondent 1, that when you see how bad it can be, you have to realize we have really good markets in the US. We have nodal pricing. We have great innovations happening around scarcity pricing and ancillary services. People are updating their capacity market designs. Maybe they'll go away. That would be also be interesting. But I think all of this is working really well, and we've seen the market do what it can do. We've seen it save lots of money. We've seen it attract investment. We've seen it attract things that have been way cheaper than anybody thought could possibly be true. So, we have to give credit where credit's due. They've been doing what they've been designed to do. They haven't been designed to achieve carbon reductions yet.

Respondent 3: I think it's working well. Just to the questioner's point, you said the price of PJM is $17, for a gas plant. If the gas plant is setting the margin, it will add $17 to the price, but that $17 will be taken away from the gas plant because of carbon penalties. So, the marginal revenue for the gas plant does not change. However, if it's a renewable resource, instead of getting additional revenues through a PPA, or a REC, or a subsidy, it would actually get the $17 through the market. So, the distortion is not that you're paying the RECs or the PPAs to the clean resources. It's that, for the conventional resources, you're not recognizing the relative carbon footprint of different resources. You're paying a resource which emits one ton of carbon per megawatt hour the same as you're paying something which emits half a ton. So, you're not looking at a fleet wide price. You're looking at a very selective technology-based price.

Question 6: Thanks. I want to tee off with something Speaker 3 said, which was pointing out that the reason we're here really is politics. Waxman-Markey fell apart, and, if you think about that as a path we could have gone on, we're in a very different world now, where it's all state driven and bottom up. And that kind of created the mess we're in, where we have a lot of state legislatures driving what really should be global policy, or at least a federal policy. But we have state legislatures, with often very parochial interests, kind of driving this.

Having said that, I did want to note that there are some glimmers of hope, and one of them is what's going on in New York. Again, a single state RTO was pointed out. I'm also going to say California, as much as there are lots of problems with the way California is going about it, with the belts and suspenders, it does have a well-designed cap and trade program. And if you look forward to what they're planning for the next period, the 2021 to 2030 compliance period, that now has a price cap. It is grounded in discussions mostly focused on the social cost of carbon. And, given the way all the other policies are going, and the stringency, and the targets, there's more of a prospect that the prices will actually get above the reserve prices and become economically meaningful.

So, given this, I wanted to ask if there are other glimmers of hope that people see alongside this focus on carbon pricing, either at the federal level, the regional level, or the state level.

Respondent 1: I do think there are glimmers of hope. I don't think they're all entirely consistent, and they come from different places, but I'll just give you some examples. You didn't mention that in California, the bill that just passed the legislature and was signed by the Governor, for 100 percent clean energy. Admittedly, it is an ambitious target. But you have a legislature that rejected that concept a year ago passing it this year, and it going into law.

And you do see some glimmers of that in other places. Some of that is from political candidates, so we'll see if that turns into actual action at the legislature, but the more that we're talking about the states getting onboard with a performance target, as opposed to a technology target, I think we're moving in the right direction.

One other sort of glimmer of hope I'll point out is at the federal level--the Baker-Shultz carbon proposal. I imagine we could have a separate debate on that here. But you have conservative statesmen, elder-type folks saying we have a way to address this, something that is largely talked about only in the green community, but what at least that group sees as an important national goal. We have a way to do that that is technology-neutral and market-based: tax the source of pollution at the source, but refund essentially all the proceeds back to customers, so that it doesn't turn out to be some sort of regressive policy. We have those who spend the least benefitting to the tune of 70 percent, according to government estimates. Customers would end up better off under a $40 a ton carbon tax, which is, as the previous questioner pointed out, a material price impact, relative to what power prices are right now. So, the fact that that initiative has attracted as much support in the business community as it has…you have leading oil and gas, automotive, agriculture..across all sectors, big, big companies signing onto that approach, and we'll see when it's time for that to turn into a political exercise, if that moves folks in potentially the next administration. But we'll see.

As I said earlier, five years ago, I don't think any of the things I just mentioned were really occurring or being discussed, and they are now. And I think that's partially as a result of the kind of dynamics we're talking about up here. We need to work towards the next evolution of how we implement clean energy policy.

Question 7: Speaker 2, when you were talking about the carbon price proposal that the New York ISO was putting together, I was wondering how that proposal would interface with RGGI, if at all, and how do you propose to accommodate RGGI?

Respondent 1: We assume RGGI exists. For example, if the price of carbon is $50 and the RGGI price is $10, we would add a $40 additional charge to a ton of carbon. So, essentially, we net out the RGGI price when we apply the social cost of carbon. So, the social cost of carbon is the price we apply, plus the RGGI. So in total we are not applying more than the social cost of carbon.

Question 8. I'm a bit concerned about one of the supposed "nonmarket" objectives interfering with the market or being over subsidized when it really should be a market objective. I'm referring to the way we've subsidized and are treating demand response. I've heard Bill Hogan talk about getting the prices right and having scarcity pricing since, I think, 2001. And I think we now all appreciate that that's really, really hard, and technically difficult, because it took until FERC's technical price formation initiative in 2014, and now we're getting PJM to look at ORDC demand curves in 2018. Maybe it will be filed in 2019. But I don't think we will ever get scarcity pricing correct unless we are accounting for the level of demand response, not only what's visible to the ISO, but a lot of these programs are occurring at the LDC (local distribution company) level. So, at the ISO, we get to the peak day, and you get close to scarcity pricing, and the price doesn't get there, because all the loads flatten out, because all the LDC programs initiate. New York had its summer operating study and I really appreciate that New York called out, for each of those hot days, how much LDC-level demand response got called on those days. I'm not sure if that LDC demand response is incorporated into the ISO scarcity pricing. I think that's outside.

So, I'm curious what you guys think about a couple of ideas. One would be to account for LDC demand response in the operating reserve demand curve, so that the ISO could estimate that, and shift the demand curves over, so we're not having all this demand response occur sort of as free capacity in the scarcity conditions and suppressing prices. And, secondly, everybody seems to talk very favorably about capacity performance payments, providing the right incentives to generators and making capacity payments look more like energy. Why don't we do that with demand, as well, where we recover from the demand during the high loss of load probability hours in order to incentivize demand response, and as part and parcel to that, we stop double paying demand response and kind of reverse Order 745? Just a modest proposal. I'm curious what people's thoughts are on that.

Respondent 1: I agree with you completely. Order 745, which is another fiasco, is a very inefficient pricing system. The way I would characterize things is that you should charge customers for what they consume, and send the right price signals, and quit all this nonsense of paying people for what they're not doing, and overpaying them, and paying them twice, and all that kind of stuff.

The other thing is, it's a Supreme Court decision on this which made the jurisdiction question the law of the land. I've also written about this, but if you look at the Supreme Court decision, there's a jurisdictional question, and there's a substantive question. And on the jurisdictional question, it says that FERC has jurisdiction. And on the substantive question, it says, "We have no idea what we're doing, and we're going to defer to FERC." And so, FERC can do whatever they want. FERC can reverse the stupid pricing thing tomorrow, as a legal matter. I mean, they have to go through the process, but [LAUGHTER] the Supreme Court did not direct them to do stupid things.

Respondent 2: I won't comment on Order 745. [LAUGHTER] But I'll comment on your first question, about what you do with the demand response and the distributed resources which are behind the meter. Actually, our load forecasts are now calibrated to figure out what's happening behind the meter. In fact, in our load forecast, we estimate what rooftop solar will be doing. I think we have to do more of that. But we are putting in a distinction between what we see at the wholesale bus and what we see behind the wholesale bus. So, if LDCs are doing demand response, in our mind, they're doing load modification and we should do a better job forecasting that. The reserves procured are still from the load that we are seeing at the wholesale bus. So, that's where we are.

Questioner: Right. I agree, you need to forecast the load, but if the LDCs are paying $2,000 per megawatt hour for the marginal LDC demand response and you're just assuming it's free, and it's just load that doesn't show up, perhaps the scarcity prices can't be right. It's sort of nice that we've put all this effort into scarcity pricing, but until you actually incorporate what's happening at the LDC level, you won't get the scarcity prices right.

Respondent 3: I think you're absolutely right that we can have better price formation if we do have more visibility and control mechanisms between the wholesale market operator and the LDCs. I think that is going to be an increasingly important part of our picture, going forward, because the amount and size of these distributed resources are only going up. So, the more that we can have that good communication and a mechanism for them to be dispatched with price formation, far better. I think, also, that increasing our Operating Reserve Demand Curves in every market, to have more scarcity pricing and more quantity, will also help to alleviate the problem you're talking about, because the more gradual that scarcity pricing function becomes, the more we'll get at least some of the scarcity pricing.

Questioner: I forgot to mention one other thing, which is that if you did it this way, you would also probably contribute to resiliency.

Moderator: Let me ask a clarifying question, because I'm a little bit confused, and if I'm confused, maybe somebody else in the room is confused. Are we suggesting that LDCs responding to price is a problem? Or, is that the way the market is supposed to work, where the wholesale customer takes less when price goes up?

Respondent 2: It is not a problem.

Respondent 3: I think the nature of the problem is, if there's just a bit of lumpiness in those LDC calls, instead of having a price that's equal to the say, $2,000, in this example, that it costs to actually curtail those loads, we end up having a price that's basically zero, because it's as if the load were just lower. So, I think it's just a matter of that price formation not being integrated, the supply and demand really not being fully integrated, at that point in time. I think that's the nature of the issue.

Question 9: I was looking at slide #12 from Speaker 1's presentation, and to take an extreme example, to illustrate my question as best I can, let's assume that all the renewables on this supply curve are solar, and that's all we have for the market--solar generation. Now, when I look at this, I can see, along the horizontal axis, that solar, for everything that it generates up to Q max, it gets a price of zero per megawatt hour, but at Q max, at 7 p.m., I can't help notice that it would get a lot of money--but it's not going to generate anything. So, it gets zero dollars per megawatt hour, and it also generates zero megawatt hours when the price is high. And this is an energy-only market, right? Because there's no capacity revenue. So, I'm just trying to figure out, how can it generate in the night time?

Respondent 1: This is a perfect example of why the energy-only market can work, because if you would start with the system you're describing, that only has solar, you'd have outages all night long, and so you'd have prices of $10,000 per megawatt hour all night long. Well, I mean, at that price, there are a lot of people who could come in and do something. There's a lot of storage that can come and play.

Respondent 2: That's my example. That's not right. [LAUGHTER] The Q max, think of it as wind. OK? For the illustration. The wind blowing, and this is what you get, and you can't get more than Q max, and the price goes up, and it's wind. If it's solar, Q max is zero at night. Right? That's your point.

Questioner: Yes, but then how does load get served?

Respondent 2: It doesn't. That's why we have demand curve and price goes up until it drives to zero. This is admittedly an extreme example.

Questioner: OK. I'm just trying to get my head around how this all hangs together when there's no capacity.

Respondent 2: We're not going to see this market. I'm just trying to cut through the chaff of these conversations here, and say, suppose it were true that that's all we had. It would still be the case that whatever they were generating, up to their capacity, they would get whatever the load was willing to pay. Everything would still be the same in terms of the first principles of the argument. It's just that scarcity pricing would now be the only story. So, think of it as wind and you'll be more comfortable with the picture.

Questioner: I feel better already. [LAUGHTER]

Question 10: This is an observation for Speaker 3 and Speaker 4. Speaker 3, you had in your presentation, as I recall, that the two nuke plants in Texas were at risk. I don't believe that's true, because both those plants are owned by gentailers that need those nukes to serve their load, which then leads to an observation about bilateral contracting, which is off market. In ERCOT, I think more than 90 percent of the load is served by bilateral contracts. The energy market, obviously, informs the price, but our measurement tool in ERCOT doesn't capture day-ahead revenue that may exist. It doesn't capture trading revenue. And it didn't capture the forwards, which this spring were triple-digit. It turned out that those were probably higher than necessary, but I would just note that there are some analysts who've said that it's been a disappointing summer. Right now, during the last two settlement periods in ERCOT, prices have been…let's see, one is almost $1300. And the other is almost $1400. And the ORDC is putting money into the market right now, during the fall. And it's not the peak period. It has to do with all the what are now called seasonal plants having gone off line, and you get erratic weather, and wind is lower than forecasted. That also leads to the other point, which is, I'm not sure that markets can't meet environmental goals, in some respects. The market certainly has cleaned up the fleet in Texas over the last 20 years. Now, would it get to 80 percent? I don't know, but the way that we keep getting wind…which is partly a function of the federal subsidies, obviously…

Respondent 1: You're right. This Platt's view does identify the two plants in Texas. I have no knowledge of those two plants. So, you may know better than me what's causing Platts to report those stations as being at risk. We are the last entity that's built anything in Texas, so I do have some sense of what happened this summer, and I know that the Commission is still looking at changes to the ORDC, because, even after the summer, there have been additional retirements, and there have been units dropping out of the queue. So, I do think that, even though all of us can agree that that market design is one that we should look to, it's not perfect the way it is, and it does need, if it's going to drive investment and a reserve margin that's going up instead of down, additional work. So, I'll just stop there, and anyone has anything else to add…

Comment: Only that, as the owner of one of those plants, I don't think we entirely agree with plats. In case there were any investors listening. [LAUGHTER]

Respondent 1: Good. [LAUGHTER]

Question 11: My question is for Speaker 1. It's actually perfect that slide 12 is up, because my question is related to this as well. I was really glad to see this example, even though it is sort of a limiting case. One of the things that it made me think of was a discussion that we had back in June, up in Boston, on retail structures. Somebody on the panel there used the example of the telecom industry, and the idea that, back before deregulation of the phone company, the basic structure was one of relatively high variable costs that we would all pay for phone calls, even though the cost structure in that industry was much more skewed toward fixed costs. Then you went through deregulation, and now we all tend to have unlimited, or nearly unlimited, calling plans for our cell phones. And it just made me think, in this context, in a world where, even if we don't get to exactly that curve, we are trending toward one where variable costs are very low to zero, but the fixed cost structure of the supply is relatively high, what is the value proposition, to both producers and consumers, to continue a market structure that's so focused on the variable costs, when that's essentially going away? And, in another extreme case, why not have the energy industry moving more towards a structure where suppliers compete to supply unlimited energy consumption plans, the same way we have for cell phones now? And, just for some context, I'm not an economist, so I'm looking for the economist's answer to the non-economist.

Respondent 1: Well, you don't want to ignore the variable costs associated with demand in this picture. So, if you were charging, for example, a constant price, then most of the time you'd be consuming too little, because, during these hours when the price should have been zero according to this theory, you would be charging high prices, and there are a lot of kind of things that you would want to do with that. That's the efficiency argument. All we're doing is making the case here, assuming a lot of other things to simplify the problem, that you could get enough revenues through scarcity pricing so that you could, in expectation, cover the fixed cost of the investment. But the point that I was trying to make was that the first principles argument of what the efficient price is doesn't change, even in this extreme case.

Now, on the telecommunication story, there are a gazillion packages and different things that you can arrange, and that's just fine, and intermediaries could do the same thing. But we wouldn't want to have the system operator imposing those policies. We would like to have them be derived from the marketplace, rather than have the system operator doing it on your behalf. And, if they do scarcity pricing correctly, the system operator can run the system just the way they're doing it now, and then the market can respond and do what it wants.

Moderator: Is your question more to retail pricing, or wholesale pricing?

Question: I would think about it in both contexts. I mean, I would agree that, certainly, it's possible now for retailers to provide that product, and they don't seem to be doing it, so there are obviously reasons why it's not attractive.

But I think about it at the wholesale level, too. We spend a lot of time trying to get energy pricing right. Part of my perspective on this comes from the fact that I spend most of my days on a trading floor, looking at energy prices and unit dispatch and the availability of reserves, and trying to make sense of those things and have them kind of tie back to the theory that we talk about here a lot about how that should work. That kind of wraps into the whole energy price formation debate, where there seemed to be a whole lot of problems with getting those price signals to really make sense, particularly when the system's undergoing stress conditions. And there's a lot of effort being put into trying to get those price signals right, while, the whole time, the real value of that short-term marginal cost is going away, and will continue to go in that direction. But the reality is, there's a relatively large fixed cost structure that ultimately has to get recovered somehow or other, and, again, from the non-economist standpoint, it seems like there's a real disconnect there, and like there's a lot of effort trying to get a variable cost that's going away correct, but what we're really try to do is recover fixed costs.

Respondent: It doesn't go away when the system is tight. And it becomes entirely dominated by this hard part, which is getting the scarcity prices right, and that's 100 percent of the story, and the frequency with which they collect those scarcity prices in expectation, will add up to their fixed costs, in this equilibrium example. So, I think it all hangs together and it works, if you get the scarcity pricing right. If you don't get the scarcity pricing right, it's hopeless.

Respondent 2: Yes, and I think that is the real trick.

Respondent 1: And the previous questioner thinks it's hopeless no matter what. [LAUGHTER]

Question 12. I'd like to pick up on this, and make a couple of observations, and then ask a question about how we begin to tie this into the demand side of the market. So, the first observation, about the scarcity pricing piece of this, is that, despite the paper that Andy Ott and Paul Centolella wrote 10 years ago, if you look at the way PJM and (I suspect) some other RTOs do their capacity markets, they still do not take into account, in their forecasts of the capacity requirements, what the response to any kind of dynamic pricing would be on the retail side. In fact, if you look at what actually happens, if a retailer or a utility in PJM begins to reduce their peak demand, it takes many years before that begins to work its way through the forecasting procedure for the zonal requirement. Yes, you could shift your capacity requirement from one retailer to another in the zone, but the zonal requirement declines on a very gradual basis. I think that in PJM, after 18 years you'd actually lose about 50 percent of the actual demand reduction that you had incurred. So, there's that piece that we need to integrate into markets.

On the other hand, and I find Speaker 2's example interesting. I'm curious about how he's going to return the carbon revenue back to customers. Having lived through the development of the SO2 allowance market, who gets the revenue is a very significant part of the issue. If we look at utility rates, we see fixed transmission costs that are sent back to LDCs on a per kWh basis. We see the volumetric recovery of fixed costs at the distribution level. We actually see volumetric charges going to customers that in many cases are above the social cost of electricity, although they certainly don't reflect the variation in those costs over time periods or locations. So, I guess my question to the panel is, we've talked a lot about this at the wholesale market level and on the supply side. How do we begin to broaden this conversation, so that we actually think about how we integrate what's going on on the demand side, where there are more and more smart devices that could respond to prices? How do we think about this in a way that begins to integrate customers in a way that is much more effective than what we've done until now?

Respondent 1: You did mention capacity markets. So, I'll just continue to point to the deficiencies of the capacity markets. Capacity market load forecasts are calculated by system planners, who are an intrinsically conservative bunch, so you have a tendency to over-procure. And when you have a lot of distributed resources, and there is an element of price responsiveness, that load forecasting becomes very complicated. That's another reason we put more faith into putting more revenues in the energy market. I think the life of the system planners is going to get very, very complicated as more and more distributed energy resources come online, because you don't even know what's load. And we're doing this right now, as we are doing this integration of distributed energy resources. Our system planners want to go and really count every lightbulb, and figure out what's real load and what's behind-the-meter generation. They say, "I want to know that, because that's the only way I can plan so that your wholesale markets can procure efficient reserves." I say, "You can't do that. You have to do it stochastically, at best." So, they are proceeding towards evolving.

Secondly, in terms of environmental response to the distributed resources, there's no difference from the wholesale. You have to find, for every distributed energy resource which interconnects with the wholesale market, what their carbon footprint is. We'll have to see, for each DER resource, what is the carbon footprint that we have to calculate, and incorporate that in the market.

Respondent 2: I'll just say that there is a parallel between the conversations going on on the retail side and on the wholesale side. To the extent that states have particular policies that they are trying to drive through the utility, that makes it harder to adjust rates to reflect cost causation and to provide the appropriate incentives. As the cost structure changes, rates should change, but politics make that challenging.

Questioner: I do think that, in some of the states that are looking at grid modernization, you are seeing efforts to try to think about how wholesale costs are allocated and how to create more time-varying and dynamic rates that we haven't historically seen.

Question 13: Very fascinating panel. A quick comment, first of all. I think there's a very broad sense in a lot of parties, certainly New England, that we want to see more use of the energy markets and less of the capacity markets for a variety of reasons, including political ones. The capacity markets are hard to explain to people.

But I will also say, I think you made a very astute point, Speaker 2, that we have to look beyond the label to what's actually going on. And the fact that we now have a very robust pay-for-performance structure built in does actually transfer a lot of the revenues, on a practical basis, from the capacity market back to an energy market, in the way in which the generators feel it. So, that's my comment.

In terms of the clean energy market, I'm intrigued, and also, to be honest, confused. I really need help. I don't want you to take a lot of time now, but I really don't understand the juxtaposition of saying that individual states would be responsible for what they would be seeking in terms of a level of carbon free energy, whereas at the same time, what I thought I understood that there would be a market clearing mechanism that would affect the price everybody would see. And I can't reconcile that, and I'm just trying to figure out what the mechanics are of how this market actually works.

Respondent 1: OK, now we're going to stay for another hour. Thank you for that question. [LAUGHTER] I would absolutely love to give you a briefing on this. But let me answer your question quickly. The description that I kind of laid out was really only the settlements. It was really only describing the product definition in the settlements, like in real-time settlements. What I didn't describe was the entire proposal, which would include a forward auction. So, the states, or other buyers, would bid in their demand for clean energy in megawatt hours. And those megawatt hours would be assumed to displace a certain amount of carbon--a certain number of pounds per megawatt hour, say 800 pounds, or something. So that would be the demand. And then people would put their sale offers into the forward auction. And you'd clear the intersection of supply and demand, and that would set a price, which would be, basically, the anchor price. So, say that clears a $10 per megawatt hour, assuming that you're displacing 800 pounds. When you come to real time, if you actually displace more than that, you get paid more than that. If you displace less than that, you get paid less than that.

Question 14: Earlier in the discussion, there was a disagreement between two of the panelists over the meaning of slide 12 that's up on the screen, and I wanted to hear the end of the explanation as to what one of the panelists thought that slide meant in terms of solar, and then, very briefly, why they disagree with the other panelist.

Respondent 1: I actually don't think we disagree. I think it was the nature of the example that was at issue. I was kind of adopting the example of what would happen if you just had the energy-only market construct, but you only had solar. I guess what I was saying is, you'd have prices at zero, maybe most of the day, because you'd have enough solar. And then, in the nighttime, you'd have a shortage, and therefore, in this type of a market, the price would be value of lost load at the price cap. So, $10,000 megawatt hour. Well, that's a market doing what it should, which is giving extremely strong pricing signals and incentives for people to show up in the middle of the night. And, at $10,000 a megawatt hour, people are going to show up, is what I was getting at. You're going to have a bunch of people who can invest in storage, and they're going to absorb solar during the daytime, when it is zero, and then they're going to inject it back, and they're getting $10,000. Well, over time, what you'll see is more entry of storage, and then you'll get to some equilibrium condition, which, I think, is kind of what we want to see. We'd be getting a little bit of that scarcity pricing for a few hours, just enough to cover the investment cost of the storage. And so, you get to kind of an equilibrium condition there. So, all I wanted to do was kind of play out that example to make the point that, if you define what you need, which is the energy, and have a good scarcity pricing function, and then let the market run, it will actually get you a solution. It might not be what you thought.

Moderator: To the other panelist, any further comment on that?

Respondent 2: Yes.

Moderator: OK.

Respondent 2: [LAUGHTER] That was my comment.

Moderator: The comment was yes. All right. [LAUGHTER] Please join me in thanking the panel.

Session Three.
Are Traditional Customer Classifications Still Relevant?

Electricity markets, driven by technological developments, economic circumstances, and, to a significant degree by social demands, are evolving rapidly. On the technology side, we have increasing use of distributed resources, smart controls, electric vehicles, storage, and other applications. Market changes have enabled demand response, real time price signals, non-tariff offerings, and alternative suppliers. As a result, customers have become far more varied in their requirements for electricity service. In theory, costs should be allocated to the cost causer. Doing that on a customer-by-customer basis is virtually impossible. Simplified allocation decisions -- according to customer classes defined on an end-use basis, such as residential, commercial and industrial -- assume consumers with similar, if not identical, load characteristics. Given the changes in technology and market design, are class-based cost allocations even meaningful anymore? Does intra-class diversity require re-defining the classes, or finding an altogether different methodology for allocating costs? If classes were re-defined, what would new classes look like? Given advances in data management, should we now be looking at cost allocations on a more granular, more individualized basis?

Moderator.
Good morning, everybody. It's my pleasure to moderate this panel discussion this morning on a very cutting-edge topic. There are so many changes going on in the industry, both supply and transmission issues, as well as behind-the-meter issues. So I'm excited to hear the presentations of our panelists.

Speaker 1.
Let me start off by saying that my presentation is really only oriented towards the issues of classifying customers for the purposes of retail rates. And the reason I want to say that is because there is lots of market segmentation that goes on relative to, for example, promoting different kinds of utility programs. If I want to have a time of use program, I might target particular lifestyles for the customers, and so on and so forth. My focus is entirely on the question of classifying customers *for the purposes of retail rates*.

So if you think about why you do segmentation, the reason or rationales are completely different for competitive markets versus what happens in regulated markets. In competitive markets, the basic idea is to essentially maximize profits. Right? You know, as my students say, segmentation helps click bait. You want somebody to go and look at your app or look at your product and then continue on to basically select it. The classic example is the Netflix recommender system. Does anybody know about that? They had a contest, right, which essentially created a huge piece of software for market segmentation, only to better target their customers to essentially choose more movies for them and to retain them. Right? And the contest was for a million dollars. So this was a non-trivial reward for the segmentation. On the other hand, in a regulated market, the rationale is cost causation. You know, the basic idea is to develop relatively homogeneous groups of customers on the basis of costs that are incurred in serving them. There are limited instances where increasing revenues might be a goal, particularly in economic development rates. But the primary goal, essentially, in customer segmentation is basically identifying cost causation.

Now, I have a usual spiel on the typical basis for doing cost causation analysis and creating the homogeneous classes. Basically, you look at load curves. Right? The whole focus, in terms of cost causation, typically is, I look at a load curve, and I decide, on the basis of the load curve, how I'm going to segment the customers. The load curves provide the basis for the variations in costs that are associated with serving those customers. Then we look at monthly peak loads by class as part of the basis for the segmentation, to demonstrate that the different classes have different peaks, and so on. And then the next thing that we do is, we take the information, and then we allocate the costs as to whether they're demand-related costs, or energy-related costs, or customer-related costs. And most of that information is going to be based, frankly, on the load curves.

Now, here's the problem. This is California in April. And, as you can see there, the prices in April, between the hours of ten in the morning and five in the afternoon, were negative. So, from the standpoint of thinking about cost causation relative to load shapes, we are in this position where things have changed kind of radically, because of the nature of the wholesale market, but also because of the nature of the equipment that's on the customer side. It used to be I'd look at this and go, "That can't be, because the peak's supposed to be in the middle of the day, and the prices should reflect that the peak is in the middle of the day."

The second thing that's different is this. We just did a study looking at very, very area-specific marginal costs for Con Edison. And, basically, you can break up Con Edison into lots of little pieces. They have about 84 pieces that correspond to different sections of their distribution system. And what you see is, with the exception of the green area, which has very high marginal costs, almost all the marginal costs are in fact quite low. All right? And, in fact, they're zero in a lot of places. So the implication there is that although clearly, we're going to look at cost causation, and we're going to work it into our embedded cost models, the fact is that the marginal cost associated with serving those customers on an area-specific basis is very different. OK?

So, here's where we could go if we wanted to use the same regulatory rationale, which is cost causation. The first thing we hope is that the utility has the data. That's not true for everybody, but it would be nice to have that kind of data, like what you get from AMI smart meters. And you know, we could abandon current customer categories, so we wouldn't talk about whether somebody's residential or commercial or industrial. We could determine the predominant customer characteristics. OK? We'd look at a normalized load shape, as opposed to looking at an absolute level of load. You know, we would take a look at the electrical characteristics associated with a specific customer. If you have a smart meter, you can, on a five-minute basis look at the power factor associated with that customer. OK? And you can include things like location on the distribution system. For example, network versus radial customers. The fact is that customers on the distribution system in a networks setting have lower cost per customer than the radial customers. OK? But, as it stands right now, you're not allowed to geographically differentiate your rates on the basis of the costs that are incurred to serve those customers on a geographical basis. Lastly, you can put together a giant database, and then use that as a basis for either clustering or you can do singular value decomposition, which is what Netflix used, to kind of separate customers out into relatively homogeneous but smaller groups, and then just permit membership fluidity over time. Don't say that a customer is in a particular class just because they've always been a residential customer. Say they put a new technology on. That technology makes them look like so and so, and then simply allocation them to that class. And then do that on a periodic basis. And then you abandon the standard residential, commercial and industrial, divisions, and move to a cost causation basis that's probably closer to the real cost causation than in fact we see right now, with our historical setting.

Is that acceptable? Well, I don't know. Whether you want to move towards that depends on your commission. But the point is, I just want to raise the possibility, given the information we have, of a new way of thinking about how to create customer classes and get to that relative homogeneity.

You have to decide how many customer classes you want to have. Right? The fact is, I can look at a standard utility. They might have 128 pages of rates. Right? So, do you want to have 128 pages of rates for each separate group? Or do you want to have something smaller? You'll have to make that decision.

So, if you don't want to keep the current rationale, well, you can choose customer segmentation like the competitive markets do. I can choose revenue maximization. I can choose cost minimization. I could choose profit maximization. Right? Any of those are criteria that we can use for creating the segmentation. I don't see any of these things being used any time in the near future, until the regulated market decides to be competitive, for example, through clear customer choice among all customer categories. But that's a possibility in the future.

So, I just wanted to give you a kind of a setting to think about what the possibilities are, going forward, if you're willing to sort of say, "I just have three customer categories," or four, you know, residential, commercial, industrial and street lighting, or however you've set it up. The tools exist Data now exists in a way that it didn't exist in the past. And we have the hardware and everything else to allow for whatever kind of segmentation we'd like to set up, to whatever degree of differentiation we'd like, and to whatever degree of homogeneity we want to go to. It's just a question of making a regulatory choice. What do you want to do? Thank you

Speaker 2.

Thank you for the invitation to participate in this great conference. I'll give you a spoiler alert. My answer to the question of whether traditional classifications are still useful is, "Yes." I do recognize, however, that, like so many areas that we deal with, this is kind of one of those gray areas, and it's important to be open to new ideas. And so, I'll be discussing a little bit about evolving thoughts on customer classification.

There's lots of thought recently about the changing utility environment, and that involves, as you all are aware, discussions of business models and interactions with consumers and consumer options, including cost allocation and pricing changes. So I'd like to start with a little background here, and the different perspectives of some of the stakeholders in these discussions, beginning with what the utility has been experiencing.

As you know, there are several factors that have been changing in the utility environment. For example, demand side management. Energy efficiency growth and growth in demand response programs have both been driving sales down, and also therefore revenues. There's been amazing growth in distributed generation, both for commercial and residential customers. And there have been a lot of technological advancements that have allowed automation and things such as appliance response to pricing changes. All of those factors have resulted, from the utilities' perspective, in reduced load growth and also lower revenue growth. And I want to point out, I'm careful not to say "reduced load" or "reduced revenue," because I think both of those are still growing, just perhaps at a slower rate than they would have without some of these changes.

On the other hand, what the consumer is experiencing varies a little bit. The commercial and large consumers actually have been seeing, I think, the cost of renewables such as wind and solar becoming competitive with the embedded resource portfolios that they have traditionally been served by. In Montana, which is today a vertically integrated state (so some of these comments may differ a little bit for those of you who are in states with competitive generation markets) the state has seen a substantial decrease in the cost of wind and solar, and a lot of large businesses and some smaller businesses see this as an opportunity to actually drive their costs down. And, at the same time, their constituents, their customers, are pressing for environmentally sensitive resources or green resources, so they can satisfy both of those objectives at the same time by pursuing wind or solar or other distributed resources.

Residential customers also are sensitive to the fact that resources such as photovoltaic, rooftop solar, are environmentally friendly, and, actually, rooftop solar is cheaper than the retail rate in many settings, and with net metering, of course, that's an economic advantage to those customers. And so they've been increasingly turning to distributed generation. And that's also been sparked by third parties entering the market and taking on some of the risks for those residential customers. More recently, we've seen a proliferation of electric vehicles and storage also driving customer interest. All of those things have been factors that have interested consumers in having additional options for service from their utilities, and that's something that we hear a lot about these days.

There's a lot of buzz about consumer choice, consumer options, and, actually you hear a lot about that as a rationale for grid investment and also for cost allocation and rate design changes, such as we're discussing today. But I think it's important to bear in mind that, despite all of these changes and the changing consumer behaviors, it's important to focus on what consumers actually want, what they're looking for in their electric utility service. And I believe, still, despite growing consumer segmentation, that electricity, really, for a consumer, is a commodity. It's a commodity market. Consumers are buying it for its application, not for its intrinsic value.

I believe that what most consumers want boils down to some basic principles. And we all hear about those things being reliable and safe service at the lowest reasonable cost. Actually, sometimes this is cast in terms of affordable service that's reliable and safe. And I just want to discuss that point briefly. I've had an ongoing debate with some of my colleagues about that notion of "affordable service" or "reasonable, reliable, and safe service at affordable rates." And my thinking has evolved on that point. I originally had argued that affordability is not really what regulators are attempting to achieve. You know, that's really a very tough standard, because something that's not affordable for someone with a very low income might be affordable for someone else with a different income. So it's not really why economic regulation was initiated for electric service. I think really what we're trying to do is emulate competitive markets and drive the rates for providing electric service to the cost of service. And so I always preferred to speak in terms of lowest reasonable cost rather than affordability. But, again, I think we're trying to emulate competitive markets.

There are some things that regulators need to be, I think, cognizant of. We had some discussions yesterday that made me think of this point in terms of cybersecurity. Consumers are interested in reliable service, for example. That's really implicated by cybersecurity. So, because there are not competitive markets for monopolistic utility service, and a lot of those costs can be shifted onto consumers, there is a risk that utilities wouldn't take those kinds of factors into account. And so I think regulators need to consider adequate service along with reliable and safe service, and actually, most commissions…I know the Montana Commission has the statutory authority and has set minimum service standards. And so those service standards, whatever the commissioners decide they would be (and I suggest that they would try to reference what a competitive market would result in), can add to a cost of service. So I like to think of adequate, reliable and safe service at the lowest reasonable cost as what consumers want out of their regulatory system.

The third point is convenience, and I think this can't really be overemphasized. This is something that consumers are very interested in. I acknowledge that there are some, and maybe a growing number of, consumers who really are into technical details, who are into analyzing their usage and things such as that. But I think it is still a distinct minority, and consumers value convenience. I was at a conference a couple of years ago, and one of the utilities there talked about a study that they had done about how many minutes their consumers spent looking at their bill. And it turned out that six minutes a year was the average that a consumer spends looking at their electric utility bill. And there actually was another utility representative in the room who spoke up and said that they had done a similar study, and actually the result had been less than six. I think it was like four, or something like that. So, convenience is very important. Consumers don't want to spend a lot of time just studying their bill.

And, finally, there's growing interest in environmental stewardship.

So, what does all that mean for evolving utility service? The utility of the future, I think, for consumers, for most residential and small businesses customers, will be what I term the utility of the past. What consumers want is really just reliable, low cost service. Consumers generally don't think about the technical aspects of the grid, such as generation and load growth and regional transmission organizations, and transmission issues. And, again, electricity for them is a commodity that's not valued in and of itself, but for its applications. It's true that there are a growing number of consumers that are installing generation, but the question I like to pose is, why are they doing that? And I think it's largely because of the economic advantage that they can achieve. If you told someone you had a deal for them, and they can install solar, for example, or a small wind generator, and it would only cost them 10% or 20% more, I think there are a few who would take that, but generally consumers would not do that, because it is convenient to receive that service over wires, without having that equipment and having all of those risks and issues for yourself. So, for the consumer, I think what they interface with will continue to be the bill, and that's how they see their utility.

So, all of that gets to, again, this issue of utility cost allocation and what effect that is going to have on consumers' bills. Cost allocation is an important issue. I recognize, again, that there is a growing segmentation of consumers. Some are using their electricity service differently. Of course, that has been the case for the last 100 years or so. And we have to allocate costs, because most of the utility costs are joint or common costs. So the goals, generally, for creating allocation systems are a fair apportionment among those consumers, however you do that. And rates that are designed to encourage optimal use is another very important goal. That, I think, at bottom is an attempt to tie the rates to the costs and the costs to usage, or, as I think we've all heard, the mantra of "cost causer pays."

So, how we should allocate costs to the various consumers becomes the issue. Assuming that costs are tied to usage, there are various ways to do that, some of which I've listed here: block rates, time of use rates, various multipart rates… But one way to allocate cost based on usage characteristics is customer classification. It's just an allocation scheme. Class characteristics typically include things such as load characteristics, load shapes, as we've heard, and end use voltage level and total energy consumption. And, historically, all of those factors have resulted in just some very broad classifications, and we usually think of them as industrial, commercial and residential. And, of course, there are subclasses. There are additional classes, irrigation and lighting, for example, in Montana. But, generally, there are very broad categorizations of customers. And that's interesting, because costs do vary much more widely.

Of course, you know, there could be many, many ways, almost down to the very individual consumers, to allocate costs. And again, some consumers are using electricity in new ways. So what should we make of that? I think it's interesting that even in Bonbright's '88 edition of *Principles of Public Utility Rates*, he spoke to this question and seemed to actually anticipate the issue of big data and the ability to use a lot of data through computing. And I think it's important to keep this in mind. So what that treatise said was, even if through the miracles of high speed megacomputers and of techniques of econometrics, all significant cost differentials could be measured without inordinate expense, they would then be found far too numerous, too complex, and too volatile to be embodied in rate differentials. Importantly, stability, and especially predictability of charges, for public utility services are desirable attributes, and, up to an indeterminate point, they are worth attaining, even at the sacrifice of attempts to bring rates into accord with current production costs.

Again, recognizing convenience. And this was somewhat echoed by Cass Sunstein in a law review article, something that some of my colleagues also like to quote recently. Mr. Sunstein wrote that life is short, and people are busy. And for many people, life is good in part because a series of desirable default rules are in place ensuring that if they do nothing at all, things will go fine. Often, we rely on the fact that choices are made by others, and we go about our business without troubling ourselves about them. This is a blessing, not a curse.

So, how far should we go in creating new customer classifications? And I suggest that in answering that question, we keep in mind this other question of, what do consumers really want? We recognize that technology is allowing more usage options, and consumers are diversifying somewhat. But do you really want to have 10,000 different rates? Or do you even want to have 1,000 different rates? If you were a consumer, and you had various different electric companies to choose from, would you choose the company that had 2,000 rates? Or would you choose the company that had maybe ten or a dozen or twenty rates? I think, generally, consumers prefer simplicity.

And do you really want to have cities or even neighborhoods within those cities experiencing different rates? Again, I come from Montana. Maybe in New York City and the various boroughs there, that wouldn't be a problem. But I think that in most cities and towns in Montana and other states, it would cause a lot of consternation for your neighbors to be having different rates than you, or even someone across town. Even in Wyoming, there are efforts to have rate disparities adjusted, even between different utilities with different cost structures for different cities within the state.

Telecom and wireless is an interesting example. About 30 years ago, regulators devised a very intricate, complicated set of what were deemed to be efficient rates at the time. We had measured service, not only for long distance, but we had measured service for within-the-city rates. And it's interesting to note what happened when competition did emerge. Most competitors went to simplified rate structures, because consumers wanted that kind of simplified rate. There was another example that's interesting in Montana, where, in terms of geographically-differentiated rates, we had efforts by some phone companies to have flat rates for service territories that had several hundred square miles of service. My office opposed that extended area of service proposal, and it was kind of a learning experience for me, because we went out to hearings in these localities and tried to explain to people that if these extended areas were adopted, more than 80% of those customers would pay higher rates, because they would be subsidizing the higher-cost rural service. And, you know, we were just roasted by those customers for opposing that, because they wanted those simplified rates. They wanted that kind of extended area community. They didn't want to differentiate between rural and urban costs. So I thought that was a very interesting situation.

So this gets to my conclusion here. I'm kind of thinking of this as the Goldilocks problem. What's too big, or what's too small, and what would be just right, in terms of customer classifications? I don't know that there is an exact answer that I can give to you. I do acknowledge that there are going to be some cases where additional rate classifications need to be created. Distributed generation is one example. This has been a very controversial cost recovery issue, and there have been proposals for straight/fixed variable rates or demand charges for residential distributed generation customers. And those proposals might fix this issue, assuming that you agree that there is an issue. I personally would suggest that this is one area where we may want to consider a new rate class, because I don't think the general residential class would be in favor of those kinds of rate designs, and so it shouldn't be imposed broadly on all residential customers, but may be needed for distributed generation customers. It's a minority of consumers, a very small minority, who are affected. And, if you adopted an opt-in rate, for example, there's no incentive for those customers to opt into that rate, because they're better off without it. So that's one case where there may be a need for rate class distinctions.

Another example would be electric vehicle rates, and the possibility of creating time of use rates to serve those customers. This is another case of changed usage, but I think, in this case, you could create a general tariff, a time of use tariff, for an opt-in kind of approach, and electric vehicle owners would have an incentive to use that without creating a new class. So I don't think that that may be an area where a class creation would be necessitated.

I've tried to provide some food for thought for this discussion, but I think it's important to not be overly confident, and proceed with some caution in this area. Thanks.

Speaker 3.

Good morning, everybody. My colleagues have done the thankless job of laying down theory and providing generalities, which gives me the opportunity to tell stories. And so I thought, well, we may as well have a sexy title: "Vanilla Class, Tutti Frutti Customers." And, of course, that's meant to highlight the fact that we traditionally think of rate classes as a glob of amorphous customers. But, in the back of our minds, we common recognize, of course, that there's diversity in there. And the question is, well, how much diversity is there? Is diversity increasing? And to what extent do we have to rearrange our lives, if we're utility people? What do we have to do with rates? Do we have to do anything with the underlying costs that show up on that boring old cost of service study? How do we handle this?

And so what I'm going to do is use some cases, or anecdotes, from consulting events that we've gone through in our firm over the past ten years or so, and then draw inferences from those examples. Whenever we've met with an assignment where the issue of rate class determination has come up, we tended to have three obvious questions come up. First, what observable information do you have about the customers within this class? And, of course, the typical things are billing information, things like that. Laterally, we get other information that's available, things like location. Location matters for several reasons, including the pattern and level of marginal costs, and perhaps the pattern of weather. One example, of course, is California, because the California utilities have worked weather conditions, and therefore differences in cost to serve, into their rate designs. And there are certain other rate designs out there in the world where weather comes into effect. I'm choosing an extreme example here, the rate designed called fixed billing. Fixed billing is a contract between a utility and a customer, and it says, "I'm going to give you a customer-specific customer charge and no energy charge for the coming year. And I'm going to base that customer-specific charge on your past usage, and then I'm going to normalize for weather." So you get a one-year contract, and it's all-you-can-eat electricity, essentially. So, essentially, what I'm trying to do is think of how data might be used in the future. And this is kind of an extreme example. So that's one question. What information is available?

A second question is, does the current rate make use of that information, capture the information, so that the rate itself will provide the diversity that you need, such that diversity and the cost to serve can be reflected in customer bills?

An offshoot of that question is, well, if that rate can't do that, how about making your portfolio more diverse? Do I actually have to go to the work of setting of setting up a separate rate class? Or can I get by with adding a rate, or two rates, to encompass the diversity of my customer class?

One of the examples, of course, at the small customer level, that's on everybody's mind these days is what to do about distributed energy resources, specifically for customers in the residential class. As you all probably know, one of the assumptions we make about residential customers is that they all have relatively similar load factors. We also assume that customers with equal total consumption have equal cost to serve. And that means we can devise a two-part rate, with a customer charge and an energy charge, and we think that that will do a fair job of evaluating the cost to serve of these various customers, and we'll charge them properly. You can already see that I'm on the road to being a stick in the mud compared with Speaker 1, because Speaker 1 said, the sky's the limit. We have new information. A customer can be their own rate class. And I'm taking the part of perhaps the poor utility person who has got to devise rates for customers who might have a perception that fairness is important to them. That's not necessarily what I think. But I think there are some institutional topics that Speaker 2 referred to that drag us back in the direction of rate uniformity.

So, do we need to bust the rate class? That's the question. Here's a picture of what a typical residential rate class looks like. On the horizontal axis, you have average usage, represented in terms of kilowatt hours per hour, and on the vertical axis is maximum usage, again, expressed in kilowatt hours per hour. And, as you might expect, if you take a sample of residential customers, they will show up in a kind of a clump, and you can do a regression analysis and get that positive relationship. Essentially, as kilowatt hours go up, peak demand goes up. You look at those customers, and you say, "Well, there are relatively few outliers. I can call them one class. Let's have one rate, a two-part rate. We'll be fine. Because I don't need that extra information of peak demand to do the job." Now, of course, when you introduce the DER customers, you have some people who bust that blob up. It's potentially the case that they could have zero or near zero consumption over the course of the billing period or the year, and they're decidedly far apart from the rest of the blob of customers who constitute the class.

The question is, do I need to develop a new rate class? Right now, as you probably know, what happens with distributed energy resources customers is that almost all of them (I think the current estimate is somewhere around 95% of them) are covered under what are called net metering rates. You're probably familiar with these, but the basic idea is that the customer is billed under the standard residential tariff, and their kWh measure is their net consumption over the billing period. There are complications that can be introduced, but that's the simple story. And, of course, if you think in terms of that graph that we just looked at, that means customers with net zero consumption are paying only a customer charge. And if I revert from rates to costs for just a minute, we all know that a common feature of residential rates in America these days is that the customer charge covers some but not all of the fixed costs to serve those customers, and a number of the fixed costs then get dumped into the energy charge. So, if you have fixed costs being recovered in a volumetric charge, so goes the argument, then you will under-recover from distributed energy resources customers.

Well, what to do? Do you create a separate rate class? The two prominent alternatives, residential demand charges and buy-all/sell-all, both require changes in metering. Essentially, they say, net metering provides insufficient information. No matter how you massage net kWh, there's not enough information to get an idea of the nature of that customer and then say what it costs to serve that customer. How big is the pole? How big is the wire? What sort of transformer do I need for this customer? All of those things require more information. So, one of the things you can do is go to residential demand charges, give everybody a demand meter, rearrange the rates slightly so that the fixed costs are recovered through customer and demand charges, and then, of course, you presumptively have enough information so that the customer diversity that shows up when people start using distributed energy resources can be encompassed in your tariff. If you can do that, then you don't have to create a new rate class.

Another way that people do distributed resource rate design is, they move to the buy-all/sell-all method. And this is one that involves an accounting fiction. You assume that that customer at the end of the line is in fact two entities. One is the customer, who buys all their needs from the utility, or the energy service provider, and the other is a generator of electricity, that sells everything back to the grid. And so the customer, who's doing all the buying, looks like a standard residential customer. They revert to that first graph and move back close to that line that represents the average of energy and demand usage, so that customer can be billed as a standard customer, and then a wholly separate contract feeds the generator. Of course, the big debate is, what price do you charge? What's the avoided cost that represents the value of that customer's load?

We don't have to dwell on this right now. Suffice it to say that for our purposes here, there are some ways to preserve the rate class, if you desire. If you don't desire, well, you can go and create a separate rate class. But if you like the administrative simplicity and the appearance of fairness and uniform treatment that a single rate design provide (certainly, regulators like that, and utilities have a preference that way, I think), then it's possible to use rate design, along with augmented information, to serve what looks, outwardly, to be a separate rate class. At any rate, the general objective of attempting to do rate design in this way is to use better information, and what tools you already have in terms of rate design in a traditional, vertically-integrated utility, to better match the bill that the customer gets with the cost to serve.

Let's think about another story. This story has to do with serving residential customers in a competitive market. And here the emphasis isn't so much, necessarily, on keeping things simple, stupid. The emphasis is on gaining market share, and it's like that old story of why General Motors succeeded relative to Ford. Ford would provide you one car in one color, black. And General Motors said, well, I can do better than that, I can give you a Chevy, Pontiac, Buick, Oldsmobile or a Cadillac in multiple colors, and that diversity will appeal to the real or imagined diversity in the customer class. But all those cars might come from the same chassis.

So here's Direct Energy in Houston. They're one of the energy service providers in Texas. When I last checked their website, which is about ten days ago, they had eight rate plans for residential customers. Now, the chassis that underpins that is really just one chassis. It's very simple--a customer charge and a flat, non-time varying energy charge. And, of course, I spent my life in the retail energy business thinking about time variation and matching your costs to your customers. And these guys come out and say, "I don't need to listen to that guy. I'm going to have a nice, simple platform. But I am going to diversify."

And the way they diversify is, first of all, through duration of contract. You can go month to month. You can have an annual or a two-year or a three-year contract with Direct Energy. They have a fixed bill product. Remember, that's the all-you-can-eat electricity. In this case, the all-you-can-eat electricity is up to 2,000 kilowatt hours. If you do that, they'll give you one bill. It's not customer-specific, but they'll charge you 160 bucks a month for electricity. There's also varied renewable energy content with each of these rates. And there's one rate, of course, that's the green energy rate, and you pay a premium for that. But then they also have this. Free electricity. It's called, formally, "Free Power Weekends 12." That doesn't sound like Chevy Corvette, but it's the same idea. Here's something sexy. Electricity is free between 6:00 p.m. on Friday and midnight between Sunday and Monday. And other than that, you have an energy price locked in at a premium relative to the charge in their other rates, the most recent number was 11.8 cents a kilowatt hour. They also have a 24-month offering.

The basic idea for them is, I'm not worried about multiple rate classes, but I am getting to know my customers with other data. Maybe I've got demographic data or preference data or something that allows me internally to break up my rate class, but, essentially, it's all one rate class. If you are a residential customer, you can have any one of these eight rates. So, competition creates product diversity, but it doesn't necessarily create the need to pull apart a rate class.

I'm going to spend a couple of minutes on large customers. I don't know where the large customer/small customer boundary is, but I think, intuitively, we can all understand that there are mass market customers out there, and bigger customers at whatever that boundary is. The hallmark for me, in this case of large customers, is that many of them have the opportunity to turn to their utility and say, "I have a competitive alternative to the service you're providing me." And it might be that I have multiple plants in multiple states. Who knows what the source of competition is? But that gives me leverage. I'm not willing to pay your embedded cost. The utility response, of course, is to diversify the portfolio and also engage in some form of discounting.

You're probably familiar with these utility responses, for the most part. Utilities have used interruptible, curtailable rates for discounting purposes, the implicit contract being that I won't interrupt you too much. They also use economic development rates and load retention rates. Those tend to be cumbersome, because they come with the burden of documentation as to why you are special and you're in need. We're seeing more frequently now the use of special contracts. That tends to be for the largest customers in utility service territories, of course, because there are person-hours that go into that negotiation, and the regulators have to approve that special contract.

The special contracts I see tend to be confidential, as well. One other thing that we sometimes see is an attempt to mimic the competitive market in an available tariff, like a two-part RTP (real-time price) that says, "We'll charge you on the basis of day-ahead or hour-ahead pricing. That price will be very close to the wholesale price that I see in the market. But then, I'm going to charge you an access charge or a customer-specific lump sum that recovers what I think I can get from you, or maybe an amount determined by the regulators, as a contribution to fixed costs."

So, there are ways that utilities can compete, but the basic outcome here is kind of similar to what we saw with the Direct Energy case for smaller customers. Competitive threat breeds diversification in the rates, but it doesn't necessarily mean that it breeds diversification in the underlying rate classes. One exception to my declaratory thought there is that sometimes you see special contracts pulled out into a separate bin in the cost of service study. But I guess the general thing that I am offering you is kind of a stick-in-the-mud perspective that says that increasing customer diversity, and the creation of competitiveness, and the rise of competitiveness and opportunities doesn't necessarily lead you to rate proliferation.

I have one more story to tell you, and it has to do with a client that approached me about four years ago, and they said, "I have a customer with multiple sites, and they're all very high load factor. They want a special deal." And so I said, "Well, tell me more." And they said, "Well, here's what they are. Here's their load profile. They probably are relatively lower-cost to serve." So, of course, the utility's issues are, is it just these guys? Or do I have to allow other people into the rate class? I can't fence them off entirely in my separate high-load factor rate class. What are the cost differences, really, between them and other customers? And then, does the current rate reflect that cost difference?

So, one of the first things we did was, we said, "Well, what are the load factors of all the customers in this rate class?" It was called "large power." There were about 150 of them, and there was a continuum of load factors, from near zero up to 80%. And, of course, the obvious inference was, I couldn't go and get the seven or eight customer sites, who were up near the top, but they weren't isolated on their own, and say, "Yes, you get a separate rate class," because, if you're going to do a rate class, you have to find some way to distinguish them and then fence them off from others. And so there was an immediate problem.

The outcome of this consulting assignment was that having divided them, the rate class, in what I consider to be a semi-arbitrary way, it truly turned out to be the case that this group of customers, and the others who fit that high-load factor bill, had a lower cost to serve than the others. They were 18% less expensive than the average lower-load factor customer. No surprise. Also, it should be no surprise that, in a simple rate with a customer charge, an energy charge, and a demand charge, that rate took care of much of that cost difference, but not all of it, so there was still some justification for splitting the rate class. However, those forces that operate on regulated utilities acted immediately to pull back away from splitting the rate class.

You can imagine what those forces were. There's an administrative cost. What does the utility do in dealing with the perception of unfairness that arises? What happens when one customer's load factor drops for no particular reason, and next year they're now an ordinary, rather than a high load factor, customer? What happens when somebody's load factor gets bumped up? You have people who are transferring between rate classes, and all of a sudden, their bills are bouncing up and down by, say, 10 or 12%. That's going to create a problem. In a competitive world, of course, that happens. Tough luck. But then, of course, the other backstop was, there was general regulatory resistance. I think we'll still find that that in most jurisdictions you'll find regulatory resistance to class splitting, based in part on that fairness effect.

So, at the end of the analysis, we didn't get to go forward with this. I wasn't particularly enthused about it. I was pretty neutral about it. It was one of those cases where the question was, to what extent should the utility be going to the trouble of diversifying its pricing and diversifying the underlying costing? Did we really need to create a separate rate class? This was a close call. If there had, in fact, been competitive pressure, it might have happened. But the key then was the competitive pressure and not the cost differences.

Just to sum up, then, as a stick-in-the-mud, I don't believe that the way things stand right now, despite the fact that there is apparently increasing customer diversity, drives you, necessarily, as a vertically-integrated utility, in the direction of increasing the number of rate classes. We saw, at the small customer level, something that really looked to be increasing customer diversity. The distributed resources problem was probably primarily a rate problem and a data problem. If you go to the trouble of getting better data and providing more rate diversity, either through a three-part rate (customer, demand, and energy charge) or a rate that is buy-all/sell-all, you can take care of that problem without having to go to the trouble of a cost of service study or breaking up a rate class.

It's a different story, though, when you get to competition. At that point, customization may cause you to segment your rate class in a formal way, to actually break classes into smaller pieces. But this is something that you can do on a case-by-case basis. It's not necessarily the case that a principle will come to the fore and say, "Here is what you must do."

So I guess that's the moral of my story. It's a flexible thing. But the diversity of customers has always been there. Maybe it's increasing. It's the competitive pressure, I think, that is the thing that causes a utility to go to work and go and get better data, and better match customer rates to cost, and that's something that can be done now that we have better data, but isn't necessarily absolutely done.

Speaker 4.
Thank you for inviting me, and I'm glad to be here today. So let's see how this goes. First of all, I have three daughters. They're teenagers. And they have all the teenage sort of attitude. And so I've come to realize that the old joke about how there are three ways to get something done right is true. You can do it yourself, pay someone else to do it, or prohibit a teenager from doing it. So, when someone says, this analysis of customers at an individual level can't be done, or if it can be done, it can't be done cost effectively, my first reaction is, "Watch me." Sort of the same teenage reaction. [LAUGHTER]

Over the years, we've learned quite a bit about customers and what customers actually look like. My company does smart meter data analytics. We run a lot of meter data through our system. Our customers range from utilities with 10,000 customers to four million meters. So, if a 10,000-customer utility can afford these analytic systems, obviously these are accessible to everybody in the industry.

I wanted to make sort of a nod to the public power utilities. APPA was kind enough to give one of our clients the energy innovator award of the year this year for some of the things that we were doing with smart meter data. We have a program called "Bring your own charger," where we basically used AMI meter data to validate that people are charging at night time. They get an incentive to do that. We were one of the first companies to run smart charger programs with EVs a couple of years ago. We've now stopped using smart chargers, because they were way too expensive, compared to just running these programs using the AMI meter data. So AMI meter data is actually starting to percolate and show up in different places in different ways, and it's kind of interesting to see all the different applications and innovations that are taking place in the industry.

So, what you'll hear me describe is looking at the utilities as a business, and the economics of serving these customers from a margin perspective. I'm not focused on cost at all. So I'm not looking at a cost allocation approach, but I'm coming from a perspective of, let's look at how much margin do these customers contribute towards fixed costs? And we're only looking at it initially from their point of view. What are the real economics? Not the regulated economics that are in rate cases--we're interested in what the actual economics are doing, and in the market prices for capacity and the market prices for energy. So, a very sort of market-driven analysis, rather than a regulatory analysis. You can then overlay the regulatory framework and the distortions that come with it. But, at the end of the day, the real margins are what actually pay for the cost of running the utility. So the first principle is, first figure out what the real business is like, and then let's take a look at what happens with the regulated frameworks on top of it.

This is the punchline, but I'll move it up front. What we are seeing right now in electrification is a truly extraordinary alignment of interests among parties that used to not be together. We have environmental interests really seeing the carbon reduction with electrification to be far greater than any energy efficiency programs. One of the casualties of actually analyzing AMI meter data is the realization that the energy efficiency programs do not work as well as estimates suggest. So that really lends itself to sort of the transition towards electrification programs. There are really significant utility shareholder economic impacts, and I'll talk about those. The numbers are really large. And also there are customer impacts, in terms of lower rates.

So it's a really sort of a rare trifecta. You can have all these three with electrification. So, what are the implications of that? Utility programs will be changing. You have regulations and regulatory strategies that will define how all those earnings and extra revenue and margins that are going to come from this business are going to be allocated. So there are really significant implications in terms of who gets some of the money that I'll talk about in a minute. And there are going to be some mergers and acquisitions, and the ownership of some of the utilities in the business will change, based on some of the things that are taking place in the business right now. AMI data is kind of the common theme across all these, and that's what brings them all together.

Most of the comments that I make today are with regard to residential customers, because that's where we see the most. Commercial industrial customers, you can afford to analyze them and have manpower looking at them and working with them. The residential customer group is its own animal. You can look at sort of hundreds of load shapes for residential customers. But we're already sort of past that. We're now looking at the individual customer level.

Residential customers look very different than what a lot of the rate cases assume. And every utility has its own different curve, and some of them dip deeper during the daytime, and so forth. I'm using a Massachusetts example. What happens when the peak load shifts a couple of hours in the day? It doesn't seem like it has much of an impact. However, when you combine it with a capacity cost that went up by a factor of three in two years, basically, you end up with really different allocations of profitability and margin. So, in just two years, there was a $500 million shift, just in the Greater Boston area, to those who had capacity assets. Now, a lot of the utilities in the area have hedged their energy costs, but they did not hedge their capacity costs. So that $500 million actually showed up as an increase in their costs, realizing amazing impacts on their economics. At the same time, energy costs are now…I mean, I don't want to call them free, but when you're at 3 ½ cents, and you sell kilowatt hours at 20 cents or 22 cents or 18 cents, that's a really high margin business. And we have the other thing, which that one summer hour now costs more than the rest of the year's electricity sold to those customers, when your load factor is below 50%. So the punchline in all that is that the customers that you had three years ago that made you money no longer make you money. All this has completely upended the economics of the business. None of the rates in the area have changed, so it's interesting sort of the things that are taking place financially within the utilities right now.

Just to give you a sense of the scale of what's being required right now, if you have a three million customer utility, they can easily collect a trillion data points a year. Now, analyzing that volume of data becomes an interesting thing.

I also want to highlight the fact that we have a very US-centric view of this conversation today. We have a representative for Italy. They alone have over 30 million meters. That's half of the entire US AMI meters. That's one company, and they have to give access to all the metered data to all the competitors in the marketplace. So they're already years ahead in terms of the market having to be competitive. The data has to be accessible. And it's a very different running the business, as a result.

So, if you classify customers based on sort of subcategories of residential classes, here's a typical residential load. There's nothing unusual about that. One single family is compared to the average. Then you look at more families. There's a customer with solar. Another has EV with solar. Then you have EV, and they are participating in some offbeat program that's reducing their peak a little bit. Then you have the solar customers. Then you have winter customers, winter single family customers, which is very different from the summer. Then you have differences depending on whether they have a single head heat pump or if they have a central ducted system. So, very quickly, you end up with hundreds of these load shapes that look very, very different. Just at this level, it's really easy to classify customers into a couple of hundred categories.

So, does the residential class even exist? We don't think so. We look at about 200 subclasses. If we categorize them, it's very easy for us to find a couple of hundred distinct load shapes. But they are extremely variable from utility to utility, depending on the customer makeup.

There are some big implications from all this. But I'm going to take a really narrow example. Let's look at heat pump customers. Some of the more interesting things are right now happening in the cold climate states, because you have electrification of home heating, which is a really significant part of the business. Electric vehicles are similar. I could run another presentation on electric vehicles, but let's sort of assume that everything that we're talking about here also applies to electric vehicles. But that's across the country.

That is a single-family load shape during the winter. That's from one of our actual customers, an average of five months. If you look at the houses that have a single head heat pump, it turns out that the single head heat pumps aren't being used for heating in these cold months. All the investment in them assumes that they were being used for heating, but they're not. There's a multihead heat pump, if you're familiar with that technology. By the way, how many here have a heat pump? A few people. And how many people here have an electric vehicle? OK, more electric vehicles that heat pumps. I have both. But if you look at usage, that's not a huge difference. That didn't really impact the business. If you had a single head and a multiheaded heat pump, you didn't really generate a lot of sales with that, or environmental impacts, because these heat pumps reduce carbon by 30-50% compared to oil or gas. Now, if you put a central ducted heat pump in there, which will replace a furnace, you get about 4,000 kilowatt hours extra use. So, for an average house, this represents about a 50% increase in kilowatt hour sales in that area. The point is that not all heat pumps operate the same.

This chart shows all the electric vehicles. Battery electric vehicles, along with long range vehicles, are worth more than say ten-mile range plugin hybrids.

A couple of technical points, because I always get the question, do heat pumps even work in a cold climate? I've been running it in my house for the last five years, in Boston, no problem. They run down to minus 17 degrees right now. And here's the key part. They're already less expensive to operate in large parts of the country, including the Northeast, including Massachusetts, and in a lot of Midwest states, depending on the rate design.

You'll find that the market's going to be shifting. But here's the interesting thing. Here's an individual customer. And all customers basically look like this. This is one customer, and each line here represents a weekday, 24 hours, so this is what an individual customer looks like on any given weekday. It's incredibly variable. The notion that there's a "residential customer…" to me, it doesn't exist at all. The volatility of customer energy use is actually very different than what we have traditionally assumed. To give you a sense of it, we have residential customers in the meter data set that range in their coincident peak from .1 KW to 40 KW. There are homes that have bigger coincident peaks than commercial does. So, again, put that in the context of that capacity cost change. As the renewables have come to the Northeast, we've had a shift from energy cost to capacity cost. This will completely change your economics when you have more renewables coming in the business.

So here I have a video. Here's a residential peak day. I'll just highlight a few things. That's a peak day from one of the utilities that we work with. If you're trying to run peak load reduction programs in the residential market, it's like playing a game of whack-a-mole. It's everywhere in there. You can't possibly hit it all. If you are wondering why your peak load reduction programs aren't working, that's part of it. They reinvest a lot of money into peak load reduction programs that are having real difficulty whacking the mole. If you compare that peak day to a fall Saturday, the video on the right, you end up with a very different looking picture. Customer use is extremely volatile. But we assume that they're homogeneous. They're not.

So what does that mean? The top down approach of cost allocation doesn't make a lot of sense to us anymore. You don't even have to do it anymore. You can actually stop it, if you wanted to.

What we're suggesting as an alternative way to analyze customers is to basically look at the contribution margin of every single customer by the hour and calculate their profitability. Every business basically does it, except the utility business. You take the revenue for the customer by the hour, then you say, how much does it cost to deliver the energy to that house? What is the capacity cost? And, by the way, this question is important in a market where at one point it was costing almost $200 a KW, and you had a house that had a 15 KW or 40 KW coincident peak, so that was $2,000-8,000 for that one hour, just to serve that customer. That sort of profitability analysis really changes the equation a lot. At the end of the day, once you take out the revenue for the hour, and the cost by the hour, you have the contribution margin, and then you sum it up for the whole year. So, essentially, what this does is it calculates the profitability for every single customer. I won't go through the math here, but I just wanted to include it in there.

The punchline from the heat pump analysis is that about a 4,000-kilowatt hour sale in heat pumps generates about $390 of margin for this particular utility, in this case we're doing. Even though it's only increased the sales by about 50%, it doubled the profitability of that house. The house had about $450 of contribution margin to begin with, and now it added in another $390. That contribution lowers rates for everyone. (That one happens to be a not-for-profit public power utility, so very extra margin goes to lower rates in that community).

If you're doing target marketing for customers, it really matters who you go after first. So, heat pump margins, 350 bucks. This is now a bigger utility. They have 1.3 million targets in their territory. That's $455 million a year in margin. Not revenue, margin. They have electric vehicles to add another 450 million of potential margin--again, not revenue, margin. So, together, you're looking at a billion dollars of potential extra margin coming your way in upcoming years. And if there were no regulatory constraints, all this would go to net income, so that would be basically pure profit, because you have very little incremental infrastructure costs serving these customers. From a business point of view, the utilities have now a lot of money that they can actually spend to acquire customers, depending on how they're regulated. But the money is there. It's just who gets to keep the money, and how it gets divided between the parties in the discussion.

Here's another illustration, if I can have that video. This is Massachusetts heat pump sales for the last three years. And you can see how it's growing, just peppering everywhere. It pretty well covers the whole state. Actually, the holes in the middle of the state, those are municipal utilities where we don't have a lot of good data. And then Western Mass doesn't have a lot of population. But it looks like everyone's buying them, and it's been growing about 40% a year. There's still very small market share, well below 10% of the total sales in the market. But when you look at it from the point of view of where is the per household share of the heat pumps going right now, you'll find some concentration. And there are a couple of explanations for it. Here, there's a gas pipeline moratorium. So, no new gas connections. So people are putting heat pumps in.

Once the contractors are trained to sell it, guess what, they'll sell it to everyone else. They have good experiences. Same thing up here on the Cape, as well. But the pipeline moratorium is actually not that entire area, also. So, you will see that the sales start to increase as people get more experience with it. And, again, heat pumps are cost competitive against natural gas. So market share change is going to be interesting to watch.

We have all kinds of things that are not currently keeping up with the changes that are coming out. There are pricing strategies that can be implemented to accelerate or decelerate the adoption of these technologies. There are a lot of environmental interests that are really driving this, and they're potentially going to be driving utilities to be more aggressive in pursuing these strategies.

So what does it mean for utility customers, in terms of lower rates? Who's going to be capturing the value? Maybe it's the leveraged buyout firms that are going to be buying a bunch of utilities that are going to be beneficiaries here. We're going to be seeing a lot of changes coming our way. We will see different regulatory strategies that need to be deployed. Regulators will be deploying strategies in order to influence the outcomes to accelerate certain things. So, it will be very interesting to watch what happens.

My final thoughts. Every utility is going to be unique. So I can't take the lessons from one utility and apply it to every utility the same way. The benefits for the programs are best captured by those who analyze the meter data. The value's there, but when we talk to the utilities, and when we work with them, most of the time what we find is that they haven't even pulled the meter data, ever. If they have the meter data, they can't find the IT person who knows how to download it. It tells us that people aren't looking at their own data. I was actually joking earlier that this slide deck should be just summarized in one slide, one sentence that says, "Look at your darned data." We really just encourage everyone to start looking at the data, because it's really insightful, once you actually start looking at it. So, the last line here, we're seeing really extraordinary alignment of interests that are going to be driving these changes. Environmental interests, utility shareholder interests, and the customer economics are going to be driving this at a really accelerated pace, and, like I said, that will imply a bunch of stuff for the utilities that are running the businesses today. That's all I have.

Clarifying Questions.

Clarifying Question 1: Speaker 4, I think I am confused about the Massachusetts example as it would affect the utility bottom line. I'm coming from a mostly PJM perspective, where the load serving entities are largely in the restructured states, but they're passing through, dollar for dollar, their energy and their capacity costs to the customer. So the profitability on the utility side is not affected by changes in energy and capacity prices. So I must be missing something in what you're talking about in Massachusetts.

Respondent 1: Very good question. There are actually two things. There are 40 municipal utilities in Massachusetts that do get to keep all those margins. But also the distribution utilities, not all of them are earning their full allowed return on equity, and all the extra volume on the distribution side will allow them to earn higher shareholder returns, as well. But the major point is that, for a lot of the utilities that are decoupled, the shareholders don't get to keep the value. The value either goes to the energy seller or the customers, depending on how the regulation is affected. So my point simple was that the money is there. How it gets divided to different parties varies.

Respondent 2: I think the issue is that if you collect your revenues, even as a distribution utility, though a kilowatt hour charge, to the extent to which your kilowatt hour charges diverge from what's going on in the market and what your fixed costs are, you get, in essence, a margin created. So, if you were collecting all of your monies through an access charge, that wouldn't exist. But, because of the divergence between marginal and average cost, and energy charges that are basically set to collect all of your fixed costs in addition to whatever the charges are for providing the service, you end up with this difference in margins. And it's really a function of the difference between what's causing your costs and the mechanism by which your costs are collected.

In a way, this reminds me of a discussion that dates back to a 1933 article by Harold Hotelling, in which he discussed the problem about declining average cost industries. And he raised the issue that in a declining average cost industry, (and the distribution system is like that, and arguably, in some sense, the transmission system), you run into the problem that you have a marginal cost, and charging at marginal cost doesn't collect the full cost of the system, and the question becomes, how do you collect the rest of the monies? And Hotelling made the proposal, and Vickrey in '48 made the suggestion that you put a tax on everybody. Coase came back and said, "Oh, no, no, no. The cost of carriage is part of the bill. It should be included in the calculation." And then, basically, Bonbright encoded that argument in his *Principles of Rate Design*. In essence, the argument for cost causation and all the things that we do, is basically in some sense traced back to the fact that we have average cost pricing, and the only mechanism by which we can think of fairly apportioning those costs is to go back to cost causation, as opposed to, in a competitive market, the price itself becomes the mechanism for allocation and for providing "fairness." Whatever the market bears. So I think that's at heart one of the issues that we're dealing with here.

Clarifying Question 2: I don't understand the graphic about heat pumps when you take your furnace out and use the heat pump instead of the furnace. What are "heat pumps that you don't use for heat pumps?" What does that mean?

Respondent 1: It simply means that most of the other heat pumps, they use them for air conditioning, because it provides heating and air conditioning, both.

Clarifying Question 3: At the very beginning of your presentation, you talked about smart charging and then you talked about AMI. And then you said you abandoned, or the entity abandoned, smart charging. And I didn't understand the discussion or why they abandoned smart charging. If you could describe that a bit, it would be helpful.

Respondent 1: Over two years ago, we started some of the first smart charging programs in the US, using smart chargers and using commercially available tools. (There have been other products that have been offered long before us getting involved in it.) And, basically, one of the things that we discovered is that 20% of the chargers were offline at any moment in time, 10-20%, and we found them to be costing more than the cost of capacity to actually operate. So we were looking for alternatives. And the alternatives actually came from solving a Tesla problem. Tesla owners would not put smart chargers in. They used the Tesla-branded chargers, and they're not smart. They're dumb chargers, basically. All the controls are in the car. And what we ended up doing was, instead of trying to do load control on those customers, we created a program where we paid those customers $8 a month, as long as they charged in the off-peak hours. And we used the AMI meter data to verity that they were actually doing it. They lose their incentive if they charge during the day. So, no hardware involved. And then we can address 100% of the market, instead of smart chargers, that were only about 20% of the market. So that was the reference to AMI.

There are lots of other examples that are going to be coming out where people are using the AMI meter data in clever ways, and you actually get better results than hardware programs. When we look at the hardware load control programs, most of them don't work as well as they are advertised. That includes everything from thermostat programs, to water heater load control programs, to A/C load control programs. The AMI meter data is kind of brutal. It actually shows you what the real savings are, rather than what you assume the savings to be. Hopefully that answers the question.

Clarifying Question 4: When you talked about Con Ed, you talked about zero marginal cost for serving portions of the Con Ed service territory. I feel like I must have missed something. What do you mean by that?

Respondent 1: What I mean there is that there's no need, at least within the planning horizon of Con Ed's distribution system, for them to make basically a dollar of investment in order to meet increased load. What we're looking at is entirely the question about what the incremental investment is that would be required to serve additional load in those areas. And because in those areas they are predicted to have minimal load growth, and they have more than adequate capacity for that, the marginal cost of meeting that additional load is essentially zero. Now, I'm not saying they have free electricity. That's a different question. You have to remember, Con Ed is part of New York ISO, and essentially it just passes through the cost of whatever the market is. But, relative to the distribution subsystem itself, there is more than adequate capacity.

You know, somebody raised the question about the relationship between telecom and the distribution system. Both of them are characterized essentially by minimal marginal costs. Right? So as a telecom, my only concern is, at what threshold would I add customers and the services that are required sufficient to cause me to have an increase in capacity? Right? That means, then, from their standpoint, they can afford to give a flat rate forever. Right? Up to the point where the incremental flow on their wires is sufficient to cause them to have a capacity issue. This is exactly the same problem on the distribution system. The parallels are kind of amazing. But the difference is, telecom operates in a relatively unregulated environment. The distribution system is clearly regulated.

Clarifying Question 5: I had to check my iPhone to make sure that the year is still 2018, because what I've heard from this panel was a lot of mid-20th century thinking. Given the diversity that we see in the load shapes today within the residential rate class, and given the fact that it's going to get worse and worse as the penetration of distributed energy resources increases, how can we justify using static customer classes and coming up with an allocated cost tariff in each rate class? It seems to me that the only thing that makes sense in this environment is to have a cost-reflective pricing scheme that you apply to every customer, regardless of what voltage level, regardless of how large they are, and to recover the cost of the system that way. Can we get some responses to that?

Moderator: That might be responses from four people. So do you want to save this answer until after the break, maybe?

General discussion.

Question 1: I just am maybe confused a little bit, Speaker 4, about the Massachusetts regulatory model that allows this margin opportunity. I guess my question would be, if you had more of, say, a straight/fixed variable rate design, where the fixed costs are covered by a fixed charge, would these opportunities for additional margin be less? Because I see, in a way, that what you're pitching is almost like the utility-side Jujitsu of the regulatory arbitrage you see on the customer side from things like full retail rate net metering. You're just having the utility be the intermediator, in order to capture those margins.

And then the broader question is, assume you're in some regulated environment, where you have these constant requests for additional customer classes or special arrangements with big loads being made to you. Appealing to the telecom example, what role is there for a price cap form of regulation that calls out caps, calls out a minimum service quality standard to make sure they're not cutting to the bone, and then allows experimentation within that, in recognition of the fact that you have greater product diversity, and greater load diversity? Similar to what you have in telecom regulation.

Respondent 1: In terms of the margins, the point was that there's a margin between the retail rate and the cost of service, from a commodity point of view. That margin is collected from the customer. The question is, how does that get split up among the parties? In the municipal utility space, for example, the utility gets to keep all of that margin. They keep that in house. In the decoupled utility cases, part of that margin goes to the energy seller. The other part goes to the distribution company. The distribution company still gets more money. The Massachusetts example is that 20 cent electric rate. Of that, 10 cents goes to the distribution company, 10 cents goes to the electricity provider. You'll end up with the distribution company still collecting 10 cents on that. That is actually 10 cents of margin to them, largely. So that still increases the earnings potential to that utility, even if they're decoupled, up to their allowed maximum rate of return on that. Did that answer your question?

Questioner: I think so. So, the 10 cents is just meant to reflect a purely sort of volumetric portion, reflecting the cost of energy and capacity supply?

Respondent 1: Yes.

Questioner: Big thinking around price caps, anyone?

Respondent 2: It's an interesting concept, and I think it's worthwhile having a discussion about how to address potential customer choices. At the same time, I would be kind of concerned about it, and a little reluctant. We're dealing with a monopolistic provision of services here. I was thinking that there was an analogy, actually, in Montana with respect to price cap regulation when we were talking about granting that for the telecom markets. And, again, the concern there was the monopolistic nature of the markets, and our office took the position that we would agree to price cap regulation when market share fell below certain thresholds, and eventually it got to that threshold, and that's when there was de-tariffing and more flexibility for pricing.

Respondent 3: I like price caps. I think they are an interesting option. I think it's very tricky, though, for the LSEs in restructured markets, because essentially all you're dealing with is a capacity charge. And I don't know how much variability you can get in terms of charging for capacity. It made more sense when you were an integrated utility, and I think that's one distinction that has to be made clearly--whether we're talking about LSEs who are sitting there, who are just basically wire companies in a restructured market, versus whether we're talking about integrated utilities, who have distribution, generation, and transition, because the story about what's going on is very different. I don't know how many flavors of charging for capacity you can come up with as an LSE, but if somebody's got some great ideas, I'm open to them.

It's another story when we're talking about an integrated utility and price caps. You have to remember that even in England, where they have price caps, and they've had them for years, they've had to evolve price caps significantly over time. And partly in result, we're now in RIIO (Revenue=Incentives+Innovation+Ouputs), and now RIIO-2. So when you talk about price caps and how should they operate, one of the questions that comes to my mind immediately is, what flavor of price cap are you going to be talking about? Because it's very hard in a price cap world to incorporate all the different social and environmental and other kinds of goals, and that's really been the issue associated with RIIO and RIIO-2, kind of incorporating all those things into whatever is the price cap framework.

In theory, price caps are very interesting. It's the old question, how do you regulate a monopoly with unknown costs? And the price cap is one mechanism to do it. But I think it becomes tricky, particularly when you've only got capacity, in the case of the LSEs in a restructured market, or when you're trying to layer onto the price cap all these other kinds of social goals. And I think that's where the problem has been in England.

Respondent 4: To just add one line and play psychologist, let me answer a question with a question. And that is, what effect would a move to various forms of incentive regulation do to the question that we have, namely, how do you define rate classes, and to what extent should they be segmented or diversified? I'm not sure that they'd have that much of an effect. Theoretically, if you put in a regulatory form that transfers to the utility, vertically integrated or not, more discretion as to how it does its costing and pricing, you might find an acceleration of the breakdown of class. But I'm not sure that the incentive regulation experiments that we've seen in North America so far have produced that. Compare that with the impact of competition, and that's where I think you find more of the customization.

Question 2: On the panel, I think maybe with the exception of Speaker 2's presentation, we saw a lot of data and sort of theoretical thinking about either improving the precision of cost causation, or customer differentiation, kind of with the same thing in mind--maybe two sides of a coin, in reality. We deployed all these AMI meters, all this AMI, and we haven't seen a lot of the kind of development in rates, like residential demand charges, for example, that might more fully utilize the data streams that are coming out of these meters. What are the foreseeable steps toward using that data that you can imagine taking to start to move us down the track, practically speaking, if we should move down that track? (I think, Speaker 2, you made a compelling point that maybe we shouldn't.) What will help to more fully utilize those data steams to solve this problem better, particularly for NEM customers or EV customers? How do you see this actually moving the project forward?

Respondent 1: I'll give you sort of a pragmatic answer. As a software provider to these entities, we thought that we had all this brilliant analytical power and all this sort of cool stuff that we could do with the data and show all the insights to the customers. And the reality has been that the first and foremost thing we have been doing, and probably the single biggest value that we've offered to customers, is to basically give their data back to them in a way that they can actually analyze. And what I mean by that is that a lot of times the IT organization, they store the data in some server somewhere, and it has sometimes taken us weeks just to download the data from there. So, a super pragmatic sort of approach is to basically say, somebody has to provide the software tools for them to even have access to the data first. Right now, it sits on the server, and IT organizations often prohibit the business people in the utilities from actually having access to it. So, like I said, we thought we were being brilliant, and the single biggest value we've initially offered is to basically let those business people have access to the data. And then, on top of that, you can build all the other stuff. But first things first.

Respondent 2: It's a giant cultural shift. I worked at a utility a long time ago which was dominated by mainframes. And I brought in a couple of the first PCs, and I said, "You don't have to do everything on your mainframe. I can run this program and do all the calculations at my desk, without your having to go hand in cards or whatever programs to IT." I just think it's a question of culture and the underlying infrastructure. A late friend of mine once posed to me the question, what's more impressive? That somebody thought of the idea of FedEx delivering something in a day, or that they can actually accomplish it? Right? And I think we're in a position where you had the great idea, let's collect all this data, right? But it just hasn't been accomplished yet. They lack the infrastructure and, I think, the culture to think about looking at big data and thinking, what are the implications of the data? As an example, utilities didn't know what the delivered level of reliability was to their customers until AMI came in. Right? Yet you could never get a utility, before AMI, to admit that it didn't know what the level of reliability was for their system. That's a huge culture change, when you finally admit, "OK, we didn't know. Now we do, because of AMI." And they're making the argument for why they should have AMI. So, to me, it's like night and day. And I don't think that happens very quickly, particularly with utilities, which are known for glacial change.

Respondent 3: I've kind of cast myself as a Luddite, but I don't want to go totally in that direction. I do think that this is an area where we need to exercise some caution. I'm not totally convinced that there's been a case made for advanced metering in every service territory, although I think I read that over half of customers now have those meters.

So how can we use them? I would urge that, again, we go kind of slowly and adopt maybe pilot programs or opt-in programs, something that has optionality to it for customers, if you're really interested in providing consumer choices. I think that there are some consumers out there who will be interested in analyzing their data. It's not going to be a FedEx or something who has an energy manager digging into big data, but there are some people out there…And it may be worthwhile to try devising some things like time of use rates. I think that could be beneficial, and maybe, over time, there will be more acceptance gained there. But, again, I just urge that we go a little bit slowly there.

Respondent 1: One important point has to do with the marginal cost of getting to the analysis. If you don't have the infrastructure in place to do analysis of the meter data, the next project is really daunting. But once you have the infrastructure in place, the marginal cost of doing the next internal analysis is zero. And that's what we've basically seen at these organizations. For the first investment, whoever invests in it internally in the organization, they pay, obviously, a price for it, but then the rest of the organization kind of gets it for free. And that's where we basically have seen the analysis explode, and I think that's where you will see more use, going forward.

Respondent 2: One of the things that I always kind of wondered about was how, when AMI was being pushed out, it was often being pushed out in places where there is no attempt to convey to retail customers the circumstances in the wholesale market. The people the utilities had in mind for advanced metering, I think, were first of all a subset of people who were inveterate energy managers. They loved their data. They were going to do things, for the sake of conservation.

But when you think in terms of the pricing of the energy product itself, there is that after-the-fact wholesale price that the utility sees and that the customers almost never see. The classic case, of course, was California in 2001. So, theoretically, what you're doing as a utility is being a risk manager, absorbing the risk that's inherent from the wholesale price structure, and then you're passing on pablum to customers.

My question is, is that what customers want you to do? People in the competitive sphere have experimented with price diversity and experimented with product diversity. In the case of Direct Energy, they experimented with some TOU or some block tariffs, and now, for their residential customers, with just a flat all hours price. That price changes from year to year. If you go month to month, it changes month to month. So, July would be more expensive than March. But if you think in terms of what vertically-integrated utilities and other providers of energy service have done, the experiments in terms of what degree of price diversity is necessary in order to attract customers and give them the sort of service they want, that's somewhat of an unknown. Some utilities have engaged in that experiment. There's one that I can think of, Oklahoma Gas and Electric, which took all of its Obama money and sank it in AMI, and then said, "OK, here we go, TOU," and Brian Scott, their rate manager, said, "I don't just want TOU. I want TOU with critical peak pricing. I want something that tells customers when my critical shortages occur, *ex ante*, and I believe we should do that, because that's where a huge proportion of the value of time varying rates is, both from the point of view of non-participating customers who enjoy the fact that reserve margins have increased substantially in percentage terms, and who maybe get some benefits, maybe don't, from shifting their load. So there's an example where people experimented, absorbed a certain number of costs, got the government to essentially pay for the experiment, and then said, "Yeah, we like being where we are, where a good proportion of customers have a time-varying rate, and buy into a critical peak product, especially if I can automate, and then I just fire and forget." For the most part, if utilities haven't gone that route, if they haven't been enthusiasts about saying, "Give me data," or if they haven't felt the nudge from their customers or their regulators to explore time variation, then it's this vast unexplored country, where the benefits are as yet unforeseen and not well understood.

Respondent 3: One of the problems, I think, with AMI is the customer interface. If you want to get responses from the AMI, you have to have a reasonable customer interface. I participated in an experiment with my local utility in which the entire interface was a screen about half the size of my iPhone. Now, you know, if this is the mechanism by which I'm to be told about what the rates are that I'm going to incurring, and I can't even download this to an excel spreadsheet to sort of think about what it looks like, then it's a one-sided deal. The only value to the AMI is whatever is on the utility side. One of the great unexplored features of AMI has been, how do we make this a two-sided game?

The other issue is that in restructured markets, we don't have a mandate, except maybe in ERCOT, for providing to the wholesale suppliers all of the customer data that's being collected with AMI. So I think this whole question about AMI is kind of an incomplete picture in a lot of ways. This question of what do you want to do with AMI information is being modified or mitigated by what's going on in the market and the way the technology is being basically proliferated.

Question 3: I want to take us a little bit into the future and where this is going and ask some questions about some of the data and what some of you think about this. Picking up on the last comment, the interface with the customer and the extent of automation in that interface appears to be quite important, at least from the data that I've seen. What we've seen in a number of evaluations where you have either a fixed time of use price or a program that gives advance notice as to when there are going to be high price periods, combined with a smart thermostat that can automate the response, is that you get rather significant reductions in peak demand. I know from my own experiences, a regulator, where we had a utility that actually ran a modest pilot program, where we gave customers a thermostat with a simple slider where they could choose between more savings and more comfort, and we had those thermostats bid in to a real-time, 15 minute distribution-level market, we got savings, and we got the highest level of customer satisfaction of any rate program that was out there, because customers felt they had control and that they were getting some benefit. So this combination of rates and automation at the residential level would seem to be a combination that could provide real social value. I'm curious about what your experiences have been with that, and where that goes.

The other aspect of this has to do with customer variation. And my question there always comes down to, how do you begin to think about hedging in that world, where you want to have some financial hedge as well as a control option, given the fact that there is all this variation in how customers behave from day to day, let alone from customer to customer? Can you develop a standard set of hedges that are good enough that they will satisfy the risk tolerance of most customers, without necessarily having to customize something for every residential customer?

Respondent 1: I think the risk side is pretty straightforward. You either hedge Q or you hedge P. Right? And you have to decide which party absorbs the risk for which side. It sounds like in the ERCOT market, they're willing to basically hedge Q and then provide a fixed P. That's pretty straightforward. I always thought that when AMI came in, you'd see lots of service marketers come in and use the data for calculating an optimal set of hedges, depending on the product they were going to offer. If you think about it, if you had really a rich data set about what the variations were in the loads and everything across all these different kinds of customers, you could repackage it as, "OK, I'm going to give you a fixed Q and a variable P, or a fixed P and a variable Q. I can work all the packages out on the market, because I know what's being offered in the market, and I know what the price is, and I know what I can contract for." This is a standard supply problem. And when you're in an RTO, you're in an optimal situation for trying to think about how to do that repackaging, because everything is essentially a financial market.

So, to me, the issue is basically creating a situation where the marketers have the information, and simultaneously the technology exists for customers on the other side to sort of say, "OK, I'm going to take this, and I'm now going to run with this in terms of how I operate or how I change things." And you're right, technology trebles the impact of these price variations. If you don't have to think about it, you're in much better shape than if you have to do something about it. So I'm in complete agreement.

Respondent 2: To second what Respondent 1 is saying, I think the mathematical formulas for risk-based pricing have been out there in the market for 15 years or so, or they're set down in EPRI documents and things like that. You name the degree of price variation and price risk that the retail customer might take on. There's a formula that will determine what the markup is from the wholesale hour price. In principle, that's not a difficult thing to do. I think the evidence from many TOU and other experiments is that technology assistance boosts the price responsiveness of customers, as we all know. So any utility that wants to start from scratch today has a wealth of information to help them pick what they want to do, provided they can get some intuition by phoning up the utilities that have done the job. I'm not sure that that's entirely answering your question, but I think the notion of risk absorption is out there.

One other thing I guess I can add is that if you think of the way the competitive market works, big customers who want to buy power on the wholesale market can buy power at spot, or they can buy what's called the block and index that you're probably familiar with. Right? In the regulated world, block and index parallels exist. The best known one, I guess, is two-part real-time pricing, where you have a contract for differences available, if you want to buy more base load from the utility. And, of course, it's just a forecasted price, rather than a regulated price, that determines that contract for difference price.

Questioner: I suppose my question goes in part to, if you think about extending that block and index model, how complicated does it have to be? Because in, for example, the large industrial case, you typically have an individualized block set of purchases, and that may not be realistic, for example, in a residential setting. I'm wondering, is there some approximation that gives you a decent hedge and still allows you to have the index component for response?

Respondent 2: A residential rate ought to be doing that job. If you were to unbundle any residential rate today, then there would be distribution charges covering demand-caused and customer-caused charges. And then the energy end of things might come straight from the wholesale market, with the degree of risk absorption that customers require or request. If they're willing to pay a premium for a flat all-hours service that's non-seasonable, then, OK, what's that premium charge? Theoretically, they ought to be doing that.

Respondent 3: I'll add the hedging question first, and then go back to the hardware question, in terms of load management. There are actually multiple dimensions that we look at with this. We've already seen these distribution utilities that hedged energy prices but didn't hedge capacity cost. They got nailed, and badly. So, when you have variability in the market, you have to, at the very least, look at your tail risks and hedge those out. I had the fortunate experience of working for an energy trading firm for a few years, so I watched this, in terms of what's realistic and what's not realistic in terms of hedging. There are three elements. It's not just quantity and price that you can hedge. In the competitive markets, you can also select your customers, and, just as importantly, you can deselect your customers. You can fire your customers that are not attractive. In European markets, that's already happening. In some of the US markets, that's already happening. Where you have a lot of data, you can actually do that. You can then figure out which customers best fit these hedging profiles that are practical in a marketplace and eliminate some of the tail risks that happen like that.

In terms of aggregation, you're still going to be in the residential market. You're going to be looking at portfolios. Customers are incredibly volatile. Even if you aggregate them into one of the 200 buckets that we've just mentioned, they're still volatile in there. But you're going to be looking at it as portfolio risk, and, at the very least, hopefully hedging the tails out of it. From a trading point of view, it's fine to trade around it, especially if you get to select or deselect your customers. (By the way, all this is from a residential point of view, because we look at large portfolios, not necessarily the commercial/ industrial customers.) If we look at load control and a lot of the thermostat programs, the water heater load control programs, a lot of them provide some value. When we actually looked at the meter data, it wasn't as good as it was sold to the utilities as being, often. However, that wasn't the biggest problem with most of the programs. It was simply lack of penetration. It was really hard to get large penetrations with those technologies to households. You can't get the load control technology into 100% of the homes. It's only a small fraction. It often costs more to put the technology in there than what the value of the capacity reduction is. Massachusetts had a really famous example of that, with $5,000 per house spent to save $25 a year. In my example about the electric vehicle charging program, it wasn't that the electric vehicle smart chargers weren't able to reduce load, but it was that they only addressed 20% of the market. For the rest of the market, you couldn't get large enough penetration with it. And a lot of the devices were offline, and so forth. So practical realities get in the way, and they just cost more to run than the actual value of capacity.

Respondent 4: I just want to take one brief stab at this question of technology interface and the ability to control load. I would urge the ability to experiment with that with a small number of customers. I can't speak to your comment about customer satisfaction. I don't know what kind of survey that was, or whether these were self-selected customers, or what the circumstances were. But what does strike me is that, in the telecom example that we've been talking about, customers did have the ability to control their load. They knew what the time-of-day pricing was, and they knew when they were making calls. And they can do it. There's no doubt about that. People did that all the time. I remember, in my own family, you couldn't call until after 11:00 p.m. There was a lot of that. But still, people preferred the convenience of not having to do that, and when there was competition, that was the satisfaction survey that really strikes me as more compelling.

Question 4: I'm watching this stuff about New York City and Con Ed, and then I'm hearing about these sort of various load profiles that we have. And Con Ed, and really all of New York, has this really clever program. They call it various things—a distribution load relief program. It's basically a feed-in tariff for demand response, where they identify geographic areas where upgrades cost a ton of money. And they'll say, "Alright, in order to defer these expenses, we will pay you a stated rate," and you can actually go online, and you can actually pull up a map of various neighborhoods in Brooklyn and Queens and see what it is worth to you to put in some sort of distributed energy program. It's a transparent price signal. Certainly it makes it look really attractive when we go out and try to sell to customers. But I'm seeing a possibility of even more granular work. If you sort of think forward a couple of years, and you have a state regulator who wanted to put in a price signal to actually drive beneficial behavior at the distribution level, (maybe not for residential, because I still see some problems with that) with the ever, ever, ever smaller and smaller C&I customers…

Respondent 1: There are direct ways and indirect ways of addressing that at the utility. One indirect way we've seen is that we have a utility that has been growing a little bit, and they have extra margins now available, so they need to figure out how to get it back to their customers in the form of lower rates. Well, one of the suggestions is actually to create a time-of-use rate by basically creating the off-peak period discount, and sell it to the customers as, "We're reducing your rates, but we're leaving the peak period the same, and reducing the off-peak period." And over time, just gradually increase that differential so you start getting the behaviors. And the analogy that I used that is that when you fly on an airplane, and you see the tips at the end of the wings, I've been told by pilots (I haven't actually verified this) that the most efficient wing would be actually a full circle, but that's hard to put on an airplane. So the winglets actually get you most of the efficiency gain, if you do it. So the analogy is that if you create time of use rates, you may actually find that you get a lot of the benefits up front. I personally like market-based solutions.

One of the things that we haven't talked about today is, how do you get the price signal all the way to the customer in a way that is meaningful, without scaring the daylights out of them? We've seen the critical peak price really scare people initially. So, that's a long way of basically saying, yeah, you have to get the pricing signals out to the customers, otherwise all this wholesale stuff and analysis stuff is kind of meaningless. Otherwise we won't get the behaviors, because when it comes to the backdoor way of doing load control and devices and incentives, when you actually look at the data, you don't get the results that you hoped you'd get out of those programs.

Questioner: Is there something you could do about that? I mean, have you seen anybody put a market into effect that does that? Other than simply time of use rates, has anybody put in a financeable market that would sort of drive that type of investment?

Respondent 2: The chart I showed you for Con Ed is going to actually be used in their calculation, and the price that they're going to be offering by area is essentially going to be a function of the marginal cost we calculated. We would have loved to have had more granular data, but we ended up looking at the load shapes of every single substation that was associated with each of the areas and using that as a mechanism to do a cluster analysis of both costs and load shapes, so that you could not only know what the costs were, but what would be likely the preferable technologies in those areas to make the offer against. It's not nearly as detailed as what Speaker 4 had done, but we were able to do that and get to something that now Con Ed can use that has a bit more granularity, both in the costs and in thinking about what technologies it wants to offer up. It has to go do its own hosting costs for the various technologies. But it has at least a basis for doing those calculations.

Questioner: How do you take that information and then create the market that drives private infrastructure investment, not just sort of utility rate base? The load reduction program sort of sends that reservation payment charge. They say, "All right, $4.00 a kilowatt if you do something in this area." You can then take that, finance some equipment, and actually put it in there and have private investment.

Respondent 2: For each of the areas, they're actually going to have an auction that says, if you can do this, here's what we're willing to pay you in order to provide this amount of load relief. So, they are not doing it themselves. They're doing an RFP for each of the areas. And so, hopefully, the private market will do it.

Question 5: I was thinking a little bit more about all those 40 KW residential customers, and wondering how many of them are running some sort of agricultural sideline. [LAUGHTER] For those that are, there would probably be a fairly high load factor, and maybe they should get their own rate class. [LAUGHTER]

Respondent 1: Wait, I have a real electric call out that has their average. They have a rate class that consists of customers whose average is 20,000 kilowatt hours a year.

Questioner: Wow. So, one of the things I wanted to make an observation about is that it seems to me that net metering is its own rate class. The essence of net metering is that the customer gets to use the utility for both the distribution system and as storage. And the net metering customer gets those things for free. So I think it's its own rate class, rather than something else.

If there wasn't net metering, I don't think that solar, or PV, would be economic in very many places, other than places where the retail rates are very high. If you have net metering, in particular in places in California where the rates are so high, you have ended up now with the duck curve where you now need utility storage added to accommodate the duck curve, and also you need to add billions of dollars in additional distribution system buildouts. So you've got all these additional costs to the system as a result of, I think, net metering, and we've also, of course, ended up with a lot of residential solar, which costs three times as much as grid solar, which we should be building instead. It goes back to the chart from yesterday about how much New Jersey's solar subsidy is, relative to grid solar.

And, of course, as an aside, I'll say the same thing about the chart about Maryland offshore costs, relative to onshore wind. I'm getting all my bugaboos out here.

Having said all that, I guess I have a question. Why can't we get real-time rates at least as an option for small customers? It could be LMP in the RTOs, and it would be incremental, largely fuel-cost-based, in the non-RTOs. It seems to me that having it as an option can't really hurt anybody. But it can help not only the customers that elect it but also everybody else by reducing, for example, peak demand.

Respondent 1: I'll be super fast. On the agricultural activity, we have an EV finder that runs through meter data sets continuously looking for EVs in the territory. We misprogrammed it originally, and we accidentally ended up finding all the agricultural facilities at homes. And we thought that there were a lot of EVs in this particular utility's territory. [LAUGHTER] It turns out that they were not EVs. So there's a lot more home agriculture than you might actually think. On the second point, billing systems often can't do that. So there's a really practical reason--they just can't do real-time pricing. They don't know how to send the bill to the customers.

Respondent 2: To give you a short answer about the distributed resources issue, the core thing is not the nature of the energy price that you charge, I believe. The core problem is the fact that the energy charges contain recovery of fixed cost. So if you want to solve your distributed resources problem in terms of pricing, you have to do something to get an energy price that reflects the marginal cost to the utility of providing energy. If you can do that, then, as a usage declines, the costs decline with the revenues. If you aren't doing that, then you haven't solved the problem. People talk about TOU in this regard, and say, "Well, if I've got a solar panel on my roof, and you're paying me for electricity, why isn't there a TOU rate?" or in your case, an RTP rate? So, that's a situation where essentially you have a buy-all, sell-all rate, and you sell to the customer at an embedded cost-based rate, but then they sell back to you at an RTP rate, or something like that. That takes the issue of revenue recovery and the issue of efficient pricing and splits them.

Question 6: A couple of things, very quickly. One is, I do believe we're going to see demand-side management by the load-serving entities, trying to step away from their capacity charge or their allocation of the ICR (Installed Capacity Requirement) in the New England ISO system. It will be interesting to see how that works, and whether we see demand side management there in lieu of participating in the capacity market.

Secondly, I thought Speaker 4's discussion on heat pumps was fascinating. It's my understanding that if you have one of those heat pumps you're describing, the efficiency is higher, in terms of a reduced amount of natural gas per comfort unit, even if the electricity comes from a combined cycle power plant, than if you use a home furnace with natural gas. And if that's the case, then there is a real market imperfection here, where New Englanders in a cold winter pay $2-3 billion more because of the constraint in natural gas pipelines that drives up natural gas prices. And there should be, if in fact the systems to the homeowner are competitive with home furnaces, a very strong incentive to provide the heat pumps, not just for the reasons you were saying, but also to drive down the cost of the energy market on the electricity side. You'd have to bring together the gas LDCs and the electricity LDCs. Some of them are owned by the same holding company, but they have very different ways of thinking about regulation. That would be a tremendous opportunity that should be exploited. I haven't done that math. I don't know how many homes have to convert to make a material difference. But there's something there that would be very interesting to exploit.

I've heard on the panel from those of you who are, I would say, more traditionalist, and you've made a very important point, which is to keep it simple, that the homeowner doesn't want complexity and isn't going to want to spend more than a few minutes a month thinking about this. At the same time, we've had questions from the floor about the value, potentially, of having the data for individual homes and sending price signals to retail customers. It seems to me that one way to think about a potential way that gets brought together is with aggregators. You're going to see a business model for companies that will say, "I get it. Joe Brown isn't going to care about lowering his electricity cost from $3.50 a day to $3.15 a day, or whatever the difference might be," but someone who could think about that being spread across thousands of customers or tens of thousands might eventually see a business model that makes sense, where they will provide both the technology and also the hedging, so the customer sees something that still looks like his old keep-it-simple-for-me-please system, but, on the other hand, that begins to actually realize the economic efficiency of what that data can mean in terms of actually shifting load curves. It just seems to me that's where that's going to come out. It's not going to come out from the individual customer doing that much. It's going to be from making it, eventually, such that there will be a profitable business model for aggregators to step in.

Respondent 1: I like your aggregator model. I think you'd have to eliminate the provider of last resort from the current retail markets, then. As it stands in New England, right, 80 or 90% of customers in Massachusetts are POLR customers. They operate with the provider of last resort. That kills the aggregator's chance for any kind of profitability. So, if you want to make the market work, kill off POLR as an option, and then force aggregators to be the providers. Most states haven't done that. You've got lots of states who have POLR. That's a regulatory issue, not an economic issue.

I can remember in Pennsylvania, in POLR, you could switch in and out every time the price went up. And so, in essence, the utility absorbed the hedging costs, because you could switch in and out, so the option value of switching was being entirely absorbed by the utilities until they finally sort of said, "Oh, no, you can't do that. We have to keep you on the system longer." So I think they've screwed up, in a way. (Did I say that? I apologize.) And they've done it because of politics. Politics are such that that's the way it's worked out. I'm for all the aggregators.

Question 7: I dug through the business cases in 2013 of all the investor-owned utility AMI installations, and, fundamentally, they were justified on operations. The demand side management and all the customer side came in when the utility already had AMR (automatic meter reading), and the savings from going to full AMI wasn't big enough to justify the investment. Then, they added in the customer side as a way to get the benefits bigger than the cost. So, it's been an operational concept far more than a markets concept from the beginning. And that's the kind of thing we're wrestling with now. We have capability. The capabilities are different across the country. The meters are not the same. But we're not using it. But there wasn't a lot of intent to use it when we started.

Secondly, I disagree with my friend about the panelists partially not being in this century. This country has 50 states, and we have very, very different situations, starting with whether the market is restructured or not. What are your resources? If the sun's shining a lot or the wind's blowing a lot, you're going to take a different path than if you don't have either of those resources. Third, retail prices vary by a factor of three in the lower 48. We won't even count Hawaii and Alaska. And fourth, consumption varies for an average residential customer by a factor of three. So, while in New England you can't see the power of these controllers, if you're in the Southeast, where they're consuming three times as much electricity because of air conditioning load, you may be getting a very different benefit off that investment. And, finally, the other things we need to consider are social policies and social values in each of these states, and whether somebody's trying to create some jobs. And when you put all that together, what everybody is saying on the panel makes total sense, because it depends on who you're working for and what state you're working in. And for those of you who are working across those parameters, I would love to hear what's wrong with that framework.

Respondent 1: I'll take a stab at it. First of all, I agree. It's context sensitive, and it matters. The operation savings-based models don't make sense to us. I think the real value is in the analysis of the data, and I'll give you an example that's sort of extreme. This is going to be controversial for those of you guys who are from Massachusetts, but we, for example, will spend $500 million a year on residential energy efficiency programs that assume really high savings. When we look at the AMI meter data, we don't see that large savings. A lot of those programs, from our perspective, can't be justified. There are a lot of savings in there, potentially. So, the value from the meter data and analysis is better business decisions, and every single region, every single place that we've looked at, there was large spending on something that may or may not make sense. Either the data validates it, and you should do more of it, or it basically disqualifies it, and so, really, that's sort of an abstract way of basically saying that, yeah, it is regional, and it depends on the context and where the spending is. But operating cost savings themselves probably aren't going to do it.

Respondent 2: I think utilities have very limited vision about what it is they can do with the data. The usual case for AMI, if you didn't have AMR, was that I was going to improve the response rate of going out with trucks, and I was also going to reduce the cost of doing the billing. And that was the case. Right? Nobody said, "Oh, wait, I now have AMI, and if I do a little bit of grid modernization, I now can look at the relationship between consumption and what's going on in the grid, and now I can change the way in which I think about the rate at which I change out my transformers and their transformer life. I can do a better job of spotting them. I can do all kinds of things in the distribution system to improve the operations, if I combine the AMI with that stuff." One of the problems is, the utilities had a very simple-minded case about what it is they could do with the data. And so when they had AMR and then they went to AMI, all they did was say, "OK, I'm going to go save some capacity in the generation market," or whatever else and they did not think about it in a much larger context in terms of, how do you actually operate the distribution grid in a way that's much more economical? And it's because historically they never did.

One of the issues is the limited vision that the utilities have about what they can do with the data and how they can think about changing it. There's a nice paper by Michael Caramanis on distribution LMPs. You can't even think about doing anything like that unless you've got AMI and everything else going on. Right? So the question is, how broad is your vision about what's going on for the system that interconnects into the transmission system about what it is you can do and how active you can be with it? Does that answer your question?

Questioner: I think that's if you have the conditions of price and high use. You're not driven to do it until you have the other conditions.

Respondent 2: I agree.

Question 8: I'm wondering why we're not much more proactive in creating sandboxes, like opt-in ways that we can go and prove out that things work. I have three specific angles on that.

First, real-time pricing. People mentioned it. They do it in Texas. They do it in Illinois--market, regulated, whatever. Opt-in, it makes complete sense. Some customers want it. Others don't.

Then, aggregators. The argument that we should stick to the status quo because customers don't want to deal with complexity basically evaporates when you have somebody who's dealing with the complexity on their behalf, and then they're also dealing with complexity in how they deploy DERs and how they use them and really innovating in a holistic way.

And then, perhaps most radically, chips are very cheap now. You can basically have a microsynchrophaser or advanced sensor like Sense Lab on a chip that is far superior to any situational awareness that the distributional utility has. It's become so cheap, in fact, that we can put them everywhere. We're going to be stepping very soon into a situation where providers will have more data than the utility. How can a sandbox be used so that utilities can actually take advantage of this development?

Respondent 1: I'm in agreement. I don't know what else to say. I mean, the only caveat that I have there is that there's an experiment in Massachusetts…and I don't mean to highlight Massachusetts. There are a lot of experiments elsewhere, too…where they basically got all the customers opt-in, because you want to see what the response is over the total population, not over some self-selection. But I 100% agree, the data is there. And we should be using and testing and experimenting with it. So that's it.

Question 9: I'm a little concerned that there's a bit of a false dichotomy between maintaining primitive rates and allowing customers to sort of understand what's going on. [LAUGHTER] I always love this when it applies to rooftop solar, where people are smart enough to make a $25,000 investment, but too stupid to understand their bill. [LAUGHTER] The thing that bothers me is, if we continue with the kind of primitive rates that we have, we may keep bills being simple, but the problem is, we are keeping a whole lot of products out of the market that can in fact benefit customers, which require relatively little action by companies. You could have aggregators, or certainly retail competitors, or utilities themselves providing things like products that actually reduce demand or eliminate the possibility of spiking or reduce it. Hedge products, if people are concerned about volatility. There are all sorts of things you can do without distorting the whole price scheme. So I think it's a false dichotomy to say, "Well, we're stuck in this choice between more sophisticated, perhaps more efficient, pricing and keeping bills pretty simple so customers can understand them." I just think that's a false dichotomy.

Respondent 1: From my point of view, the place that any vertically-integrated regulated utility would start from is to go and look at the competitive market. What's succeeding in that market? Do you have a lot of distributed energy resource rates out there in competitive areas? If you don't, well, that's a sign. So, I wouldn't like to see regulators mandate a certain residential portfolio for their regulated utilities, for example. I think the research is fine. Trying something new is great. It's fine if a regulator says, "Well, electric vehicles are coming. Is your utility ready?" You do a proceeding and say, "Well, do you need TOU rates or not? Or will your rate suffice?" In some cases, it will. It's fine and dandy to inquire and be proactive, both as a utility and as a regulator, but I'm a little concerned that if we start to go down the path of intensively requiring that utilities offer a full portfolio in order to meet what you have in mind, that you're going to run into the Hogan problem, which is a proliferation of rates and provisions that will then need fixing with other stuff.

Respondent 2: I agree with that, and also just wanted to say that I'm in favor of the sandboxes. I think those options ought to be provided.

Question 10: I just wanted to go back to a comment on building in inefficiency for the Provider of Last Resort, so we can have others take that efficiency away. Back in the '90s, we had some arguments on wholesale market restructuring that kind of tried to do that. And I'd also like to remind us that in New Jersey, the Basic Generation Service does indeed pass a wholesale price through to large customers that can manage that price.

I want to go back to the plain vanilla versus tutti-frutti. The intention of the Basic Generation Service at the time that we were making those policies and choices was that the PJM wholesale market could be the plain vanilla, and that third-party providers needed to bring a little tutti-frutti to the party. I just wanted to circle back on that and remind us that building in those inefficiencies, at least when those decisions were made, was thought to be the way to give value to customers as best as possible.

Respondent 1: It's sort of a chicken and egg problem in the sense that we now have much more developed markets than we had early on. We now have much more developed technology in providing price signals to the customers in terms of AMI and everything else. And, in a way, we are stuck with the model that is dated 1998, and it's 2018. My iPhone right now has the computing power of the computer that I worked on when I was a graduate student. Right? The markets have changed. The technology has changed. But I don't think that the regulatory setting has really kept up with those changes. And the net result is, we get these very odd sort of things happening.

And, you know, I'll be Johnny One Note on this one. A lot of these questions revolve around capacity decisions and pricing capacity, at least at the LSE level. And that's a tricky problem, because how do you pay for it? As it stands right now, you collect the money through these volumetric charges, and they are completely distortive, in terms of what's going on relative to how the distribution system operates and what the economics are. But we're stuck there. I just think that it's a different world than we had 20 years ago, and I don't think that we've necessarily kept up, in terms of the changes that have gone on.

Comment: I have a house on Capitol Hill. My average electric bill during the year, on a monthly basis, is about $110. I spend about three times that much every week on food. I'm a very sophisticated person with regard to how utility costs are incurred, and I have absolutely no incentive to play with my bill and try to save a nickel or a dime or a dollar or even $5.00 a month on my electric bill. And so, why are we having this discussion?

Moderator: That's a Bill and Ashley question. [LAUGHTER] Let's give this panel a round of applause. [APPLAUSE] Thank you, Bill and Ashley.