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Rapporteur's Summary*

Session One.
Environmental Dispatch: Now? Or Never?

The notion of using environmental criteria to dispatch power plants has periodically arisen as an approach to reduce emissions. The theory seems simple to some: namely, that plants are to be dispatched on an emissions merit order basis—least emitting sources first—subject, of course, to security constraints. While the idea may be simple, actual implementation would raise many questions. What would environmental protocols look like? How does one balance between economic and environmental merit orders? How do incremental costs for out-of-economic merit order get allocated? How might such a system fit into Section 111(d) SIP's? What impact would environmental dispatch have on LMPs and FTR markets? Would the standard market design collapse or adapt? Are all plants capable of operating in a fashion that would allow for emissions based dispatch, and if not, how should that be dealt with? How do multi-state system operators dispatch in an environmental merit order when various states may have different, if not conflicting, compliance programs? How would emissions trading be altered by environmental dispatch? In short, how would such a system work, and can it be done on a reasonably efficient basis?

Moderator.
Good morning, everyone. This panel this morning is on the issue which is labeled "environmental dispatch." And I think it's a particularly interesting topic to look at here, because of the expertise of everyone in the room around our energy markets that so many of us depend upon. But what we're not going to be talking about today, in my hope anyway, is the term "environmental dispatch," because I think it's become very value laden and political. And what we really want to talk about is, "How can we make some of the regulations and proposals

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work within our systems of markets that we all live within right now?" So that's the challenge.

And so what we have today are some technical economic experts, people who have actually managed markets and thought deeply about markets. And the first speaker we will hopefully hear from shortly, but we've asked his associate to pinch hit for a few minutes, just to give us an overview. Our first speaker did submit a presentation that I think all of you have, to give us just some of the conceptual overview of how environmental factors, what their implications are for the electricity markets.

Speaker 1 (alt).
Thank you. I am not Speaker 1, but I'm going to do a little interpretive dance of Speaker 1's presentation, which will at least be brief.

So, Speaker 1 starts with this slide, which is basically to acknowledge that there is a social cost of carbon. And it summarizes this various analyses of what the cost might be, and there's uncertainty, but there is sort of a range that people agree on. It depends on the assumptions you make, but $42 a ton comes to mind. Something in that range. It's not zero and it's not infinity.

So, the EPA, as you all know, in its Clean Power Plan, has felt it needs to address carbon. And it's come up with this plan that has four building blocks. You know, basically make the generators run better. Dispatch national gas, things that pollute less than coal. Dispatch zero carbon power. And have more energy efficiency.

So then, Speaker 1 wants to remind us, well, wait a minute, let's go back to the basic fundamentals of what we know about how electricity markets work. And that is, bid based, security constrained economic dispatch with locational prices. And I think the economic dispatch is what he probably really wants to emphasize here.

And on the next slide, if you looked at this carefully, this is an illustration of all the different things that have been tried that are not economic dispatch. Just to remind us of why we do economic dispatch.

So, what do you do then, if you want economic dispatch and you care about carbon? He says, what about a carbon tax? What about cap and trade? You could do those. It would change the price of carbon, that would ripple through the system, and you could still have economic dispatch. And it would work.

This is not what EPA is suggesting. It's hard to reconcile the two building blocks that have to do with dispatching natural gas and dispatching zero carbon energy, with economic dispatch. And he cites here at the bottom, some research findings that I am not sure where they're from, but it's an EPA analysis that says that improved efficiency for coal plants can result in more CO2 emissions.

If you use more gas, you could be substituting for renewables or nuclear. You could use more renewables. You could be substituting for other renewables or nuclear. And it says, energy efficiency can interact with grid congestion to cause higher CO2 emissions. I guess, the grid is complicated and you don't always get what you think you're getting.

He's been interested in this PJM analysis, which I would say, let's ask the authors, if we have questions about it. It looks like what PJM did is, they ran a series of simulations of different ways to follow the EPA rules, and then they backed out of that.

The kind of question they asked was, if I did this, what's the implied cost of carbon for doing this? And they found that, just depending on what you did, the implied cost of carbon could be all over the place. So, the EPA rule isn't consistent with one settled carbon price. It can mean a lot of different things for the price of carbon.

So, in conclusion, Speaker 1 raises some questions about this. He reminds us that wholesale power markets depend on the economic dispatch framework. He reminds us that if you monetize carbon, if you have a carbon tax or cap and trade, that will mesh right in, very nicely, with an economic dispatch system. He notes that we don't have a carbon tax. That's not what EPA's Clean Power Plan is. And that the building blocks are connected in at best a confused way to what the price of carbon would be.

So, he raises four questions, which I am just going to read, and hopefully as the panel talks, they'll be addressed in more detail. Will state implementation plans thread the needle to meet environmental goals? Will the necessary electricity market design survive the regulatory gauntlet? Will environmental dispatch implementation create perverse outcomes and arbitrage opportunities? Will the future be the RGGI or CARB-CAISO-PacifiCorp models, meshing carbon pricing and economic dispatch? Or will the future repeat the fiasco of the California-Enron electricity market design that prohibited economic dispatch? And I hope that Speaker 1 will be here later to answer questions. Thank you.

Speaker 2.

Speaker 1's last question makes me feel as if RGGI has been blessed as a potential approach. I'd like to just highlight a few aspects of the Clean Power Plan then talk a little bit about RGGI, for those of you who aren't familiar with it. And then, finally, talk about one or two of the challenges RGGI moved through over the time while I was there, and some of the analysis that went on.

The EPA's Clean Power Plan is built around four building blocks. State implementation plans have wide latitude to incorporate those building blocks either singly or to combine them. The first is reducing carbon intensity of generation individual EGUs, largely through heat rate improvements.

The second is reducing emissions from most carbon-intensive EGUs, by substituting with less carbon intensive EGUs.

The third is reducing emissions from low or zero carbon generation. And finally, reducing emissions from affected EGUs through demand-side energy efficiency.

Those building blocks are largely, I think, what Speaker 1 is talking about when he's concerned with the environmental dispatch non-economic modeling. RGGI has taken a very different approach. The RGGI states submitted comments to the EPA, and I think view very optimistically the opportunity for RGGI to go forth as a model, not just for the nine current RGGI states, but also for other states that need to perform and submit state implementation plans.

The EPA's Clean Power Plan specifically authorizes states to engage in regional approaches to meet their compliance requirements. And RGGI is really the only regional program in the United States. California's program has linkage with Québec, which is obviously outside the bounds of the EPA regulation.

RGGI began in 2005 with a memorandum of understanding among 10 Northeastern state governors. Bipartisan. It had modest goals of 2.5% reduction of CO_2 emissions from the electricity sector only. The forecast price was between three and four dollars a ton of CO_2, with a minimum price of $1.89.

The legal structure that RGGI went forth with was parallel, state-based programs in 10 states. There was a model rule that was developed and passed in 2007 by all state legislatures. And one of the innovations of RGGI was to auction the allowance permits.

The basic mechanism is that each generator located within a RGGI state needs to submit an allowance for each ton of carbon dioxide emitted at the end of the three-year period,. Some of those allowances are directly allocated, based on a number of state economic incentive programs. Something around 10%. But the vast majority, 90% of allowances, are auctioned in quarterly allowance auctions.

And those auctions have raised, since 2008, about $1.8 billion for states. And those proceeds (not "revenue," because this is not a tax, they are proceeds from auctions) have been reinvested in energy efficiency. Over 60% has been reinvested in energy efficiency, another 20% in renewable energy, and 20% to a variety of other programs.

So that's the basic structure. The largest issues that RGGI has had have really been around emissions leakage. And that is particularly true with respect to the departure in 2011 of New Jersey from the RGGI program. Obviously, New Jersey and Maryland and Delaware formed sort of the southern portion of RGGI, which extends from Maine to Maryland. And as a part of PJM, at least represented from the RGGI states, a coherent geography with respect to electricity transmission and emissions leakage.

The absence of New Jersey significantly disrupted that coherent whole, and I think the policymakers in RGGI states recognized that their ability to impose a high carbon price that would approach the true social cost of carbon was limited by the fact that the higher the carbon price, the greater the emissions leak to nonparticipating jurisdictions. And so I think RGGI was always designed to be, in its first instance, a sort of test bed for the mechanics of regional trading and regional compliance programs.

That said, in 2009, after a year of operation, it quickly became apparent that there was a problem in the trading scheme with a massive over allocation of allowances. The initial budgets that had been negotiated among 10 states represented over 180 million tons of CO2. And though it was based on an average of 2003 through 2005 data, by 2009, it was clear that emissions had fallen by about a third, to 120 million tons.

We began in 2009 to understand what had caused some of those emissions reductions, with an eye to understanding whether they were going to recur or not. And you see, in concert with NYSERDA, some rough analysis of what the causes were. Some real load reduction. RGGI auctions had produced real revenue that was being invested in energy efficiency. Some reductions related to fuel prices. This was the era of the first natural gas switching, away from fuel oil and coal. And then, finally, available capacity mix. During those years there was a very optimistic scenario for nuclear availability, and for hydro availability, particularly in New York State, resulting in a significant decline in carbon prices.

So, this raised the question of the extent to which the RGGI price, around three dollars a ton, actually caused the emissions reductions. You can see in your handouts, probably better than this slide, a little bit finer detail of some of the issues that we developed to address causality. And each of these has a feedback to the RGGI price. For example, the energy efficiency funding represented by charging a price for the allowances.

And at the same time, there are some that are really separate from RGGI. But at no time did RGGI states claim that the fact that they had a price alone caused reduction in CO2 emissions. So it's a much softer mechanism that were seeing at play here than some of the regulatory mechanisms that have been proposed elsewhere.

And this is the final slide that I want to show you. For RGGI's 15 largest emitters, moving forward from 2009 to 2013, in the face of a $2-$5 price per ton of carbon, you see that the vast majority of the largest 15 emitters across the region had significant reductions in their operating hours over the period from 2009 to 2013.

I think I want to leave it there. In the wake of a lot of these findings, RGGI states have significantly reduced their emissions cap. The cap has gone from 180 million tons now to 90 million tons. The price of carbon has increased from about $2-$3. Now it's $5. In California, it's still trading at 10. But these prices are layered into the wholesale electricity markets, and have had no impact on the operation of the current electricity wholesale market. Thank you.

Speaker 3.
Good morning, everybody. I am going to look at the key environmental regulations for PJM, and certainly there are more than two, but these two I am going to discuss are probably the ones that are the biggest hot buttons in PJM. The first is MATS (the Mercury and Air Toxics standard). And the second is Sections 111(d) and 111(b) of the Clean Air Act.

A lot of retirements come out of things like MATS. And the next slide will show some of the locations in the footprint that are either, have retired or are scheduled to retire. And then 111D and 111B obviously are the policies that are sort of out there now, and sort of being developed in terms of how they're going to be implemented, whether implementation is state-based or region-based or what have you.

And as you might guess, there are significant implications relative to whether that's a state-based or region-based approach, certainly from PJM's perspective, but also from a societal perspective. And I'll try and touch on some of those as I go through the presentation.

At a high level, here's a slide that shows generator deactivations. I don't want to say that these are all from MATS, but certainly a lot of them are driven by EPA regulations. The red dots are the retirements, the blue dots are deactivations. And the bigger the dot, the bigger the size of the power plant. And you can see there's a significant amount coming across the footprint.

In PJM, obviously, we are in a fairly decent spot, because of shale gas and the low-cost natural gas, and the building of new natural gas combined cycles. So from a capacity perspective, except for a couple tight years in between here, over the long term it looks like we're going to be in fairly good shape, notwithstanding, maybe, some of the implications coming out of 111D and 111B.

If you look at a yearly basis, from a deactivation perspective, I think you get somewhere on the order of 30,000 megawatts of deactivations.

Obviously, 2015 looks to be a fairly big year for deactivations. So that will be, from a reserve margin perspective, a tight year for us. But, again, we are not projecting any reliability violations, just tighter than we've seen in previous years.

So when it comes down to environmental dispatch, the presentation is sort of a talk about, what's the least we could do, and what's the most we could do? And what are the implications on the energy markets as we know them today? Economic dispatch, LMPs, FTRs…what do they all end up meaning?

And so, if we go with the do-nothing approach, which is sort of the world that we are in today, we essentially have a dynamic where the environmental limitations are largely managed by the generation owners themselves. The LMPs and the FTRs and economic dispatch tends to occur like it does today, but a lot of what we see today is environmental limitations manifest as maximum runtime-type constraints. And there's not a lot of great visibility into that kind of thing, or what causes those maximum run time limitations.

I'll give you a high-level example. If PJM schedules a generator on, let's say oil, instead of natural gas, that generator might be able to run for 24 hours on natural gas, but it can only run for six on oil. And unless we have that information when we schedule that generator, we can actually schedule it in the morning, needing it for the morning and the evening peak, and that generator calls five hours later, and says, "I'm bringing it off-line. Because I can't get natural gas and I've hit my environmental limitation on oil."

And so that puts us in a tricky position in trying to manage the grid when we see all these environmental restrictions manifest, really, as maximum runtime constraints, as opposed to some kind of economic emissions cost type of problem. So there are some reliability implications there.

From a market perspective, the market prices tend to suffer, because that generator that now has a six hour maximum runtime on it is actually losing an opportunity to generate during the peak period, because it has to come off prematurely early. And so the cost of that generator, while it might be just the cost of oil as the marginal cost, is actually forgoing an opportunity.

And so it has an environmental opportunity cost that, unless those procedures are used in PJM, the prices don't actually reflect what the real cost of that generator is to run. And so that becomes problematic from a pricing approach, from a transparency perspective, and things like that.

And efficient utilization of those assets over the course of the operating day becomes sort of a juggling act, if you're in the control room. You're trying to juggle some of these environmental limitations with what appears to be the generator's operating capability, versus what it is when it gets down to brass tacks with environmental limitations.

So that's sort of approach number one. Approach number two is the other side, which is the full-blown, let's the problem on its head approach, and now we're going to dispatch based on some combination of emissions tonnage and economic dispatch. And as far as what that trade-off becomes and where it falls out, I don't really have an answer to that. But it really is shifting the paradigm.

So if you think about LMPs and FTRs and all these kinds of products that we understand today, and if you take them in the context of 111(d), if PJM starts having to dispatch generation based on a state-based emissions limitation, the concept of economic dispatch sort of falls away at that point. And you can get state-based congestion which is really driven by emissions limitations.

And so what does that mean from an LMP perspective? I don't really know. There are no components in LMP today that we know that capture that kind of concept. But that is certainly a potential implication if we go to this regional-based approach, where there are state-based levels and we have to re-dispatch generators on a state-by-state basis to meet those emissions targets.

And while it's probably one of the more interesting concepts, it's also the scariest from a standpoint of departing from what we know and what we're comfortable with today. So it's definitely something that piques your interest, but it's really a state change from where we are today, if we go down this road of state-based environmental targets, dispatching based on emissions tonnage maybe, and less based on economics.

And of course there's some kind of trade-off when you get to that point, right? Because if you're dispatching based on emissions tonnage alone, the system production costs can go like this (steeply up), right? So what defines that cost function for that trade-off? I don't really know what that is, but certainly that's food for thought, and food for discussion, hopefully, for this group today and on into the future.

So if we look at this problem from a purely emissions based approach, we're looking at additional generator retirements, because the generators that emit the most are not going to run. I think it's pretty much common sense.

NERC has been on the record as saying they have concerns with the declining system inertia of the Eastern Interconnection. Further coal and fossil generator retirements are going to push that system inertia further and further down. And so, from a reliability perspective, you look at system control, things like that, as potentially becoming more problematic in the future.

Infrastructure changes. If we just, tomorrow, start dispatching the systems differently than we do today, the transmission system wasn't designed to be dispatched completely differently than how it's run today. And so, there will be new congestion patterns, new transmission lines that need to be built, new compensating devices that need to be installed on the system. And so it's not just something to think of from a market and a cost perspective. There is an infrastructure dimension to this as well.

Revenue shifts. If you look at "clean assets," things like wind power, solar, and things like that, those resources typically have very low incremental costs. And so, consequently, you would sort of intuitively think, "Well, maybe the energy prices fall."

And so, from a revenue perspective, if energy prices are falling, at least in PJM, where we include both energy and capacity revenues and sort of a fixed cost of the unit, you would tend to see more costs shift from the energy market into the capacity market, because energy revenues intuitively would be lower due to relying on lower marginal cost assets.

Flexibility likely becomes the king. And so, what I mean by that is, if you look at wind resources and solar and things like that, these are typically not greatly controllable assets. And so the resources that can provide that system control are now going to be highly valued by the ISO or RTO.

California has obviously done the flexi ramp product. Those become highly critical from a grid control, and probably from a market revenue perspective. So these are some interesting paradigm shifts that we might see if you go down this road of flipping the problem on its head.

Another question is who ends up paying for this paradigm shift, and from a cost benefit perspective, is the cost commensurate with the added value? I don't know, but certainly these are questions for the group here today.

So there are some logical steps that we can do today. And certainly, coming out of the winter of 2014, and also some summer periods, there's a situational awareness piece for PJM that we need to improve upon. We need to better track environmental limitations on generators, so that we can use them to more intelligently schedule and control the power system. A lot of that flies below the radar, or historically it has flown below the radar, but we need to bring that into the forefront.

We have market rules that allow for the computation and the inclusion of environmental opportunity costs in resource offers. And by and large, that doesn't get used a ton today. And so what we end up doing is running an environmentally limited resource at a low incremental cost for a short number of hours, which is not very intuitive. Because if I use that resource, there is a reliability impact, and that needs to be reflected in the cost of that resource.

Emissions adders on resources is another step. I think the most critical point here is if there is some kind of paradigm shift, and we really start talking about collecting emissions data from generators, and re-dispatching based on that, that shift needs to occur over time. Because the policy can change like this, but the infrastructure and the system control capability can't. And the market rules probably won't, as well.

So if we go down that road, it's a significant shift in what we know today, and we need to make sure we spend the appropriate time figuring out how to make that work. Because it diverges quite a bit from what today's model is. So with that, I'll close my comments. I appreciate everybody's time, I look forward to the discussion.

Question: Could you just describe what system inertia is?

Speaker 3: Sure. So, on the 60 hertz power system, all of that rotating masses on a conventional generating resource contribute to the system inertia, which is just the sort of momentum of the system to maintain that 60 hertz. And if you pull those rotating masses away, that inertia declines. And that inertia is what helps maintain the 60 hertz cycle frequency of the system.

And so NERC has come out and said they have concerns because of the replacement of coal, natural gas units, and things like that, with environmental resources which don't contain those type of typical rotating masses. And so the nuts and bolts of it becomes, as the system inertia decreases, it becomes harder and harder to maintain the frequency control.

Speaker 4.

Good morning, everybody. In my talk this morning, I will briefly describe the greenhouse gas regulation in California. It's the only state in the West that has such a regulation. I'll discuss problems that we encountered in our design of the Energy Imbalance Market that went live on the first of last November, and trying to comply with this regulation, and how we solved these problems. I want to describe how we implemented that solution in our market system, and the changes that we had to make in the market model.

I will describe the associated settlement for that and how it works for the participants in the market. And then I will open up a discussion of future challenges that we may see in this area and how we can apply this methodology in the general case as smaller entities join. And I will close the presentation with a reference I will give you for more information and examples on the methodology.

The greenhouse gas regulation in California is administered by CARB (the California Air Resources Board). They have very specific regulations that they administer. First, the cap and trade regulation, which involves annual emission allowances that decline every year. The entities that are regulated under the program are generating units that provide energy in California for serving the load in California, and also importers, that import energy in California for serving load in California. Under that regulation, they must acquire emission allowances, and they have to surrender these compliant instruments, as they're called, to meet their obligations under the program, for their emissions.

The allowances can be acquired in an auction or in the secondary market. And CARB maintains a compliance system and tracking system that tracks these instruments as they change hands and how they are retired by the participants. The interesting thing about the auction is that it has a floor price that increases every year by about 5% plus the rate of inflation. And that, in combination with the fact that the volume of allowances increases as well every year, makes the cost for acquiring these instruments more and more expensive every year. Which is one of the objectives of the program.

The other regulation is the mandatory reporting. Every entity that is regulated by the program is required to provide an annual report by June 1 of every year for the emissions of the year before. And they have to also, at their own cost, do a verification of that report using an independent verifier, which is accredited by CARB.

And the third regulation allows the CARB to collect administrative fees for the implementation of the program. These range between six and eight cents per metric ton, and it depends on the emissions that are reported.

So far in our Energy Imbalance Market design, we haven't had any concern about making specific design changes or recommendations for greenhouse gas compliance in California. The assumption was always that participants include these kinds of costs in their bid.

So generating units in California and importers of energy into California provide energy bids to the market. We always assumed that these costs are reflected in the energy bids, and therefore in the market clearing prices. And this is still true with the Energy Imbalance Market for the entities that import energy through ISO interties or generate energy in California.

We soon realized, though, that when we're designing the Energy Imbalance Market, that we could not make the same assumption for the units that are outside California. We currently have importers into PacifiCorp through an EIM intertie. And the reason was that part of that energy could be used to serve load in PacifiCorp that doesn't have greenhouse gas regulation. So asking the participant to include this cost in their bids would make them unnecessarily less competitive in their local market.

So we looked into how we could solve this problem. And basically, what we wanted to do was to separate the energy that is produced in the EIM entity, and is used to serve load in the EIM entity, which is free from greenhouse gas regulations from energy that is deemed to be exported to California through what we call EIM transfer.

And we wanted the market to find the market solution of this problem. So, the energy that is consumed within the EIM entity has a cost that is submitted by the participant. That's your traditional energy bid. And then, the energy that is imported to California has an additional cost, we call it the greenhouse gas bid adder, that is submitted by the participant. And this reflects the additional cost of the participant having to acquire compliance instruments for meeting the greenhouse gas regulations for the imports to California.

So this was the idea. And to implement it, we had to make some changes in our model, besides allowing for the greenhouse gas bid adder. Right now, participants can freely bid it. There is a cap on that bid, like the energy bid has a cap, which is thousand dollars, currently, so the regulation is that if you add this adder to your bid, you still should not go above thousand dollars, but it's an open bid.

Under the direction of FERC, within the first year of EIM, we have a stakeholder process we started. In the course of this stakeholder process, we could convert this bid to a cost-based bid, based on emission factors.

So to have the solution being calculated optimally, we introduced a new decision variable, which is the portion of the energy that is generated and is deemed to be exported to California. And we assign a cost for that, which is the GHG bid cost. So, we added a timely objective function to represent the additional cost that this energy has, as it's imported to California.

We had to add a few constraints, of course. The obvious one to cap the EIM export allocation by the dispatch, and this new decision variable. So we can't allocation more to EIm export than what is actually generated. And a very important constraint, which allocates the entire transfer from the EIM entities to the ISO, fully through the participating resources, so that we have revenue neutrality.

This is an important constraint, because when we discuss settlements, that is the constraint that gives us the economic signal of what is the marginal cost of the greenhouse gas regulations. So, the shadow price of that constraint, when it becomes binding, and it's binding when there is an export to California, that tells you what is the marginal cost of the regulation.

So that cost is reflected in the locational marginal price of all the nodes in the EIM entities. It becomes the fourth component of the locational marginal price. You're familiar with the other three components, the startup components, the marginal energy, marginal loss, and marginal congestion components. So, we introduced a fourth component to represent the cost of greenhouse gas regulation.

Now, you say this component is only in the EIM entities. But the EIM entities are not out of the regulation. How does that work? Because it's an export allocation, it's a negative price.

So, actually this has the effect that if it's the only constraint in the system, basically the energy cost in the EIM entity is less than the energy cost in the California ISO. And that difference reflects the cost of California greenhouse gas regulation. So it's similar to transmission congestion.

And the same as transmission congestion, when you do the energy settlement, you charge the load, and you pay generators the cost of imbalanced energy, because when this constraint is binding, you have more generational load in the EIM area, because there's an export. And when the component is negative, you actually collect revenue.

We call that greenhouse gas compliance revenue. So that's the revenue that the market operator collects when it's doing the energy imbalance settlement. And it's similar to the congestion revenue that's collected because of transmission congestion.

So what the market operator is doing now is collecting this revenue, and then paying it back to the EIM participating resources, based on their export allocation, this new decision variable we talked about. So this has two effects. It keeps the market operator revenue neutral, and for the participating resources, it provides the revenue stream that they need to offset their cost for acquiring compliance instruments for their energy imports into California.

So one of the challenges that we'll probably be faced with, and we'll have to resolve, is as the EIM becomes larger and more EIM entities join the program, how can this methodology be maintained or expanded in a scalable fashion? And right now we don't have an issue, because no other state in the West has a greenhouse gas regulation.

So when Nevada joins next fall, the same methodology will apply. And if additional greenhouse gas regulations develop in other states, what we have seen is that there is a tendency or a willingness to standardize its products.

California has linked their compliance regulation program with the province of Québec, Canada, and that way you can acquire these complex instruments. Either in Québec or in California, you can use them anywhere. And CARB has mentioned that if other states develop greenhouse gas regulation programs, they will link their program to these other programs.

So under this scenario, which is the happy scenario, you will always have two worlds, the world that has greenhouse gas regulation and the world that doesn't. So this particular model will always work between these two worlds.

What we don't want to see, and what we're particularly concerned about, is a situation where the rules and the costs develop in an inconsistent fashion, with the result that California won't be able to link their program to other programs. It will be very difficult to manage this through the market, if you have multiple different compliance regulations to put together under one market.

I will close my presentation by saying that you can find the mathematical formulation, a lot of description about the program, and also numerical examples on the California ISO website. Thank you.

Question: How do you distribute the revenues you collect? Because congestion revenues would be distributed to FTR holders, and things like that?

Speaker 4: That is correct. Good question. In this case, you have as part of the solution, the total energy that is dispatched for a participating resource that gave you a bit in the market. And then also the portion of that energy that is selected to be imported into California. That's the export allocation. So the product of that export allocation with the marginal cost of the greenhouse gas compliance, will give you a revenue. And this is exactly the additional cost that the participant will be faced with for its portion of its energy that is imported into California.

So that's the revenue. So let's say the resource is dispatched for 100 megawatts, and 60 megawatts is selected optimally though this market mechanism to be exported to California. And let's say that the marginal greenhouse gas compliance cost clears at four dollars. Four dollars times 60 will be your revenue for this particular hour.

Question: So let's say I'm a load serving entity, and I have a contract, I inject the electricity here and take it out here, and on net I pay the greenhouse gas charge, like a congestion charge. Are you saying that the same entity gets it back?

Speaker 4: If that entity is a generation producer. For a load serving entity, for your load, you will see a locational marginal price. A locational marginal price has a fourth component, which is negative, which means you pay less for your energy. You pay the cost of the energy without the cost of the greenhouse gas compliance.

If you are in an EIM entity, then if you are in California, you pay a high price because that negative component is not in the LMP, because your LMP now reflects the additional cost of the compliance greenhouse gas for the import that may be serving your load.

Now, if you're a generator provider in the EIM entity, for the amount of energy that you will export (the 60 megawatts in the example that I mentioned), you will have to acquire compliance instruments from the CARB auction or in the secondary market to cover your emissions, assuming that you are an emitting resource.

But you don't want to include that in your bid, because the other 40 megawatts of your energy is serving local load in your control area. And you don't want to be uncompetitive with respect to other generator providers for the same load.

So what this mechanism does is effectively it gives you the ability to have two energy bids--the energy bid for the energy that is serving load outside California, and your energy bid plus a bit other for the energy that is imported to California to serve California alone.

And for that portion of the energy, whatever clears the market, you have an additional revenue stream, which, because it's marginal cost pricing, is guaranteed to be no less than your greenhouse gas bid.

Question: It just seems that if the person who's bidding it in also gets the revenues, won't that affect the bids? I mean, usually these mechanisms work by not distributing the revenues back to the same people who are selling it.

Speaker 4: You can see this as being a market for imports into California that runs at the same time with the market for clearing load. So you have all these different greenhouse bid orders from providers. You evaluate them economically, the market clears, so the last bid order you select sets the marginal price for compliance cost. And everybody who provides imports to California gets that price.

Moderator: I'm going to ask us to wait until after for further discussion of this.

Question: I want to make sure I understand the nexus to the comment you made about Nevada being interconnected with Californian greenhouse gas emissions. Is the trigger event for that legislation from Nevada? Or is it the next step in the EIM development?

Speaker 4: Nevada is going to join the Energy Imbalance Market in fall of next year. It's going to become another EIM entity like PacifiCorp, so it's going to be part of the Energy Imbalance Market.

Question: So are you anticipating that for other markets that might join EIM, that would be a requirement--connecting to California greenhouse emissions rules?

Speaker 4: Yes, every EIM entity that joins will be faced with the same problem that we had with PacifiCorp, that participating generators will have to give them the ability to price their energy product separately if it is serving load outside California than the portion of the energy that serves load in California, for which they have to have compliance instruments, and they have a cost for that.

Question: So, is this bid adder automated in SCED, or is it a post-processing process, or how does that work?

Speaker 4: Right now, it's a fully supported bid. We have a system that receives bids from participants. And the same way that you submit your energy bid, you also submit this greenhouse gas compliance bid adder, which is currently not time differentiated. It's the same price for the entire day.

We had plans to have this cost-based from the beginning, but it was a little difficult to acquire all the policy agreements on how we're going to calculate the emission factor for these resources, which is what CARB does. So we left it open as a bid, and as I said, under the direction of FERC, we need to make it cost-based now. So we will be changing that during the course of next year.

Question: I just wanted to follow up on the question about Nevada. Independent of the EIM, what are the obligations for entities that want to sell into California?

Speaker 4: For any entity that imports energy into California for serving load in California, they are automatically regulated by CARB, and they have to acquire compliance instruments for their emissions.

Now, how do you calculate the emissions for an importer? The CARB has certain rules and regulations about how they go about determining that. If you can show that you have a specific contract, or you're the owner, or you have some agreement with a specific resource and you can demonstrate that to CARB, CARB will calculate an emission factor based on the resource technology and information that you will provide.

If you are providing certain portfolio resources, (CARB has the term asset controlling supplier, there are two right now, Bonneville Power Administration and Powerex, that provide from a portfolio of resources), then CARB calculates an average emission factor for the portfolio. And if you are an entity like PacifiCorp, that falls under a different category, it's called "multi-jurisdictional providers." For this, CARB has a default emission factor of .428.

So there are regulations that you have you satisfy when you're importing energy into California. You get some credits if you're exporting. So, if some of your energy is pass-through, you get some credits for that. But generally, if you're importing to serve load in California, you are falling under the regulation.

Question: So for markets participating in the EIM, do you foresee that CARB will be a sufficient mechanism to accommodate the GHG compliance, or would that require a separate mechanism?

Speaker 4: At this point, because California is the only state that has compliance for greenhouse gas regulations, and CARB has been on record that they intend to link their program with any other state that will develop similar greenhouse gas compliance regulations, I'm confident to say that we can have this methodology working.

As I said in the challenges that I listed in my slide, the only concern that I have is, if these programs cannot be linked because they're administered in a way that is completely different, and we have to recognize them separately, then it will be extremely challenging both for us to implement a market solution mechanism to consolidate all these different programs, if they are so radically different, and for the participants.

Because you can imagine if a participant has to acquire different compliance instruments for importing to California, and different compliance instruments for importing into Nevada, or another member of the EIM. It's becoming very difficult to manage this. Hopefully we will not end up there.

Question: Your slide says GHG compliance revenues are paid to EIM participating resources that import into California. Is it only paid to a resource, meaning a generator, or if a marketer is importing into California, is it paid to the marketer?

Speaker 4: That's an excellent question. The allocation of the payment goes to participating resources. And I have to explain what participating resource is. As you have probably heard, the Energy Imbalance Market is voluntary. So the program is designed in such way so that a generator outside California, being an EIM entity has a choice as to whether they want to participate in the Energy Imbalance Market by submitting an energy bid, or whether they choose not to participate, in which case they're dispatched flat at what we call a base schedule, which doesn't have a bid.

You have to be a participating resource to get this allocation, because you have to be dispatchable. As I said, the solution is a market solution, and markets work with bids. So we can only import into California out of what we can dispatch. So, therefore, we need an energy bid.

Specifically for importers, currently, although our system supports it, PacifiCorp does not allow energy bids on their interties. So currently we don't have participating imports. But that could be changing. Within the next year, PacifiCorp will allow intertie bids, in which case these providers will become now participating imports, and they will get an allocation and a payment for greenhouse gas compliance.

Question: So the only company that would get the extra compliance revenue is PacifiCorp when they start allowing interties?

Speaker 4: No, no. You can be a scheduling coordinator, which is the representative of a generating unit that markets the energy from that generator that participates in the market and supplied a bid. That scheduling coordinator is the counterpart for the settlement that the market operator does for energy imbalance purposes. And if they participate, which means they submit a bid in the market, and they clear the market, they will get payment the way we discussed here.

General discussion.

Question 1: I'm hoping the four panelists will kind of channel themselves and pretend that they're EPA administrator Gina McCarthy, and you've heard this presentation from Speaker 1, and he says on slide four, anything that upsets the design will unravel the wholesale markets. And at the end, he talks about the potential for this being like the fiasco of California.

And so, if you're administrator McCarthy, what would you do, and secondly, would you use your lifeline and call FERC for help? If you were being asked by the Administrator, or you were the Administrator, what would you do to try to deal with this issue of building the power markets based on economic dispatch with the environmental goals of the program?

Speaker 2: I think we are conflating two different terms, and regional approaches in the Clean Power Plan are certainly encouraged. Whether it's regional or state matters a lot less than whether you are putting a price on carbon explicitly, and setting the environmental compliance in terms of a price on carbon as opposed some of the constraints we heard speaker 3 talk about--the run hours or some other metric.

So, for example, if the state of Virginia says it doesn't wish to engage with other states, and wants to develop a Virginia-only plan, that it would impose either in the form of a carbon tax or a cap and trade program for in-state facilities, which is like a carbon tax… For most of my tenure at RGGI, the auction price didn't really vary, and was trading about two dollars a ton. There was relatively little secondary market activity, so, you saw a great deal of similarity to a carbon tax.

I think whether it's regional or state-based, it doesn't matter that much. And that's clearly the approach that's favored and encouraged by the plan. Whether state regulators choose to take that approach or not is really up to states. And that constraint is really deep within the Clean Air Act, in the way that the Clean Air Act is structured for states to submit their own SIPs.

And just to be a little more pointed on that, you know, if state regulators choose to develop SIPs that would violate their wholesale markets that they participate in, there's little that the EPA can do. Gina McCarthy has, I think, encouraged, to the greatest extent possible, participation in market-based programs, and we should note her origin from the state of Connecticut, one of the founding members of RGGI.

Speaker 3: From my perspective, and I'll play devil's advocate to Speaker 2, that decision about the state and the regional based approach is critical, because you could potentially unwind the efficiency gains you get from an emissions perspective, from a production cost perspective. And so, you create these boundaries between the states that you need to dispatch around that don't necessarily play with what we understand to be the societal benefit gained through a regional economic dispatch approach.

I know you mentioned the lifeline jokingly, and asking FERC to step in. From my perspective, the regional-based approached is a critical component in maintaining the efficiency of the wholesale markets we have today.

To the extent we go to sort of a sub-regional approach, we have to recognize that we're going to lose efficiency going down that road. In terms of quantifying how much efficiency we are likely to lose, I don't really know, but certainly it's going to be less efficient than a regional based approach.

Speaker 4: I would go back to what I stated in my presentation. I think the most important element here, as energy markets start expanding and incorporate bigger and bigger footprints, involving multiple states, to have a market that functions optimally and rationally across all these different states, it's very important that the states develop consistent and compatible greenhouse gas regulations, whether it's a cap and trade program or a carbon tax, so that they can have a uniform representation in the market. And I think this is the most important thing. I hope that the states are going to be encouraged to cooperate and come up with an agreement on how these regulations should play out.

Speaker 2: I agree with that, and bigger markets are better, everything else being equal. They tend to be more efficient. Not just in terms of geography, but also in terms of greenhouse gasses. We should note that we are only talking about electricity, because of the structure of the Clean Air Act. And electricity makes up between 35 and 40% of overall U.S. GHG emissions.

So we need to contextualize, when we talk about markets and efficient markets, the price we are willing to pay for one sector of emissions while ignoring several other sectors. But I would just say that I think it's a second order decision, whether it is regional or state.

And the first order is, do you take action to put a price on carbon, or do you choose some other metric? And then, as we think about region, we may want to be a little more specific about what we mean by region. Do we mean an entire ISO, or do we mean some random collection of contiguous jurisdictions?

I think one thing that we could talk about here, that I would propose, is that RGGI has demonstrated that a sub-portion of an ISO--Delaware, Maryland and New Jersey--can participate with other ISOs in a trading scheme without significantly disrupting the ISO functionality.

Question 2: My question is for Speaker 3. When you were talking about the run times in terms of a difference of, for example, eight hours if the generator is gas, and six hours if it's oil, and the forgone opportunity cost, is that shown in the generator's offer?

If it isn't, and it is going to be shown in the offer, would it be considered as part of the marginal cost? And is this something that PJM is reviewing in any one of its committees?

Speaker 3: The constraint I was talking about was the maximum runtime constraint. And the short answer to your question is, yes, a generator today can reflect environmental opportunity costs in its offer price. So, yes, that can happen today.

Does it happen consistently? No. And that really is part of the problem. We have some methodologies today that can handle that, but they don't get used for one reason or another—because, "It's too complicated," or, "I don't know where the screen exists." Now, those kinds of issues, they limit the absorbability of some of those environmental issues, to us, as the control and the grid operator, and we make sub optimal decisions as a result of that.

So, yes, those mechanics are there today, but they are not consistently used. And I think if we go down that road of making them easier to use and more manageable, such that we get better information, I think that's a step forward.

Questioner: Just to follow up on that, do you think, if you did get more visibility into it, or had, you know, maybe perhaps more training, so the generators would be able to use this information more consistently, would that help with the gas-electric harmonization?

Speaker 3: Yes and no. I think it would help us better schedule the generators, because we would have more information in front of us. But there are still some pretty large hurdles with gas-electric coordination that we need to get across--timing of the gas/electric days and things like that are things that are still outstanding issues, that no matter what we do with environmental opportunity costs, that still looms large in the background. So yes, it helps, but there are still other issues outside of that, that we've got to work with.

Question 3: Obviously the criticisms of 111(d) can be grouped into three buckets. One is, we can't maintain electric reliability. And the virtue of what you're talking about here today is a co-optimization of reliability and environment benefits. So arguably it deals with that issue.

The second complaint has been around timing, how quickly the EPA is moving. And the third complaint has been around consumer costs. And I wonder if you could each cover those last two issues, first talking a little bit about how quickly a program like the one you've been describing in the case of RGGI and the California program, what the lead time was to actually implement those. And Speaker 3, in the case of PJM, could you comment on how long it would take PJM to develop the systems necessary to implement this?

And then, lastly, you did not talk about consumer price impacts. And obviously, there have been claims that this rule is going to result in de-industrialization, and horrific price impacts for consumers. And so if the three of you could give a sense of what you think…

And, again, Speaker 3, I know that your analysis indicated a range of potential carbon prices. But assuming you took those monies that are earned, and allocate them back to the customer, what would we be looking at in terms of retail rate impacts? And again, that's against the total generation, distribution, and transmission costs that consumers presently face.

Speaker 4: Well, let me address the consumer pricing question. So, with the mechanism where you integrate the cost of greenhouse gas compliance into the market, you have the ability to provide economic signals for the cost of that regulation.

How you do that is, when the market clears, and you have a marginal cost that shows you the additional cost that, let's say, the load that is served in California has to pay, for the explicit cost now of greenhouse gas that is reflected into imports from an EIM entity, that provides an economic signal that is what you want to have out there to incent technologies that provide lower emissions and have more renewables to compete successfully, because they have a lower emission factor.

So, yes, there will be a cost that the consumer will see. And I believe it is far better to have that cost more explicitly shown, rather than to be hidden in some general electricity market rate. If it's more expensive, it provides a more direct economic signal about how much carbon will cost you.

Speaker 3: I'll try to address your question about the timing from implementation and the reliability implications.

So, if we end up where we're taking a region-based approach (and when I say "region," I mean the RTO as a whole), and we're putting emissions adders on resources, to me, that's something that fits within the model that we have today, and so the turnaround time on that's very small. Reliability implications are a lot smaller, too, because the wider the region is, the more dials and levers I have to manage the constraints that I'm controlling against.

So from that perspective, the closer we stay to that side, the shorter the implementation time is. The further we get from that, if we start dispatching around sort of emissions requirements, and if it's all state-based…if we're collecting new data, trying to reformulate all our complicated algorithms, you're probably talking years at that point.

As far as the wholesale market, and making the required changes to implement something along those lines, from a pricing perspective, I'm going to use my lifeline and punt to my colleague who is in the room and who engineered a lot of that analysis.

Comment: Thanks a lot, leave me with the tough ones. I think the issue is, on the two slides that Speaker 1 pulled from some of our analysis, the price impacts are going to depend on whether it's state by state or a regional approach. It's going to also depend on a lot of assumptions.

Do we see all the renewables that EPA forecasts? Do we see the energy efficiency? How are states going to treat new resources? The way we did our analysis, new resources, that's 111B. That's completely out of the program.

And so, to the extent that we're talking about price impacts, we shouldn't get wrapped up at this point in the actual magnitudes, because it's going to be so sensitive to assumptions, we don't know what the world's going to look like in 2020, let alone in 2030.

But qualitatively, we know regional compliance, with a single price on emissions, is going to lead to lower compliance costs, lower LMP impacts, as compared to state-by-state compliance, and it's also going to lead to a lower number of generation units at risk for retirement, because, again, the impact of the policy is going to be more dispersed. So, from a reliability standpoint, at least on its face, that regional compliance approach is going to make a big difference.

Now in terms of the bill impact, this is where things get dicey. If you assume that the renewable portfolio standards are in effect, and it is not as a result of 111(d) policy, then it's true there aren't compliance costs associated with the policy. Those are associated with a different policy.

Now, those costs are going to show up somewhere. If it's not in the wholesale market, energy market, it's going to show up in the capacity markets, or it's going to show up on the retail bill somewhere. The same is true for energy efficiency. Are those actually programs that are separate from 111(d), or are they because of 111(d)?

And so this is where I think it's important to not get wrapped around what the price of CO2 is, versus the overall compliance cost. I can drive the price of CO2 to zero by building a ton of renewables. But that's a really expensive option, because those resources are more expensive than, say, building a new combined cycle gas plant, for example.

We have experience with that, with the Title IV SO2 trading program. So, too, prices were lower, but compliance costs were very high, because everybody over-complied by installing capital intensive controls. The same would be true by going with energy efficiency or renewables, as opposed to simply re-dispatching the system. You may see higher CO2 prices if you take the re-dispatching approach, but at the end of the day, it may lead to lower compliance costs.

There's a bunch of nuances here, though, that we have to consider. The last thing I'll leave you with is, under a rate based program, you get some very counterintuitive results, in the sense that you could actually see lower LMP impacts, but higher compliance costs, and also see more generation at risk for retirement, because of the nature of how a rate-based program works versus a mass-based program. And so there are a lot of nuances here, and quite frankly, I don't think EPA has thought through all of these things.

Speaker 2: On the consumer cost impact, I would second everything we heard from PJM. The RGGI states talked about cap and trade as one component of a suite of carbon reduction policies--renewable portfolio standards, energy efficiency standards--and one of the things that we've done at NYU, for New York State, is developed what we call a carbon calculator, taking all of the various interventions in energy and environment that New York State engages in, and New York State spends about 1.2 billion dollars a year on various energy programs through the New York State Energy Research Development Authority--an enormous amount. And it calculates the carbon reduction of each of those programs to develop a price per ton of CO2. And they're very different. The renewable portfolio standard is about $40 per ton. And state-procured energy efficiency in New York State buildings is about $9 a ton. So you can ask yourself, how much CO2 are we reducing, and how much more bang for the buck could we get, et cetera. But I think it is really important to think of cap and trade in that context.

The second point is that, in terms of readiness, certainly the first programs took longer to get off the ground. The MOU was 2003, the model rule was 2005/6, the first auction was September 25, 2008. However, California came along more quickly than that.

There was a lot of conversation between California and RGGI. The documents were all shared, there were MOUs developed, nondisclosure agreements between regulators were, you know, engaged to have some private conversations.

And there have also been a series of meetings, from 2008 through 2011, including Western Climate Initiative states, more than California, Midwestern states and Northeastern states, that were convened in Washington, DC on a quarterly basis, to talk about the logistics and policy issues around linkage of potentially three state-based regional climate cap and trade programs.

Those got stymied by a number of things, including Kerry-Graham-Lieberman. But there is a foundation of readiness that's there, that I think would allow programs to move more quickly now.

Question 4: I've been trying to figure out what happens to that when you start dispatching with externalities, including environmental prices. Does the differential LMP still give you a congestion price signal, or is it something else, and what is it? And what does that do to the value of FTRs that people have bought into? A lot of people own FTRs whose value will all of a sudden change when we start changing LMP prices. I was wondering whether anyone on the panel has thought that through, and thought about what this means to the whole FTR idea of the market.

Speaker 4: It's a very good question. It's one we pondered a lot, too. It really depends on how you're going to internalize and reflect the cost of greenhouse gas in the market. The way we did it in California, although it resembles how transmission congestion plays out, it's different in the sense that it's a revenue mechanism, where basically participants that are faced with the additional cost of meeting CARB regulations are getting their revenue stream to offset this cost from that mechanism.

So you don't have an issue of hedging against that, you're actually perfectly hedged, because whatever your cost is, assuming you reflect it in the greenhouse gas adder, you're guaranteed to receive that cost for every allocation that you have paid for.

So we didn't see an interplay that would disturb your transmission congestion instruments. You still have transmission congestion because that EIM transfer that reflects the energy that is transferred from EIM into California, or vice versa, is subject to constraints that reflect the available transmission based on how much transmission capacity the entity will bring into the market, right?

So these are different than the constraint I described for the greenhouse gas, and they can be binding. And this is with your regular transmission congestion that will result in different prices for California and for the EIM entity. And for that, you still need a transmission congestion hedge, but it's completely separate from the price differential that you have because of the cost of greenhouse gas regulation. And for that, you don't need to hedge as a provider of that energy, because you're getting a direct revenue stream.

Speaker 3: So if we're going with a regional approach where we're putting emissions adders on the generators we have today, and we are re-dispatching them because transmission limitations would otherwise be violated on our system, to me, that holds true to the current definition of transmission congestion. Because the cost of that is driven by the asset I'm using to control it. If that asset's costs went up because its emissions now cost more, to me, that falls in line with where we're at today.

Separating that from where we could be, which is dispatching resources because of the states that they're in-- there's a potential that now Virginia, which borders West Virginia, has no transmission limitations, but the prices are different, because the emissions limitations are different.

Those state-based congestion differences, based on emissions limitations…you might be right. That might not be something that falls in line with congestion today. I'd probably argue that it doesn't. It's a type of congestion, but it's not transmission congestion, it's emissions congestion. And how we handle that remains to be seen. I don't have an answer for you today.

But I look at those as sort of two different types. Because, in one, the controlling action to control a transmission limitation, the cost of that just changed. In the other, I don't have any transmission limitations I'm trying to manage, it's emissions-based congestion. And that's a little bit of a departure from the type of congestion we have today.

Speaker 2: In a well-designed carbon regime, you end up with an appropriate result. What we're essentially doing is diluting the impact of congestion-based pricing by now including the additional criteria of the environmental attribute, the carbon attributes, of whatever the generating resource is.

And so, on the one hand, you have the location-based impact. And on the other hand, you have the carbon-based impact. And those two would need to be balanced. And to do that within the ISO price mechanism is the reason why you want to put a price on carbon, as opposed to have carbon be regulated through some other methods. So you would necessarily see a dilution of the congestion pricing impact. And the extent of that dilution would be based on how high a price you put on carbon.

Questioner: Isn't it the case that the change in prices could be so great that it overwhelms the congestion pricing signal?

Speaker 2: You would have a price signal that more significantly reflects the environmental attribute than it does the transmission attribute. And we can talk about whether or not that is appropriate.

Moderator: OK, so, welcome, Speaker 1. If you'd like to give a little discussion right now, I'm sure everybody would appreciate it, and then we could continue on with our questions.

Speaker 1: What I tried to do with the presentation, and what I hoped would be the continuing discussion here, is to say that the carbon problem is a real problem. There are good ways to do this, and there are better ways to do this.

And the good ways to do this, EPA recognizes, are monetizing the carbon, putting the price on carbon and letting it go through the economic dispatch, and then that doesn't screw up everything else. And the thing I'm worried about is that when you read the Clean Power Plan proposal, it looks to me like the intersection of their authority to actually have a system that monetizes the price of carbon and a well-designed market might be empty.

And so they're talking around it all the time, and talking around it all the time, and saying a lot of things which are not true that have to do with simplified views about how the system works, and then coming up with these numbers and then saying, "Of course, the states have a lot of flexibility so that they can undo everything we did here, and do it the right way, even though it's not something that we can mandate."

And I think that's extremely dangerous, and I close by reminding you that we have tried in many ways to screw up economic dispatch in the past. And we have paid dearly for it. In the case of the California energy crisis, we had an economic design for the electricity market that prohibited economic dispatch, at the behest of Enron. And we saw what happened there.

And I don't think there's any evidence that people at EPA really understand this problem. And so it could come out very well, but if you look at that document, and you look at the legal authority in terms of what EPA can require, basically what you have to have is all the policies that we have talked about taken off the table. You can't have a carbon tax and you can't have a cap and trade, unless the state's proposed it. And then the states have very conflicting incentives there.

I just was reading on the plan, since I had all that time, a very interesting paper that came out of California a couple days ago, from the folks at Berkley, and Chris Knittel at MIT, analyzing this regulations under different interpretations of what they mean. And their focus was on the perverse incentives that get created for the states, which will prevent cooperation.

And this is a really, really serious problem. So, we could do it right, and it would be just fine, like RGGI, you know, that would work, but, boy, are there a lot of ways to do it wrong.

Moderator: We did hear some discussion earlier about how RGGI has been an option, and it sounds as though you agree, if the states could be, if not mandated, at least incented to participate through that mechanism.

Question 5: Earlier, Speaker 2 noted that the electric sector is one of the main sources of GHG, and I think in fact, nationally, it's probably the largest contributor to GHG. However, it's certainly not alone, and in California, for example, the transportation sector is a significantly greater contributor to GHG output than the electric sector is.

And so, when I'm thinking about transportation electrification, at least in low marginal GHG emitting states, it can be a valuable contributor to reducing GHG overall. However, if the GHG rules are limited to the electric sector, whether it's through what the EPA is doing, even certain, you know, cap and trade regimes that are limited to the electric sector, at least aren't broad enough to include all the others, then they have the potential to provide a disincentive, not just being neutral, but a disincentive in the electric sector, for transportation electrification, which, if ultimately we're trying to get to a particular level of GHG output, we need to include, and include sooner rather than later, as part of the solution.

Of course if we have a broad solution, as Speaker 1 just described, the ones that seem to be politically infeasible, that might deal with it. But otherwise, how can we develop a structure, especially if we're limiting our focus to the electric sector, that provides appropriate incentives for the electric sector to help in contributing to the solutions for the transportation sector?

And this may be particularly important as intermittent renewables become a bigger part of the mix, and the flexible load that comes from transportation electrification can actually help be part of the solution to that. Any thoughts?

Speaker 2: Sure. I think the extent to which transportation electrification is forecast is one of the main ingredients that jurisdictions need to consider when they set their initial cap.

And one of the lessons of RGGI is, how you set the cap is really important to the overall function of the system. And more important, perhaps, than the initial cap level, is the flexibility, and the mechanisms you allow for flexibility for that cap to adjust.

Two RGGI states actually required legislative approval for changes to the cap, and that was a significant issue. Eight other states required a full suite of regulatory approvals for the cap to change--so, an 18 month process.

The current RGGI regime has a much more flexible system, with reserve allowances. In the event that prices get too high, there would be additional allowances released onto the market. And part of the motivation for that was foreseeing the electrification of transport.

So that's a partial answer. California has included oil stationary source emissions in its overall cap and trade regime, although they're not currently participating, is that right? What's the timing of CARB bringing in oil refineries?

Speaker 4: I think it's supposed to happen starting next year, but there continues to be strong political push by the oil companies to put off --

Speaker 2: To delay it, right. It was going to be 2015, 2016, you know…I think the RGGI stages viewed that as a potential complication for the California program being used for Clean Air Act compliance. I think there are a number of aspects of California's programs that might raise eyebrows for compliance--imports and the Interstate Commerce Commission aspects of that.

The link with Canada is just an enormous complication--the extent to which states are authorized to engage in trans-border commercial treaties, as opposed to the federal government doing that. And then, the allowing of international offsets is another major issue.

But one of the things that we haven't really talked about in the Clean Power Plan is the difference between rate-based and mass-based programs. And the Clean Power Plan is rate based. So, presumably, if overall electricity sector emissions were to increase, but the emissions rate were not to increase, there shouldn't be an issue there for current compliance.

The RGGI states have commented strongly to EPA that mass-based programs are the best and lowest-cost route to overall GHG emissions reductions. And how one translates between rate-based and mass-based is one of the major questions for people to figure out and for EPA to provide guidance on.

Question 6: I'd like to direct this question to Speaker 2. Having been around too long to mention in polite company, I've learned a couple of things. And one is, there is a difference between causation and correlation. That's one thing I've learned. The second thing I learned is, timing is everything. If I understood you right, Speaker 2, the first RGGI auction was in 2009?

Speaker 2: September 2008.

Questioner: OK. Have you taken a look at whether it's the auction that's causing it, or whether just the drop in natural gas prices is causing the drop in the CO2? There's a substitution effect, obviously.

Speaker 2: Sure, some of the charts that were in my slides suggested that it really is a number of exogenous factors, including weather, availability of non-fossil emitting resources, increased nuclear and hydro capacity, and fuel substitution, which is probably the biggest factor.

And we're also coming off the late 2008 economic slowdown in manufacturing activity. This was the introduction of cap and trade for carbon dioxide. The first time in North America. One can ask, in retrospect, whether those soft market conditions were in fact the thing that allowed the program to be introduced without more significant pushback. In tighter market conditions, there might've been significantly more resistance to the program.

Question 7: This is, I guess, mostly for the ISO gang at the end of the table. I work a lot with power electronics, advanced transmission technologies, things like that. And I hear a lot about inertia.

What are we going to do to move out of the past into the future? What are the physical limitations and possibilities, and what are the regulatory and policy things that need to happen?

Speaker 4: It's a very interesting question, and specifically in the inertia the department, unfortunately we're still rely on conventional technology. And one of the objectives of the market operator is to maintain flexibility in the grid that has the ability to provide the inertia volumes that you need to maintain system stability.

And that's why we're particularly concerned with generator retirements because of these regulations. So we're looking into providing additional revenue streams through ancillary services that are specifically designed to exploit the flexibility of plants, like flexible ramping capacity.

It's a product that the California ISO will launch next fall, and we believe that will be an additional revenue stream for conventional technologies that have rotating masses, so that they can maintain some of this much needed inertia in the system.

But it will become more and more challenging as we go into an era where renewable energy will penetrate the grid at larger content. And then, on the other hand, we'll have to balance it with energy storage. And this technology will not provide the inertia that we need to see in the grid. So we're definitely hoping that technological innovation will come up with a solution for this area.

Speaker 3: From PJM's perspective, I think things like smart inverters and things like that that can bring sort of that pseudo-inertial response to non-inertial-type assets, is hugely critical. But there's really no mandate to do that today, there's no NERC requirement, for example, that every wind generator has to have a smart inverter tagged to it.

And if you look at governor response across the board today, that is largely uncompensated in the United States. And whether we can continue like that or not, I don't know. Certainly if we want new resources to come with that capability, we probably can't stay in that mode. And I don't know that we are completely in the danger zone today, but conceivably, we could get there, depending on where we go with some of these environmental and emissions-related regulations.

So from my perspective, it's probably going to take some kind of outside action to make sure that the market economics reflect the value and the need for those types of capabilities. I don't know that we're there today, but perhaps we need to start looking in that direction.

Question 8: I know that in California, with AB32, leakage has been a big issue--sort of megawatt laundering, so-called, to bring in megawatts that are high carbon and somehow try to get around the AB32 requirements.

And in RGGI, obviously, the leakage issue has been a big deal. But the leakage issue that I want to ask you about is the issue of leakage between 111(d) and 111(b). Under section 111(d), it's only existing resources. And as a possible compliance option, and not having to reflect the cost of carbon, one could simply build a lot of new combined cycle gas, and automatically meet the resource performance standards.

And yet, they don't count against the emissions rate standard, the mass-based standard, if you wanted to convert to that, under 111(d). And so my question is, how are you all thinking about dealing with those issues, in terms of leakage? This is not leakage on a regional basis, this is leakage on a vintage basis. Old gas versus new gas.

Speaker 4: Well, where we designed this greenhouse gas regulation market mechanism in California, we were right away very much concerned about how CARB will see this market mechanism in terms of what they call resource shuffling. which you alluded to. To bring everybody on the same page here, resource shuffling is a term that is used by CARB to, in a very nebulous way, refer to any kind of mechanism that a power market could use to substitute energy from resources obligated to comply with the law in ways that reduce the compliance obligation.

So, we were concerned about how CARB would see the Energy Imbalance Market. And after discussions that we had with them, they were comfortable not to consider that resource shuffling, and they went along with it.

And the reason for that was because it is not a particular scheduling coordinator or market participant that has control over the allocation of resources that provide the export to California, but it's through the market. The market operator globally calculates an optimal solution.

So therefore, they didn't consider that resource shuffling. So we managed to get through CARB an agreement that this is a good market solution for the compliance question.

Speaker 2: Yes, new fossil fuel generation would have to comply under an existing cap. So the fixed number of allowances would remain in effect, so it would further constrain the supply of allowances, increasing the price, and any new generation would have to balance that, and would have to include that cost in their overall economic feasibility. So, that's one way that I think 111(b) and 111(d) interact.

I would say that what you're pointing out is the insufficiency of the Clean Air Act, which is a 40 year old law that was revised significantly 25 years ago to address some of these problems, and the fact that EPA is very robustly trying to deal with a public policy problem with the tools that they have at hand, given the inability to create new legislative tools in the current congress.

Question 9: I'd like to make a modest suggestion on inertia and governor response: Pay for it.

Speaker 3: I'm not disagreeing with that. I'm just saying today we don't. So, why do it?

Questioner: Well, where's the filing? [LAUGHTER].

Speaker 3: I'm writing it right now [LAUGHTER]. I mean, you raise a good point, because a generator in that scenario, you know, if they enable their governor control, they operate at a point that is lower than their most efficient operating point.

Questioner: Pay the AGC (automatic generation control) price.

Speaker 3: That's certainly a solution.

Questioner: It's a pretty short filing [LAUGHTER].

Question 10: I would like to get back to the revenues. You know, if there is increased congestion because of carbon price, or carbon cost adders to individual power plants, or if there is a fourth LMP component that's environmental congestion or something like that, where would those revenues go? Even within California, would they just be distributed along with other congestion revenues to FTR holders and others? Or should it go to loads?

Speaker 4: Well, as I mentioned previously in response to a similar question, the cost differential that materializes because of the marginal cost of greenhouse gas regulation is different from transmission congestion costs.

And in transmission congestion, we require hedges because of the price differential, and that's why we have all these instruments that we can use, to hedge against congestion. But for greenhouse gas price differentials, it's inherently a revenue neutral settlement system, in which you don't need a hedge.

The environmental price differential is directly paid out to the providers of the import energy to California who face the additional cost of complying to the greenhouse gas regulations in California. So, that directly offsets the cost for acquiring the compliance instruments.

So, you don't have the classical location mechanism where you collect congestion revenue, and then you have the dilemma of how to allocate it. Here, what you collect is directly allocatable to the parties that actually see this additional cost.

Questioner: Well, let me approach this question differently. I find it problematic to give the money back to the generators, because there's no real change in anything. But let's forget about imports. What about within California? I mean, you would have environmental congestion revenues from dispatch within California. Where does that money go?

Speaker 4: Within California, what you see is that the cost of carbon is reflected in the energy bids that participants give to the market. So, it's reflected in the electricity prices out of the market. So the cost of greenhouse gas regulation is already included in the prices paid by load.

What's happening now with energy that is imported from areas under the market where there is no greenhouse gas regulation, is you have an explicit signal for the marginal cost of environmental congestion because of the greenhouse regulations in California.

But, fundamentally, it's no different. The only difference that now you see this cost separately from the cost of energy, whereas before, it was part of the LMP, and you wouldn't see it separately. But, it's still there.

Speaker 3: The other example is RGGI. There, the generators bid at auction or purchase credits on a secondary market, and those costs are passed through into the wholesale market. The auction proceeds are allocated to each state by the central coordinating entity. And this central coordinating entity has come under legal challenge.

RGGI is a 501(c)(3) corporation, it's called RGGI, Inc. And there are strict limits on what it can and cannot do, and the kinds of conversations it can engage in. I think it is most analogous to the EZ-Pass toll coordinating authority that is a multi-stateproceeds collection agency that has its headquarters off of the New Jersey Turnpike, I think it's in Delaware, that operates on behalf of a number of states and allocates revenue. So it's very nicely analogous to RGGI, and those proceeds are allocated back to each state, and each state has developed its own plan for how they are invested. For RGGI funds, across the region, about 60% goes to energy efficiency. So, you're mitigating the bill impact of the potential rate increase. And Maryland spends more money on low income consumers.

Unfortunately, early in the program, New York took about 130 million dollars for budget relief, and New Jersey took about 90 million. That hasn't happened again. That was in the depths of the budget crisis. But overall, you're seeing relatively high rates of reinvestment in a variety of customer benefit programs.

The one other point I want to make, which is about this whole theme of pricing carbon, and integrating carbon into the economic dispatch, is that one of the opponents of cap and trade, while RGGI was under consideration in New Jersey, proceeded to make a series of phone calls to regulators, asking where on their consumer bill could they see the charge line, for RGGI. And recorded those phone calls. And had a number of regulators give inarticulate answers, and then created sort of a YouTube-like commercial about the lack of transparency in carbon pricing and cap and trade.

And so for policymakers, at the same time that you bundle the carbon price in with a number of other attributes, it's important to keep in mind the kind of challenges that can sometimes come from consumer advocates and from people who are purporting to be consumer advocates along those lines.

Speaker 1: I'm in a small minority, which I think consists of me and my brother in law, but I still think that the breakthrough that's going to happen, not for sure, but with a significant probability, is that the money is going to be irresistible when we're doing, when we have that meeting where we're doing fiscal reform across the board.

Then a whole lot of things are going to have to change that are politically impossible. They're all going to change as part of one package. And then, if you can adopt a carbon tax, you can deal with many of the things that people have mentioned, because now you can go across sectors, and you can go across regions, and have one number for the country, and the money goes to budget needs, because you're either going to raise some other tax or raise this tax.

That's what's going to happen as part of that fiscal reform. And I don't know when it's going to happen exactly, but I can't imagine how else we're going to get out of the crap we're in with the expenditures being too high and revenues being too low. That can't go on forever. And there's going to be a meeting, and they're going to raise taxes on something. And this would be terrific. This would be the right place to do it.

So, I think that's my hope, and I don't think it's even a crazy hope. I don't think it's certain, by any stretch of the imagination.

Question: At what level of government?

Speaker 1: The federal government.

Speaker 3: If you look back to the PowerPoint presentations that Peter Orszag at OMB was giving in January 2009, it was that a national carbon price would pay for healthcare. So that was very explicit, and the conversation has changed significantly since then.

Speaker 1: If you do it as a package, the externality numbers are even bigger for small particulates. So the revenues that'd be collected from that are even larger, maybe twice as much. This is something that Dale Jorgenson's been writing a lot about.

Question 11: Speaker 3, when you talk about environmental opportunity costs, are those the same as environmental compliance costs? Or do you mean something different?

Speaker 3: The environmental opportunity cost is really centered around the question of, if you run for a certain period of time, what amount of revenue do you potentially forgo, by running in some given hour instead of the peak hour. That's really what it comes down to, and it's based on seasonal kinds of complicated sort of measures.

Comment: This has been a FERC-approved mechanism since back in 2009. The issue comes up when you have generators that have run time restrictions in their air permits, and you want to run them in the most valuable hours, you know, for reliability, which also turn out to be the most valuable hours financially.

And as Speaker 3 said, there are a lot of complicated formulas there, but this is a FERC-approved mechanism. The one thing that's different, and Speaker 3 alluded to this in his comments, is that it's not mandatory. And so, again, because it's not mandatory, a lot of generation owners either don't know about it, or can't find where to do it, or don't think about it. And then all of a sudden, we get calls going, "You've just run us out of our hours!" Well, you didn't actually put a put in a price for that.

Now, if we take that to its logical extension under 111(d) (and we've had states tell us not just no, but "Hell no. We're not going to put a price on CO2, not going to happen.) So how do you handle this and comply with 111(d)? You put runtime restrictions on units. If that happens, the only way we can possibly manage the system through economic dispatch is by forcing people to use this opportunity cost mechanism-making it mandatory. Is it the most efficient way to go? No. But at least it puts a price on that restriction, and we can still manage the system in a somewhat rational manner.

Speaker 3: Just to piggyback on that, I think that as a result of it not being widely used today, and not being mandatory, there's sub optimal decision making, and the market suffers as a result of that. And so do operations. We operate, I don't want to say less reliably, but certainly less optimally, by doing that.

Questioner: So what about baking environmental compliance costs into the bidding process as a way of incorporating at least some of these environmental costs into the economic dispatch? If I understand what Speaker 4 was saying it sounds like that's what's happening in California.

Speaker 3: Are you talking just specifically about emission adders and things like that? Or are you talking about something different than that?

Questioner: We can start with that. That makes sense.

Speaker 3: From the emissions adders perspective, I think that's probably the logical next step, right? To have those resources for which it's costing them more to generate because of their emissions reflect that in their offers, and then we sort of weave that into the current model we have today, and it sort of all comes out in the wash, so to speak. I realize I'm oversimplifying there, but more or less that's where you end up.

To get into the more complicated things, such as the state-based approach, it becomes a little bit of a tougher problem to navigate, because when you put that compliance allocation at a smaller level, you limit the ability to use the different dials and levers for the ISO/RTO to manage it. And any time you limit the flexibility, the cost is going to go up as a result of that.

And that's why I think some of PJM's studies and things like that show that the regional approach (and when I say "regional," I mean RTO-based) is, from a cost perspective, significantly better than the state-based approach.

Question 12: One of the presentations mentioned the concern about frequency control, and it appears NERC has raised this issue without doing actually any analysis on what might retire. They just said that it may be a problem.

But as someone said earlier, there's a difference between having governor response and inertia. And we can talk about paying for the governor, but inertia is part and parcel of the turbine generator that you buy. And so I guess my question is, if it's not priced right, that means the regional cost, you could end up paying more for a very small amount of inertia, than for large steam turbines and nuclear units that were put in 30 years ago at a lower price and provide a great deal of inertia.

And then the second part of my question is, for those people who simply have cost of service, not in RTOs, but have cost of service, one bundle price, how would you do it? I guess I would caution them not to do it the way you do reactive power. Otherwise, you're going to be paying for the wrong thing.

Speaker 3: Yeah, I don't disagree that some level of compensation for inertial response is probably appropriate if we're trying to assuage where it looks like you may end up going. And I don't want to make it sound like NERC did nothing, I think they recently passed something which actually puts frequency response requirements on all of the balancing authorities within these three interconnections.

So I don't want to make it sound like we've done nothing, but as far as compensation for maintaining that response, to be frank, we have nothing. And your point's well taken that governor response and inertia are not necessarily always interchangeable, and so we need to make sure we think long and hard about the product that we're trying to compensate for and the costs of that.

As far as what those costs actually are, I don't have an answer for you today. But certainly, your comments are well received, I certainly understand where you're coming from.

Speaker 4: Let me chime in a little bit on this, and, you're right, and as I said before, those two products are different. Governor and inertia are different, so you're looking at the mechanism for putting incentives in for these products to exist, you need different market mechanisms for the two products. And for the governor, that is commonly referred to as primary reserve, there are markets out there that they do have a primary reserve market.

In Europe, several markets do recognize primary reserve as one of the ancillary services. It's just another capacity ancillary service. We haven't had that in this country, and it's something that we should probably look into.

For inertia, you also have to come up with the market mechanism. And we can develop requirements for inertia based on stability studies, on systems, these are traditional electrical engineering studies, but they require certain inertia in the system. So you could come up with an inertia requirement.

So, there are mechanisms. We just don't have the incentive to develop them right now. These are products that traditionally have been been taken for granted. So if at some point some regulation requires the development of these markets, I don't see any potential problem in developing them.

Moderator: While we're getting the last question, to use my prerogative to ask all of the panelists to think about a final question, which is that we have a number of policymakers in the audience, and we also have a lot of stakeholders.

So, if you were to try to think about one action that you think is most necessary or effective to be taken in the next six or 12 months while the EPA is trying to sort through the millions of comments, to actually help us get towards utilizing our markets in a way that can help achieve the objectives of the Clean Power Plan, what would that be?

Question 13: Earlier in the discussion, someone said that the according to the 2009 order, the opportunity cost filing requirement is not mandatory. Are there efficiencies to the market if that requirement was made mandatory?

Speaker 3: I think so, yes. Because I think it puts us in a spot where when we're scheduling and dispatching the system, we have better visibility into what the implications of that are. And it's more specific to the utilization of a single asset. If I commit it now, what do I lose later? Right? And it has the ability to differentiate itself on a cost basis now. But by and large, like I said, that's not used. And I think that as a result we probably do some things sub optimally, because of that lack of situational awareness.

Moderator: OK, so, who would like to start with their final thought of what we can do to move forward? Can I start with Speaker 1?

Speaker 1: Well, when I read the Clean Power proposal, I see that EPA says several times something to the effect that monetizing the effect of carbon makes it easy to include it in economic dispatch. And the way they interpret that is, this is an interesting capability and a tool which we can then adapt for our purposes so it can be helpful with meeting the environmental objectives.

But, what they don't say, and what I'm not sure that they recognize, is that monetizing and including the price of carbon in the economic dispatch one way or another, is necessary if you want to preserve the electricity markets. It's not just a nice feature. It's not just a handy tool. This is necessary.

And if you don't do that, we're going to have all kinds of unintended consequences, where you're going to end up with people who are going to have dispatches which are going to be uneconomic, in the sense that the prices that we're using are not going to be consistent with the dispatch.

And then you're going to get all of the crazy things that happened in California and Texas and PJM and every place else where we did that, where people start torqueing their own plans, their own schedules, their own everything, in order to get around the incentives that are created by having a pricing mechanism that's inconsistent with what you're doing.

This is a really fundamental, existential problem for electricity markets. And they must monetize or they shouldn't do it.

Speaker 2: I think states are in very different places on this. Some states are reaching out, having conversations about how they can join existing programs or begin their own. Other states are filing law suits against EPA. And that's natural to have that level of diversity.

So focusing on the states that are less ready to accept market-based monetization of carbon dioxide, I think it's important for them to act as states like Kentucky have, with both their left and their right hand. On the one hand, the attorney general and the legislature have filed lawsuits against EPA. On the other hand, Kentucky is engaging in conversations with a number of its neighboring states about how it might develop its own regional carbon trading program.

The first step to doing that, I think, is to develop a state-based carbon dioxide tracking system. Regardless of what other policy measures one may or may not want to take, having a state-based program that is linked with EPA, that sort of leverages the experiences with the SO2 emissions accounting program, is a really important first step. It's a very detailed process that takes six to 12 months to develop.

But that, I think, is a really necessary, important first step.

Let me just highlight that we haven't had any discussion or dissent from what has been the main underlying principle of this panel. That monetization is optimal, and you're saying stronger than optimal, necessary, and that regional is more optimal than state-based. And to me, those are major takeaways for policymakers.

Speaker 3: I'll be brief, because otherwise I would just be piggybacking on these two guys, but the other thing I'll throw out there is, if the implementation of some of these regulations deviates from the models that we have today, and we don't allow the necessary time for those models to evolve to capture the new world that we're living in, we certainly run the risk of unraveling a lot of the efficiencies we have today.

Speaker 1 mentioned economic dispatch as a necessity, and it absolutely is from our perspective as well. This doesn't mean it can't get augmented to work in a new paradigm. But we don't allow that development time and that maturity time for the electricity markets. You're absolutely right.

We will be inefficiently operating, because we'll be operating and dispatching units in a manner that's inconsistent with what actually want them to do. And that is hugely problematic from a system control perspective, from a pricing perspective, and from an incentive perspective.

So I agree with what both of these gentlemen said before me. Economic dispatch is critical, and certainly a regional approach, from our perspective, is much preferable to a state-based approach.

Speaker 4: I would also agree with the previous speakers here on this panel, that it's important to find a market solution that incorporates the environmental costs. It's also important for the states to develop programs that are compatible with market design.

But it's also even more important for the various states to develop compatible programs, so that they can now be integrated into energy markets that today span several states, and that have the tendency to increase and go beyond boundaries.

So it's very important, as states develop these programs, to coordinate and collaborate so the programs are compatible.

Session Two.
Technology and Resource Choice: What Value Diversity?

Natural gas has clearly become the "fuel of choice" for new generation in the United States. That "choice," of course, was not dictated by policy but rather by the marketplace. The competitors of gas—primarily coal, nuclear, and renewables—have either been more expensive, less reliable, or environmentally riskier or perceived to have some combination of those market disadvantages. The result has been what some have characterized as a market driven "rush to gas." Some would contend that resource decisions need to better take into account the benefits of diversity in resources. Prior to the emergence of competition, vertically integrated utilities, as well as regulators, through integrated planning processes could try to optimize such long and short term considerations. Is such an effort possible in a competitive market? Is it needed, or, over time will market forces balance things out? Renewables in many jurisdictions have their own set aside market: renewable portfolio standards. Nuclear and coal have no such set aside haven from the market. Should RTO planning processes be required to explicitly address portfolio diversity? If so, what criteria should be used in forgoing currently knowable price information in favor of longer-term insulation from volatility? What reasonable risks should a merchant generator be expected to take when it opts for a resource that is out of the market at present? How would the costs of any above current market plans be allocated? Are the prices for "out of market" resources actually brought back into the market by virtue of having fuel on site or other reliability/systems operations perspectives? What would such a planning process do to the competitive nature of the marketplace?

Moderator.
Welcome everybody to the Session Two panel, "Technology and Resource Choice: What Value Diversity?" An important panel. Many of us in our regions are seeing less diversity in our resource mix than we have in the past. And many of us in our regions are continuing on that pathway, if we make no changes. So this is important, and it's having economic and reliability impacts that many of us are grappling with in the room. So I look forward to this panel. And I just ask the panelists, in your remarks, if you could help baseline the audience a bit, and make sure that you guys are bringing out questions like how are resource decisions made today, and from today's paradigm? How is diversity considered or not, but also, why do we need or want diversity? So really, what's the point there? And what are options to address this, and are there pros and cons or considerations as to some of the options that you guys are thinking about in terms of diversity in our generation mix?

Speaker 1.
It's a pleasure to be with you today. I've never found people that are against the idea of having a diverse power supply. But what's striking is how little effort seems to be out there to put numbers on it and really effectively incorporate this into a lot of decision making.

The good news is that we've inherited a very diverse generation fuel and technology mix in the US based on decisions people made decades ago. And that's the good news. The bad news is that, because we inherited it, I think we kind of take it for granted. And as a result, there are some things happening in the power business today that are problematic and really threaten that we're going to lose a lot of the value we have in diverse power supply.

So in looking at the challenge here, what we know is, the power business is a fundamentally risky transformation business of taking these primary energy inputs and making them into electricity. That risk is something that we don't see emphasized enough in the planning process. So, for example, we looked at about 80 different integrated resource plans. Most mention the value of diversity in supply, but few quantify it. And when you know how IRPs work, where you're trying to make tradeoffs between all these multiple criteria, not putting a value on something leads to an under emphasis on it in the decision process.

There are two major challenges to fuel diversity, and I think the panel we had this morning really pointed to one of them. There are a lot of simplistic ideas about the power business that are getting traction, and there are a lot of faulty cost assessments that are getting credibility. They're getting embedded into policy formulations, and so one of the threats to the fuel diversity that we have in the US today is poorly designed energy policy. And I think in the discussion we had about the Clean Power Plan, I think there's a major concern that this plan wasn't developed well, and its implementation could create some big problems.

The second big threat, and I think this will be a topic tomorrow, is that there's a missing money problem in the power markets. Our research suggests that there are two major dimensions to this. One is an inherent problem associated with power technologies, such that you're going to come up short on cost recovery, and that's what capacity markets are trying to address. The second dimension is that we've got a lot of interventions in the marketplace, like renewables mandates and other things, that are depressing the energy price. That's squeezing the cash flow out of the energy market, which is typically what you rely on to pay for the cost of cycling and base load units, the additional capital above that of a peaker.

So the concern here is that you've got plants like a Kewauni nuclear plant in Wisconsin, or Vermont Yankee. The market has given them \$45 a megawatt hour. They keep going at \$55, and they're going to have to be replaced with something that's going to cost \$70. And so it's an inefficient, premature set of retirements from these market signals, on top of the kind of energy policy impacts that we've been talking about. And the bottom line is that it seems that we're on a path to retreat from coal and nuclear, to have an erosion in our hydro generation, to push our renewables to about 25% of our supply, and thus we end up with about 70% or more of our generation coming from gas. So that's kind of directionally where you can see the US power system going. And the question is, what's the value of going from where we are today to that less diverse mix? And the answer that we came up with is, it would be about \$93 billion a year in costs to go from where we are, to lose the diversity we have today, for this less diverse case.

So to put that in perspective, you know, revenues in the power business are about \$370 billion a year. So this is not a trivial amount of cost. To quantify it, what we did is we said, "Let's look at the years 2010 to 2012. And let's run a counter factual. What if the US, during that period of time, didn't have meaningful amounts of nuclear and coal, ran the renewables up to 25%, had hydro drop 20%, and the rest is gas?" And so we run those simulations, and we came up with the quantification.

Now what's interesting about it is that the first thing that comes out of this is that you lose this substitution effect. We talked about economic dispatch. You know, when relative prices change, you're able to move from coal to gas when the gas price is favorable, and move from gas to coal when it reverses. So we get some significant savings year in and year out. So diversity gives you the flexibility to switch back and forth.

The other thing, though, the big value was that you don't have all your eggs in one basket. And so, the answer there was, look, "If you don't have coal generation, and you generate with gas instead, on a fuel basis, that's another \$12 billion a year. And dropping nuclear's another $22 billion a year." And we can talk about the loss of hydro, and then the cost of the renewables, so roughly half of that value, the $93 billion, is this more expensive operating cost.

The other half of it, though, was something that I thought was interesting, which has to do with the fact that diversity is a characteristic of a cost effective generation mix. And so what happens here is, when we lose sight of that, and we move to this less diverse mix, we're moving away from the kind of diverse mix of peaking, cycling and base load fuels and technologies that give us the most economic power supply. And that's true even if we assume a price on carbon. So if we assume a $10-15 a ton price on carbon, the generation mix that you would come up with as desirable doesn't look like where we're headed with this scenario of 25% renewables and largely gas as the rest of the story. And so it's that movement away to a less efficient generation mix, and we saw some evidence when we were talking about the inertia at these base load plants, that's just more of the kind of engineering economics behind the basic conclusion that we're moving away from a cost effective mix of fuels and technologies.

So the analysis really focused on trying to get at what the cost of moving away from that cost effective mix is. It was a conservative estimate. The years we chose didn't include the $8.00 per million BTU gas prices we had in '08 and '09, or the polar vortex we had in '13. But those are other things to consider here. The polar vortex, when you look at New England, really illustrated that here's a system that's getting close to what we're talking about here. You've got nuclear at Vermont Yankee dropping out this month. We've got Braden Point getting retired next year. We're moving towards this kind of less diverse case, and utilities are telling their customers, "This winter be prepared for a 37% higher power bill than what you saw last winter." And it doesn't really sooth people to say, "Look, this is going to be a high year, and look, on average in the long run, we think you're going to be OK."

So it just kind of illustrates the fact that there's a value to fuel diversity in kind of dampening the volatility that people see. But the polar vortex showed us as well that there are reliability implications that we haven't incorporated here. There were, as I think most people know, power plants, even with firm gas supply contracts, that didn't get the fuel during the polar vortex, and thus we had some reliability challenges. So there are macroeconomic impacts and these microeconomic impacts that really suggest there's a high value to the power supply diversity we have today. We're going to lose it with a business as usual and with some of these trends accelerating things. By 2030 we can lose two thirds or more of the value we have today.

Question: I just wanted to ask you about the $93 billion cost figure you came up with from 2010-2012. This is a particular window of time. Did you try to extend it beyond that or try to calculate the costs of having diversity to offset that?

Speaker 1: Yes, we could easily have kind of run a forecast. And then there's a lot of the data about, well, what really is a baseline these days, and so forth. And I thought the backcasting exercise would be a cleaner exercise. The years that we chose there I think are instructive because the gas price that we saw over that time frame, I think it was about a $3.80 per million BTU at Henry Hub, and the kind of variation we saw there kind of comports to what people are thinking the long run price of gas is going to be. So it didn't include extremes, and it did kind of look like what people are expecting in the future. So I thought it would kind of anchor the discussion as kind of an estimate of really what is this value of diversity, because everybody kind of recognizes it, but nobody puts numbers on it.

Question: How do you find cost effectiveness? Have you considered capital investments needed for plans that provide the diversity? I mean, how would you do that with transportation? We don't have any diversity in the transportation industry. It's all petroleum, for the most part. For home heating, it's all gas. And I'm just wondering how you define cost effectiveness in this one.

Speaker 1: The insights that we got in doing some of this cost analysis were kind of interesting. One thing that we talk about when you're talking about the cap ex, we've got this existing generating supply so that much of it, the cap ex is sunk right now. And so one of the things that we talk about here is, and particularly in the policy area or where we've got premature closures because of the price distortions in the marketplace, when you close down a power plant prematurely, for example, and replace it with a new plant, one thing we talk about is the cost to the macro economy. What we're doing there is, and take Vermont Yankee for an example, that's a plant that could have run at least another 20 years. But because of market prices, it closes down. So the average length of deployment of capital in the economy is 12 years. You know, you deploy a dollar of capital, the average depreciation rate as it gets recovered in 12 years, so that over that period, its impact on GDP, for every dollar of capital you spend on new productive resources, you get about $1.80 back in GDP. So when we prematurely close power plants and replace them, we're not producing any more goods and services. There's actually pretty interesting opportunity cost of deploying capital inefficiently because we're accelerating this uneconomic turnover.

The other cost impact that we thought was really interesting here was, we have to reconcile. A lot of people do their levelized cost of energy calculations, and they say, oh, gas wins. But you wouldn't want an all gas power system. You know? And so gas isn't the fuel of choice for power generation. What to build next depends on what you already have. And with the levelized cost analysis, the flaw there is that when people do it, they typically have a cost of debt that's maybe like 7%, a cost of equity that's higher, like 11%, and there's a risk premium there. Well, if you've got an all gas generation portfolio, it's a much riskier portfolio, and you've got about a 300 basis point risk premium to being all gas. So if you build an all gas portfolio and assume the proper cost of capital, you can improve upon that by adding diversity, and it lowers the cost of capital for all your supply. So that was one of the aspects of cost effectiveness generation mix that I think a lot of people overlook.

Question: So do you just say that natural gas plants have a 300 basis point higher cost of capital than other plants?

Speaker 1: There were two ways that we came at this. One way was, we looked at the diversified generators, which were largely the utilities, and we looked at how their cost of capital changes with greater variation in their earnings. And we looked then at how much more variation would we expect if you were all gas versus diversified. And based upon that quantification, that move from where we are today to all gas was about 300 basis points. The other piece of evidence was things like the PJM cost of new entry calculation, there's about a 300 basis point differential, and you see this with the merchant generators that are largely all gas. Their cost of capital seems to have that kind of risk premium on it. So it was a ballpark estimate of the risk premium associate with a less diverse generator.

Question: So you're basically saying that despite the fact that there's higher cost of capital, private investors cannot adequately judge the differences in risks and the costs when they make investment decisions?

Speaker 1: No, I didn't say that at all. I said that in understanding what the risks are here, we do in fact see this risk premium in the marketplace.

Question: It's asserted that if you have a diverse mix, you won't use as much gas, and that will help moderate gas prices. Was that included in the $93 billion?

Speaker 1: No. What we did was simply alter this generation mix. The historical prices on fuels didn't change.

In the work we've done on the Clean Power Plan, where we've got a lot more gas in use, we do see an impact, a higher price for natural gas, although there's a lower price for coal when we do that.

Question: I've heard this presentation several times, and you make the point that during the polar vortex, there were people that had firm fuel supplies from gas supplies that weren't in fact delivered to them. And my understanding is that that actually represented an incredibly small problem--there were a couple of compressors that had some problems, but that almost everybody that had firm fuel supply was delivered. The problems with the gas supply had to do with people that were buying after hours or without firm contracts. Do you have any sense of how to quantify that statement that you've made?

Speaker 1: I don't have those numbers in front of me here, but in PJM…

Comment: On the fuel side, actually, coal accounted for the vast majority of fuel-related outages. There was over 13,000 megawatts of coal steam out. That was the largest segment of outages. In terms of gas interruptions, I think it was in the ballpark of about 9,000 megawatts of gas interruptions. And that was for interruptible.

Questioner: Right. Your point, Speaker 1, was that people who had firm pipeline capacity and firm fuel contracts weren't able to get delivery. And I just am wondering about the order of magnitude, because I don't think that was common. There were other problems in the system. I'm not trying to whitewash those. But I think we need to be clear on where those problems actually developed.

Speaker 1: I know a specific example. I know Dominion had some units that didn't get the gas that they had contracted for, and there were others. But the point that I'm really trying make, and I'm not trying to blame people for not contracting and so forth, but the point here is that besides the cost issues, there's a physical risk of nondeliverability. People have a tendency to underestimate these risks, you know, but there are fat tails in these risk profiles to power system operations, and it's not just gas. You know, we've had times when rivers have frozen, and you can't get the coal supplies. The point being, there are physical risks to fuel delivery that you can manage better with a diverse supply than if you've got all your eggs in one basket. And the polar vortex was an example of that. And it's not that there's any one fuel that's the cause of the problem here, but there were, I think, clear examples of that risk being manifest.

Speaker 2.

Thank you. My presentation today is going to be a bit of a cautionary tale. I didn't have a model to run, so I can't give you any results. But I have been involved in the debate about diversity and resource choice and things of that nature since the Limits to Growth report came out from the Club of Rome in the '70s. That's given away a little bit of how long I've been in this debate. I'm not saying not to plan, but I'm saying that we should to be skeptical of a lot of what comes out of these models, because they depend a lot on forecasts, which we have traditionally been very bad at.

I've noticed that everybody who talks about diversity leaves out the demand side of the market. And if there's one thing that I think is important, it's to factor that back in. And I'm not talking about any of the Order 745 issues or other things. I'm talking about something very specific, and that's price responsive demand.

And it's very simple. It is the demand that tells the ISO at what price it's going to get out of the market, and in return for that, it does not have to participate in the capacity market, which is to say it doesn't have to pay for capacity, because it doesn't need any capacity for its reserves.

When you start to think about this, and when you start to put these in your models, a lot of these price spikes and various other things start to disappear. You don't have shortages, because any time you have an impending shortage, you can use the demand side of the market to get you back into a very safe and reliable position.

With that said, let's go back to the good old days. Probably everybody is fairly familiar with this. We have two nuclear plants under construction today. They fit the historical pattern. That is, a 300% cost overrun with a delayed implementation date. A lot of the portfolio theory that we're talking about here is imported from the financial literature. In 1952, Markowitz told us how to design a portfolio to maximize returns based on risk tolerance. Now, we have Capital Asset Pricing Models, Black Scholes... In the last 20 years, the financial community has really embraced mathematical modeling, and they do it fairly well. Those models are all well and good, but they strongly depend on what your assumptions are about the future. I mean, if your assumptions about the future are correct, then a lot of these models are very good. If your assumptions about the future are very bad…and most of these simply assume that the past is prologue, in other words, that whatever is the trend, it's going to continue. Now, the nice thing about financial portfolio theory is that there is very easy entry and exit into a financial portfolio. We have the gold standard in the S&P 500. There are transaction cost problems that most of the mathematical models assume away.

And so now we have the first interesting, at least in my opinion, exercise in diversity in 1978. And I was a part of this analysis at the Department of Energy at the time. And we ended up, and this was Carter's program, producing a whole suite of energy legislation. We had PURPA, which is still around today, which required you to buy wind, solar and cogen at avoided cost, which is a very reasonable thing to do. And the only thing that was doing is forcing the utilities to do what they actually already should have been doing. But certain states took advantage and calculated avoided cost very generously.

The Power Plant and Industrial Fuel Use Act actually outlawed natural gas in generators. It basically decided that coal was the fuel of choice. That Natural Gas Policy Act was passed based on the theory that we were running out of natural gas. And it instituted, interestingly enough, although it never said this, Ramsey pricing for both the buy and the sell side of the market, and of course, it had curtailment rules, because it was pretty sure we were running out. The Natural Gas Act of 1938, or the regulation at the federal level was from the well head to the city gate of the distribution system, and the Commission used all kinds of rate design approaches to try to manage consumption. And when it issued gas certificates, it used to look at the reserves behind the pipeline, and in my opinion, the fact that the Commission used to look at the reserves behind the pipeline before it approved the pipeline led to overestimation of reserves--one Exxon engineer told me that they used the upper limits of engineering judgment to estimate the reserves that were going to be behind the pipeline. And when you use the upper limits of engineering judgment, and the calculation is multiplicative, it soon becomes a very high number. And then in the '70s, after they estimated these very high numbers, they were forced to recalculate them based on the actual production. And they had to write down a lot of their reserves, and a lot of people thought we were running out, because they had to write the reserves down. But it was in fact because they had to write them up to get a certificate in the first place.

Now, Integrated Resource Planning started in the ‘80s, to deal with oil price spikes and nuclear cost overruns, and then it faded in the ‘90s and is being essentially revived today with a focus on clean energy and climate change. It requires a bunch of forecasts. It requires that you forecast the weather, fuel cost, load, technological innovation, and sort of…well, it doesn’t actually beg the question of who should bear the risk of a wrong forecast. It basically essentially socializes the risk.

The biggest problem, in my opinion, is forecasting. We are absolutely horrible at forecasting, and that’s a fact. And additionally, the IRP has poor incentives, because it has both the moral hazard and the principal-agent problem, meaning that unless you have a benevolent social planner, you basically have two problems, a principal-agent problem and the moral hazard problem, and we all know you play differently with house money.

Now, this will turn out to be a bragging point, but it won’t be obvious to begin with. If you look at the first column there, in 1980, EIA forecast gas prices for ’95, ’90 and ’85. And it turns out that I was the head of the team that did this forecast, [LAUGHTER]and EIA forecast prices (and these are in constant dollars) at \$5.98. It turned out that the actual price was \$1.59. The DOE policy at the time had a separate forecasting effort. They estimated \$8.00, and DRI (Data Resources Incorporated) estimated \$15. So we were on average off by a factor of six. My claim to fame is, I was the best of breed. [LAUGHTER] So now I’m a recovering forecaster.

Now, what does it take to be a successful forecaster? Well, timing is very important, because if in the 1980s, you would have predicted exactly what happened in shale gas today, we would have found you an office over in the corner and told you never to speak again. And if you did this in 2010, you would be classified as clairvoyant. Successful forecasters have to forecast early and often, be able to quickly and glibly explain why they were wrong, defend their assumptions in their model, and probably more importantly, get institutionalized, because whether the model is good or bad, how many times it’s been used in trial proceedings gives it credibility, [LAUGHTER] whether it’s gotten the answer right or wrong.

Now, let’s revisit the energy diversity picture in 2014. Well, we now realize that oil is a worldwide market, and the price fluctuates up and down, and there’s hardly any economic analysis of world oil anymore. There is geopolitical analysis--who is Saudi Arabia trying to punish? Are they trying to punish the Russians or the shale gas producers or ISIS or Iran? Who knows? But there’s virtually no economic analysis in oil.

PURPA’s still around. EPAct 2005 clarified that avoided costs were the LMP, although they didn’t say it exactly that way. The Fuel Use Act has been repealed. As a matter of fact, it was repealed about two years after it was passed, maybe three, because it was obvious that they’d gotten it all wrong, because right after they passed it, the gas prices started to plummet. Most of the NGPA (Natural Gas Policy Act) has been repealed, except for Section Three, which combined the interstate and intrastate markets, which was a good idea. We deregulated the commodity, which probably should have been done in the ’50s, but for various and sundry reasons, mostly political, it never got done. And it turns out that natural gas is not a depletion or running out story, but a loaves and fishes story. That’s a New Testament story. So if you need to refresh your New Testament, I’ll be glad to do it later.

And now pipelines are not closed to the city gate. They’re open access. They get straight fixed variable rates. They’re allowed to negotiate. For gas certificates, you’re allowed to negotiate your rates. In 1978, this would have been completely heretical. And we have ISO markets, which also were unfathomable at the time.

Now, IRP (integrated resource planning) is actually harder than portfolio theory, because you can't get in and out of your portfolio very quickly to make a decision and choose for 40 years or more. A lot of utilities love IRPs, because it basically validates their capital program. But often times these things have multiple objectives--some of them jobs, some of them building in-state resources. Some argue for reliability. And last but not least, sometimes, actually, they do it for economics.

Transmission plans are part of portfolio plans. Doing transmission planning alone, in my opinion--I don't even know how to do transmission planning alone. You have to either explicitly or implicitly decide where the generation is going to be. And if it's right, the generators will show up, and if it's wrong, you have an expensive capacitor.

Now, one of the questions is, are we studying the correct contingencies? I would argue that after the last two or three years, the largest contingency is weather--hot weather, cold weather, windless weather, cloudy weather, or stormy weather. For example, when the weather is hot, it turns out that the probability that you're generator's going to fail is probably higher than when the weather's not hot. The same is true with coal. As a matter of fact, in the Vortex, we found out that we thought that we were having gas problems. Well, part of the problem in the Vortex was that the cold weather basically had an impact on this. The generators couldn't start up. It's not necessarily they didn't have fuel. It's just that they couldn't start up in the cold weather. That came as a big surprise to me, once the data had been sorted out. Also, if it's prolonged cold weather, you can expect more outages from your generators, because you've been running them hard. As Speaker 1 said, coal piles can freeze. So can the rivers that the barges traverse.

So if you look at where we should be studying, in my opinion, in terms of contingencies, it's almost all weather dependent. For example, the duck curve in California is a weather related curve. It's when the wind and the sun sort of don't act the way you want them to, and you have to basically schedule generators that have ramp rates that can accommodate them. I believe PJM's base unit is now dual fuel? So now you have to have, well, an oil storage tank somewhere near your --

In SPP, we're worried about rail congestion for coal supplies. In ISO New England, we worry about pipeline capacity for ten or 15 days a year. And nobody, to my knowledge, although they talk about it, has studied the idea of a pipeline failure. And this is especially interesting in New England, because a single pipeline failure would probably be traumatic. Most of the world uses the old clunker approach to reserves. Instead of retiring plants, you just keep them around for the cold weather. One of the problems is, the old clunkers don't perform very well in cold or hot weather, and are very costly to maintain.

Now, as part of the work for putting this presentation together, I had a relapse, and so I went back to forecasting. Now, this is the total electric end use in the United States, so I fitted a simple linear function to it, with a very nice R^2. And I think maybe using that long data series wasn't a good idea. But if I needed to essentially project more generation, I would use the linear function, and it would probably give me a nice demand to shoot against. But if I thought conservation would dominate, I could set a quadratic fit, and then I'd see demand tailing off. So both of them had very nice fits--well, in fact, the quadratic has a higher R^2. And I looked at the average price of electricity, and this looked like something that was hard to predict. But Microsoft allows you to go up and get a polynomial up to the sixth order. [LAUGHTER]

And I would have gone higher, except for the fact that Microsoft doesn't allow you to go past polynomial degree six. I have no idea why. [LAUGHTER] And then if you do that, you forecast that electricity will become too cheap to meter, but if you have a lot of renewables, that could be actually true, and eventually it's going to go down below the zero line.

When it comes to forecasting the natural gas wellhead price, once again, I employed the sixth order polynomial. [LAUGHTER] And we found out that crude oil is so valuable that you'll actually pay people to take your co-produced natural gas. There is a historical precedent for this, because in the old days, they didn't have the outlet for natural gas, so they would have probably paid people to take the natural gas, except they didn't have a hookup, so they couldn't. Coal prices, according to my forecast, are headed south also. [LAUGHTER] By the way, these are all very good fits.

Now, if you're worried about prices, we have a very well-developed market in bilateral contracts to hedge your risk. I'm not sure why you have to do the hedging as part of your Integrated Resources Plan. There obviously is a problem with the wholesale and retail markets, because we have different programs for diversity at the state level and at the national level. And these are causing problems that I won't go into. But I couldn't resist my favorite quote from Woody Allen, when he's talking to Annie Hall, and Annie Hall said it was a sin in my family to raise your voice, and Woody thought for a second and said, "In my family, it was a sin to buy retail."

Now, as to what a future capacity market looks like, well, and this is my vision, we're going to decide that we need a certain portfolio of wind, solar, old clunkers, batteries, natural gas, CTs, some oil tanks on the side for diversity. I'm not sure that we have a place for coal. And we should worry about nuclear for radiation purposes.

Now, all of these created tranches, and we had a capacity market conference a while back at the Commission, with a panel that was essentially made up of representatives from these groups, and all of them thought that they were very deserving of their own special tranche, which then shows you that there may be competition inside the tranche, but there's probably very little competition between the tranches.

When it comes to capacity markets reforms, I'll just repeat myself, price responsive demand is the key. Getting the prices right in the day ahead and real time market is probably more important than anything you can do about the capacity market. Now, just to make sure that we got the message, suppose you were doing long term forecasts before 1950. Say that at the turn of the century, you were doing a 50 year forecast. Well, one of my favorite predictions is from the *Times of London*. You'll recall that in 1894, there wasn't very much automobile traffic, and the *Times of London* said that in 50 years, London would be buried in nine feet of manure. That didn't come true. Samuel Morse said that no one would use the telephone. (Interestingly enough, the Millennials prefer texting without actually talking). And Lord Kelvin said there was no future for radio, that heavier than air flying machines were impossible and that X-rays would prove to be a hoax. We have Irving Fisher saying that "Stocks have reached what looks like a permanently high plateau." And there's Einstein saying that he didn't think nuclear energy would ever make it.

Now, if you were doing this in the 1940s or '50s for 2000, you could buy into Thomas Watson's prediction that there was a "market for maybe five computers." Ken Olson said in 1977, "There's no reason anyone would want a computer in their home." And Fred Smith's paper at Yale got a C, because his idea for Federal Express was not possible. [LAUGHTER] And Limits to Growth projected that all known oil reserves would be consumed in 31 years. But again, we're still consuming.

If you're in the business of forecasting long term, think about how good you are at tech forecasting, and then think about discount factors. This has been the debate for at least 50 years, because if you buy into the idea that the future should be discounted, by the time you get to 50 or 100 years, it's not important anymore. Thank you.

Question: When you talk about weather and forecasting, what are you telling us? That we're looking at extreme weather events?

Speaker 2: If you're planning contingencies, your estimates and probabilities and contingencies are probably too low, because the cold weather is what's driving the probabilities, and they go much higher in hot and cold weather. And then when you're putting in all the renewables, the weather, the cloudy weather and the windless days, become big contingency issues that in the past we never studied before. Cal ISO is studying it, because they've identified it as a problem. I don't think they've identified it as a classical contingency, but in fact, that's what it is. That's why they're studying it. That's why they have ramp rate products. It's because the contingency is that the clouds come and the wind goes down, and you don't have any generation. So you have to ramp up your natural gas stuff very quickly. And that's how you avoid having to forcibly curtail demand. But if you have actually price responsive demand, you simply say, "OK, the price is now at a level that you need to get off the system. Or you promised me you'd get off the system." So, to me, the most important ingredient in all of this is getting price responsive demand into the market, because it is, as far as I could tell, probably the best and cheapest alternative to putting in more iron in the ground, as they would say.

Speaker 3.

Thank you. I have some presentation materials for you on specific issues surrounding nuclear. And I'm going to try to tie together, to the extent it's even remotely possible, Speaker 1's comments and Speaker 2's comments with those of the panel we heard from this morning. And I think nuclear's a particular technology that does kind of run through the themes that we've talked about.

And as I hear Speaker 1 talk, I think he reminds us smartly that there is a value in diversity. And we all know that intuitively. It's a very difficult value to model, but I think we've seen enough illustrations where that has come out to be true. And I think, when I hear Speaker 2's presentation, it's focused on the question, well, how do you make that actionable? And if making it actionable means predicting the future, then chances are we're going to mess that up.

And I thought that perhaps one way for all of us to think about this problem is not necessarily to predict the future, but to ensure that we're not doing things today that inadvertently are robbing us of diversity through policy failures or policy inaction.

Picking up on some of the comments we've heard, we obviously had some work to do on energy market reforms. We obviously have some work to do, coming out of this past winter, on capacity reforms. I know there's a group talking about that tomorrow, and I'll talk a little bit about that in the materials as I go through. And then the last big piece, at least as it pertains to baseload zero carbon generation resources, is that we need to figure out to value that, if we're going to value zero carbon from these units.

And so what I'd like to describe for you is the economic circumstances that the merchant fleet faces, and walk through some solution sets, talk about the implications for all of us, the implications for climate, the implications for fuel diversity, the implications for reliability. And then walk through some solution sets.

Not to bury the lede, I think we've come to the conclusion that Speaker 2 has outlined, that IRPs on an RTO scale fail, and if you look at the questions that are in the agenda, just walking through those, in terms of trying to figure out how we value diversity, how we're going to allocate the costs, whether in a system like PJM we can ever expect to get customers in New Jersey to pay extra to keep a coal plant in Ohio alive for the fuel diversity it brings to the grid… And in a world where we have great conflict over simpler issues, it's hard to imagine we're going to get a uniform IRP in an RTO with multiple states. It may be possible in New York. It may be possible in other markets, where the interests are more cohesive, but it's hard to imagine we'll get to it here.

And then the other solution set we'll talk about are contracts. I do think that there is work that can and should be done, relative to pricing carbon and the dispatch model. We'll talk a little bit about how that might impact nuclear. And the other issue that I'm sure, if you know anything about Exelon, you know we're talking about, is whether or not we need to acknowledge that in this future world, with the impacts we're seeing in the energy market, that nuclear energy is going to grow increasingly less competitive unless we begin to treat it like other zero carbon emitting resources that benefit from programs the RPSes and gravitate to more of a clean energy standard.

So let me start off, as I said, with walking through some of the metrics here. And I realize this is a little bit of an eye chart, but nuclear, as most of you know, comprises about 20% of the generation sector. But in terms of the production of zero carbon electricity, it's about 63% of that market, with hydro coming in batched at around 21%. And then there are some of the technologies that are being developed, like wind and solar.

Nuclear remains, I think, the only zero carbon source that is completely predictable, in that it doesn't depend on water. It doesn't depend on sun. And it doesn't depend on wind availability to operate. It has a number of other benefits. And in this context, I'm calling it "clean"--and I don't want to invite a conversation about nuclear waste. I don't want to invite a conversation about backup power for wind and solar and birds and so on. We all know that there are other issues with all of these technologies. What I'm simply referring to here is zero carbon energy, when I use the label, "clean."

If we look at this picture from a state by state perspective, Illinois, the home state for the bulk of our nuclear generation (we have 11 units in Illinois) is the lead state in the country in terms of the generation of zero-carbon electricity. The blue in these bars, for all of the states, represents the relative contribution of nuclear, and you can see the legend, and how all these other things play out.

There are six units that have gone out of business. We heard about Kewaunee. We heard about Vermont Yankee. SONGS falls into that category, as does Crystal River. We have announced that we will take Ginna New York out of service, and that has qualified now for an RSSA in New York, which is the equivalent of a Reliability Must Run agreement. But whenever that agreement ends, that unit will be retired. And Oyster Creek we have already slated for retirement in 2019. In addition, we have two dual unit sites in Illinois, Byron and Quad Cities, comprising about 4,000 megawatts in Northern Illinois that did not clear the capacity market this past May. And we have a unit in Southern Illinois by the name of Quentin that is probably the most stressed unit in Illinois.

What this chart attempts to represent is the national goal of about 400 million metric tons of reductions by 2020, at least the national goal that we had set for before the President kind of re-upped that. And we had gone to about 60% of that goal, mostly through coal to gas switching, which has been the biggest driver. We heard about that this morning. If we lose the nuclear that is projected for retirement, we will unwind about half of the benefit that we've gotten from cheap natural gas, leaving the goal much larger. And of course, commissioners at FERC, EPA, state commissioners, and others have remarked about how significant nuclear is to the solutions for carbon. So I won't go into that.

A couple of things that were notable to me was that the SONGS retirement unwound about 20 years of renewable development in California, probably the state that's been one of the most aggressive, certainly (maybe Texas being the most). And we've heard some of the stories about consumer pricing freezes as nuclear plants retired, and so on and so forth.

We all know it's a complicated industry, and sometimes when we hear stats like a 37% rate increase coincident with the announcement of the retirement of Vermont Yankee, I think we've got to be careful to unpack that a little bit. Quite obviously there are other things going on in New England that have triggered some rapid price increases. But at the same time, we have evidence right in front of us that these things aren't necessarily coincidence. We saw a price increase in California as we saw SONGS come out, and it certainly affects both the carbon side and on the pricing side.

I do want to tie in to the earlier discussion of what happened during the Polar Vortex. And as was mentioned, the real issues in the polar vortex were unit performance issues. We had an astounding number of coal plants at this particular point in time, the evening of January 7, where the system was stressed. We lost about half of our gas plants in the system, lost 34% of our coal plants in the system. We lost 40 gigawatts of generation, so when you think about a state like Illinois, it's almost the equivalent of two Illinois-worth of generation that we lost instantaneously on the evening of January 7. And frankly, only because of some fortuitous events, some imports from other regions, some demand response that participated that wasn't obligated to participate, we were able to avoid a load shedding event. And that's the crux of the work that PJM is doing now, related to capacity requirements.

I just would point out the irony of being in this situation in January last year, and fast forwarding to May and having nearly 5,000 megawatts of nuclear, which was one of the reasons the system carried on, not clear the capacity market, but we clearly have a mismatch in terms of the valuation of some of these resources.

Far and away, I think the biggest challenge for nuclear is natural gas. No surprise. We know that we also get affected by some of the collateral effects, unintended consequences, if you will, of some of the policies that have incentivized negative bidding, some of the federal subsidies for wind. Our Midwest fleet is particularly vulnerable to that.

The plants that I talked about that did not clear the capacity market were Byron and Quad Cities, which is right on the border of Iowa. Those two plants, over the last four years, on average, experience negative price events in off-peak hours of about 12%. Clinton also experienced pretty significant off-peak price impacts. And if you were to correlate this to the location of the new wind that's been built, that's PTC eligible, you would see those impacts.

We took three categories of reactors, and we modeled the costs of keeping them in operation. The categories were large dual unit reactors, large single unit reactors (and that would be something that's 800 megawatts or more), and then the small single nuclear reactors.

The cost bar is really a reflection of UBS's work and some Credit Suisse work, and what the implied cost of operating those plants are on a megawatt hour basis. The contingency above the bars, and the components of the bars, are the ones you would expect, capital, O&M (which is a huge component because of the number of employees at the plants), and fuel. And what you see here is that a large dual unit site in the US on average requires about $35 a megawatt hour to cover its costs, less contingency.

What is not included in here is return, and obviously Wall Street expects us to make a return on these plants. And the other thing that is kind of expected from this bar chart is perfect operations. So a failure of a major component isn't priced in here, nor is the cost of penalties for not operating a capacity performance product, nor is the cost of removing the unit during a critical time period where you have to basically pay back in the market the hedges that were the market.

To give you some sense of this, nuclear did perform extraordinarily well during the Polar Vortex. I'm embarrassed to say that I have one unit that didn't. This was one that we have a joint ownership in, and it was Calvert Cliffs. And at Calvert, we suffered a dual unit trip. And the costs for that dual unit trip were about $120 million. And we suffered those losses in about five or six days, and found it ruined our winter from a revenue standpoint. But that's not included in these bar charts.

So if you were to really reconstruct this from a merchant perspective, you would need some return, and you would need the recoverable risk of penalties for capacity performance and the risk that you're going to lose the unit during a critical period.

So what I'm saying here is, of course, that these cost bars on the left hand side are somewhat conservative. And then the bars on the right hand side represent the forecasted energy price in 2016 and the merchant markets. So as you can see, with the exception of the large dual unit sites, we're going to have some challenges, and we'll see how this goes forward.

Obviously, we're making resource decisions based on economic price signals, and that's why it's so important for those price signals to be right. But we also are thinking about fuel diversity. I mean, in reality, if you had a coal plant, and you had a particular view of natural gas prices or something, you might very legitimately want to keep it around in the market for a period of time, even though it was losing money. And that is effectively an internal company IRP, to hold on to assets that are losing money presently, but to keep them for a better period of time.

The challenge for a company like ours, which has an intensive book, is that when you have 24 nuclear units, and you have a lot of those bets all going in the same direction, you are less likely to hold onto particular assets. I don't need to hedge against higher gas prices 24 times, and I'd be willing to shed a few units instead.

Let me give you this slide here for the distressed units in Illinois. When we talk about the negative price impacts, the impacts of policy that is robbing revenue from these plants, the shadowed portion here, the block, represents the net effect of those negative price events on the revenue of these plants. So you see Quad Cities, you see Byron, and you say, "Well, wait a second, these plants…you just told me dual unit plants are economic…." Yeah, but once we get the overlay of negative price events that are fairly severe at these plants, you are robbing a substantial portion of the revenue that you otherwise think you might get.

So let me kind of wrap this up with this slide, and you have the numbers showing fairly significant employment at these plants, huge payrolls at these plants, and I'll come back to this in a second. But I'd like you to pay some attention to the red print for Byron Station (remaining useful life 30-32 years) and Clinton Station (remaining useful life 32 years). When you look at a Byron and Clinton, these plants have not reached even half of their useful expected life.

So we're not talking about old coal plants that have been a foot on the banana and the other on the banana peel, and they're going to go. Right? Eventually, in short order. These plants are prepared to operate for another three decades and provide zero-carbon electricity. These are some big policy choices to shut these down, because we could debate what the value is of keeping these around for diversity, keeping around supply and demand, and the environmental value. But whatever value we come up with on an annualized basis, it's going to be a value that's going to have some life over the course of three decades, in terms of lost employment, and that sort of thing.

Where we presently stand in Illinois is that last spring, the Speaker of the House introduced a resolution asking the ICC (Illinois Commerce Commission) to do some work to understand energy value impacts. I understand PJM and MISO have been working with the ICC on those things, and we'll see a report on that. We have done some internal modeling using PROMOD results, and this is going to be in the hundreds of millions of dollars for the effective units. Concentric is going to release a report shortly, and the interesting thing there is that Concentric modeled not just the supply and demand impacts in normal weather, which is really what the model predicts, but really looking at price volatility and some of the other issues. And what I think will be interesting there is, it almost doubles the energy value proposition.

The environment benefits we can quantify in any number of ways, but it's the avoided emissions times some carbon price that we would expect to achieve in reductions. In terms of economic impact, you've seen the jobs and salary numbers. And of course, reliability, hopefully, will be tackled by PJM on the capacity performance side. But this is going to be quite a real issue for us in the spring in Illinois as we turn our attention to seeing if there are some solutions.

Turning to possible solutions, I don't necessarily see a role for PJM to say, "Well, we need X number of nuclear plants," or, "We need to preserve all the nuclear plants." I'm not exactly sure how we would thread that needle and get that through FERC to take action on it. I think the role of PJM and FERC, quite frankly, is to ensure that markets work.

We do think that there is an appropriate discussion to be had around including nuclear as part of the resources that have a special category status in terms of allowing nuclear to compete with other zero emission resources in state clean energy standards. And then, finally, we think in the long term the solution that frankly works best with the market is to put a price on it. Put a price on carbon and work through it. It may in fact be the case that politically we're so constipated that we cannot get to that outcome in a reasonable timeframe. But in the fullness of time, I think we would imagine that eventually, after exhausting all options, we will come back to that, as Speaker 1 on the morning panel said. I'd probably weigh in with you and your brother-in-law and bet that somebody's going to tax this as a revenue source some time. It's not going to happen soon enough for a lot of these plants. And that's the stupidity that I hope we can avoid, because once these things are shut down, they can't be restarted.

Question: I heard you mention that the costs to operate these nuclear assets had risen 33%, and that ran counter to my sort of intuition that deregulated assets like nuclear had become more efficient. So could you explain where those cost increases come from?

Speaker 3: Actually, I don't remember saying that. I might have, but I think, quite honestly, the data is even bigger than that. The Nuclear Energy Institute has published some results over the last decade, from 2002 through 2012, and we've seen an increase of something like 59% in the cost of operating the plants. So when we think about the efficiencies gained through deregulation, we've done much better in terms of capacity factors in operating the plants, but a lot of that had already occurred by the middle of the last decade. And what really drives the costs are a couple of things. First of all, O&M--big, big employee centers, and so we're obviously seeing year on year increases in the cost of our employees. But more than anything else is post 9/11 security issues. The capital requirements for the internal security at the plants has been quite enormous, as well as the additional manpower to staff the armies of people we now have on site to protect these plants 24/7.

Question: You mentioned that you cannot recommission once decommissioned? You can't resurrect a nuclear plant, to borrow a New Testament term. Is that true?

Speaker 3: Yes, but I was, in fairness, speaking from a merchant standpoint. You can shut down a nuclear plant and restart it five years from now. From a merchant standpoint, you couldn't do it, I mean, economically. You're going to shut down. You're going to start the decommissioning activities as soon as possible to start absorbing some of those costs, being able to take advantage of that accounting. You're going to lose that workforce. The NRC hurdles that you would have to go through to restart a plant once shut down like that is going to add a prohibitive amount of cost to it. And the end result is that I would find it highly unlikely that you could effectively mothball a unit. We have looked at it. We've run the numbers. It just doesn't work.

Question: Thanks. Given the number of slides focusing on Illinois, [LAUGHTER] I noticed Pennsylvania is like number two in terms of nuclear power. Yet there's not the focus there. And is that just because of proximity of renewables to the West? And are there factors that could change that in the future?

Speaker 3: Yes. Moody's just issued a report, talking about Three Mile Island as a plant that was in jeopardy of economic retirement. And certainly Oyster Creek, which is in a good market for us in New Jersey, not really affected by renewables, is already one that we're slating to shut down in '19. I'd say that in the case of Oyster, it's really the size of the reactor and the age of that reactor. For TMI, I would say it's large single units, and they're going to be challenged. I think that would be the kind of category of reactor that's just challenged by natural gas prices, challenged by lack of load growth. But the real issues we're seeing are Illinois, obviously, which traditionally has had lower energy costs. So that's one big driver. And then the renewables is the other.

Speaker 4.

Good afternoon, everybody. I'm just going to be talking in sort of in broad brushstrokes about resource diversity and capacity performance in all of these other issues. So in the words of John Cleese, and now for something completely different.

What is fuel diversity? I still am confused about what we mean by fuel diversity. I'm not sure what the objective is, necessarily, with fuel diversity. I hear the term thrown about. But I harken back to the days before I joined PJM, and I was working down in Florida. We had the same discussion a decade ago about fuel diversity. And at that time, fuel diversity was code for, "I don't like natural gas." Now, to Speaker 2's point, now I hear "fuel diversity," and it means, "My technology can cure cancer, bring world peace and do all kinds of great things," whatever the technology turns out to be.

And so at the end of the day, is it really about diversity? Or it is really about performance? At the end of the day, if we're talking about reliability, it just matters if units perform. I don't care what they are. If it's a nuclear unit, as Speaker 3 showed…during the Polar Vortex, very little nuclear out. If it's a coal unit, and it performs, fabulous. If it's a natural gas unit, great. If it's storage, fabulous. If it's a hamster on a wheel, as long as you keep feeding it, I'm OK with that.

As Speaker 2 talked about in his comments, we've been through PURPA. We've been through IRPs. We've tried to pick winners and losers. And we're doing a really poor job at that. And, actually, that's what has gotten us wholesale markets, at the end of the day. And so really what we're talking about in wholesale markets, is that we should not be favoring any one technology over another. We should be fuel neutral, technology neutral, age neutral, size neutral, subject to reliability constraints. And that's where performance comes in. It matters if the resources perform when we need them to perform.

And so, whether it's diversity or anything else, really at the end of the day, I think what we're talking about is performance. Because, from a PJM perspective, we're actually becoming more diverse. Back in 2007, coal accounted for 55% of total energy, nuclear 35%, gas 7%, and then there were a bunch of other dogs and cats out there. In 2012, gas was nearly 20%, coal about 42%. Nuclear still about 35%. The nuclear number hasn't changed, by the way. It's been pretty rock solid. It's 19% of total capacity, 35% of total energy. Again, it's about performance. Are the units there when we need them? But we talk about fuel diversity, and really we're actually becoming more diverse in PJM, not less diverse. And so that's why I made the comment, going back to the days working in Florida, that when I hear "fuel diversity," I hear, "I don't like gas."

And so I think we have to be very careful in talking about fuel diversity, in terms of trying to pick winners and losers here. Because as Speaker 2 said, we can make all kinds of predictions. Chances are they're going to be wrong. Now, in terms of what Speaker 3 is talking about, and going back to some of the questions in the morning session, I'll summarize the advice. Put a price on CO2. Get the prices right and all will be well. And so, yeah, Speaker 3, you're talking about carbon-free energy and this and that and the other. Look, if we get the policy right, if we get the prices right, we don't need to talk about resource diversity at that point. Everything will work itself out as the markets will determine. So with that being said, let me kind of just dive into some of these issues.

If we think about the issue of being technology neutral, resource neutral and so on, to Speaker Two's point, we have price responsive demand. If we put demand back on the demand side, there's actually a lot of optionality here and innovation that could occur. Rather than pulling the trigger on either retiring units or building new units, the fact that demand can choose to reduce provides a great deal of optionality. Rather than making a huge investment, you can work with demand, and to the extent that demand decides that it doesn't want to reduce, it's reversible, and that reversibility is actually fairly low cost, as opposed to building a facility, and then all of a sudden realizing, "Oops, we don't need it."

And so in that sense, what we're seeing is that by being neutral, we're seeing innovation, whether it's in new technologies, new combined cycle technologies that are highly efficient, or putting demand response right now on the supply side, or price responsive demand. I think that gives us a lot of diversity and a lot of optionality. And, again, you only get that if you're trying to be neutral on how we meet all of these different issues, regardless of the fuel type. It's going to be about performance.

And so, obviously, as many of you know, the PJM board did make a decision to go forward with capacity performance. I can talk about it a little bit. There's been nothing filed at this point. But, effectively, if you read everything that's out there in the public domain, it's going to look an awful lot like ISO New England, with some twists. But, again, regardless of the type of technology, we're going with one single product. It's just going to be capacity performance at the end of the day. It doesn't matter what the fuel is. It's just got to be there and perform.

Now, I think one thing that is also interesting when you talk about fuel diversity and resource adequacy, is the idea that we've got a three year forward capacity market in PJM. And you get price signals, as Speaker 3 has talked about. I mean, they are getting a signal. They had units that didn't clear. Some other units had cleared new resources. But we're seeing a lot of new steel in the ground. And, again, it's about competition over price. Now, if we get capacity performance, then we'll get the performance we need as well. But the three year forward look actually reduces the real option to wait for additional information. So people can pull the trigger on these new investments. There's hedging going on out there now with financial marketers offering short term, three, five, seven year hedges, but it's happening. And so, again, if it's about diversity, the market's not saying that we need more coal or anything else. Everybody's going in with the technology that makes the most sense, from both an environmental perspective and a cost perspective, which is what you would expect markets to do at this point.

So, unfortunately, Speaker 2 actually stole most of my thunder with his presentation, so whatever he said, I agree with.

Question: You mentioned it's all about performance. I can see that from a system operator perspective. But from a consumer perspective, what about costs and prices and price volatility? Isn't that part of the diversification story?

Speaker 4: It is. But I'm going to use one of Steve Schleimer's now famous, or favorite, sayings. It's about the law of conservation of risk. And I used this the last time we were here. The whole diversity issue is about risk, if you want to look at it that way. Now, we can talk about reliability risk or cost risk. But at the end of the day, if it's about performance, and we set the performance standards, there's still going to be competition over resources to meet those performance standards. So, yes, there's a cost associated with that. But what's the cost of actually having to shed firm load with the value of lost load? Is it work paying for that? I think a lot of people would say, "Yes. It is worth paying for that." But, again, if you're saying that there's a consumer cost perspective, do we want to actually translate that by keeping those costs low and adding to reliability risk? All we're doing it just turning financial risk or expenditure risk into reliability risk.

Question: So as an economist, do you think there's a fundamental market failure that makes us not sign the long-term contracts and pay the premiums for baseload and things like that?

Speaker 4: No, there's no long-term market failure. If you think about it, there are hedges already going on out there. There are three, five, seven year hedges that are being done with new merchant facilities. There are counterparties willing to take that risk. And also, if you're talking about long-term contracts and self-build, if I'm sitting on the other side as a load, why would I want to self-build when I'm looking at capacity prices? We're long on the system. I can always reduce my demand for capacity as an option, and I can do so for much lower costs than doing new build. Why? And that's the beauty of the transparency of capacity markets. Here, there's actually transparency as to the cost of maintaining that reliability. So when I hear questions about, "Oh, we can't self-build," people can self-build. They've always been able to self-build. That's a red herring. The reason people don't self-build is, why would you pay full freight when you can by capacity at a fraction of building a new CT or a new combined cycle, potentially? Why would you do that? Or why would you do that when you can actually reduce demand and wait for better information? Again, that's part of the innovation. It's about the transparency, and that transparency's powerful. And I would argue that those who are saying that capacity markets don't work, that it argues against self-build, it's because they don't like the transparency that brings about information about bad decisions that have been made. A recent new coal unit that just went online, and now everybody's regretting it. I think we all know where that's at. Self-build. "Hey, we did it ourselves. Oops, I wish we hadn't done that now." And that transparency makes that look like a bad decision.

General Discussion

Question 1: My question is to you, Speaker 1. Correct me if I'm wrong, but I think what I really was hearing here is that in your value for fuel diversity, you're really saying, going forward, that instead of building so many gas plants, it would be better if we continue to build more coal plants and more nuclear. And so my question is this. Have you run the numbers which look at the following? Instead of staying only with more gas as being the new plants to be built, more nukes and more coal plants at $7,000 a kilowatt for nukes, $2,000 per kilowatt for coal, would be built. And then you go forward 20 years, and you find out that gas prices stay where they are today. How much extra will consumers have paid over the course of those 20 years for all those plants that were built, where otherwise gas plants could have been built, solely because today we felt that diversity was a good thing? And I felt that that was a cornerstone of what really has to be thought about in the economics. But I didn't see it come from what you're saying, and I think I'm asking that question because I'm resonating off what Speaker 2 talked about, which is how hard it is to forecast, and clearly there is a world out there where gas prices stay low for a very long time.

Speaker 1: It's a good question. And the primary message is that we currently have a very valuable diverse mix of fuels and technologies, and we're doing a number of things right now that are uneconomic, in that we're losing a lot of this. And this is stuff that we don't have to rebuild and spend that fixed cost, so that these premature closures are particularly troublesome. But to your question about, well, even though this heavy gas and renewables future is more expensive on a production basis, aren't we saving, on the capital cost side, which is a different comparison, which I've kind of worked up, which is, if I had to rebuild the existing power system and incur all those fixed costs, and then compare it to building out that less diverse case that I outlined, what you'll find is, based upon our estimates of what it costs to build these things, that you do find that you've got a higher investment dollar per kw if you were to rebuild our existing mix from scratch, although the difference is not that great, because in order to meet the peak demands, you don't get a lot of credit for all those renewables, because of the intermittency and a lack of dependability at time of peak. So with the less diverse case, you have to build significantly more capacity than in the current case, because the renewables are so much bigger, and then when you take into account the higher cost of capital, because you've got a more risky cost profile in your generation, when you apply that, it's basically a wash. If I had to rebuild our power system as it exists today against this less diverse case, I don't see capital cost savings in the process.

Questioner: I think I hear what you're saying but I don't think that's responsive to my question. The point I'm trying to make is that if there are developers out there who are looking at building new plants (let's leave aside the renewables for a moment), for the people bidding into PJM or also into ISO New England and other places, the practical work is going to be to bid gas. That's what they can do. So what I'm really looking at is, if alternatively you were to somehow say, "That's not good. We don't want that much gas. We want them to go to something else," and it caused them to pay much higher prices to put in nuke or coal, where the operating costs are not less than gas, OK, you have a lot of increased costs. And what happens then if gas prices stay low? What I'm really challenging here is this sort of assumption that we would know so much about how fuel prices are going to work in the future that we can put that kind of torque into the market, which is what you have to do in order to cause the market to do something it otherwise will not do.

Speaker 1: In your question, there sense there is that the lowest cost option right now is natural gas, and that's why people build this, and we've got kind of this market phenomenon here that's displacing other sources of generation, because gas is the economic choice, the winner in the marketplace. And I think that's something that, if you look at it in more detail, I think it's a questionable assumption that that's really what's going on here, because I think we've got serious problems in wholesale power markets, in both the capacity and energy side. So what we've seen is, companies whose business model was, "Let's build new gas-fired power plants in the competitive marketplace," they haven't won. Look at your major gas-fired generators. Calpine, NRG, Dynegy, they've all gone through a bankruptcy reorganization in the past decade. So we've had enormous write offs of gas-fired generation. So the idea here that we've got a simple economic phenomena of a disruptive, cost-effective technology displacing everything else doesn't seem to square up with the experience. And my point is that because wholesale markets are chronically clearing too low, this missing money problem has really been a big problem for these gas-fired generators, and likewise it's undervaluing the other types of generation. And if you start to put the kind of numbers we're talking about in terms of dollars per ton of CO_2, if we're talking a \$40 a ton kind of CO_2 number, you will find that some of these nuclear technologies are economic.

Question 2: I have a question for you that I'm going to try to phrase in a restrained way, because I want you to like me when this is over. [LAUGHTER]

I'm really sorry to say my question is about nuclear waste. But it's about 111(d) and about being concerned about greenhouse gas emissions, without getting into the pit of legal challenges. You know and I know that the Natural Resources Defense Council has brought a suit challenging the Nuclear Regulatory Commission's continued, I think we call it continued storage of waste confidence. The reason I mention it is because I think, taken to its extreme, as kind of a hypothetical, it can undermine three categories of NRC licenses, one for plant life extensions, two for new plants, and three, God forbid, maybe even challenges to existing reactors as no longer being legally sufficient. So I have two questions. One, does that mean that in order for the US to really tackle climate and safeguard reliability, we need to worry about disposal? In other words, if what we have now could end up being changed so much by virtue of a lawsuit that we end up losing nuclear capacity we would otherwise keep or attain, does that keep you up at night? Do you think we should worry about it?

Speaker 3: I think it's an ordering of problems. I do think the waste issue needs to be addressed, and there's, as you know, a great deal of politics around that issue, and whether Yucca Mountain is the appropriate repository for the waste or whether regional solutions can work. I will tell you, and I think many of the other companies that are represented here that have nuclear reactors would agree, we feel very confident in onsite storage for hundreds of years, and that's dry cask, and I think that's been proven. I don't think there has been a single incident, a single injury or anything that would cause us concern around storage of waste in dry casks.

That said, I think it continues to be a cloud over the continued development of this industry. I don't lose sleep over it, because I think it's a problem that could be put off, if you will, for hundreds of years. I guess in the ordering of concerns, and at least in the way that risks are filtered through my brain, I think climate is a much nearer, in the next couple of decades, concern that needs to be addressed, so I'm willing to continue to incur a problem that hopefully will be solved by technology and by a political solution hundreds of years from now to deal with something that is nearer term. And four of the nation's most renowned climate scientists kind of broke with the environmental community last year, as I'm sure you know, and said that nuclear needs to be a part of the solution. They would go so far as to say new nuclear needs to be a part of the solution. I'm not sure I'm there, as far as new nuclear is concerned, just because I think the lifespan, the economic recovery for a new nuclear plant is so long that one should have to anticipate improvements in storage and renewable energy and other things that may make those investments more difficult to run economically, but my simple answer is, I'm not so worried about the storage issue as I am about the climate issue. But I think both are significant concerns for the industry and need to be addressed.

Questioner: I worry about climate policy, and the particularly the cost effects that might come out of the EPA 111(d) rule. That's why I worry about the potential undermining, through this lawsuit, of our ability to retain the existing nuclear fleet. So I worry about climate, too, and I worry about waste storage because I worry that we won't be able to have enough nuclear to meet the climate demands.

Question 3: I'm going to say something about forecasting in response to Speaker 2's very funny and on-point presentation. You made, with the Peanut people and lots of Clip Art, a point that I tried to make before, that we talk about these issues like we know what's really going to happen 20 years from now. But I want to make the point that just because forecasts are always wrong doesn't mean that they're not useful. What I mean by that is, we put out these futures, and we go out 20 years, and we say, "This is what's going to happen." And I think that information is what inspires people to say, "I'm going to figure out a way to make fracking gas work. I'm going to study this technology," and so we're using the market. That provides information, which is good in that sense, that it triggers a lot of the technological change that we can't see in these models. But I still think it's important that somebody tries to do long-term forecasting, because these are very long lived assets.

So as I was sitting there listening to this discussion, a question that came back to me is, if we had a price for carbon, and we knew what it was, or we could at least agree on a number five years at a time, a rolling average, why wouldn't that solve a lot of these problems that we're trying to argue about through policy? Wouldn't that make huge inroads? And then you let big time entrepreneurs, like the guy on the end there, decide, yes, we're going to save this fleet, or no, we're not, and make decisions. And consumers buy, just like they buy automobiles that are made from steel, which is equally capital intensive and long lived, and yet people take risks and do make those decisions.

Speaker 2: Actually, if I didn't say that, I meant to say it, that it's not to not do forecasting, but to be very skeptical and questioning of forecasts. I mean, you have to do it. But we've never been very good at it, and there's no indication that we're getting better, to my knowledge.

But you know, you have to think through the problem. I agree with you, if we could just put in a carbon tax, a lot of these problems for nukes would go away. We might be able to sort out solar and wind better, and batteries, too. I mean, a lot of the problems might disappear. You combine that with price responsive demand, and you might be able to solve 99% of the problems. So, yeah, getting to a carbon tax would be nice. The speaker from the morning basically sees the virtue of a moral hazard in seeing that as a revenue source for tax policy. Maybe it's a good moral hazard, as opposed to a bad one. I don't know which. But actually, I think that's what Al Gore proposed, that all of the revenues from the carbon tax would go to tax reduction, but it was too late, I think.

Speaker 4: To the questioner, you're just proving the point that I was trying to make, which is, why are we trying to pick winners and losers? Because we have no idea what's going to happen ten or 20 years from now. Hey, five years ago, did we expect gas prices to be where they're at today? I challenge anybody to think that we were even thinking about that. And so the whole point is, yes, there is an issue for forecasting, because if we have that information out there, you're letting market innovation take place, and the markets are actually going to find a better way to go about this, and in ways that we can't even imagine.

Speaker 2: And if you do it through an IRP process, you're socializing a lot of the risk. People play differently with the house money. And so the discipline helps, if you have private entities making a lot of these decisions.

Speaker 1: On this forecasting issue, you know, it's important to keep in mind the timeframe. So the decisions people are making today about generating plants, these are things that operate to 2040, 2070 in the case of Southern and Vogtle, the nuclear unit. But if you analyze the forecast, and Speaker 2 showed the historic growth of electricity demand, if you look at the NERC forecast of that growth, there was a consistent overestimation, and consistent underestimation, which led to a big surplus in the early '80s and then shortages in the early 2000s. What we see is that not only is it hard to predict the future, but our predictions tend to show bias in the error. They're not sometimes high, sometimes low, and on average right. We see a lot of evidence that there's bias in our forecasts, and, you know, if you look at the new work that's been done in behavioral economics, it's part of our human nature to think that we understand and can predict the future better than in fact we can. And we tend to have a persistence of belief. When we believe something, we tend to gravitate towards evidence that support it and dismiss evidence that contradicts it. And these are things that contribute to this difficulty in anticipating the future. But to me, all that says is, it's all the more important not to bet on a single view of the future, to have a diverse portfolio, because that's going to be robust against the uncertain possibilities that we're going to be living in down the road.

Speaker 2: It's interesting, because EIA keeps very good track of their forecast record, and you can see exactly the pattern that Speaker 1 was talking about in those forecasts. They'll be over for a while, and then all of a sudden they'll go back. It's not that they sort of oscillate around the right number. They get into a group think that says that the prices were always going up, and then when they're wrong, they switch and for five or six years go in the other direction. So there's a lot of group think, and EIA has no obvious financial bias in what they do, but it's still there.

Speaker 4: And I think the same thing's also true if you look at the macroeconomic forecasts. CBO actually will go back and look at the blue chip consensus forecast, the White House forecast, Federal Reserve macroeconomic forecast for GDP growth. In the '80s, macroeconomic performance two and three years out was consistently overforecast. In the '90s, it was consistently underforecast. Starting in 1999, the average forecast error (being biased upward) is 2 or 3% two years out. I mean, so we're still in sluggish economic growth, but, again, that goes back to the whole load forecast issue and everything else. We're talking about doing planning for resource adequacy, transmission, and everything else. We're talking about commodity forecasts, but look at macro forecasts. They suffer from the very same biases that Speaker 1 and Speaker 2 have just pointed out.

Question 4: I work for a company that obviously has to manage investment decisions and paradigms in sort of this environment, and look at risk in all its forms, and how it can impact the investments we make. And so this discussion's been very close to the things that our company deals with all the time. And I have to a quick comment to say that I agree that weather is a big factor and a big uncertainty in this area, and we consider weather affects always. However, I would say a much bigger risk element is not weather but the "whether," which is [LAUGHTER] whether the rules are going to change, and whether a regulator or other structural elements are going to be pulled under us in the timeframe of the investment. And this discussion around, you know, trying to, I guess, impose diversity, raises the specter of that particular risk. And that is not something that as a company we can really deal with. In other words, it's hard for us to measure that.

Now, could we manage weather risk? Well, that's tough enough. Tough enough to predict hurricanes, and so on. But the other whether is actually more like trying to predict oil prices, and I think Speaker 2 decided that was just really not in the realm of rational economic kind of exercises. So I would have to say that this discussion, in my mind, raises the risk premium. So just even by having the discussion, everyone who needs to make an investment in this market now has to factor in that risk premium.

Speaker 1, you suggested a risk premium for natural gas, for concentrating our resources in natural gas. Here I'm saying, "Oh, any investment decision now has to have a risk premium, just because we've had this discussion." So that aspect is sort of a concern of mine.

How would I say you would optimize yourself as an industry in this? Well, first of all, you want to have as much transparency as possible. Speaker 4 talked about that. So I totally agree. You want to have the factor costs, the options, and so forth, being extremely transparent. You also want to be able to delay all commitments until the last possible minute. And that's why it may feel uncomfortable for regulators to look at this, because all the participants like me are just kind of delaying. We're just delaying. What's going to happen? Well, wait, because if we don't have to commit, we won't. And then the other aspect would be to maintain as many options as possible.

So I wonder what are the structures you could put in place to actually achieve what you're trying to achieve? So, Speaker 1, you talked about preserving resource diversity. What does that look like? And why should I not be scared about it? Because I see any kind of structural element being put into the market as something that would essentially entrench a rigid approach and reduce options, potentially, and kind of corner us in, in an area we don't know what the future's going to look like. So that's my question. What is the solution that wouldn't kind of have all these negative connotations and have me kind of run back and say, "Our risk premium just went up?"

Speaker 1: Well, I think we've talked about a lot of the solutions, and if we get the price signals right, I do not believe that it will be the case that if capacity and energy market prices are right, you're only going to build natural gas. And look at Southern Company. Southern Company has got about half their generation in natural gas. They're looking at their portfolio, and they're starting to look like New England, which is now getting to be about half natural gas, and they've got too much exposure to what is the most volatile fuel input. And this isn't, as Speaker 4 had said, this isn't an anti-gas story. You want gas in the portfolio. It's a question of how much is too much. And I think we've got evidence. Southern Company is building, in part, and Tom Fanning has talked about this, to create a much more controlled expected variation on their output. AES had some coal in their portfolio that prevented them from going bankrupt when the other all-gas generators did. We're seeing IPP's business model transform to expand more outside of gas and into renewables. So I don't think the market is just going to go gas, if you get the market signals right. But what we're missing here is effective capacity market pricing in a lot of places. And on top of that, there was a negative price event graphic that we had here from Speaker 3. The size and the frequency of the negative prices we're seeing, I think, are clear indications of this problem I'm talking about of a misalignment between the generation mix and load profiles. And the objective is to have the fuel and technology mix that gives the most cost effective supply against the load profile. And I think what we also have to do is, besides fixing capacity markets and getting a good price signal there, I think we need an energy price adder that keeps people whole for the way we depressed these energy prices with the addition of a lot of renewables and so forth.

Speaker 4: All I can say it, I agree with the questioner on this. I mean, really, there's risk everywhere, whether it's regulatory risk, whether it's price risk, or reliability risk. There is risk. And we're just transforming that risk and changing its form from financial to reliability to whatever we're trying to do. I mean, it's out there. But some of that risk you can try to manage, because you can see it in prices. And I think the point you're making is, some of it is just that we're trying to outguess things. How do I even manage that?

Speaker 1: And to the questioner's point, with the way the Clean Power Plan was put out, the way it was designed, and the kind of comments that have come back on it, and the kind of legal challenges that are going to posed against it, you're right. It doesn't matter what the plan looks like. The fact that it's going to be so uncertain as to what it will look like ultimately, and when it will become binding, that uncertainty alone is going to discourage a lot of the investment that I'm talking about here that would prevent the premature closures, where we're losing diversity.

Question 5: We've got a lot of ingredients on the table here, whether you agree about the value of fuel diversity or not. Speaker 2 talked about price responsive demand. Speaker 3 talked about production tax credits and negative pricing. Speaker 4 talked about capacity performance. And Speaker 1 talked in general terms about problems in energy capacity markets. So if you really were pressed to name one to two or three things to do urgently, what would they be? And embedded in that is, how urgent is it that we act? In other words, we come to these meetings. They're great. We all learn a lot. It's great discussion. But I think sometimes it helps to try to force ourselves to be in the shoes of a real decision maker. There are some in the room, of course. And so, pretend you're in that role. What, if you had to pick one, two, three things, what would they be in the next, you know, six to 12 months?

Speaker 3: As it turns out, I had occasion just on Monday to write to the EPA administrator with some recommendations. [LAUGHTER] Just as many of you did, I assume. But there's been concern about how nuclear has been treated. Given, there are a lot of technical issues, but as you look at the cross section of comments, the one thing that just pops out to me is that you have the lead industry organization, the Edison Electric Institute, in a letter and comments that are several hundred pages long, saying, "It can't be done. You don't understand the electric system. You're going to shut off power to our customers," and all that stuff. EEI has talked about price responsive dispatch, exactly what we talked about this morning, and suggested that

EPA look carefully at that issue. Likewise, we see environmental groups weighing in on price responsive dispatch.

And so what we have suggested to EPA is, it's time for a game change here. After we get through this process of figuring out that something could happen here, and maybe all these lawsuits that people imagine having may not work, and when they go forward, we have a responsibility to create some real options. So what we have proposed is that EPA set out a safe harbor for states that participate in an RTO dispatch network at a carbon price that will ensure that rates will not go up within the region by more than 5% retail capacity.

I asked the question to the panelists this morning about what the cost of their programs would be. And I didn't hear a number. [LAUGHTER] So I will tell you, I did get an answer. And if you take a look at what PJM has done, and I think this is illustrative perhaps of what ERCOT has done, they look at a bunch of future scenarios. Understand, we're not going to be able to forecast the one base case that's absolutely right, but they look at a number of different scenarios with renewables, energy efficiency, nuclear retirements, which produce a pretty heavy carbon price in the market that you have to make up for the lost emissions. And when we look at that, it creates a spectrum of something like zero dollars per ton all the way up to about $20 per ton. And if you could collect that in an RTO dispatch system and if you just take the money collected, and refund that back to customers, we could avoid about 80% of the retail impact. Meaning that you could get there at something like 2-5% retail rate impacts. And what's quite interesting about this is, if you look at the last year of rate increases for retail, nationally, the rate increase has been 3.2%, with New England leading the way at, you know, over 10%. This is based on EI data that just came out, and actually for the Pacific Northwest, it's seen an increase in retail rates. But nationally we've seen a 3.2% increase over the last year. And so that tells us that if we allow PJM to apply its price and dispatch the system regionally, taking advantage of all the regional economics, we could get there, and we could get there at a price that looks to be roughly in line with what's happening to customers right now.

Now, if EPA could step forward and say, "I'm taking the model of this. If you do this, you've got safe harbor for compliance for X number of years…" and we propose that should be through 2029. Then you don't have to shut down coal plants. You don't have to do boiler replacements. You don't have to build renewables for energy efficiency. You don't have to save nuclear plants. You might want to do all of these things. But you don't have to for compliance purposes. But EPA has to give the states that ability to control their own destiny, or they're going to get swallowed up in this thing. Because they do have a reliability issue, because the state by state approach isn't going to work. They do have a timing issue. But not with the dispatch model. They can implement that readily. And they do have a cost issue. They have not come out and said, "We're going to put our money where our mouth is, and this is going to be the cost impact." The key, though, in our comments is, that the collected monies get refunded to customers. And that was our attempt to step forward and change this dialog in a fairly significant way. But EPA has to provide some guarantees to customers on rate impacts, where industry retrofits older equipment that doesn't support an economic case for retrofits, and a safe harbor for the states. All voluntary, of course. States have the option to participate or not participate.

Question 6: I'd like to go over to the price responsive demand side of this equation, and I think the last success we had with price responsive demand was 15 years ago with the basic generation service in New Jersey, where we actually coupled retail prices for large C&I to the wholesale prices at PJM. And in the next 15 years, I'm not sure I can point to another success story. So I'm working right now, mostly in California, with microgrids, distributed energy, working with water facilities, waste water facilities, and trying to get those processes to be optimized and managed in a way that you can create the customer side response to help with balancing for the system. You can help area regulation. You can do a 24/7 little bits of demand response, little bits of response. And you can do flexibility. You can do fast up. You can do fast down. There are all kinds of things that you can do.

And in California, for example, there's 500 megawatts of water demand just in San Diego, which is 10% of the state's load. So we could be looking at a fraction of 5,000 megawatts of customer load just with water and waste water facilities. So I just say that as sort of a starting point for a conversation, because then you look at what are these potential 5,000 megawatts allowed to do? If they peak shave, then they've reset their energy, and they can't do it again without a penalty. If they have a demand charge, they'll have a demand charge, even if they take energy when the prices are negative, and so there's a disincentive for them to do that. They also have a metering requirement. If they want to provide reliability requirements, one megawatt of load has the same metering requirement as 1,000 megawatts of generation. If you want to use a smaller meter, then the rest of it is made up in what they call calibration charges. And so I really do think that we might be already deciding on winners and losers when we put these sorts of barriers up. And so my question is, is it worth getting started? Are there real barriers, or are these barriers that can be lowered? Have we already picked winners and losers, and we're just going to talk about this price responsive demand for another 15 years?

Speaker 2: Well, I'm willing to talk about it until we get it right. First of all, you have to basically allow the demand to actually express its value in the market. There are certain constraints today that don't allow that to happen. One of the incentives is that anybody who's willing to tell the ISO how it will behave under certain scenarios…if you give the ISO the ability to understand in advance how you're going to behave, it's much easier for them to make the system reliable, and because of that, that demand doesn't have to be in the capacity market. Now, it takes a bunch of small changes in the current market design to make that happen. And I think it causes a virtuous cycle. Once you realize that the price was higher than what you were willing to pay, and you didn't participate in the market, you may actually start participating in the market, when you may get a lot more. We have a lot of this technology sitting around. I mean, PEPCO told me that I can finally access the smart meter that they put on my home system. I haven't done it yet, and there's nothing for me to respond to, other than to look at the data. So, yes, there are things that have to happen.

Questioner: Just to add onto that last point, if I'm in California, and want to participate in the Cal ISO market, I need to post a million dollars in tangible assets to be a scheduling coordinator. And if I want to go through my local utility program, I need to turn my facilities over 24/7, which obviously water and waste water facilities would not be able to do.

Speaker 2: The scheduling coordinator is an artifact of the original market design, I believe. I don't think anybody else has a scheduling coordinator requirement. So you could just get rid of it.

Speaker 4: Let me add to this. How about dynamic retail rates? Show people the prices, and let them respond to them. So it's not just at the RTO level. But you've got to translate that down to the retail level. So the only way to do that is through dynamic retail rates. And so going back to the earlier question about what would you tell people are the three biggest things? Well, that's one of them. If you're a state regulator, and you're looking at all these things, dynamic retail rates make a lot of sense to dovetail with RTO markets. And we've already got the mechanism set up within PJM. And so it's just a matter of getting that translated down to the retail rate level. It doesn't do us any good to have all of the market design in at the wholesale level. If retail customers don't see that price, it's all for naught. And so I think that's a big issue.

But it also comes down to getting the prices right on CO2. And you know, EPA talks about energy efficiency as one of the building blocks, and looking at energy efficiency as a resource. To paraphrase Bill Hogan, it's not a resource, it's a result. And so, really, if you get the prices right, and you get dynamic retail rates, and you let people respond when they say, "Oh, wow, because of these environmental externalities, my bill has gone up. Let me consume less…" Because ultimately customers, while they may respond to a price in real time, if they've got all the real time metering, at the end of the day, I think one of Speaker 2's slides is really telling. Demand is dropping off, and retail prices are coming down in real terms. Why is that? It's because it's an income story. People are managing their total expenditures rather than responding to price. And so to the extent that retail prices go up, or people see those dynamic rates, they'll actually consume less, and that energy efficiency becomes a result, rather than a resource. But, again, that comes from getting the prices right with CO2, or any other environmental externality, as well as getting dynamic retail rates in place.

Question 7: I'm a little bit puzzled by some of what I'm hearing, because there's some discussion of cost of capital differences that justified a different technology. And so a couple of questions here. One to you, Speaker 1. Did I hear you say that you think the cost of capital for natural gas plants is 300 basis points higher than for baseload plants? Is that what I heard you say?

Speaker 1: No, I said that if you have a generating portfolio that's all gas, the risk profile of that portfolio, compared to the portfolio that exists today, the mix we have today, that difference in risk is about 300 basis points.

Questioner: But we don't have an all-gas portfolio, do we?

Speaker 1: No, but what I'm saying is, when you're trying to read the tea leaves, where are we headed in this country right now? I think there is a case here where we're moving towards that less diverse case that I talked about, that when you look at the age distribution of our nuclear plants, you know, by 2035 or so, most of these things are dropping off at a pretty rapid rate. You can't build any new coal plants. In our lifetimes, this kind of generation mix that I've analyzed could be commonplace, and we're seeing some regions that are going towards that pretty quickly right now, including New England, where I'm from.

Questioner: So if that's true, then the cost of capital for New England would be so much higher. But if the cost of capital is higher, that would make capital intensive investments even more expensive, so you would build even more gas, because it's lower capital cost. I don't see some of the logic there. But the more fundamental problem I have is, are we saying that financial markets aren't good enough at figuring out these risks, and so we need to intervene, because there are regulatory risks, and because of regulatory risk, nobody's making investment? But why do we think that waiting isn't the right response, given the risks we have?

So in some ways I'm saying, what are we trying to fix here? I still miss a clear definition of the market failure that wouldn't allow us to rely on the market. I can see that without carbon pricing you can't get nuclear back in the money. But the fact is, we don't have carbon pricing, and until we have that, waiting seems to be the right answer, and, you know, if Exelon thinks there's going to be carbon pricing soon, presumably that will be factored into a retirement decision, and the cost of retiring early, when five years later you have carbon prices, could be huge. So why do we think that investors and markets and financial markets are unable to make that decision?

Speaker 1: I don't see a problem in financial markets quantifying risk. And as I suggested, I think there's some ample evidence out there that, you know, in the case I gave you at AES, their fuel diversity helped them avoid bankruptcy when gas prices ran up. You see, when you look at the competitive power players that haven't gone bankrupt, what's the successful business model there? It's typically people that are the second owners. They're buying the distressed generating assets of the original developers at 50 cents on the dollar, and they're buying a diversified set of assets. You look at somebody like Energy Capital Partners and others out there. So you see that the marketplace does reward people with diversity and with cost structures that are lined up with the market clearing prices. And so if we get the market signals right, I think the diversity will fall in line. But, as I said, there are two problems here. One is, we've got some market distortions. And the other problem is on the policy side with the uncertainty and some of the unintended consequences we're looking at with some of these environmental policy designs.

Questioner: So the market works perfectly, and the people who were invested in one technology went bankrupt. And so it's great. The next generations should be smarter than that. What are we trying to fix here? I still don't see the problem. And in terms of diversity, maybe the problem is that we had overinvested in coal. If we hadn't invested as much in coal, we might be in a better position now with respect to environmental compliance and things like that.

Speaker 1: Here's the problem. You know, to Speaker 4's example, he said, "All right, let's say we do a really good job of fixing capacity markets so that they give a good, solid price signal there. And so a competitive generator can make it building new CTs, and they will perform, and you're not going to have a reliability crisis, because the market price is going to build you enough CTs." The problem is, if the energy price is depressed, all right, a CT doesn't rely on cash flows in the energy market. So if you have a depressed energy price, these negative prices that we're talking about, and we've got perfectly good economic nuclear plants closing down and being replaced by combustion turbines, we're going to get a very inefficient generating mix, and that's going to be the price we pay for not getting the market signals right. So the market will work with distorted prices and give you a much less efficient result, and that's the problem I'm talking about.

Speaker 3: Yes, we believe in competitive markets, and we believe the solution should work through market solutions. I think you understand the tension that we're facing. We do have a great deal of government intervention into these markets right now in the form of doing exactly what you purport not to do, which is picking winners and losers. And we're doing it through policies that affect the other remaining incumbent generators in the market in ways that will bring an uneconomic response. And so I think it's appropriate for us to raise these issues with policy makers, like the ones who are here today, to say, "Look, let's take a look at some of these distortive mechanisms and address them." But we have to deal with the reality that what we're looking at in terms of government intervention through renewables is a pretty significant number of megawatts at this point. And it's not a technology change that I could predict. We've got a pretty good team that looks at innovation and the rate of change for solar, wind and other things. But I studied the financial energy markets in Europe, and there hasn't been the rate of technology change. It's frankly been the rate of policy change. And so we have to have this discussion about, if we're going to allow financial markets to work, then we really need to allow them to work. We could get a great deal of attention at FERC when it comes to something like that MOPR, which represents a way to prevent people from building a couple of gigawatts of gas-fired generation on an uneconomic basis. But FERC would look aside at the issue of 50 or 100 gigawatts of renewable generation, which once in place also has distortive effects in the energy market, and actually does something that we never could have foreseen. It drives energy prices below zero on a fairly frequent basis in many parts of the country.

So I don't think you were hearing from folks here that we don't believe in financial markets. Certainly you're not hearing that today. You're certainly not hearing that we don't believe in competitive markets. What you're hearing from me is, let's recognize that we really don't have that right now. And to the extent possible, we have to lessen some of these interferences, or we're going to pay the consequences of losing resources that we want to really keep, not only for the good of our customers, but for the good of the country and maybe the world.

Question 8: I've heard all sorts of things that put me in a thumb sucking risk state of anxiety. [LAUGHTER] I've heard that a risk of imposing diversity, that's a risk. We have a risk of not doing diversity. We have a risk in delay. And then we have a risk in not delaying. [LAUGHTER] So, you know, what's a mother to do [LAUGHTER] by the end of all this?

But the one that made me put my card up was the idea of assuming that we're going to be going towards a kind of lower cost pro-natural gas future and putting our chips on that play and going heavily into that area. And one of the things that I know my membership is quite concerned about, and which we put in our comments, is, first, whether the infrastructure is there to support that, but that's well known. We have a lot of smart heads in this room, but what we don't have are representatives of the environmental community here. And you just need to go to the Sierra Club's website--their "Beyond Natural Gas" page…you know, it's not just beyond coal. It's beyond natural gas. And what concerns me is the risk of going in and saying, "Well, the shale gas revolution is here to stay, and this is the technology, and I'm going to move in that direction," and then five or ten years from now, we're in a situation where the investments we made, thinking we could use them for 25 or 30 years, are all of a sudden not good either. That leads me to go to the 401(k) approach to managing risk, which is that I don't want to put too much in any one of these baskets. I believe in truly an "all of the above" strategy. And I have a lot of members who do, too. They're putting money into, for example, new run of the river hydro. That's a very expensive upfront solution. But when you get it, you know, you've got many, many years of no fuel cost. So I think we need to think about the idea of trying to keep all sorts of geothermal, all sorts of different items in this mix, and also don't underestimate the environmental angle to this, because those forces are not in this room, and I guess I ought to just ask if people have comments on that.

Speaker 4: I feel your pain with respect to the environmental groups. It's that they want everything, and they want it now, and I'm sorry if I'm going to speak out of school a little bit here, but I think that some of it, and we've actually run into this recently, a lot of it's going to be about fundraising, that they're trying to make a big splash on some of these things just to raise money.

There are environmental groups, however, Environmental Defense comes to mind, for example, that have been championing markets and getting the prices right. So I don't think we can paint everything with a broad brush stroke here. But I do share your concern with respect to that.

But I think also you talk about some of these, you know, the zero cost resources, since you brought that up, you know, run of river hydro. It could be wind. It could be solar. All of the things that we're talking about, whether it's RPSes (by the way, I like to refer to an RPS as PURPA with a smiley face). And then you've got CO2 pricing, and the stuff that we've shown in our recent analysis. And what that does is, it actually puts a greater premium on capacity markets, because you're eroding those energy market revenues, to the point that Speaker 3 has made with some of his assets out in Northern Illinois, some of the coal assets that are potentially distressed, either because of lower cost resources or natural gas, wind, etc. And to the extent that it's economic to keep these around, we're now actually shifting money out of the energy market and into the capacity market, because, like the laws of physics, there are certain laws of finance. And that is, these resources, whatever they turn out to be, it doesn't matter, have to cover their going forward costs, period. If they're not going to cover their going forward costs, they're going to go away. They're can either do that through the energy market or through the capacity market. You take away energy market funds because of CO2 prices, or RPS, where it drives prices down very low. It's like a balloon. And you squeeze one end, and it's got to come out the other end, somewhere, somehow. It's the only thing that's going to work, unless, again, then you have $9,000 prices in ERCOT. But we can't get away with that in PJM. But it's just something to think about. But I do sympathize with the environmental groups. I mean, we've had some interesting experiences recently with that as well.

Speaker 1: I would add, on the environmental side, I think you're right, you can't paint everybody with the same broad brush. I would say, though, that what we observed in a lot of cases are the embrace of some simplistic ideas and some faulty cost analyses that are creating some trouble. And I see some of these reflected in the EPA proposal, for example. So, you know, there is a problem that the EPA doesn't have the legislative authority it would need to implement a cap and trade or a carbon tax. But that's not the only problem that they've got. When I look at their formula for the carbon intensity, the fact that they said, "We're going to let you go outside the fence, but you get full credit for renewables or efficiency, but little, partial credit for a nuclear upgrade," for example. That doesn't make sense. So there's something else going on here. Or a hydro upgrade. That doesn't make sense. And there is a very emotional influence often that leads to some bad environmental policy. And I think Germany is a case study where emotions have trumped engineering economics. Here's a country that within the span of a decade has closed down a third of its supply, which was nuclear, and not producing CO2, and is replacing it with wind and solar, solar in a place that has the solar intensity equal to Anchorage, Alaska, that's Germany on average. And backing it up now with coal. So their CO2 emissions are going up. So we've got some emotionally driven policy aspects that can really get you in trouble. And I think there are some case studies out there of places where things have gone very badly because some of these simple ideas are getting traction.

Question 9: The truth of the matter is that when you're talking about fuel diversity, you're really talking about two things, either coal or nuclear, and neither is ever going to be built for different reasons. With respect to coal, it's just impossible to build it. It's impossible to permit. Even in Texas, where you can build almost anything else. [LAUGHTER] The last couple of attempts, both by public power entities as well as private developers, they got tied up in the courts, at the environmental agency, hearings and hearings. And they finally gave up. In the case of the co-op, it wasn't for lack of finance. It was just, they threw in the towel. You just can't get it done. In the case of nuclear, it's different. It's the time it takes to build. That's not an RTO or market design issue. But if it takes you ten years or 15 years to permit and build a facility, I don't know of any RTO pricing that would enable the construction of a new nuke plant.

So I guess my question to the panel is, what's the point of the panel? [LAUGHTER]

Speaker 3: I think the point of the panel is probably more around existing generation than it is around building new generation and cleaning up some of the rules. I think the discussion has gone back and forth a little bit about that issue that you're raising, which is whether we should retain control and build new coal plants and build nuclear plants. I think, generally speaking, you're hearing from all of us. But there is kind of this middle piece of this, and in fact, it's going to persist for a few decades, where we do need to make some decisions, or we're going to lose some of the existing steel in the ground.

Now, I happen to think that there are already opportunities to do that. For example, in the PJM states, if a state wants to drop out of the capacity market and go to an FRR, fixed resource requirement, they could do that. They could opt out. And then they could enter into the bilateral contracts that you were referring to. And so it's an exploration of those sorts of ideas, and a discussion with you, frankly, of the issues.

And I think lastly, this session is a discussion of what are we going to do about carbon? It's one unknown that we all think is potentially out there.

Speaker 2: And I thought it was about price responsive demand and also the future of Clip Art. [LAUGHTER]

Speaker 1: I would add, too, that the primary focus of our analysis was on the value of our current diversity, and you know, in the case of Texas, what's very clear is, I think that if you were to sit down and say, "What are the risks that the Texas ERCOT power system faces from more and more exposure to natural gas?" Well, it's a very different risk profile than New England, given that you've got the Barnett there and all the rest. The point here is, though, that when you picture the existing generation mix, one of the lessons from the Polar Vortex in New England was that oil fired generation in New England was .35% of all generation in 2012. But during that critical week of the polar vortex, it provided 12% of generation. So a very small piece of diversity actually turned out to be really valuable in New England. And so I think an analysis of Texas might suggest that preserving some of the diversity that you've got long run may turn out to be valuable, rather than an accelerated move way to this least diverse kind of case that we talk about. And, similarly, on the proper way to integrate the demand side resources. There is a cost effective price signal to demand side resources, and you can create inefficiency by having too much of it, or having too little of it. And in particular, things like a capacity price signal are a pretty important way to get the right signal to demand resources. So there are issues specific to markets like Texas about, how do we get the right mix of demand side and supply side, given the kind of prudent risks that we can assess going forward? And I think preserving some of your existing diversity is probably something that an analysis would say would make sense.

Question 10: I'm going to try to answer the last question. [LAUGHTER] And I've actually found this panel very helpful. And I must say, before and even during the day here, I'm still struggling with, what is this all about, this diversity story? And in particular, what is the private, and what is the public story here that we need intervention to do something about it?

And a lot of the argument uses the word diversity, but what we're really talking about is optionality, which means you want small scale things, and you want a delay. Then you want to be able to adapt when you get new information, rather than making big commitments that you're stuck with for a very long time. And that seems sensible, but I don't think of that as diversity, necessarily. That's a different kind of way of dealing with risk and uncertainty.

Some of the discussion is about the volatility of prices, and how they might go up or down and all that kind of stuff, and what I was expecting to hear was some sophisticated version of capital asset pricing model and correlation with the rest of the market and diversifiable risk and signing long term forward contracts, which you could do. So you could make a natural gas plant look like a wind facility with a high capacity factor. Right? So you could buy all the gas forward, and then you can have that gas at whatever you paid for it. And now all you're doing is, paying that debt off. You're going to be paying it down and paying it down. It's just not paying for fuel. You buy the fuel up front, and then you have a big debt. You can make it look like the same thing. The problem is whether or not it's worth doing that, and so forth, but you can solve that kind of a problem. So I don't think that's the issue.

There's a little bit I hear about ex post exploitation, which is, I'd really like to stick it to you, and circumstances change, and I don't want responsibility for it. We can have another conversation about that. [LAUGHTER]

So I don't think diversity is really important, per se. But I hear diversity being used for two kinds of problems, which are quite real problems, and they had to do with what Speaker 1 was talking about, which is that electricity prices are not high enough, and they're not volatile enough. We should be making them higher and more volatile. But we should have more price responsive demand, so we get all of that, effective, the kinds of things that Speaker 2 was talking about. And we should charge for CO2 in the Speaker 3 policy, which I think is also the right thing. And then the diversity argument for really expensive solar and wind goes away. And the diversity argument for subsidizing nuclear goes away.

And so now it's not a diversity problem. It's a pricing problem. And we could fix that. So how do we fix that? How about an operating reserve demand curve? [LAUGHTER] That seems like a really good idea. How about a price on carbon? That seems like a really good idea. And that's something that the RTOs can be lobbying for, and we could all be lobbying for. And I think this diversity conversation is a distraction, frankly. I think markets are very good at dealing with that kind of stuff. Bankruptcy of people who invested in natural gas is a way better outcome than what we saw with Shoreham, where it was clearly under water at $2 billion, and it was underwater at $3 billion, and it was underwater at $4 billion. And it was underwater at $6 billion, when they finally stopped, because the governor intervened. But they were going to pour money down that rat hole forever, because they were playing with the house money. They weren't playing with their own money. And so markets do much better. They go bankrupt. I don't like it, but, you know, that's better than the alternative. So I think it comes back to basically market design principles are the story here, and it's got nothing to do, really, with diversity. Markets can take care of it. Does that answer your question? [LAUGHTER]

Speaker 1: You know, I agree with you. And it's interesting, because when we started the work, the study that I told you about, the real genesis for it was that you looked at the kind of trends that we're seeing, and it looked like we're headed to this all gas and renewables future. And so we said, "Gee, that's a lot different from where we are, and people just don't seem to understand. They tend to undervalue what we have currently got," which is why the study focused on, "Well, let's try to quantify the current value of diversity." But you're right. As we did this study, what we realized is, "But we’re not trying to optimize diversity. That would be equal shares of every available source.” So we’re not trying to optimize diversity. But what it turns out is exactly what you’re saying. We’re not getting the right price signals, and we’re getting some troubling policy influences that are going to move us away from where we’d otherwise end up. If we got the market signals right and had good public policy, I think we’d have a nice diverse resource mix from that structure. But that’s not what we’ve got. And we’re moving away at a pretty rapid pace from the cost effective generation mix you get with the right market signals and some very logical policy. And so, yes, focusing on diversity was kind of the initial thing, but that’s really not the issue. The issue is that we’re moving away from a cost effective mix right now to something that is going to be very difficult to manage down the road.

Speaker 4: I have one quick response. Amen.

Session Three.
Resource Adequacy Reconsidered: Mandates and Markets

Assuring resource adequacy has been an ongoing challenge since the transition to competition began. A number of measures have been taken to try to address the matter. These include the development of capacity markets and demand response programs. Events and continuing reform initiatives challenge both the effectiveness and costs of these programs. Criticisms of capacity markets continue, and the court decisions on Order 745 raise new questions about how to address demand response. An addition to resource adequacy concerns is fuel supply and pipeline capacity. While this issue has been of particular concern in New England, where pipeline capacity is highly constrained at certain times of the year, it has the potential, given the country's increased reliance on natural gas, to become a problem elsewhere as well. How far can we rely on markets to assure resource adequacy? What mandates are required? Does the mandate of capacity markets mix with the market model of generation supply? What alternatives are available to supply and demand options organized in mandatory capacity markets? Do mandates support or replace market solutions?

Speaker 1.
The first question to address is, what is resource adequacy? Physics requires that electricity supply match demand in real time, and that voltages stay within tight limits. Reliability problems occur when system operators lack the resources, information, or judgment to maintain power balance and voltages. Deviations can erode grid reliability and, in extreme cases, cause blackouts.

Security and adequacy of electricity service depend upon reserves. Security depends upon *operating reserves*, or the amount by which available resources exceed load. Adequacy depends upon *planning reserves*, or the amount by which total resource capacity exceeds annual peak loads. Operating reserves and planning reserves are indicators of system reliability in short- and long-term timeframes, respectively.

The traditionally regulated market model and the restructured market model have different approaches to resource adequacy. Under the traditionally regulated model, state regulatory agencies set prices based upon utilities' average costs of service. Investments to develop transmission or new generation are based upon integrated resource plans. Under the restructured market model, competitive bidding sets wholesale market prices of energy, operating reserves, and capacity, based upon supply and demand. Investment responds to market prices.

In the traditionally regulated model, vertically integrated utilities manage security and adequacy through self-supply and bilateral contracts. Capacity markets are bilateral and non-centralized, and utilities participate in reserve-sharing arrangements allowing them to rely on each other's capacity, thereby reducing overall reserve requirements. States have integrated resource planning (IRP) processes that determine resource requirements and identify resources that meet those requirements at lowest cost.

In the restructured market model, Regional Transmission Organizations direct resource commitment and dispatch and administer centralized energy and capacity markets. Originally, markets were energy only. The theory was that when there were shortages, prices would rise to attract new capacity. As things actually developed, price caps were put in place in these markets, and the "missing money" problem was discovered—in a market with price caps, plants operating limited hours a year could not recover enough revenue to justify investment in them. In an attempt to address this, some RTOs have developed capacity markets.

To compare capacity cost recovery under the two market models, under the traditional regulatory model, investors receive return of capital based on annualized costs of actual capital investments, including and allowed rate of return. Under the restructured market model, investors receive whatever return is achievable through market prices for energy, and through capacity payments, in some RTOs. Capacity prices are determined through a variety of regulatory/administrative rules, including Minimum Offer Price Rules and penalties for load-serving entities that fail to procure sufficient capacity.

There are certain problems with the restructured market model. In theory, investment should respond to price expectations. Investors will develop resources when they expect to profit from sales at projected market prices, hedged by bilateral and derivatives contracts. Locational prices induce generators to locate where generation services are most valuable. And long-term markets develop to facilitate hedging against price uncertainty. When demand threatens to exceed available capacity, high energy and ancillary services prices encourage immediate load reductions, and customers do not receive service in excess of the resources to which they have purchased rights. In this theoretical construct, there is no capacity product, and market rules are stable.

In practice, the market model does not work like the theoretical version described above. The problem is that public policy will not allow the price mechanism to work under shortage conditions, and, further, it distorts the price mechanism under all conditions. Market participants do not want the extreme and unpredictable price volatility of unfettered electricity markets, so price caps are used to limit upside volatility, which reduces incentives for invest in or postpone retirement of resources. Public policy distorts the price mechanism as well, because policy favoring particular resources—RPSes and PTCs—subsidize those resources while implicitly taxing other resources. Furthermore, the minimum offer price rule is unevenly applied to some resources but not others.

The price mechanism is further inhibited by institutional limitations. Limited demand-side participation restricts the extent to which prices reflect consumer value. Furthermore, there has been little development in practice of long-term markets for energy and ancillary services.

Adding on to this may be a “fatal flaw” related to the nature of reliability itself. Different customers have different willingness to pay for different levels of bulk system reliability, but only one level of reliability can be maintained. Society in general values reliability higher than individual customers. Thus, reliability must be maintained at levels that exceed many customers’ willingness to pay for reliability.

Since, for all of the above reasons, the price mechanism does not suffice to get the “right” level or type of resources, RTO rules often specify the quantities and locations of resources that must be procured, and RTOs regularly make large out-of-market payments to resources to ensure reliable operations. In taking these actions, RTOs typically ignore fuel diversity and fuel security (particularly natural gas)—two considerations that are important and neglected.

Complicating the effect of these interventions, market rules continually change, creating an uncertain investment environment.

As things have developed in response to the various rules and incentives added on to the market, demand-side resources now make up a large portion of reserves—we may want to ask ourselves whether this should be a concern. The level of incentive needed for actually putting steel in the ground is not there—as you can see in this chart, on average, net revenue for a combustion turbine gas plant does not begin to approach the levelized cost of a plant in any of the RTOs.

Given this situation, are markets securing sufficient capacity? Forecasts are for falling summer reserve margins in traditional market model regions, with some markets falling below minimum reserve levels by 2023. RTO regions see a similar forecast, with significant reserve shortfalls projected in ERCOT and MISO, beginning in 2018, and worsening by 2023.

In terms of fuel mix, some RTO regions are heavily reliant on natural gas. The overall US resource mix, in terms of summer capacity, shows increasing reliance on natural gas (over 40% by 2017), with a corresponding decline in the role of coal, reflecting, significant projected retirements of coal plant capacity.

To review the conclusions of this analysis, the RTOs' short-term centralized capacity markets do not provide incentives for long-term resource investments. The political process will not allow peak period demand pricing that is consistent with a market solution. The mis-match between the social and private value of reliability is a continuing issue and perhaps a fatal flaw. And markets cannot ensure fuel diversity, which in turn has reliability implications. Furthermore, fuel security is a major issue. We should ask ourselves whether generation without firm fuel supply contracts can be considered "firm" for capacity purposes. Additional retirement of coal plants resulting from the proposed EPA Clean Power Plan only exacerbates the problem.

Will we act in time? There are some potential solutions. The obligation to maintain capacity and reserves should be reinstated, and should rest with load-serving entities, with a certain % of the obligation being for long-term resources. Furthermore, there should be a competitive supply requirement. Capacity markets can still provide short-term options. The costs of meeting this obligation should be placed in the rate base of the load-serving entity. Revenues obtained in the energy market in excess of costs should be credited against capacity costs in the rate base. And finally, competitive retail suppliers should have an obligation to pay for capacity

Speaker 2.

The title of this session refers to "mandates vs. markets." I'd like to begin by arguing that what we are talking about her are administrative constructs, not "markets." Extensive market mitigation is required to ensure what are considered "competitive outcomes." At the same time, rule changes that impede new entry are justified in the name of protecting "competition"—for example, by raising concerns about "buyer-side market power," or "out of market resources."

So I suggest we reframe the question: "What mechanisms best enable Load Serving Entities (LSEs) to meet resource adequacy and other public policy requirements *at a reasonable cost?*"

There are certain unanswered questions about capacity constructs that should be looked at:

- Are reliability standards being met at the least possible cost in RTOs with mandatory capacity markets?

- Are crucial resources retiring that should be retained? Will new resources be sufficient to replace the retiring resources?
- How do proposed changes to energy and ancillary services markets interact with changes to the capacity markets? What is the total cost of all the changes?
- How will states implement the EPA's Clean Air Act 111(d) rule without control over capacity resource decisions?

On this slide, you can see some of the data from a recent APPA study of power plants, indicating that capacity constructs do not incent resource development. Looking at the new capacity starting operation in 2013, APPA found that the vast majority was built either with a purchased power agreement in place or for ownership by the utility or other energy customer. Only 2.4% of new capacity was developed with market sales in mind.

What is the optimal role for demand response? The D.C. Circuit Court rationale in its *EPSA v. FERC* decision also applies to capacity markets. Demand Response is not a wholesale supply-side product, but a retail demand-side resource. Therefore, Demand Response can participate in RTO markets on the demand side, as a reduction in the LSE's energy needs/resource adequacy obligation.

It is worth examining some of the arguments in favor of capacity markets more closely, contrasting claims with realities.

One claim is that the goal of a capacity market is not just to incent new resources, but to obtain the least-cost resources, for example, by preventing retirements. In reality, it is not clear that those plants that are retained are the ones that are most needed for economic and public policy reasons. For example, despite capacity markets, we are seeing retirements of no-carbon baseload nuclear plants. Perhaps, in fact, capacity markets allow bad resources to drive out good resources?

A second claim is that capacity markets provide a price signal for the bilateral market. The reality is that auction prices are volatile from delivery area to delivery area and year to year—often for seemingly arbitrary reasons. Furthermore, bilateral markets function without mandatory capacity markets in non-RTO regions. And Minimum Offer Price Rules (MOPRs) hamper the free ability to develop bilateral contracts and to self-supply.

A third claim is that capacity markets provide needed revenue to cover fixed costs. But the reality is the generators' fixed costs vary significantly by age and technology type of plant, yet all receive the same payments. And new generation requires a steady stream of payments over a longer term that these markets do not supply.

A fourth claim is that new merchant plants are being built within capacity market footprints. The reality, however, is that about 7,600 MW of new merchant combined cycle plants cleared PJM's auctions for 2016/17 and 2017/18. Not all of this cleared capacity is under construction, and many of these plants ended up financed with a larger equity share to the financers, and/or more exotic financing, resulting in higher plant costs if these plants are ever built. Furthermore, an unaddressed question, given these planned new natural gas plants (Maryland's natural gas share, for example, is projected to increase from 29% to 47%), is, who will contract for and build needed new pipeline capacity? What will be the impact on natural gas prices?

A fifth claim is that restructured markets shift the risks from consumers to investors. But the reality is that generators facing a loss of profits claim that price signals are too weak to incent investment and often obtain rule changes to increase prices—rule changes such as MOPR and buyer-side market power rules; creation of new zones; RTO switching; shifts in the demand curve; creation of new capacity products; and offer cap increases to cover fuel security.

There are a number of reasons to be concerned about capacity markets:

- Restrictions on self-supply and threats to the public power business model;
- Higher and more volatile costs, and frequent rule changes;
- A semi-Kafkaesque stakeholder process;
- The fact that financial benefits accrue to owners of existing capacity when the markets are *more* constrained;
- The fact that there is no long term planning for generation diversity or public policy goals, and every MW is paid the same, regardless of technology, fuel access, age, emissions, etc.

So what is the future of capacity markets? Are the RTO-operated markets best suited for achieving the most 'efficient' use of existing resources in the short term, rather than producing an optimal mix of resources needed by the industry and society over the long term? If so, a new paradigm is needed for the long term.

What could capacity market reforms look like? A transition from a mandatory capacity market to voluntary, residual capacity procurement mechanisms. Resource adequacy standards with penalties for non compliance. A FERC/state working group to evaluate seller-side market power and, if needed, place appropriate restrictions on pivotal sellers. LSEs able to self-supply through ownership and bilateral contracts without constraints. RTOs and states determining the most economic and efficient options to relieve transmission constraints.

In conclusion, capacity "markets" are not now and should not be the primary means to support needed capacity. FERC needs to think outside of the capacity "markets" box and seek new solutions. The proposal: transition from mandatory capacity markets to voluntary residual markets with the primary procurement of capacity conducted through bilateral contracts and Load Serving Entity ownership.

Speaker 3.

The track record is that pipeline capacity is not being developed in organized markets specifically to meet the demand created by wholesale generators. The anchor shippers for downstream pipeline projects remain predominantly the natural gas LDCs. Generators get to ride the coattails of these expansions via additional pipeline capacity that will be available in the secondary market. But they likely will have little or no access to this capacity during peak periods when the inability to access natural gas pipeline capacity has the potential to create electric reliability problems and to result in extreme prices to consumers.

Here's the question: Even if you assume that the market reforms will value fuel assurance appropriately, will this provide a sufficient incentive for developing the incremental pipeline capacity that may be needed? In particular, if the greatest certainty that a generator can get in the capacity market is a seven-year payment stream, how does this square with the need in most cases for a 15-year firm contract from anchor shippers as a prerequisite for developing new pipeline capacity?

Who wears the risk associated with years 8-15? There is no reason why a pipeline company and its shareholders should assume that risk. There is no reason why other pipeline customers would be willing to subsidize capacity from which they receive no benefit. And to date, no one has expressed a willingness to hold that capacity on speculation, e.g., an energy marketer or a financial player.

Is there an answer, other than assuming that generators in organized wholesale markets will continue to ride the coattails of new pipeline capacity built for others and that no pipeline capacity will be developed specifically on behalf of generators in these markets? If that's the case, fine; but don't complain when there is no capacity available for generators on cold days or when pipelines cannot always provide the types of services that meet generators' needs.

Do we need to look at public policy and regulatory initiatives that can address this shortcoming and that can work in tandem with the direction taken by the initiatives in those markets to address fuel assurance concerns?

The NESCOE proposal was on to something in terms of the respective federal and state roles on these questions and the bounds of what can be done under the current legal framework.

Here's a suggestion: Why can't the New England states agree to encourage and, if necessary, require the region's electric distribution utilities to be the anchor shippers for the natural gas pipeline capacity needed to serve the generation market? And, as part of this, provide the distribution utilities with the assurance that the cost of that capacity could be recovered in their regulated retail rates.

In connection with this, I would note that three of the biggest electric distribution companies in New England -- NU, National Grid and UI – had offered to be the anchor shippers for the pipeline capacity that was contemplated under the original NESCOE proposal.

Speaker 4.

This is an important topic. Resource adequacy and reliability is always job number 1 for regulators in the power sector. This is where the rubber meets the road—and if you are going to use markets rather than mandates, you need well-functioning markets based on sound economics and engineering realities.

Whether you use markets or not, it is crucial to recognize that resource adequacy, and therefore reliability, requires adequate revenues. Specifically, for fuel, it requires that economic incentives and fuel assurance be aligned. Set the prices correctly, and market participants will respond—if they don't have fuel, they lose revenue.

Markets can work if you let markets be markets. But if you start using mandates, at some point you will have too many or the wrong type of mandates, and you will tip the scales and end up suffocating the markets. Are we approaching this point?

I'd like to examine three specific points based on talking with senior executives who allocate capital and make decisions about risks:

- Resource adequacy is more than capacity markets and demand response, though both are important. Energy markets matter, too;
- Capacity markets are messy and controversial. RTOs that have them need to make them work in the light of changing needs, policy, resource mix, and available technologies;

- With respect to demand response, however the current question of jurisdiction is decided, there are numerous policy reasons grounded in reliability to better think through the role of the demand side in resource adequacy.

So, first, on the point that resource adequacy is more than capacity markets and demand response—we need an equal focus on energy itself, the numbers speak for themselves. Energy is the biggest source of revenues in the market. While capacity markets deal with changes three years in the future, energy markets affect supply 24/7.

So we need to understand energy markets and their current problems, including the impacts on the energy markets of uplifts, offer caps, and operator actions. To address these issues, you might look at some of the work from Susan Pope and Bill Hogan about the advantages of incorporating things like operator actions taken for the sake of resource adequacy into LMP.

FERC's November 20 "fuel assurance" order, requiring RTOs to report on their efforts to ensure fuel is available for electricity generation, is a step in the right direction.

Overall, energy market improvements can relieve some of the pressure on capacity markets.

Second, capacity markets have largely worked well up until now (despite attempts to derail them), but the needs they address and the context in which they function are changing, which needs that we need to change how capacity auctions work. Up until now, capacity markets have largely worked well, given supplies at or above reserve requirement levels, excess supply offered in as uncleared resources, competitive prices which assisted with retaining existing resources and supporting new building where needed.

However, new factors are becoming more important as the resource mix shifts. Variable energy resources (such as wind and solar) require flexibility and ramping capabilities, and they may result in some generating units running for fewer hours and earning less revenue, thus needing more in capacity revenues to stay in operation.

At the same time, capacity markets face new challenges. One challenge related to attempts to use mandates to undermine markets. This can include out of market new entries, as in Maryland and New Jersey, or regulatory measures to keep plants running, such as are being discussed in Ohio. A second challenge relates to clarifying an understanding of what "capacity" is. The capacity product needs to be clearly defined in a way consistent with resource adequacy needs—capacity is physical, not financial, and the expected physical capacity performance needs to be clearly defined.

Turning to my third main topic, demand response, more is at issue here than the question of jurisdiction, as important as it is. Order 745 did a disservice to demand response, by going too far in terms of its compensation requirements, and it also confused "balancing" the system on the margins with overall system resource adequacy, which requires well-functioning markets for baseload, mid-merit, and peaking capacity.

Demand response may be thought of in relation to peaking, but even as a peak shaving resource, demand response can be problematic, since peak prices help sustain, not only peaking resources, but all types of resource, including baseload and mid-merit resources. (There is a Credit Suisse report out today on the importance of the top 1 percent of price hours to overall price formation during the year.)

The current emphasis on who has jurisdiction over DG is important, but even assuming this is resolved, there are serious issues, as we've seen, with DG as a capacity resource. There have been some key improvements in the past few years in how DG is handled in ISO-NE, imposing "must offer" rules on capacity resources and in PJM, with new notice rules, etc., but other RTOs still have inadequate capacity resource provisions.

Assuming the Court upholds states has having jurisdiction over demand response, it doesn't go away, it just shifts to the demand side. Under the Federal Power Act, according to court cases, FERC retains exclusive authority over capacity markets even if DR itself is considered retail—the impact will be on how much capacity is procured.

FERC and the RTOs need to plan for multiple scenarios, given 2015 capacity auctions that will determine resource adequacy in large RTOs on the eve of the implementation of the 111(d) rule and in the face of other policy and economic headwinds. If FERC seeks, and the Supreme Court allows, a cert petition by December 16, that could further undermine the legal/policy environment within which investment decisions now will impact resource adequacy into the next decade.

In concluding, to come full circle back to the "mandates and markets" topic, we need to make each model in each region work. There is no more time to experiment or to change fundamentals. We may be in the Big Easy, but these issues aren't easy—they are very hard. All the more reason for HEPG to tackle them. To return to first principles, it is necessary to get prices right. Prices are the oxygen of markets. Accurate prices and revenues from these prices are navigational beacons for the investment necessary to efficiently and effectively provide for resource adequacy in turbulent times.

General Discussion.

Question 1: For Speaker 2, would it be better to replace capacity markets with price-responsive demand, or an Operating Resource Demand Curve, or some other mechanism like that?

Speaker 2: Some of the issues raised today could be summarized as, would we prefer the Texas energy only model? And that's a scary thought. I'm not sure, to be honest. I will say that the capacity market hairball has gotten to the point where we'd consider a whole lot of options in contrast to that, but I'm not sure we'd go all the way to absolutely no limits on the energy price.

We feel like the MISO market is probably a better model. I can't unequivocally say we would prefer that, I can say that we are certainly getting sick of what we are seeing.

Speaker 1: I would say yes, but it is kind of like asking, is there a Santa Claus?

Question 2: Quick question, Speaker 1, you discuss the very complex way that LOLE is calculated. I guess the question is, does that need to be looked at again? When that process was set up 30, 40 years ago, we had a great base of forced outages to just crank through the sausage makers and we get an output, but that was before the issue of firm fuel ever became an issue.

Should that somehow be cranked in, either to modifying the forced outage rates, which I think is what PJM did, or should we start modifying those algorithms to try to keep up with the mix, as opposed to going along with our 30 or 40 year old methodology? There's lots of good backward-looking data but not forward-looking data.

Speaker 1: I am not sure that even if we modified the methodology, we would get to the right answer, because, again, I think there is this disconnect between how people value reliability versus how they really value it and what they'll pay for versus what they'll value it at. I think, in the case of reliability, they are two different things.

On the natural gas point, I just continue to fail to understand why that isn't a risk that the generators who bid into capacity markets, ought to be thinking about. In the case of vertically-integrated utilities, we don't count gas capacity that doesn't have firm contracts and firm capacity. Why do RTOs allow gas capacity that doesn't have a firm gas supply to be counted as capacity? I still don't understand that.

Questioner: Maybe I wasn't clear. I'm not talking about who can be a capacity resource. I'm talking about determining the required reserve level. As we know, there are a gazillion inputs, load, load forecast at a certain date, forced outage rates and partial forced outage rates… In none of those calculations do we ever imply a single contingency, loss of a pipeline, and what that would then do to the reserve margin.

I'm simply, without taking a position on what you said, asking that question.

Speaker 1: Now I understand, and I think the answer to that is absolutely yes. I think we really need to revisit the methodology to take into account the new world we are living in, because things that were counted as not being contingency…I don't think we ever needed to count the loss of a gas pipeline as being a contingency because that had never happened in the old world, but I think there is that possibility in the new world.

Speaker 4: I just want to make sure—the question included LMP-- I thought that is what you said at the beginning. Were you asking about LMP for energy markets?

Questioner: The reserve requirement calculation that goes into however you set your capacity requirement objective or whatever. The thing that goes up there on the board that NERC says, you are adequate or not in your assessment.

Speaker 4: Just to give a brief reply to what Speaker 1 said on the second issue about natural gas and not having to be firm in order to bid and all that. Obviously right now, it is working 99.9 percent of the time, as I said, and the generator has every incentive to do it.

The reason why is that there are rules on what you can and can't bid. You can't put something like that into the capacity market bid because, as we all know, the capacity market is generally supposed to be for variable costs, not fixed costs. That is a big part of it.

And obviously rules can change and things can improve, which is why things are changing on the market. As I said, in the Texas example, once the incentives were aligned and changed, people responded for the obvious reasons, not only not to miss out on revenues that they might lose if the plant's down when prices are higher, but also, particularly in Texas and also in the Eastern markets, we have companies that are both wholesale and retail suppliers, so they get hit on the retail side if they don't have their own generation to cover the retail obligation so they have to go out and buy spot when the price is higher. So, again, getting prices right.

Speaker 1: But if the power isn't there, people don't care about the penalties.

Speaker 4: But that's the point, the power has been there and what is interesting about your chart, which I'm going to put in my evidence vault, is that the difference between what you are advocating and what I'm advocating is, everything in the RTO markets is least cost.

You would be hard pressed to argue, when you have that chart with the high capacity, and the reserve margins in the non-market areas--somebody is paying for that and it is rate payers in Mississippi from the Kemper overruns and rate payers in Georgia from the Vogtle overruns, and if that's not least cost, I think that is the world that Speaker 2 wants.

Speaker 2: Now that my name has been invoked, I guess I do have to talk about this. I would just say, it may be true that in a cost service environment, not every investment at any one particular period in time would be considered least cost in the way that a merchant would say that. That's not the goal. The goal is to develop a diversified portfolio that is neither in the money nor totally out of the money over a long-term period.

Going back to this issue of the firm pipeline capacity, I spent the first 15 years of my career in the natural gas regulatory world and I know that model very well. These guys are not a Field of Dreams bunch. They are not going to say, "You guys want more natural gas for generation, let us help you with that. We'll build these pipelines on spec and hope we get it recovered." They don't do that.

To them, it's like, "Sign a 15-year contract on the dotted line and then we will go spend the three years of pain, suffering and mental anguish that it takes to get that pipeline constructed, sited and built." That is what they do. I don't blame them.

In the Southern Company territory, they have that firm capacity that is rolled in. It is not an issue for them. Things are so screwed up in New England that we are talking about putting the cost of the pipeline in the ISO's electric tariff because they are the only person standing who can finance it.

It got to the point where my members, my Massachusetts Joint Action Agency, actually suggested in a letter to NESCO, why don't you let us fund this? We will float tax-exempt debt and we will build this pipeline because it is needed so badly.

When you are reduced to those kinds of mechanisms, something is screwed up. Just saying.

Speaker 4: Brief reply. A couple things, one is that pipelines are coming into New England now. Secondly, I read the Ten Commandments this mornings. I didn't see that the 15-year contract was written in stone. He is talking about setting 8-15 years, they don't want to take the risk but they want to put the risk on the rate payers of Massachusetts and New England and the rest of the region, so somebody's bearing the risk.

Our members are building 15- and 20-year assets and not getting 15- and 20-year contracts, and they cost a billion dollars. I think help is coming from the East. If Speaker 3's members don't want to build it in New England, let's keep in mind that on January 7th, the coldest, toughest day in New England, New England actually sent power out of the region. The problems in PJM were greater than in New England.

What's happening is, people are responding to the market signals. You are seeing offshore gas terminals, you're seeing people looking at on-shore storage, you've got Canaport (LNG terminal), you've got the existing Everett facility, you've got people talking about LNG right down the road here.

So there are other ways to do this, not just mandating a specific firm contract for everybody to have to sign. Members sign them when they think it's in their interest and the economics justify it, but to just mandate it doesn't seem to be the way to go.

Speaker 3: I mean, the 15 years is not set in stone but you've got to ask yourself, if you are the developer of an interstate pipeline and you've got a capital intensive, long-lived immobile asset that is selling subject to cost-based rates based on depreciating facility over 30 years, that you are wearing the risk whenever that contract expires as to whether you resell that capacity and at what rates, there is good reason why pipeline companies are not going to build on speculation or not going to build subject to very short contract terms. Let me offer you an example. Back before shale came along, back in the early part of the last decade, when it was assumed that Rockies natural gas was going to be the incremental source of domestic natural gas supply, a lot of pipeline capacity was built by pipes in the Rockies signing producers to ten-year contracts. I think the assumption was, at the end of ten years, you would roll it over and you'd probably get close to your max rate again. Then shale came along, and those contracts are coming pretty close to expiring if not expired, they are not refilling, and if they are, it's not anywhere close to the max rate. So I think that, As I said earlier, the historic anchor customers for the pipes are the LDCs (local distribution companies) where you can reasonably count on them re-subscribing at capacity.

When it comes to a generator or a producer or somebody else, probably that confidence isn't as great in terms of re-subscribing at capacity, which again puts a premium at what ought to be the initial term for it.

The other thing is, you talk about bringingLNG into New England, whether it be into the Canaport or Everett or whatever--who is going to commit that cargo. Again, like with the pipeline capacity and other things, to make that commitment you need some assurance of recovering your costs.

What happens if it is a warm winter and you've delivered cargo, about a BCF, and you end up having to resell it into the market at a loss?

Again, you've got the question of who picks up the cost and also the question of thinking about it from the perspective of the New England governors, notwithstanding the support for the competitive markets.

When they look at the havoc that was wreaked on the consumers and the economy of that region because of the lack of pipeline capacity, you can understand their motivation to try and find some way to bring that capacity to the market where, at least to date, and certainly looking forward, there is no assurance that the rules in ISO New England are going to result in anyone, whether it be the generators or third parties, stepping up to pay for that capacity.

Question 3: I just want to point out that NERC, in their recent assessment of November, has ERCOT above its reserve mark through 2018.

Just last week, ERCOT released its new winter CDR (Capacity, Demand and Reserves Report). It showed them above capacity reserve margin percent through 2018 and only slightly below the target in 2019. As the CDR noted, even that doesn't include several thousand megawatts of new gas that just didn't quite meet the criteria for being included.

I only make that point because when you use ERCOT as an example, you need to be real careful.

Speaker 1: I apologize for that. I should have updated those numbers, they are almost a year old.

Question 4: I want to stand up in defense of the politically impossible. It was politically impossible to have more than a single price for every place in New England. It was politically impossible to have more than a single price for every place in PJM. It was politically impossible to have more than two prices in California, north and south.

It was politically impossible to have scarcity pricing in an energy-only market in Australia. It was politically impossible to have an energy-only market and authorize exercise of market power in Alberta.

In all of these places, we have seen the politically impossible accomplished, so I think these arguments about, "You can't fix the fundamentals and you can't fix based on first principles," you have to take with a very large grain of salt.

Where that leads in terms of public policy… I don't know whether Speaker 3 is right or wrong about who is going to buy and build capacity in those markets, but I know that the pipelines aren't going to do it and speculators aren't going to do it if speculators can't make money.

We have a system set up where the pricing, particularly in New England, (they are trying to fix that now because of the timing and so forth), were such that basically when you got into these constraints, you had to eat the costs associated with it. You really couldn't make money in that kind of environment.

We have changed some of the rules in New England with timing, and we are going to see some different results. It worked much better in New York where they didn't have that same kind of problem because of the scheduling and all that kind of thing.

I don't think it is completely crazy to think that speculators might say, "I'll take your risk and buy this capacity" and go forward and do it, some hedge fund. That would be fine. I don't have any problem with them doing that. I think having a regulated entity that has to have cost ceilings on what it could do so it's the lower of cost or market is not going to do it, and that's the pipeline problem, but then someone else could come in and resell on the secondary market and make the money.

I am really making a pitch here for not accepting the constraint, which is riddled through a lot of this conversation, "Well, you can't do the right thing here because it is politically impossible, you can't do the right thing there because it's politically impossible, and we know what the outcome is supposed to be so we could mandate the outcome through some kind of other mechanism that we are going to have through regulation."

I think the lesson should be, particularly for the regulators, that they should look back to first principles and they should do what they do in Texas, they should do what they did after they changed all these rules to go to a full blown market where they get the signals right, and then let's see what happens.

Whether or not you need capacity markets, whether or not you need additional mandates, is an open question, I would say, but if you don't fix those fundamentals, this problem is just going to get worse and the hairball is going to get worse and worse and worse.

I think the fundamental problem is the basic economy of the markets and getting the prices right, the same theme I always come back to. If you don't fix that, these other problems are just too hard. I don't think it is politically impossible to fix that, as I went through the litany of all the places that did fix a lot of those problems even though at the time, people said it was politically impossible.

I am very much in the view that some of these problems could be solved very easily, and it's not politically impossible, and I hope we can take that kind of courage, particularly as we are going through the conversation about the Clean Power Plan and all the other stuff that is going on here.

Speaker 1: I would point out a couple of things. The U.S. examples are wholesale markets, not end use. I think scarcity pricing is important, but I don't think it is the only factor. As long as we decide, as a society, that we are going to subsidize certain resources or favor certain resources within states, that will have an impact.

Question 5: I keep hearing from Speaker 1 and Speaker 2 that these are administrative constructs, they are not markets. Well, the last time I checked, the definition of a market is an arrangement that brings together buyers and sellers for any commodity, and every market in the world has rules, has administrative constructs and rules and institutions. It is not the Wild West.

To say that these are administrative constructs and not markets is at best disingenuous and meant to evoke an emotional response over the idea that, "Oh my God, we have actually transparency about what the cost of capacity is, what the cost of energy is and gee, maybe we made some bad decisions and it makes us look bad…" whether it is the Kemper facility down in Mississippi or whether it's Prairie State in Southern Illinois. These were decisions that were made in the name of resource diversity, and who is paying for it? It's the very rate payers we are supposedly there to protect, whereas if they were merchant projects and they ran out of the money, and the project went bankrupt, it would be on the investors, it would not be on the rate payers.

With that being said (that is more of a statement than it is a question), at the end of the day, what is it about capacity markets that is so offensive? There is nothing to prevent bilateral contracting. It happens already. There are financial deals being done as hedges already in the marketplace.

The other question I have is really more targeted to Speaker 3 on the gas pipeline stuff, talking about markets working. We have the politically impossible. We have LMP, we have almost standard market design in the energy market now, which would have been unthinkable ten years ago.

Markets are working. We effectively have locational marginal pricing in the gas industry. If you look at what happened last winter, if you look at the production area at Dominion South versus the prices in the East, that is the same as LMP. That is sending a price signal about the need for new capacity, or the need for dual fuel, to your point, so how is it that the markets are not working there?

Maybe we don't necessarily have to build the pipeline capacity, but people are getting a price signal, and then they can make decisions based on that. So I would like kind of your reaction to that, and then everybody else's reaction on the capacity markets.

Speaker 2: I'm going to go back to the earlier part of the question about why is this an administrative construct and not a market. The answer I am going to give is not my answer, but I think it couldn't have been stated any better than Bob Ethier of ISO New England did at a technical conference a year ago September.

He was asked by Cheryl LeFleur, "If you were going to go about designing these markets again, what would you have done differently?" What he said was, "Well, we have many sellers (actually, not that many sellers, which is a problem), but we have the ISO standing in for the buy side of the market." To me, many buyers, many sellers, full information--we don't have that. We have one buyer, that is the ISO.

He said, "What we don't have are any entities on the buy side who are able to take on a long term obligation, and if I were doing it over again, we would have done that differently." I went up to him after and I said, "I can't believe you said that, because the only people left in New England who do have the ability to take on a longer-term obligation are my members." He said, "Yes, I know."

I guess that is my answer, I think it is a dysfunctional administrative construct because there is only one buyer and that buyer doesn't have skin in the game, that buyer is the piano player who ensures reliability, which is one of the big issues that my members have with PJM. With them, it is all about making sure that reliability is ensured, and the price is not important to them. That is answer number one.

Going on to Prairie State, let me just say that that is a plant that, one, is a state-of-the-art new coal plant; that, two, has mine-mouth coal, so there is no rail issue with it; and, number three, it is going to be around for many, many years. It has had some issues, there is no question, because it is brand-new technology. It ran last month at a 90 percent load factor. I think those issues are being addressed. There are, I think, at least nine different entities in that plant, so nobody has taken 100 percent. That capacity has been chopped up into a whole lot of different blocks.

There have been some issues with that, in part because I have members who, at the time they took shares in that plant, thought they were going to be able to have no problem getting it to their load, but then new locational delivery areas have appeared out of the mist, and they've been told, all of a sudden, "Your capacity has to come from inside that area, it can't come from what you contracted for."

There's no question that RTO market rules imposed on them since the time they made those deals have changed the economics. That's one of the reasons they are kind of upset about some of that, because they made their deal.

The fact of the matter is, no one investment is going to be in the market all the time. When I came to NRECA (the National Rural Electric Cooperative Association) in 1995, we had what we called our list of troubled borrowers. These were co-ops that had minority shares in nuclear plants, and at that time, they were way out of the market.

Well, guess what? They went way into the market for a period of time after that, and they'll be out of the market, and they may be gone, because some of these markets are so dysfunctional now, but the fact of the matter is, if you have a diversified portfolio of different kinds of resources with different contract terms and different economics, some buy side, some demand side, some supply side, I think, over the long run, you are going to do better than just sitting there doing price responsive demand and awaiting further information.

Speaker 1: I'd like just to add, I'm kind of glad you gave that definition. Under that definition, Southern Company is a market also, because they bring buyers and sellers together. That gets me to my point. I have had this theory for years. There was a session at HEPG years ago, "Are RTOs the new utility?" and I think RTOs are the new utilities.

With time, PJM is going to look more and more like Southern Company, and Southern Company is going to look more and more like PJM. You are adding administrative rules, this set of regulations about capacity markets…

I don't think there is that much different any more between the RTO markets and the vertically-integrated markets, because we both have rules. There are differences in who assumes the risk, but I think there are arguments to be made on both sides about who should assume the risk.

I mean, suppose Kemper works out—an extremely expensive, first-of-its-kind plant, but that may be the only way we get to use coal in this country in the future. The good citizens in Mississippi decided that it would be an investment they wanted to make to see if the bad coal in Mississippi, the high sulfur coal in Mississippi had a market, so there were particular reasons for building that plant. They decided that their customers would assume the risk, and is there anything wrong with the state making that decision?

Speaker 3: As I took it, your question to me was kind of, why aren't the markets as they are now constructed and functioning well enough? In both the electric markets with LMP, and the gas markets with basis differentials, you've got price signals out there. Isn't that good enough? What's the problem?

I have a couple of answers, one of them being, if you think they are good enough, as I said in my remarks, don't complain when there isn't enough pipeline capacity or when, during certain events, the gas prices go high for those who do not have pipeline capacity. Don't complain about the lack of the quality of the pipeline services that some people would prefer to have but don't want to be paying for on a firm basis. Live with it, but don't complain, or don't somehow expect the gas model or gas pipelines to bail you out by changing what has been a very well-functioning commercial and regulatory model.

Beyond that, in thinking about the markets and whether they are working, let's remember that in a lot of these markets, the pipeline capacity that the generators are relying upon is not capacity that was built for them or that they paid for, or that they have been paying for. They are effectively living off the fruit of the land. They are living off the fact that in certain parts of the year, firm shippers are not fully utilizing their capacity and it is available and that works quite well.

But it does beg the question, when you get to that point that the next increment of capacity is needed to meet their needs, and the fact that because of the way the gas market is structured and the pipeline business is structured, there is no cross-subsidization, no one is going to spread this out or say, “Oh, let’s roll it in or do it for the greater public good,” you then have to ask the question of, do the markets provide the right signals and right ability to have someone build that capacity, whether it is the generator or someone on their behalf?

The answer has got to be either, as the questioner said, you juice up the prices to the point that somebody is willing to step in as that speculator, or that it’s worthwhile for the generator to do it, or if that doesn’t work, you look at the question of, OK, is someone else developing that capacity that can be made available to the generators if that makes sense?

Also, looking at the New England perspective, I would say that for the governors, there is a legitimate concern in terms of the impact on their citizens from the fact that we’ve got these capacity constraints and the fact that with the current rules, there is nothing really on the horizon in the near term that you could say looks like an answer.

That is the answer. I would tend to agree that the first, best answer would be the one that the questioner put forward, which is, get the pricing right to establish the incentives, recognizing the answer isn’t always going to be gas, it’s not always going to be pipeline or storage capacity, but let’s have the wherewithal to pay for whatever the answer is.

Speaker 4: One of the things we haven’t talked about, and I think it puts some of the prior comments into a different light, is the context in which long-term obligations were assumed in the past versus the world we are in now. I would argue, based on the presentation yesterday about the difficulties of forecasting, that it’s always problematic, because you are taking on long-term obligations largely on the basis of forecast, and there’s a lot of room for error and ability to get it wrong with demand accruing as fast as it was.

So when you had the lumpiness of a lot of nuclear coming in at one stage, and then it was coal, and then gas came in, that was an environment where the overall demand was rising and the demand served by the centralized grid was basically the market. Now we are in a world (we haven’t mentioned the term du jour) of “prosumers” with disruptive technologies. (That’s the new buzzword at these conferences).

People are going to be both producers and consumers, and in that world, I just think there are structural changes that make this whole argument about long-term obligations a lot different. Everyone is now assuming that demand is going to flatten down, even overall, and the amount that is going to be supplied from the grid is down. You have to assume that gas is going to stay within the range that gas is in.

Then you hear about storage. The Brown report came out about storage …I think it would have been hard in 1980 or 1990 or 2000 to sign a 15-year contract of any kind. Now, in this world, it just makes it that much more dangerous.

So, with that, the quick remaining comment is, one of the conundrums in New England has been the schizophrenia about what the state wants to do. Speaker 3 alluded to the political troubles in the Legislature, when the Democratic legislature refused to support or endorse the Democratic governor’s proposal that would have been along the lines of the NESCOE (New England States Committee on Electricity) plan, and the same legislature and the same governor that want somebody to sign these long-term contracts, they are the same legislators and policy makers that want long-term transmission lines to Canada, so Provincial Canadian Hydro would come in under long-term contract, and at the same time, they want subsidized off-shore wind. At some point, the region can't have it both ways.

You are right, it is very difficult, and maybe some of these solutions aren't as economic as they could be, but the states have to get their act together and figure out—you're either going to give everybody some kind of long-term protection or not, particularly in this environment, where entering into any long-term obligation is more hazardous.

Speaker 1: I think you are right. That is why Speaker 2 and I feel that a long-term obligation has to be mandated from the utility or the state, depending on your regulator. IPPs that we sign contracts with have to be compensated.

Speaker 4: What happens to the stranded costs? I'm thinking about, if somebody today signs a 15 or 20 year gas contract or a power contract, and then five years from now, we have the equivalent of the shale gas revolution-- storage, smart grid, whatever it might be--somebody is left holding the bag. The answer to the long-term obligation you enter into, I don't think is to have more long-term obligations.

Speaker 1: I think that the customers ought to be assigned the risk, because they are the ones who benefit from those long-term contracts. Granted, there are going to be some winners and losers, but, again, it's not a symmetrical problem. It's not as though our worry is as much about too much generation as it is too little generation.

Reliability is so important and so valuable, so I would much rather have too much generation, and I think from the beginning of the industry, that has been the philosophy--we'd rather be oversupplied than undersupplied.

Speaker 4: At the risk of channeling Huey Long, since we are in Louisiana, let's face it. Everybody in this room is probably pretty prosperous and doing OK. This country is not, as a whole, representative of those of us who have the good fortune to do what we do.

So when you've got stagnant incomes…you said the people of Mississippi decided on Kemper. We all know better. You are taking these risks that we all are admitting are increasing, and we're saying, "We'll put it on the customer." The customers are people. If incomes were rising and things were going well…thank God the jobs number was fine today, but that is not the reality of a lot of people in my family, in North Carolina and Illinois and other states.

I don't remember the number, but NRG looked into doing nuclear, and the cost was at least tens of millions of dollars if not hundreds of millions of dollars. There are other examples where people are willing to take on the risk if the prices are right, and if it doesn't work, it doesn't work.

I don't want to sound like I'm Huey Long. Maybe I'm getting there, but the customers are people that don't necessarily have the means… This dismissal of least cost is sort of troubling.

Speaker 1: When electric generators talk about the wallets of poor consumers, I'm just touched.

[LAUGHTER]

Let me just say, I think our definition of "least cost" may be different. For example, when I see fully depreciated nuclear plants going out of the market, to me, if those were priced in an appropriate way to keep them going, that could be a better resource for poor people in Chicago for the long run than a lot of rooftop solar that comes in because we have screwed up the pricing so badly that all of a sudden that makes sense.

That is one of the things I worry about. If we load wholesale charges up with, "Let's change the demand curve, let's do pay for performance, let's just…" You know, generation demanded capacity markets because they had missing money. Then we found out we had missing generators last winter. They got the missing money but it wasn't enough, so it's like "OK, let's give them more, let's create a new, super capacity plus, let's move the demand curve out, let's do this until we finally get enough." You keep loading up the charges like that, what you are doing is making distributed generation all the more attractive to customers, and potentially stranding wholesale assets that actually do make sense in a more economically rational environment.

I think you have to balance what is going on at wholesale with what is going on at retail, and try to prevent sending these bizarre price signals to retail. I'm quite concerned about it, and it's why I keep going back to this. If you have a portfolio approach--I am not saying have 30-year capacity for 115 percent, that's insane--You've got to have a portfolio of staggered, different kinds of resources, both supply and demand.

I have members who are doing one megawatt solar in a community installation to shave their peaks to reduce transmission charges at the wholesale level. The people are doing all sorts of frankly very interesting things as part of a portfolio approach that is designed on an all-in basis over time. It may not be the lowest cost at any particular day, it may not be the lowest cost this year, but over time, my hope is…and, frankly, we've got to. We have got to make decisions, because we are serving customers. Let me just give you one example. We had a member who wanted to put in natural gas fired generation close to load, and had difficulty doing that in an RTO market environment. One of the reasons they wanted that was to keep their wastewater pumping. People care about that. People care when the lights go out. They really care when the toilets don't work. You have to think about this holistically.

I guess that is my answer. A lot of what you are saying is true. It is scary to enter into long-term agreements at a time like this, but they shouldn't all be long-term.

Speaker 4: The numbers will show that the revenues in the wholesale market are a fraction, well below the Cost of New Entry.

Question 6: I have to confess that I have been experiencing some major déjà vu listening to these suggestions that consumers be put on the hook for long-term gas contracts. I have to remind people that in the '80s, it wasn't that long ago, when there was this rush to sign up IPPs and gas, the Commission insisted, "If you are going to have this contract, you have to have firm fuel," so that meant firm gas contracts.

The IPPs came back around and said, "We need long-term contracts with you, Niagara Mohawk, on behalf of the customer, because we know what is right, so they are going to have to pay for it." Just like Speaker 1—I got the heebie-jeebies there when I heard you say that.

It wasn't even five, seven years later when all of that was out of the money. We went through a pre-bankruptcy workout, Niagara Mohawk did, to unwind all of that, and that was a big driving force to setting up wholesale markets. They said, markets, this has got to be better than that.

The IPP contracts, by the way, and the gas pipeline contracts, were a big part of their costs that they had signed, much bigger, like five times bigger than our stranded nuclear costs. The nuclear problem is what drove us to this, so we have been through this before, and the scars are on a lot of us from doing that.

I don't know what to say when I hear Speaker 1 saying that obviously the customers are the ones who are going to benefit so they should pay, and we know what is right and we can figure out how to do this.

Having gotten that off my chest, I want to make one small suggestion. I am not advocating this, necessarily, but if the problem in New England is that sellers are not lining up long-term gas transportation (because that is the issue, that the pipelines have a low load factor so there is lots of surplus except during winter peak) make suppliers who are gas fired who want to be paid in the capacity market demonstrate they have purchased firm pipeline capacity to deliver the fuel to make sure they are there, the way you require other sorts of demonstrations that you are actually going to run on peak when you do that.

This is a much smaller step than, "Oh my God, we know we need this and so the ISO…" (this is really horrifying to me, to just hear this)....ISO New England is considering being the mother ship who is going to decide all of that and sign up and mandate these gas pipeline contracts. Why isn't anybody else's hair on fire just listening to that?

Speaker 2: Normally, I would agree with you, the idea that we are putting a gas pipeline into the ISO's transmission tariff… that is like cross-contamination…

Questioner: It's like marrying your cousin, you know? There are reasons why we don't allow that.

Speaker 2: I think that is one of the reasons why my members are saying, "We have a slightly different take, how about this idea?" Not that it is necessarily the best idea, but it's the old, been down so long, it looks like up to them. These guys are telling us they aren't going to come in unless somebody is willing to sign for it so somebody's got to sign for it.

Question 7: I have a question to start out with for Speaker 2 that is sort of a political science question, more of a fact-based question. I thought I would take it up a level. Back to your point about APPA's proposal to transition from the mandatory capacity markets to voluntary residual markets, I have two questions about how to make this transition take place, and what you see could happen.

One, can it take place in existing law? And two, is that likely? Which I think really goes on to three, which is, which branch of government will this happen under?

Speaker 2: On question number one, is it possible under existing law, the answer is, absolutely. We got here under existing law and we have diverse approaches to resource adequacy across the United States, all under the same Federal Power Act. That is the answer to that.

As for how to politically accommodate that, how do I put this, I think we may be approaching a teachable moment. When I was referring to *Game of Thrones*, I was only half joking. Winter is coming and we just had the Red Wedding in New England in the last market. That was just dysfunctional. I don't think it is going to take too many more of those for people to figure out they've got to do something different.

If you look at SPP, you look at MISO, that model is there. The question is, how do you walk back? That is very difficult. First, you have to honor existing commitments. You must do that, because I know that merchant generators have made commitments under a regime, and that needs to be honored. We have always said that. Eventually, as you are doing these options a number of years out, you have to start moving gradually towards a different model. That is the best I can tell you.

Interestingly to me, my members in New England were always the ones who were like, “We can make this work, let’s try this, let’s try that.” Something has snapped in those guys in the last six months. It’s just like, no, they’re done. It is interesting to me to watch this. There are other constituencies reaching the same approach, but it is not going to be easy. It’s a political science matter.

Questioner: Do you think of it as an evolution?

Speaker 2: We have only been at this for six years with no success, so I’m not feeling --

Speaker 1: If I could just add to what Speaker 2 said, I think PJM, to an extent, is already doing what I’m suggesting, because there are members within PJM that have capacity obligations and do have either their own generation or long-term obligations. I think PJM could do it without missing a step, retain a capacity market, but only for those who have a capacity obligation who want to use that market to meet that capacity obligation. I don’t think it would require a whole lot.

Speaker 4: Speaker 2 mentioned New England as being sort of the harbinger of things to come. I think it is important to point out (many folks know this better than I do) that the capacity market is very sensitive, which is why a little bit of additional supply out of market is a problem.

In the case of New England, I think they were short around 150 megawatts. Only now, when that happened at the last auction, did the price get close to the cost of new entry, either at or above the cost of new entry. As one company mentioned, they’ve got a plant ready to go, 700-800 megawatts. There is a non-member company that said the same thing. There is a third plant in the Boston zone that will be built if they can get the financing.

The second point is that even if you think it is a good idea to do what Speaker 2 and APPA had said, the issue is not just the legal commitments to the auctions that have already been held. It’s also that when people argue that it’s taking the risk about the long-term contract, it’s the expectation of what future auctions are going to be.

If there are serious discussions about doing this, I question how lenders and investors would react. Let’s take the two plants that have been announced in response to the New England market. You have to think that it would be awfully tough to get someone to build on a merchant basis on the capacity price if they thought that that was going to go away in the 15-20 year life of the contract.

Speaker 2: Just given the volatility in the capacity market prices from year to year, I think it would be silly to be depending on those capacity market revenues a few years out, anyway. It’s not a reliable price signal.

Speaker 4: A quick retort. That’s why the newer projects that are being exposed to the market risk, their whole model is to think more about equity. They actually take on more risk and they do five to seven year hedges. You don’t need

10-15 years, but you need something beyond the immediate.

Question 8: A few comments and then a question and then I guess my main point I want to make. First of all, in respect to the New England markets, pay for performance, which will be going into effect at the auction that is coming up in February, was obviously designed to make sure the capacity really will be there when it is needed.

It is certainly something that the ISO pays a lot of attention to, and we will see how it works out, but what we are hearing from the generators is that they are taking it all very seriously.

Second, I have to make this comment. Bobby Ethier is a terrific person and does excellent work for ISONE, and it's certainly fine to quote him, but it is also the case that he would certainly represent that the ISO runs markets, not administrative constructs.

The third point is, in the ISO's position about the gas pipeline, the ISO has not been putting itself out front to try to take this over and work with it. I just want to make sure there is no misunderstanding there. The ISO's position has been that if the governors got together with their proposal, the ISO would be prepared to work with the tariff at their request to submit to FERC. I want to make sure that is clear.

What the ISO has done, and what CEO Gordon Van Welie has talked about, is the issue about winter supply of gas and how that is going to be obtained. That is a real issue, but that shouldn't be connected directly to any particular solution as to how the ISO would want to see it resolved necessarily or that it would want to put itself out in front.

In any event, with that aside, the question I will ask is to try and input numbers into a question I asked yesterday so I'll phrase it differently. What would natural gas prices have to be to Southern Company such that they would actually find that it would have been an economically smart thing to do to build a new nuclear power plant for $7000 per kilowatt and with operating costs that would probably still be $45 per megawatt hour?

How high would the natural gas prices have to be over the next 20 years in order to say at the end of that time that in fact, it was the right thing to do, a way to save money, to have built that nuke instead of having built another gas plant? That's the question.

While you are thinking about that answer, let me give my plea. One place that I think really ought to be brought together here is the importance of demand side management. I appreciate, Speaker 2, that you are looking at this from the point of view of responsibilities and the Federal Power Act and what's retail and what's wholesale.

But my plea, from the perspective of supply side economics, is that there's a tremendous opportunity for megawatts and negawatts to be brought together in the same market. It's a real shame that the way this is playing out right now is going to prevent that from happening.

It would be tremendously useful and tremendously good for competition, for price formation, for the utilization of the capacity markets, to be able to have the companies that aggregate demand side management, meet the requirements, including in New England, which means also pay for performance.

They'd be on the hook. To have them meet the requirements to be able to participate in the capacity markets so they could earn the revenue would help drive innovation and get more people involved who would have a different view of lots of those difficulties.

In terms of trying to hold down prices to consumers, bringing together those two markets under a single market, I think, would have enormous benefits. It's just a shame that all that is sort of going to be brought up and dragged out. There's really a lot of economic value. So that's my plea.

Speaker 1: I don't feel obligated to defend Southern Company, but as it turns out, I think Vogtle is going to turn out to be a very good deal for Georgia Power customers, not because of gas prices but because of the price of carbon that is going to be established because of the Clean Power Plan.

Southern Company did see that coming in their resource planning. I know for a fact that they had been taking into account the cost of carbon and realized they were going to have to shut down a substantial number of their coal plants to reduce coal energy production. The only way to do that without going 100 percent gas is to increase their nuclear supply.

I realize that several people here believe that a 100 percent gas utility is not a bad thing, but Southern Company really does believe in all of the above, the need for fuel diversity and not putting all of your eggs in one basket. I think the regulators of Georgia Power and Alabama Power also believe that to be true, plus you have a utility that is pursuing a very diverse fuel supply and believes it is the right thing to do for its customers.

Speaker 2: First of all, I would just say, going to your point about price-responsive demand and the demand side participating, my members have a slightly different take than some investor-owned utilities on this, and I think in some cases we are more willing to look at this because, one, we are not for profit and, two, we are owned by those customers, and if they want that, then we are going to help them do that.

We do have members that are going to full time of use pricing. Sacramento Public Utilities District is an example of one that will be doing that. …I am going to stop there so our friends can come back, but I hope you get my point.

Question 9: Thanks. Some of these points have been made earlier and I'll make them again and then invite any comments folks want to make. With respect to gas infrastructure in New England, yes, my hair is on fire on that. You are not alone on that. The issue is really, as we have seen so far, a peaking issue. It's something between 20-40 days during the winter. It is not a year-round problem yet.

I think we are addressing a peaking problem with a base load solution, and I think a peaking problem suggests that you look to your existing peaking infrastructure that you have in the New England area. There are two on-shore LNG terminals, there are two off-shore LNG terminals. I think there are 40-plus above ground LNG storage tanks, many of which are not fully utilized.

There is fuel switching. There is the ability to build new on-shore storage. There are lot of things that, if the market signal is there, will be utilized. I think what we had last winter was a market signal. I would be very surprised if this year and coming years if you don't see the truth of the old axiom that we tend to be skeptical of, that the best solution to high prices is high prices. Those solutions will come. I think that many of those solutions are in fact developing, forming up and in place as we go forward on this.

I also want to re-emphasize the point that was made earlier, that the ISO New England has at least begun to take some big steps forward in this, including the performance incentives order, which doesn't go into effect until 2018, but I think that is a big step forward, so we need to really think about whether additional big steps forward need to be made on that.

I guess the last thing I would say is, our company invested about 400 million dollars in an off-shore LNG facility on the basis that we thought it was going to be utilized quite a lot. That was the market view about six years ago, which turned out to be very wrong.

I think before we enter the world of making big expensive investments for 15, 20 or 30 years, as one of our speakers pointed out yesterday, sometimes that forecasting is not so right, we really need to think hard about whether some of the peaking solutions that are being reacted to now in very affirmative ways, don't have some wisdom in the marketplace.

That's a comment I will make, it's not really a question, if anybody wants to respond to it, happily do so. Thank you for that.

Speaker 2: I would just say we see gas pipeline storage, above ground storage, as you were talking about, as a very viable way to address the needle peak issue, and I don't disagree.

Speaker 3: You're right, you're addressing a peaking problem, but you still have got to have a mechanism in place to compensate for making relatively large commitments. LNG is not something you can turn on and off on a dime. If somebody makes that commitment, particularly if that is wrong and it turns out to be a lot warmer a winter than was forecast…are you going to have something in place to induce someone to take that risk and make that bet? It's a pretty darn big bet.

Also, I think with regard to an LDC (local distribution company) behind the city gate, when it comes to LNG peak shaving, again for the LDC, there is that risk of, "OK, I put it into the market and then guess what, we get that next cold wave and I need that for my behind-the-city-gate load." How do you deal with that one?

Also, I think there is just kind of a proportionality problem. We didn't get to it in the discussion today, at least not yet, but some people say, "Why don't you get more demand response on the gas side?" I would argue that in the wholesale market, you've got it in the form of capacity release. In the retail market, we have got kind of a proportionality issue. I haven't checked the numbers, but there was something put out by NERC a couple years ago, one of their gas/electrical liability assessments, where they said that the load of an average gas-fired combined plant is a small-to-medium sized LDC, which means that, where gas is used for space heating, in order to knock off enough gas load to to free up enough gas and free up enough pipeline capacity to serve the generator, you've got to knock off a heck of a lot of gas load.

Let's just bear that in mind. There is nothing wrong with demand response on the gas side, but you've got a pretty big proportionality issue.

Question 10: You are hitting pretty close to where I was going with my question. I was going to start with, "Those who don't learn from history are doomed to repeat it." Some of us lived through the 70s where they shut down the way people had their homes heated in New England. What's going to happen if we continue to shut down nuclear plants that are already operating, forget about new ones, shutting down the existing ones?

That's really not my question. My question to you is, we have 111(d) and we have heard from time to time that the impact of 111(d) could be a depressive force on investment in new gas pipelines, because if you look at it a little bit, what the gas industry has kind of determined is that with the efficiency targets and these other things, the gas demand may not go up.

Can you comment on your view of the role of 111(d) and its impact on gas?

Speaker 3: We have not taken a close look at it, nowhere near as close as most of the folks in the room have taken a look at it. I do think you put your finger on an interesting question there, which is that if you look at the EPA assumptions (of course we dealt in the discussion yesterday with a lot of reasons to question them, but let's at least assume on the face of this discussion that they are right), my understanding is that when you get out to about 2030, the impact of increased efficiency is to reduce the demand for natural gas for electric power generation.

So it does beg the question, from both the shipper perspective and in terms of that party that has to put their name on the line of the contract for let's assume 15-year pipeline capacity, are they going to do that if the end result is that when you get to about year ten, you are no longer needed, because the demand isn't there?

It also creates an issue for the pipeline company and the shareholders, because remember, after that first contract expires, whether it is ten years, 15 years, whatever, the pipeline company and its shareholders are bearing the risk of, can you re-subscribe that capacity?

If that capacity is built for an increment of demand that goes up over the next five to ten years but then goes away, it could affect the choice of the pipeline company and its shareholders of how much risk to take on.

Question 11: Some of us who have been around a long time do remember the history. Previous questioners talked about the 70s and 80s, and I am going to talk about 90s, when I had to go explain why we had rolling blackouts in PJM.

The reason was, extreme weather in New England. We weren't running on gas, we were running on coal and oil, and the coal piles all froze, and the oil barges couldn't get up the ice-filled rivers, and the plants started shutting down. We didn't have the incentives to have extra coal or extra oil or to bring it in earlier, and one of the results of all of this…oh, and I think we had capacity margins around 23 percent at that time, if I remember properly.

This was one of the incentives to invite in Dr. Hogan and look at establishing markets to shift the risk, to use our plants more efficiently, lower the capacity margins, and to start segmenting and paying for specific products. The result of that, of course, is that cost to customers went down quite a bit.

You know, as was noted earlier, people are going to have to be compensated to make the investments that they need. I believe very strongly in markets. I think we have to send the signals and protect the consumers. We will have Red Wedding days, but if the lights go out, that tiny little spike is quickly forgotten and it helps provide customers an incentive to conserve.

As someone just said, when politicians talk, we have to work within their framework and figure out a way to make it work, but I do strongly believe that history has shown us that markets are the way that we will get the most efficient system that we can have, and an experience of

40 years and some of the gray hair here says that's what has worked well.

Speaker 4: You make the point very well as to why we need to really pursue different energy price formation issues that I briefly touched on. Again, action has to be taken for reliability.

The problem now is that not every action that is being taken is being priced into the market. You will never completely eliminate uplift, but that is where there are teachable moments and that is where the FERC process is enormously helpful, because now there is data on the table.

The analogy I have used is, when gas prices were higher, there was a lot of room for these things, kind of like going down a river on a raft. The water level is high, prices were much higher in the 2000s, and things that are problematic on a price-setting basis weren't a problem.

Now we have to assume structurally lower gas prices for reason of the shale revolution. Things that weren't an issue are going to potentially cause the problem we are trying to avoid, and that is why doing energy ancillary services and capacity together is so important.

Questioner: People pay for what is of value to them. You have to structure the markets properly and send the right price signals.

Speaker 2: I guess the one thing I would add to that is one aspect of competition is allowing for diversity of business models. FDR had the concept of a yardstick, where different business models would be out there. At any one time, perhaps somebody else has a better mousetrap. I strongly believe in not-for-profit, consumer-owned utilities and that approach that we should be out there, we should be a viable alternative, and we should not have to be subject to rules that say, "Well, because you have a different business model, you are somehow subsidized or you are out of market," or whatever that is.

That really does concern me, because what that is, is trying to eliminate diversity of contracts.

Questioner: As in so many things, we are in violent agreement on that.

Speaker 1: I just want to add, I hope my comments weren't taken as anti-market, although I'm sure some of you did take it that way.

If you believe that markets are the answer to every question, then maybe we have a disagreement, but I think markets play an important role in traditional regulated markets.