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Rapporteur's Summary*

Session One.
Computational Frontiers in Electricity Markets: Not Your Grandfather's Economic Dispatch

The long development of sophisticated software for economic dispatch created a foundational framework for organized electricity markets. Absent the computational tools, developed well before the era of electricity market reform, the fundamental design found in all organized electricity markets in the United States would have been no more than an ivory tower aspiration. The early development of markets fully exploited these tools, and their existence disposed of otherwise powerful arguments against open access markets operated under principles of non-discrimination. Since then, two parallel developments have advanced the capabilities and the need for better computational environments. First, the software has gotten better, in some cases, much better. For example, formal optimization for unit commitment was beyond the capability of the early economic dispatch models, but is now available and allows for improvements in market efficiency and market design. Second, the demand for new market products and expanded markets is increasing rapidly. For instance, the interest in exploiting distributed resources may fit in the framework of economic dispatch, but at an unprecedented scale compared to the existing wholesale markets for bulk generation. What are the expanded capabilities of the software? How does this improvement in software change the scope and reach of electricity markets? How could and should better software change electricity market design? What are the limits of the frontier tools? Are proposals for greatly expanded markets and markets products constrained by unrecognized challenges of big data and big optimization?

Speaker 1.
Thank you for the invitation to participate in this meeting. So I'm an expert in optimization. Optimization, and in particular this funny sounding thing, "mixed integer programing," has become a very important tool in this space. What I'm going to try to do in this short presentation is to give you a sense, at least from my point of view, of how we got there and where we are today with this technology.

So first, and the most mathematical thing you're going to see here is a definition of what a mixed-integer programming problem is, which is what you see on the slide.

* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the discussants. Participant comments have been edited for clarity and readability.

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This part up here says we've got a linear programming problem, and it's this thing at the bottom that's critical. This condition that some or all of the variables have to take on integer values is what makes it into a mixed-integer programming problem. Simultaneously, that makes these problems much, much harder to solve, but it's also the thing that makes them useful as a modeling tool. Without that, nobody would be using these kinds of models in this space.

And the power of this thing as a modeling tool was recognized back in the 60's. Early on. And it was, in fact, recognized in this space relatively early on. Here's a statement from 1989: Mixed-integer programming is a powerful modeling tool, "They are, however, theoretically complicated and computationally cumbersome." *In other words*, at least then, mixed-integer programming was an interesting modeling "toy," but the perception was that it just didn't work in practice. And that was a correct statement at that point in time. That perception began to change in 1999, thanks more than anything to Dick O'Neill, who organized a meeting at Rutgers University, and at this meeting somebody was up giving a talk about a unit commitment model which he labeled as the "California 7-Day model." It had close to 50,000 constraints and 26,000 variables, and the long and the short of it was, he put up a bunch of numbers and said, "Sorry, this problem is hopeless." I went up after his talk and pestered him to give me the instance and I went away that night and came back the next morning and reported that, in fact, with the technology that existed in 1999, that story was no longer correct. In fact, I could show that we could solve that problem, the optimality, in 20 minutes or so on a machine that was available then. And, in fact, I just ran that problem again the other day. It's a tiny little problem that solves in about 15 seconds. So that was sort of the coming out party for mixed-integer programming as a tool that would actually work, not just a way to represent your models.

I want to give you the story of how this happened and, as I said, where we are today. Here's my explanation of the history behind this and what happened that led up to what was for us a transformative event around 1999.

Integer programming really goes back to about 1954. Between 1954 and about 1970 there was a whole bunch of important theoretical developments and they led to the development of two very powerful codes, written in the early 70's, which actually made mixed-integer programming, for the first time, commercially viable, to some extent. But, the technology was still actually very, very weak.

Then followed a period of about 25 years or so, up to 1998, which I like to call the golden age of combinatorial optimization. There was a ton of theoretical work being done by mathematicians and the like that was clearly applicable to mixed-integer programming. And in fact, there were computational studies that demonstrated that. Nevertheless, the commercial codes simply didn't use it over that 25 year period.

So in 1998 people were basically still using these codes. Computers were faster. The underlying linear programming was a little bit better, but the integer programming technology was 25 years old. And that changed. We literally sat down and went through that literature and mined it and put it in the codes within a period of four or five months. And that led to a whole new generation of mixed-integer programming codes. I won't bore you with all the stuff on this slide, but this thing called Presolve and these things called cutting-planes that really what came out of the mathematics is what made the difference.

So what I'm going to do in the minutes I have left is to just show you what that amounted to and how the codes speeded up, and I'm going to give some indication of where we are today.

A few years ago I did some very extensive computational tests. I founded this company called CPLEX back in 1988 and stayed connected with that code up until about 2008 and then started a new company in 2008. And I have results here from both of the codes, from both of those companies, that combined to give us the story of where we are today.

So these initial results are for that CPLEX code. And as always in this space when we do these tests we use our internal libraries of real models that we've collected from customers. So when I put up these tests, these are not academic, randomly generated models. These are models that real companies gave us over the years, and in this particular case in the end I used a test set of 1,852 models. I ran every version of CPLEX from 1991 to 2007--11 different versions. And I ran pure defaults, and for whatever reason I let each instance run for about a third of a day. Of course some of them took 10 seconds to solve. Some of them didn't solve after 30,000 seconds. I looked at all of this data and put together the following chart.

So let me explain this thing to you. It's not so complicated. Let's take this first bar. That's a comparison between the first version of CPLEX, which goes back to 1991, and the next release, which was version 2.1, which was probably less than a year later. I don't remember the exact date. Based on that test set that I gave you and the way I was doing the tests we measured that Version, 2.1 was about 3.2 times faster than the first version. And this is machine independent. This whole thing is machine independent. There's no machine effect here. I used the same machines for all the tests. And so that explains all of these bars all the way up to Version 11, which was about 2008. So you can see the progress from 1991 to 2008, and you see two bars that are higher than the rest (showing jumps in performance improvement). This first bar that's higher, that's about 1994. That's when we really understood for the first time how to do the linear programming part. It's interesting, because in 1985 people viewed linear programming as a mature subject. They thought that there wasn't much progress to be made, and they were wrong. Wrong by a lot. So that's the first big point.

And the really critical event occurred right around 1998 or 1999. If you think about the slide I mentioned about that Rutgers meeting, that's that year, that short period of time in which we just took all that stuff people weren't using and put it in. And of course there was a lot of software engineering involved in doing it right, and so forth, and so it wasn't easy necessarily. But in this one-year period we got over a 10X improvement in that technology. Now, think about it. Back a few years ago we were used to machines getting getting 2X faster every 18 months, right? That was Moore's Law. And I remember those days. A new machine came out and you started using it. You didn't want to use that old machine. 2X faster you could really feel that. This is 10X, and it's at that point in time that the subject changed. It's at that point in time that people began to realize, we can solve mixed-integer programming problems with out of the box software that's not customized to the problem and solve it in reasonable amounts of time in real instances.

And then that story continued. If you look at the combined effect, it's about a factor of 30,000. That brings us up to 2008.

And interestingly enough the story has continued. Starting about 2008, 2009, I no longer had access to CPLEX and that internal library, because I had left that company. We started a new company. The story here is not about the new company, but just the fact that the improvements continued, and I suspect you could show similar results for CPLEX. These results are for this new code called Gurobi. Our internal libraries have gotten bigger, and this is a representation of the internal library that we used for the tests. The point I want to make with this slide is that there are about 3,550 models here that we were using. Models are getting big. That's the point I want to make. We're solving models now regularly with millions of constraints and millions of variables, in reasonable amounts of time. The biggest model we have from a customer has 115 million variables and 44 million constraints and it solves in two hours. So that alone is evidence that things have changed.

So if you go back to Version 1.0 of this new code, back to 2008, from that point in time to the present, machine independent improvements have been like a factor of 46. It doesn't seem so like so much when you look at a number like 46, but if you invested your money back then and you got this kind of return, I think you'd be happy. Right? [LAUGHTER]

So if you put all of this together with what you saw in the previous slide, you get something like a 1.3 million times improvement. Now, what does this mean? I always struggle to explain what this means. It does not mean that if you took some problem that you could solve in two hours, 10 years ago, that you can now solve it in 0.01 seconds. It doesn't mean that. What it means more than anything is that there are problems 10 years ago that appear to be impossible, which today you can probably solve in two or three minutes. And we have a lot of evidence of that sort of thing. This is an average improvement of 1.8X/year, machine independent, and that certainly exceeds the machine improvements.

And I will just end by giving you one little slide I like to show that gives us a sort of a different way to look at this number and then I'll be done. Option one, you can solve a mixed-integer programming problem with today's solution technology on a machine from 1991. Now nobody wants to use a machine from 1991. If you go back that far, it's painful to think about it. Option two is to solve a mixed-integer programming problem with the 1991 solution technology on a machine from today. What option should you choose?

The answer is, you should choose option one. You'd be ahead, on average, by a factor of about 300. You can't say that about very many domains, and that in a nutshell is why people can used mixed-integer programming these days. And I think the ISO's across the U.S. now, after 15 years have passed since this Rutgers meeting, have pretty much uniformly adopted mixed-integer programming in one form or another, and it's getting more and more powerful. Distributed computing has been added to our capabilities, which more than anything improves the robustness, and we're actually, for the first time in the last couple of years, working specifically with Midwest ISO and some other people as part of an ARPA-E project to try to improve the solvers, so they specifically do better on models from this space. So at least in terms of this technology, there's a powerful tool and I think it's going to get more powerful.

Moderator: Thank you. I think the takeaway is something a lot of us over the years have heard--that the software, if it could be made better, could allow you to do so much more, rather than upgrading the machine, and this is proof. So are there any clarifying questions for Speaker 1?

Question: What is it that you got going faster and faster? Is it just a better algorithm, or what?

Speaker 1: So if I understood, the question is, why has it somehow gotten so much faster? I put up that slide with things called “cutting-planes” and things called “Presolve,” and I don’t think there are too many people in this audience who want to be bored with the details of that. But the main mathematical contribution has been in those two areas, where you use some logic. Some of it is number theoretical logic and so forth to reduce the size of the problem enormously in some cases, and tighten the formulation so that it’s actually a better representation. And then these cutting-planes, essentially, once you start zeroing in on where the solution is, allow you to cut away the stuff that’s getting in the way that you don’t care about. That’s where the mathematical X comes in.

In the last 10 years or so, unfortunately, very few of the improvements have come out of the academic community. This is an academic community story. In the last 10 years they’ve mostly come by recognizing things in real models that we get from customers, and it’s interesting that it’s very difficult to say, “Here’s what did it,” and you can’t really say that because the latest version that we came out with (it’s just about to be released) is about 70 percent faster than the previous one, measured based upon our test set. There’s no single idea in there that leads to more than a five percent improvement. And literally there’s a three page list of improvements that add between one percent and four to five percent that have accumulated to get here, and these come almost exclusively by staring at customer models of one kind or another and recognizing, “Here’s something we didn’t exploit,” and putting that into the code. And that seems to be continuing.

Question: I wanted to thank Gurobi for making so much analytical power available to the academic community. The phenomenal help that you’ve had in implementing commitment models, transition planning models, transmission switching models, all those… So thanks very much, for Gurobi particular, since it has pushed CPLEX out.

Speaker 1: Exactly. When I sold CPLEX I was still involved with it, but I lost control. I tried to convince them for years to do that. They wouldn’t do it. So we figured out a way to force them to do it. There you go.

Moderator: OK, so given the idea that these models have gotten bigger and more complex and there are more constraints and more variables, the next presentation is going to tell you why the capability is needed to deal with that as we start adding things that need to be looked at in the optimization mechanism.

Speaker 2.

What I’m going to talk about is a mix between why we need this additional computing capability and how we have been able to actually make further improvements by some new sort of distributed algorithms. So it’s a mix of the two.

Things are changing. We do not pay our “light” bill anymore, because the load has changed completely. Besides lights, we have demands that we satisfy through electricity that are quite different. They’re very flexible at some times. They involve the capability for storage-like behavior, and they involve the capability for a very fast response and for the provision of other things other than just real and reactive power. They allow the provision of reserves. They allow for the provision of voltage control and reactive power compensation, which I’m going to argue is very important.

And at the same time, on the generation side, of course we have the renewables that have also changed the picture, both in terms of what is required to maintain the stability of the system and in terms of the special volatile and the non-controllable characteristics.

So the question is, with all of these changes, are we about to observe a paradigm shift from generation following load, following consumption, to consumption and loads, if not fully, but at least partially, following generation, which is now changing as it starts modifying itself to something that's not necessarily as dispatch able as it was before?

In making that case, we have to keep in mind some very important key issues that are on the table.

At the high voltage transmission network level, you have congestion. And you have stability issues that require reserve procurement and deployment.

In the distribution networks, you can have transformers that overload. Distribution networks have losses that are much more important than the losses we see in high voltage networks. And there are voltage constraints which sort of act as the equivalent of congestion and line capacity constraints at the transmission network.

And, of course, at that transmission and distribution interface you have to be able to deal with the way that the distributed loads respond to transmission needs for stability. And also, you have to make sure that the distribution-connected resources that provide these additional services are following reserves and can deliver reserves. Why shouldn't they be able to deliver? They might not be able to deliver because of voltage limitations and so on.

So you see there on the left a diagram which is sort of the big picture of a transmission network. This is our rendition of the transmission network that's meshed with the sub-transmission network and then those lines that stick out like antennas which represent their distribution networks. And if we blow up one such antenna, then it becomes a whole distribution feeder with thousands of loads, and so on.

So that distribution network interfaces through sub-transmission to the transmission network, through the substation which makes a connection and steps down the voltage, and so on and so forth.

And if we are to look at price-directed participation of distributed loads--and distributed sources in general, because they're not just loads, you can have generation, microgeneration, and so on and so forth--how do these resources interface? They interface through some sort of a price that changes dynamically, and that price has to form at the connection of the distribution feeder. There are many such distribution feeders within a transmission network. And then at the distribution network you have to further specialize these prices to the sub-distribution network locations. Right? So there's some sort of an explosion of the prices that you have to calculate, and you have calculate them dynamically, and so on and so forth.

I'm alluding here to the fact that the prices range over not just electric power/energy, but range over a wider number of products. So if you follow how high voltage wholesale markets are developing, what they clear is not just the price of energy, but they also clear the price of reserves. Right? And I'm arguing now that if you bring the distribution network into the picture you'll have to deal with reactive power as well.

So why are reserves important? They're important because the incorporation of new kinds of generation is increasing the need for such reserves. Why? Well, our power system is a huge machine, right? One that's interconnected through essentially synchronization and frequency that has to be abided by, by all generators and consumption appliances and so on and so forth. We try to maintain this frequency. If we deviate more than a few millihert--you know, we can afford maybe 200, 500 millihertz deviation. Then we get into trouble and the system may become unstable. We may have to close it down and incur huge costs.

The rate at which we move away from the desired frequency increases as we have less and less connected energy stored in the system. So you see at the top this equation, it says the rate of change of frequency should be zero. Right? That is, it should be zero if we want to maintain frequency at a particular level; however, it changes if we have mismatches. And the rate of change becomes bigger if we have no inertia. Now, that inertia becomes less and less as we have more and more generation that comes from non-rotating sources. Even wind is considered to be a non-rotating source, because essentially there we convert you know, power to direct current. And in Texas here, we have observed, for example, that that slope (system frequency change in relation to MW loss) is becoming larger as time goes by. So you see the slope is the instantaneous loss of frequency, with a disturbance of increasing quantities. So the red line, which is above, shows what is happening after we've experienced more renewables on the system. The way to deal with that is to have more reserves. And, in particular, fast reserves that can be secured and then respond to the requirements of the system operator. There has to be some sort of a matchup of system control, grid control requirements, and the response. So one of those is secondary reserves that sends out some sort of a frequency and you have the provider of these reserves go up and down. You can see the frequency control which is the almost real time kind of response and the secondary reserves that respond to every few second to commands.

So who can play the role of let's say this combined cycle natural gas unit that I showed you before? There are many distributed energy resources. For example, photovoltaics…why do I call this a distributed energy resource? Because photovoltaics have power and electronics that can provide voltage control. Other distributed energy resources are electric vehicles; computing, because server farms have incredible capability of responding; duty cycle appliances; and so on and so forth.

With respect to reactive power, I think of reactive power as some sort of pollution of the current that flows, which introduces aimless flow of current that burdens the lines, increases losses, and forces voltage to go down.

So here is an artist's depiction of the interconnected transmission network and the distribution network. You may have congestion. You may be forced to go away from inexpensive to expensive generation in order to avoid overloading of lines and at the distribution network level, you have to sometimes curtail load or have brownouts if the voltage dips, you have to deal with losses and if you want to provide reserves back from the distribution feeder to the transmission network, then you have to make sure that voltage is not violated.

So today's markets at the wholesale level are incredibly capable of addressing many of these issues, and they address these issues by doing planning and operation, and operation and planning, and with real time control at various time scales that go for months for longer markets, hours in the hourly adjustment market, and then shorter time scale--the five minute sort of real time market that dispatches slow or operating reserves. Then the regulation service or signal that dispatches every few seconds, and so on in the real time.

So here are the three types of prices that we may need to be able to determine at all levels, not only at the few thousands of buses off the transmission network, but also at the millions of locations of distribution networks.

So if we try to expand the methods that we use today to clear wholesale markets, can we do it? No, we can't, despite improvements. We just can't do it. Why? Perhaps with the transmission, high voltage system, we may be able to deal with that, but the distribution network, this is distributed energy sources that are much more idiosyncratic and complex beasts than are resources at the transmission level. Generators have relatively simple cost structures and requirements, et cetera, et cetera. The distributed energy sources are incredibly complex. They have intertemporal coupling. They have nonlinearities that have to deal with the way, let's say, a heating and cooling system operates. Even an electric battery, if you want to look at the electric chemistry as a lot of nonlinearities. Right? So with the Tesla, you can charge half of the battery over a small coffee break, but to charge the other half of the battery you need hours, right? You need long breaks. So there are many nonlinearities there. And you have reactive power that needs to be tended. Load flow has to be modeled using alternating current. So you have nonlinear relationships. So the problem is non-tractable.

Here is sort of the math side. There is sort of a mathematics breakthrough that we've had. Even since I was a student, we were being taught about Lagrangian relaxation and decomposition, decoupling and so on, but most of those algorithms, just like early mixed-integer programming algorithms, were unstable, very slow, they were requiring technical requirements that are not met here. So recently we've had a leapfrogging of this, and the capability of these algorithms known as proximal message passing algorithms or alternating direction method of multipliers which have made them work in a much more stable manner and allowed them to converge very fast, because they can rely on parallel computations. So rather than doing millions of computations to represent the complex bid of a distributed energy resource that has this complex cost factor, you can have each distributed energy resource solve its own problem. A non-linear problem, but small, and all the data are available. You don't have to aggregate the data at some central point. So you can have each distributed energy resource solve its problem. And each line, transmission or distribution line, can solve a sub problem with nodes or buses. (There are a few thousand buses at the transmission system. In each distribution network you have small number of buses, but all of them together, of course, are increased to the millions.) And you can have some sort of an interaction that leads to the simultaneous clearing of prices and of resources.

So this synchronous, parallel sub-problem solution is the big breakthrough that might allow us to extend markets to the distribution network. Of course, there are issues here, because sometimes you have to resort to a hybrid solution that brings back the network structure and regional reserve requirements in order to impose deliverability of resources.

Here is an example of how much you can do by implementing this full DLMP, distributed locational marginal prices, for real and reactive power. This is a small feeder in upstate New York that we are evaluating over a whole day, by comparing not having information that represents the distribution network as opposed to having this information and providing this information to a limited number of distributed resources. The bulk of the load is still inflexible load, but you can see that inflexible load can also gain. With respect to charges to inflexible load, if you look at the fourth line, you can see that they can benefit quite a bit, by more than 10 percent, in terms of decreased charges, if you go to DLMP.

There are some regulatory issues, having to do with the size of the market for reacive power. If you do most of your compensation from this distributed energy resources, then the marginal cost of reactive power goes to zero, despite the benefits to the overall system. Therefore, there might be an incentive to withhold, right? Particularly when you have sort of coalitions in energy service companies.

Many distribution and transmission utility people will tell you, “Well, we can do all of this with standards. We can do all of this with centralized utility control. We can invest in capacitors…” this, that, and the other. The idea here is that things are changing so fast that the only way to support innovation is to allow this distributed reseources to participate through prices, so that they can take up the risk and incorporate new technologies as they become available, much in the way that we’ve seen things happen in the communications industry.

So is it possible to make this leap forward and extend markets to more products, real, reactive, and reserves, to the distribution retail level where you have millions of users? Well, we have been able to demonstrate, under sort of simple situations where voltage control is not a big issue, et cetera, et cetera, that it can solve millions of variables in a second if you assume power computation. However, there are still quite a few open issues. You can’t fully have a distributed algorithm. You have to bring in, periodically, if not at the fast tick of the clock, the call management of multiple nodes, as opposed to doing everything distributed. We have to prove that the price directed stuff works in practice as advertised. That if you have volt var control devices that are distributed responding to prices, that they don’t introduce harmonics and funny things into the system. Communication architecture has to be established to allow this distributed calculation. And so on.

All of this will also, if it works, support the integer programming issues that deal with the quality control or line switching at the transmission network, and a fair amount of reconfiguration of the distribution networks that can take place dynamically as well at the retail level. If things work out, we have to worry about regulatory issues. New financial instruments for risk mitigation may spring up. And that’s the end of my presentation.

Question: I think I got a nugget out of this and I just want to confirm if I did. So I think that I heard that PV and wind, they’re renewables, they contribute to sort of less system inertia and the frequency controls around that. So it seemed to me like the PV on the distribution system was sort of part of the problem, if you will. But then I also heard you say that PV and the other distributed resources actually can be part of the solution, because they actually could be good sources for fast reserves, which really helps with frequency control. And I just wondered if I got that right or if that's wrong?

Speaker 2: No, the distributed energy resources that are like PV (because distributed energy resources include micro generators and they include electric vehicles and other things)…But the photovoltaic resource, for example, is a distributed energy resource in the sense that it has inverters that are today used only 10, 15 percent of the time. The rest of the time they're idle. When the sun is down, when the sun is at a low angle, these inverters have a lot of excess capacity. This excess capacity can be used to provide voltage control which enables, then, the provision of reserves from distributed resources. Right? Because otherwise, if you try to provide reserves you may violate voltage requirements, as you're providing these reserves from the distribution network. So distributed energy sources that are PV, they have this advantage of helping with voltage control. That was the point.

Moderator: OK. And now we've heard from software development point of view. From an academic point of view. We're going to hear from a user, who will provide a presentation from ERCOT's point of view.

Speaker 3.

So my focus will be more on the distributed energy resource. And I'll just jump right into it.

So this is the ERCOT grid. We're an electrical island. We're connected by DC ties to everyone else, including Mexico. One of the big things we have done for the grid is developing CREZ (competitive renewable energy zones) transmission projects. This is an amazing thing that we have built up. About seven billion dollars' worth of transmission, and it has been incredibly successful.

So coming to the question of what you expect to see in the future, as you see right now, because of the extremely low gas prices, coal is on its way out. There are a host of other issues leading to that, but what you do see coming in the future is more renewables, especially in the distributed realm.

As to the question of why the resource mix will change, the reason is that some form of the Clean Power Plan will come into effect, we think. And if it takes effect, a lot of our coal fired plants will retire. And they'll have to be replaced at some point in time. And what we're recommending, of course, is that we have some sort of transition plan for that.

So essentially, resource mix is changing. We are thinking that the resource mix will include a lot of increase in renewable energy sources.

I'm just going to give you a brief description of our main number crunching optimization. That SCUC (security constrained unit commitment) on the diagram, that is the commitment and dispatch. And then we do a feasibility study on how many megawatts resources are providing and how much energy the load is consuming. We ask, is that feasible on the network? And can we deliver that? So that second box is the Power Flow and Contingency Analysis. And we have to be N minus one secured. That's a NERC requirement. So what it really means is you have to do an "if" scenario. Once you get your megawatts and your dispatch, you do a "what if" scenario. You take out every line in the system and see if it is still feasible. If it is not, you generate transmission constraints and then feed it back in.

Now, thinking back to Speaker 1's presentation, if I combine the first two blocks, the SCUC and the power flow, into one thing, that would be ideal. And I just did a quick computation. We have about 4,000 nodes, 8,000 lines and 8,000 contingencies. That comes to about 64 million just in terms of the linear constraints, if you do it in that way. So it's a challenge, and I'm hoping there are some breakthroughs--we at the ISO might be behind the times a little bit. We can see if we can get something better.

Now, this is a graph of the day-ahead market objective function, which is typically what I guess economists call a net social benefit. The area between the supply and demand curves. And that gives you an idea of what the MIP (mixed-integer programming) algorithm is trying to solve too. Our MIP gap averages around .01 percent relative. The absolute value is around $100,000. So we're pretty good. We're using CPLEX. So that's just where we are today.

We have some ongoing initiatives. We are talking about future ancillary services, and it's because our resource mix is changing and, like Speaker 2 said, inertia is probably going to reduce, so we have to deal with that. Do we have a problem today? No. We are thinking we need to be prepared for the future. And there is an ongoing discussion in that regard.

We have drastically improved our scarcity pricing mechanism, using Doctor Hogan's ideas. And unlike other ISOs we don't have real time energy and ancillary service co-optimization right now, so we are going to work on that. There's some other stuff, I think, things like transmission switching, that are also on the table. I'm hoping Speaker 4 will describe that a bit more.

One of the things that MISO worked on was a concept called extended LMP. Right now, our location marginal price is based on the energy offer curve. But, if a resource is stuck at a limit, they do not contribute to price formation. So if they're stuck in the minimum, they are incurring a cost. We are making them whole, and it will be better if that cost, that the loads will have to pay, is reflected in the prices. That's an ongoing research item. We haven't done anything on that except for a simplified pricing run.

So I'll just quickly come to the future ancillary service work that's ongoing right now. So this is what we have today. And what we're really doing is unbundling things. So if we look at regulation as a current ancillary service, you see a corresponding thing called "fast responding regulation" as a proposed ancillary service. We ran a pilot for a storage device, which is a battery, and the deployment mechanism was two ways. Traditionally, the regulation signal comes from the ISO, if it's a single control area. Here we have two batteries. One is governed by a signal from the ISO. The other one senses your local frequency and responds. And in the local signal response, batteries are very good. They're extremely good, but the issue comes up about this cost-benefit analysis. Will they ever get their money back? And the same thing with the response. Responsive reserves are currently a bundled product and we are looking at unbundling that service in the five proposed services listed. The proposed ancillary services are more in line with saying, what does the ISO need in terms of reserves? Rather than the current proposal, which has been there for a long time, and it was primarily based on conventional fossil fuel rotating mass kind of machines. So this is one of the things that we're looking at, and again, I'm still talking about short term future stuff.

Now, this is another thing that's short term. It might be a long term one. If you look, this price data was from September 13. It was a Sunday. It was the morning, but September is a summer month. Look at the yellow ones. The prices are negative. This is primarily because of the wind, and a lot of the conventional resources that are online were running at minimum. They were not contributing to the price formation. Is this what we expect to see more and more in the future? And we do anything about it?

We tried to figure out, if you think this price is not appropriate, how do you fix it? If it is appropriate, then what is the revenue stream for conventional resources whose marginal costs is way above zero? But they have another means of earning revenue. Maybe the major source of revenue will be ancillary services. So we'll have to start watching this and seeing what happens.

So now let's come to the real thing, distributed energy. ERCOT has got very good solar potential. PV prices are falling. We know they're coming. We don't know exactly when. That's the billion dollar question. On the DER (distributed energy resource) side, just look at this. On peak summer days, half of our load is residential air conditioning. If we could have a mechanism to tap that, it's going to have enormous impact. This is what we have right now in terms of demand response. This is mainly coming from commercial and industrial customers, because they have a demand charge or a full CP (critical peak) charge. And you can see, the response is about 600 megawatts. So there is demand response. It's pretty active.

This is our traditional diagram for how the ERCOT marketplace is. As you can see I've drawn a black arrow connecting consumers with energy resources. When it comes to the resource and the consumers, the lines are getting blurred now with increased distributed energy resources.

Again, this diagram is a typical distribution grid. The main thing I would like to point out here is the top cloud (the transmission grid) is what ERCOT models. It's greater than 60 KV. We have good status estimation. We have good telemetry. We know what's happening in the system. Under the distribution grid, we don't control that, and depending on which utility you're talking about, the amount of situational awareness varies drastically. The distribution grid is a predominantly radial operation, the urban areas are more meshed, there's limited telemetry available, it's more resilient to unbalanced 3 phase flow, and it's mainly designed for pwer flow from transmission to customer. We always model the transmission grid as a balanced network. I don't think you can say the same thing for our distribution grid. And mainly it's because of cost. So as more DER starts coming in, distribution utilities have to spend a lot of money in telemetry as well as, you know, redesigning the protection systems.

If you're talking about residential solar, there is a push based on California PUC making some rules. IEEE is coming up with new standards. To me, the most exciting over there is the two way communication and control. So now these guys can be controlled by a remote entity. So that's going to havew a big impact if they want to participate in any kind of market.

So these are the kind of things we're thinking of in terms of how the distributed energy resources will participate. The column that says "DER Minimal" is status quo. They're just self-responding. They will be settled at what we call the load zone settlement point price. So you can have a single meter at your house, so if you're ever injecting into the grid you get your load zone price. You cannot participate in the ancillary market, because we are not asking for any kind of telemetry. The other columns are "DER Light" and "DER Heavy," and these are the new things that we are proposing. And we are proposing that they can get a local price. So the key idea here is that ERCOT will not model the distribution grid. We'll stay where we are. We map each individual DER to the closest transmission point, and we just provide that price to them, the closest transmission point. Now, why are we doing this? Well, there was an event last October where we had a regional constraint and we had to do firm load shed, but there were DERs, I'm not talking about rooftop solar, but backup diesel engines that could have started up if they had gotten a locational price. They got the load zone price, which is peanut buttered to them for a large area. The price really didn't materialize, so they didn't come on. But if they had gotten the local price, they would have come on and mitigated some of the load shedding we had to do. But in order to do that we are expecting some real time information.

Now, how could roof top solar be part of it? It will come in through the aggregation. And this is just now a description of how we propose it. So the DER on the bottom could be a residential thing, and if it's part of an aggregation, it will be multiple copies of that, bundled together aggregate into one resource.

This chart is about dual metering. And right now we are not considering demand response as part of our DER because of our interpretation of the specific rules.

And this is my last slide, and what I'd like to say is that storage is going to be a game changer. Now, the question is, what's the cost benefit for the people installing storage? And if that comes in, it's going to change things, and some of the policies might also have to change. One of the things in terms of the computational front here that I see is the big data analytics. Now, if I'm aggregating, I'm getting a resource that's an aggregated resource, and we tried it out with trying to put in demand response and our security concerns and economic dispatch. The major challenge so far has been, how do you validate what you're getting? Because you might have thousands of residential units as part of the aggregation. Each one has a meter. And you're getting a telemetry every two seconds which is virtual. It's a cooked up telemetry based on some statistics. We have to validate that after the fact. So I think in that scenario the person who is doing the aggregation, if he doesn't know what's happening at every residential house, every two seconds, then he has to build up the virtual telemetry based on some kind of data analytics, and that's where I think the big push is going to come. So it's going to be big data analytics for the aggregator. It's going to be big data analytics for the ISO, because we need to kind of have a forecasting mechanism, if it's solar PV that we're trying to forecast.

So that to me is one of the big areas. And the biggest area in the short term is that if we put demand charges on all classes of customers we might start seeing a big chunk of residential DER come into play, because they want to skip out. But there are a lot of policy issues with that decision too. And I think that's all I have.

Speaker 4.
What I'm going to try to convey in the few minutes we have is where we are in terms of computational challenges, why we should care about computational challenges, and where we might end up in 2020 or 2030. To a great extent my presentation is very consistent and complimentary with what you've heard already today. So we should get going.

First of all, the purpose of this slide is to say nothing more than that small savings can amount to big numbers. And investments in software are relatively cheap. We optimize in this system over time frames from 10 to the minus six to 10 to the minus ninth. The whole idea of using computers got started in the 60's when Edward Teller, in studying the response to the '65 blackout said that we should probably be using a communication sensors, computers, and controls. We're still talking about that today. But we've made big progress since then. And, as Bob said in 1999, we to a certain extent to encourage ISOs to look into unit commitment models using MIP. We organized a conference and produced a book of papers from the conference in 1999. And the net result is positive. In 2008, FERC staff introduced the concept of Optimal Transmission Switching in some simple models. They saw savings greater than 10 percent. And started on a path to investigate whether or not what was true in small test cases could be true in reality.

We also have a whole bunch of new technologies, as you've heard in the previous presentations, and prices that go down to minus $30/MWh, and a lot of problems when we see that happening.

In 2010 FERC adopted a strategic initiative to promote wholesale markets' efficiency through software and hardware to optimize operations. In 2015 this seems to have made a dent. All the ISOs have now adopted mixed-integer programing software for their unit commitment and other models, and although it's hard to add numbers up like this, there have been roughly somewhere upwards of a billion dollars a year in savings, simply by using the better software.

What do we do well computationally? Well, we solve sparse linear equations, linear optimizations and convex optimization problems very quickly. More difficult are problems with binary variables and problems with continuous non-convex functions, and these are the problems that are to some extent perplexing the industry today.

Software is a binding constraint on market efficiency. Even though we have faster software and hardware and better measurements, we still have a reasonable way to go in terms of software. And when I say that, often times the software's not good enough to find the optimal solution and we make ourselves happy with a rough approximation to the optimal solution.

And the other binding constraint is the utility practice. Now, why is that a constraint? Well, if you develop a new technology and you want to implement it, it's not the internet model, where you can hang the app up on the internet and see who comes to use it. To get new software and new ideas implemented in utilities, you first have to go through senior management, which is 30 years out of school and learned their electrical engineering out of different text books and different algorithms. Then there's a bureaucracy that you have to go through. Even if you get senior management interested, lower level people in the organization object to what you're doing because they've been doing things one way for many years and aren't interested in changing.

It's very difficult to implement large scale testing on real data for a number of different reasons. You pretty much have to get access to the ISO's models in order to convince them that your ideas are worth implementing. And you have to get through the myths and the shibboleths in the system.

Now, I want to talk about is the Alternating Current Optimal Power Flow (ACOPF), and that is the problem we would like to solve, but can't. And the reason we can't solve it is because it's highly nonlinear and highly non-convex. Now, the nice thing about this formulation is it comes in various flavors. You can use Polar formulations, rectangular formulations and actually linear formulations. If you formulate the network equation in terms of current and voltage, the equations actually are linear and that's something we can solve very well, except that we sell real (and, well, we don't actually sell reactive power), we sell real power and we don't sell current. But it's an interesting question about solving your network equations with linear relationships rather than the equations at the top, which have quadratic terms and trigonometric terms which makes the nonlinear problem more difficult.

Now, the nice thing about the ACOPF is it includes reactive power, and, along with that, voltage constraints, and you've heard two of the speakers talk about reactive power today. The standard nonlinear solvers are getting faster and can work on these problems and get decent answers. But today they're not anywhere near production quality, and the speed is not enough to get them into the actual real time mix or the day ahead mix. And we rely on convex and linear approximations to solve this problem. Recently ARPA-E has undertaken an initiative to create a set of test problems so that the academic community can actually solve these problems and report results, because today there is no good set of academic test problems for academics to work on.

You know, we've heard reactive power is too cheap to meter, but it probably isn't as cheap as we think, and in many cases in the ISO models it looks like you're putting in a real power constraint. And what you're actually doing is putting in a reactive power constraint by forcing local generators to start up and generate when they're not needed for real power, but they're needed for reactive power. And the marginal cost of reactive power is fairly small, but the incremental cost of reactive power is huge, because the incremental cost of reactive power is starting up these old clunker generators and setting them at minimum load for their reactive power, and all of those costs arguably can be attributed to reactive power. And so the incremental costs are significantly different from the marginal cost of reactive power.

And you get now this issue mixed up with joint products, because if you start up a lot of these old generators for reactive power, you now have them for N minus one, minus one contingencies and inertial response and things like that, and so you're not really sure what you're doing, but the way they do this in almost every ISO that I know of, is they simply force more real power to start up, and as an ancillary result they get the reactive power, but you never see that in any of the LMPs or any of the pricing algorithms. And in fact, when you start up these other generators and move them to minimum load, you actually suppress the LMP of the real power, so they have some very nasty consequences. And then if you go to the ELMP, you actually are setting the real power LMP based on the fact that you started up these units for reactive power. So there are a lot of confusing issues.

Now, with respect to the day ahead and real time market process, we solve the distribution factor unit commitment problem. We get the answer, and then we send it to some alternating current system to check for reliability, to look for N minus one contingencies, to look for voltage stability, and a whole bunch of other things. And if the check for reliability comes back negative, we modify the distribution factor model by adding constraints or just simply forcing commitments of certain units, and then we resolve the distribution factor unit commitment.

One of the approaches today is to try and move more of the issues in step two into step one. That is to say, create a linear approximation to the reactive power output from the generators so that you can more explicitly model reactive power and the needs for reactive power in the unit commitment process, as opposed to creating these closed loop interfaces, which is what we do today. So this is a simple sort of attempt to move more of the constraints into the actual optimization. So you want essentially a better linear approximation. Because today we use RMR (reliability-must-run) choices, which are often simply operator choices. As I said, cut sets are very rough approximations, and introducing more linearization, albeit an approximation, may be a way to deal with this problem.

Also, you want to deal with the issue of topology improvement and corrective switching, which I'll talk about in a minute.

To me, one of the fascinating things that has happened over the past five or six years is the work that a person named Javad Lavaei has done with various and sundry co-authors on solving the ACOPF with semi-definitive programs. And what he identified, strangely enough, is that if you take the standard test problems and solve them by using this semi-definitive programing approach, that all of the solutions that he gets are globally optimal. And nobody fully understands why that's the case today, and he's also demonstrated that with enough phase shifters in the system you will essentially get the global optimal solution. Most solvers only guarantee you a local optimal solution. And it's still an open question as to why for the standard test problems almost every solver finds the global optimal solution. You can also demonstrate acyclic networks have a global optimal solution, that is to say, the tree networks in the distribution system, and initially these programs were very slow, comparatively, and due to some other work in trying to make this thing more efficient, the algorithms are getting much faster and possibly competitive with some of the other algorithms. So there's a reasonable positive outlook for solving the ACOPF problem.

The other issue is optimal topology. And optimal topology is a very broad subject. It includes everything from corrective switching, which is to say, when you have a contingency you use corrective switching to get yourself out of the contingency and back to N minus one reliability. That's as opposed to protective switching, which says, I will anticipate this and I will just be able to survive it.

And the topology question goes all the way through to transmission planning, if you look at transmission planning as choosing the best set of transmission lines to optimize the system. It has the same model formulation as the optimal topology problem. As I said before, we started on a project in 2008 where we were able to show significant savings. This year, two teams that were sponsored by ARPA have not come to the point, although they're not optimizing the system, they're just looking for incremental improvements. They have developed a software to the point where, just using optimal topology or improvements in topology, you can get $100 million savings in the real time market, and about $50 million in the day ahead.

When you go to corrective switching, PJM on their website has a whole list of corrective switching actions. When we first started doing this, people said we couldn't do it. Then we discovered that PJM had a website full of corrective switching actions that they took, but most of them were heuristic and basically developed on a study program of individual issues. Kory Hedman took the PJM corrective switching data and improved or developed software that improved or actually did as well as PJM's individual studies, and they estimate that they can eliminate a lot of post contingency violation with a savings somewhere around 100 million dollars a year.

Another problem that we're worried about and work on and don't seem to get anywhere on is joint optimization. In particular, the Commission has been spending a lot of time on trying to get PJM and MISO jointly optimized, but it hasn't gotten very far. And one of the reasons why we can't jointly optimize PJM and MISO is because we probably couldn't solve the problem in the time horizon that we have. And we don't even know what the size of the possible benefits of joint optimization are, but hopefully we'll be working on that problem in the near future.

To turn to the distribution optimization you heard Speaker 2 talk about, and the issues involved there, the fascinating thing there is that there are a lot more losses on the distribution system and there are places on the system where you can find losses up to 30 percent, which may initially give you opportunities for reconfiguration switching and location of new assets, because if you can find spots in the distribution network where you have losses of 30 percent, locating things like solar and storage facilities at those places can yield significant benefits, as opposed to places with low losses, where the benefits don't come as quickly, but this requires some new computation.

I decided not to spend a whole lot of time on stochastic issues, because these are probably the toughest nuts to crack. The old stochastic issues were the probability that the generator was going to be running or the probability that the generator was going to actually go down. Today it's starting to look like weather is going to be the largest N minus one contingency. And why do I say that? It's because if in fact the weather forecast is wrong, suppose on a cold day you under-forecast the weather, you not only get more demand than you anticipated, but as the weather gets colder, generators have a harder time starting up, so that the probability that they will fail or fail to actually start up is much larger. And today we don't take that into account. Well, we're actually starting to take that into account.

The other issues are forecasting the wind and the cloud cover, which are relatively new, I believe, to the industry. These models, as you can see from the graph on the right, blow up very quickly. You can create scenarios that essentially make the model computationally infeasible very quickly.

So what could we see before 2000, or around 2020? Certainly you could look for price-responsive demand. Price-responsive demand is an understudied and somewhat under-paid-attention-to issue. PJM started on a process of price-responsive demand several years ago, but it got swamped by the 745 process and the court hearings on the 745 process, which is now at the Supreme Court level. But price-responsive demand, and you've seen that in the other two presentations, in very subtle ways, is very important.

Also, a faster real-time look ahead. A better reactive power approximation in the linear model. And a better transmission supply function.

In 2030 I think it's probably reasonable to expect that we will be able to have the ACOPF in the optimization systems, distribution systems optimization, and possibly a unit commitment for demand. Thank you.

General discusson.

Question 1: My question relates to price based response which I think everybody here would agree would be great if it happened, but certainly in ERCOT, if I look to the retailers, they almost universally seem to be completely uninterested in price response of their customers. I mean, it's just hard to get them engaged, as far as I can tell. At least at the residential level, maybe the C&I level is more interesting. How do we square the circle?

The real problem in ERCOT is an air conditioning peak which is driven by residential retail sales. And so the real solution surely has to be getting that into the mix. How do we get retailers interested in price response for residential, and begin to bring the promise of price based response out of a few, you know, 300 megawatts plants going on and off into a smooth response that helps with running the markets? So how do we square those two things?

Speaker 3: Yes, so let's look at the different scenarios. There were some retail electricity providers that did offer index pricing, which would presumably encourage price responsive behavior, but residential customers kind of get lazy, and what this retail electricity provider found out was that even though they tried to educate the customer about what it means to have real time pricing, an index pricing, when the customer didn't respond and he looked at his bill at the end of the month, he got really mad at the retail electricity provider and switched. And after that experience, given that the retail electricity provider spent a lot of money acquiring customers, that avenue just dried up. No one is really offering that because it's more about acquiring customers and keeping them. And no matter how well you educate the consumers saying, "Hey, if you're going for a real time index pricing, this is what you should do…" They might do it for the first month or so, then they might just forget.

Now, what happened last year is that one of my colleagues who is in a competitive area, he got automatically signed up for a big reduction program and the deal was, hey there's no obligation, but we'll give you an advanced notice, maybe a day ahead notice, and if you respond during these hours, and if you make money--if the real time price is, say, $500 per megawatt hour and our retail rate to you effectively is maybe about $100 a megawatt hour, we'll split the difference. And he was really excited. He got that notice. He responded. But the price never materialized. So nothing happened. So looking at this anecdotally, people are responding to this program, but prices are pretty low.

I think it's about how do you incent them? It depends on the rates that they offer and why would an REP offer a rate like this until he was mandated to do so, which I don't think we like to do. We don't like to get in that business. So the key is prices, I think, and whether prices are high enough. Because let's look at it this way. For commercial industrial customers, greater than 700 kilowatts, they have a demand charge. We have a pretty good price response in that customer class. On the residential side, it's pretty much just an energy charge plus some flat fee. So how do you incent them? Do you change that? I don't know.

Speaker 4: One of the issues is that if you have a capacity market and you're willing to be price responsive demand, you don't have to buy capacity, and so there is a positive incentive in the fact that price responsive demand doesn't have to buy capacity. So that's a positive, and possibly a virtuous circle where more and more people recognize the fact that they don't have to buy capacity, and it's not a trick, because the reason you buy capacity or have capacity markets is because your inelastic demand means you won't respond to prices, but if you respond by getting off, you don't need to buy capacity on their behalf. So in markets with capacity markets that is a positive issue.

Question: So your recommendation is to go to a capacity market?

Speaker 4: I didn't say that. [LAUGHTER]

Speaker 2: I'd like to say something very quickly. The problems are enormous.

Particularly with current rate structures and so on. But I'm a little bit more optimistic that we can go to multiple products. We can price multiple products by commoditizing, for example, different types of reserves, which is another way of viewing demand response and allowing certain customers to respond to that, whereas others may choose to stay in the business as usual. So this is a way you can deal with the rate payer revolts that we've seen.

And then, anyway, I believe that it's quite easy to calculate marginal costs at the distribution level, at the retail level, for real power, reactive power and reserves. Maybe price different types of reserves, and then have people respond, and have customers respond to these, and they can respond on the basis of mobile apps on their iPhones. But certainly something really qualitative and different has to happen. We have to have some sort of a new platform, a mobile platform, that facilitates this sort of approach. There was a paper by IBM and by many others who claimed that things should move away from energy service companies and aggregation and be customers specific, sort of load specific, and so on. And I think that the technology allows us to do tha,t and if it's done in a voluntary fashion, on a partial basis, we probably will see it happen faster than 2030.

Question 2: I have a question about the data and the data sets that can be used to sort of further the understanding of how to address the problems that are computational as well as market rule structure issues. And Speaker 1, you mentioned that you had 3500 models that that you were using with Gurobi. I imagine those aren't public, and they're probably related to specific instances and may not necessarily be a reflection of like what's happening tomorrow or something like that in the network. And I'm wondering also, Speaker 4, you mentioned that getting the right academic test problems available to researchers is a key problem. And so I'm wondering, what can be done to provide greater data access to not just a few researchers, but to a large set of researchers, and to perhaps also not just academics who may not make apps, or who won't necessarily go out and create market products to essentially address this, but essentially more public availability of appropriate data sets. So what can be done there?

Speaker 1: I can at least make a small comment on our data sets. So the data sets that we have are from our customers or potential customers, and when I say we have 3500 models, we have probably like 10,000. This was a subset. But, these are from across the spectrum of applications, from supply chain to scheduling. We schedule for the NFL, for example. We have problems from them, and so forth, and so on. Among these, probably a hundred or so come from this space, or electrical power, perhaps I should say. And they are what they send us, you know. We're typically not involved in the modelling process, and often don't know much about them other than they come from MISO or wherever. And my final comment is that I get requests all the time for, "Can't you release some of these models? Can't you make them available?" Which would be enormously valuable. That's essentially impossible for us to make that happen. You have to go to the company, your contact at the company, and get them to get it released within their company, and when you think about the person that's doing this, the incentives are all wrong. You know they're not going to be a hero in their company for going around and asking to release one of their models. It just doesn't happen.

Speaker 4: Actually, the biggest constraint on test problem development is critical infrastructure information. The network model of all the ISOs has been declared to be critical infrastructure. Now, that doesn't mean its secret, or anything else. It simply means that you have to sign a form, you know, saying you won't use it for nefarious purposes. But it's a bureaucratic process. It takes quite a while to get that permission, and a lot of people give up before they get the permission, but that is the biggest barrier to date to actually getting access. The research money is there to develop these problems so they're plug and play. So that they are easy to use. The biggest issue is getting over that critical infrastructure issue.

Now, if you are a market participant in PJM, you can get access to that information. But it's not always in the form that the optimization community, for example, can handle.

Questioner: And also I think there're models and then there're models. Often, what is available is a very simplified version. And going into some of the issues that were discussed today, then you're just in a different ballgame, I think. So is there a way to kind of expand that? Is it all just corporate, or, you know, piece meal--one local utility could potentially give some data, and then another one, and to kind of get a full picture would require a lot of energy and a lot of work, and perhaps be beyond the capability of any one professor or anyone short of a market participant?

Speaker 4: Well, ARPA-E right now is in the process of trying to develop something of that nature. It's still in a very rudimentary phase, because of the barrier of the critical infrastructure.

Speaker 1: I will say that the models we get usually seem to be representative of what the current challenges are. So I know that they MISO models that we have, they're having issues handling these volumes of transmission constraints, and they're difficult. They're difficult models. So we do learn things.

Speaker 4: I assume that's what's available from PJM and other ISOs is a planning model, but is not the dispatch model.

Speaker 1: That's correct.

Speaker 4: Just to clarify for people. So those are not made public to anybody. Because there's some extremely proprietary information.

Comment: Yeah, the dispatch models are not available, but certainly the planning models are available for the members. But to Speaker 4's point, there's still the critical infrastructure issue that everybody has to sign off on. But, yeah, it is available.

Speaker 4: You're right. The actual data for the generators is proprietary, but if you go to the EPA data and the EIA data, you can reconstruct the generators from those two data sources, and you know exactly where they are in the network. So FERC has a test problem that is representative of PJM, with a constructed version from public data of the generators and the network which is CEII (critical energy infrastructure information), and all you have to do is get CEII clearance and you can get the whole model.

Moderator: I never thought signing the CEII paper was much of a deterrent for anyone. You just had to go through the process.

Speaker 4: Yes, right. It's a bureaucracy. You know, it could take months and, especially for the FERC model, you have to go through FERC bureaucracy and PJM bureaucracy.

Question 3: It looks like fast response reserves is one of the areas of interest to address this issue that's coming up of there being less system inertia. And my question is, what are some of the best kinds of either resources or solutions to that problem that we should be thinking about? And "best" in terms of reliability or affordability or achievability, sort of those types of angles. And also, is there a view of the timing at which we really need to be having a solution in place, because the issue just has to get addressed at that point? Maybe it's 2020, 2030, something like that?

Speaker 3: ERCOT already has it. We've been having it for many, many years, in terms of a fast frequency response. We call it "responsive reserve from load resources," so these are large industrial customers that have high under frequency relays. They can respond extremely fast, and they can stay off as long as they have that responsibility to provide that service, and they get rewarded in the day ahead market, and they participate in the day ahead market.

In the future, what we have proposed is two kinds of fast frequency response. One is the existing one, that once they come up they can come off really fast and they can stay off for a long period of time.

As we were talking with our market participants, a couple of ideas were thrown out. So batteries. If you ask a battery to start injecting energy into the grid, they can do it extremely fast. Probably within half a second. But right now, the technologies, they don't store enough energy. They can't provide it for a long enough time. But let's say a big unit trips and the frequency decays, right? The way the system should respond is to arrest that decay. And that happens within the first couple of seconds, five seconds maybe, maximum. So a battery could provide it for five seconds. So we created a new sub-product of fast frequency for that.

The other idea is if you have Walmart that has got all kinds of distribution centers across the state, and they have refrigeration systems. They are cooling the stuff, and they can suspend activities for short periods of time. Maybe 10 minutes, something of that sort, but not for an hour, right? So they can participate in that.

So the way we have developed is not pointing at a particular technology, but instead focusing on what we need. We need two types of fast frequency. Both of them have to come up really fast. One has to be off for a longer period. One has to be off for a shorter period. If you qualify, if you meet those standards, I don't care what kind of technology it is, you can participate in that market. So that's where we're going.

Speaker 4: One of the other interesting issues is that even though we value inertia, we don't pay for that response. And not only that, we don't pay for governor response. And so a lot of generators have essentially turned off their governor response, and then only respond to an AGC (automatic gain control) signal which comes actually later in the process. A governor response starts immediately as soon as it detects the frequency change. And we don't pay for that. And so, not surprisingly, the generators have turned off their governor response. We should be getting them to turn it back on, and paying them for that response.

Speaker 3: On that issue, we are proposing to pay for governor response. We call it primary frequency response. And in ERCOT you cannot turn off your governors. I mean, this is Texas, and I think we have probably one of the tightest and best CPS (control performance standard) scores in the country, and it's all because of the stakeholders themselves going back, looking at the governor response after every event, tightening the dead band and monitoring the frequency. We are an island, so we are worried about governor response.

Moderator: So you have enlightened the regulators?

Speaker 3: Yes. [LAUGHTER]

Speaker 2: So the idea is to commoditize these reserves. And, indeed, ERCOT has two types of response, PJM has going to the second, to the AGC (automatic gain control) type response of two or three seconds. They have reg A and reg D for dynamic response. It's faster. It's more energy neutral, so it caters, not to generators that can do something and keep doing it, but to loads, to storage, and so on. It has to do something that's more or less energy neutral.

Other providers here that we rarely think about are data centers. So data centers consume on the order of 20 to 40 megawatts, and they can respond in milliseconds because of ADFS (Active Directory Federation Services infrastructure), because the ability to increase or decrease the speed of the clock. And all the duty cycle appliances and so on--the millions that you have there--can do that as well.

So I believe that sort of commoditizing these things and pricing them and rewarding them is going to unleash the innovativeness of the capitalist system in some sense, to the extent that people will be able to respond, not by running around and doing things, but through sort of mobile distributed appliances.

Queston 4: Let's suppose that I'm a businessman, an aggregator, and I have 10,000 customers whom I've been able to line up. Say I can see the value of shedding retail load, even though the customers may not be proactive and responsive in a timely way, but as a business model I want to take advantage of that opportunity. If I've been able to get, say, 10,000 individuals to sign up, and I'll be able to direct their air conditioning compressors to not come on at certain times, what I'm curious about is my ability to participate in the wholesale market with the aggregation of those 10,000. And let's assume that those customers are at least spread across a wide number of nodes, but let's say they're all within one utility distribution service territory. That would be one case.

The other case would be where you might have thousands of those customers across many different utility wires companies, OK? But, I'd really like to bid the aggregation into the ISO. Can I do that today with the technology and the software that you have? If not, do you think it could be done, and how many years from now?

Speaker 3: It can be done now. In ERCOT we have implemented software changes to enable that, but we haven't gotten any participation yet. And there are a couple of reasons for that. So describing what we've implemented, you could aggregate air conditioners or pool pumps, or some combination of that across a load zone. Remember, you will be treated as a resource. So we need to have a good idea what your impact to a transmission constraint is. We approximate that using a load zone shift factor. The idea is there's a combination of all of these different nodes that make up a load zone. But you might be only concentrated in one part of that load zone. So using the whole zone is an approximation we make. There is an error in the approximation, but the funny thing is, if the aggregation really becomes big, it's like wind. If wind penetration increases drastically, it's not going to be that much of a problem because the wind won't die out everywhere at the same time. You're geographically dispersed. So if your aggregation becomes big, load zone shift factor is the correct way of modeling that, in terms of condition. If it is really small, it's noise. It's the middle ground that's kind of, "Oh my god what am I going to do? I know it's kind of wrong. Do I just go on?" So that's how we model it.

Now, why has no one come? There are people who are interested. That's what I kind of alluded to in my presentation. It's the big data analytics that are key, because if you're trying to sell to me, I need to know what you're selling me. I need a good way to validate that. In real time, probably you're not getting telemetry unless you spend a lot of money for each of those 10,000 residential participants. You're using some sort of statistics. I need to validate that. When you send me a single resource offer or telemetry saying this is what you're doing right now and this is what you're offering to sell, when I buy it from you I need to make sure I'm getting what I bought. That has been the biggest challenge.

The other challenge is more of a control system infrastructure thing. It's that we dispatch in the real time market. We're running it every five minutes. Right? And some people say, "Yeah, that's not a problem, we can meet that." Other people say, "Hey, we would like to get a 10 minute notice, or maybe a half an hour notice." Well, our real time market doesn't look forward. We are just running for the here and now. And then we wait. So I can't tell you to do something 30 minutes from now.

So there are two things. One is a temporal constraint if you're looking at resource modeling. The other one is measurement and validation. That's key, because that's where money comes in. And today in ERCOT we have a candidate who has qualified for the other part. They can respond to five minute signals, but we're still working through the validation. And the thing is, we have a short window to do the validation. They want to be there in the summer months. It's residential air conditioners and pool pumps. And that's the only time you have to do measurement and validation. And once that's off you say, "OK, we're going to wait until next year if things don't work out." So I hope I've answered your question. And they can participate in some ancillary service. The slower ancillary service and energy.

Questioner: I know I've been listening to some presenters from New York State where they have their Vision for Energy future, where they seemed to have decided that a lot what they would consider to be micro demand side management has to be done only within a given utility, and is not really something that even gets up to the ISO. And there could be a lot of reasons why they took that decision. What they said was that they thought that the complexities of figuring out the net impact of an individual action, air conditioner or compressor or pool pump, whatever, on a distribution wire was so complicated that it wasn't something that the ISO would be able to handle. And so they kind of enforced what I would call balkanization of that aggregation function to the level of the wires company. And I think you've answered the question in terms of ERCOT by saying that you do not see that distinction. You see no reason why it couldn't be aggregated and still bid directly into the ISO market. That's part of what was behind my question--I have understood, from another state's perspective anyway, quite a different answer.

Speaker 3: Yes, for us, if they qualify for a resource, they're in the market.

Question 5: I thought this was a very interesting discussion, and I want to raise a question and talk about history, and then I will re-enter this and direct it to what we've just been talking about, because I think I'm nervous.

So if you look back and you remember, and I certainly remember, when we started the reforming electricity markets process and we were talking about how to design the markets and so on, we already had economic dispatch software in place and operating. This was old news. This wasn't new news. And that economic dispatch software inherently produced locational prices as a byproduct of the computations. So when the first numbers were looked at in this domain, which I recall quite vividly being at the meeting where Andy Ott was talking about this, and that was before PJM and the software people were telling him how it would take, you know, two years and 10 million dollars to get the numbers, as all software people do, in my experience. Then Andy said, "I can do it over the weekend," and what he meant was, "We're already computing these numbers. All I have to do is go look them up and write a little report writer. And then you'll have them and then we can go forward." Now, that's not the same thing as a commercially robust system, but it made the point that this wasn't a big innovation. It actually took them two weeks to do it.

But that made the conversation much simpler, because you didn't have to come in and say, "I have a great idea for you, system operator. Why don't you use economic dispatch, as opposed to you know, aggregating and then getting everybody 30 percent of the aggregate or something like that?" They were already doing it, and the prices were already there, and we could use those prices.

The second part of the historical story is that when PJM, you know, first was starting to make the transition to implement the LMP process, they were taking that software and doing it in parallel with the actual operation of what was going on, but they weren't using it for commercial purposes yet. But they started publishing the prices, and at the time, everybody was shocked. "What are these numbers doing here? They're going all over this way and that way. I don't understand what's going on here." And then Andy would go back and try to find out if there was a mistake, and he'd find, "No, no that's because this interacts with that, and that interacts with this and so forth. So you can get negative prices, and, you know, of course with the constraints, you can get very high prices over here." And all those things were completely consistent with the optimization problem. So people did not have a good sense of what these prices were and what they meant, and what the implications were going to be for operations and so forth.

Now we're on the threshhold of this going to the distributed energy resources story. And the world is different. We're not doing economic dispatch down in that system, so we're going to have to do something different. We're talking about all these kinds of flexible resources that are going to respond in ways that we don't understand and don't fully know about. And we don't have the prices available even to look at these systems, much less to have it being familiar and something that people could actually transition to. And what I'm worried about is that we're getting way ahead of ourselves in this conversation in New York and other places, where the answer that I would give might have been the opposite of what Speaker 3 just said.

So if you're taking aggregation and you're trying to aggregate across large areas, and then you want to bid them in as a single resource, you are creating an enormous problem, because the conditions are completely different in each one of those situations, and it may be desirable to have this one go up and that one go down, not have all of them go up. And if we're not representing what's actually happening, we don't understand what's going on, and Speaker 2 knows about the computations that they've been doing on this, where you start looking at what happens when you get into the distribution system. And you look at real and reactive prices, and when you look at them, particularly far down the distribution grid, you get numbers that are only tenuously related to what's coming off of the high voltage grid system. There's quite a big difference—numbers twice as big or larger.

And these reactive prices makes sense. I just don't understand how we can have a market and a distributed energy resource system with flexibility and choice if we don't get the signals to people to be reflecting the conditions that are actually down there and that system. And I just don't see how this is going to come together very quickly, because people just don't understand reactive pricing. They don't understand how you're going to actually compute these things efficiently. We don't even know for sure that we're going to be able to do it. You know, we think we can. We're optimistic about all this kind of stuff, but its way different than a situation where we've been doing for 20 years, and now we're just going to use a report writer in order to go collect those kinds of numbers.

And what I'm concerned about is that we're going too fast because we haven't thought about this problem, and we're being to glib about the ease with which we could just take the numbers we've already got and use them in such a way that it won't turn out to be counterproductive.

And the alternative to this, I think, is not to have command and control technology and the utilities in charge and they tell everybody what to do. You know, we don't pretend that we have a market in that kind of a system, and that has its own cost and all those kind of things. But I come away from this with a different view about the optimism with which we can actually put together these distributed energy markets and the time to meet the onrush and the desire that people have, like they have in New York and other places. Because I don't think we really understand what's happening down there in the distribution system, and people have choice and they're given bad signals. What's going to happen when we give them the wrong signal for the prices and they have flexibility and choice and they respond and go in the opposite direction? Is that likely to make things worse rather than better? Should we do something else?

But the experience we had at the high voltage grid with locational pricing, I think, was instructive. It was hard to do that, even though computationally the problem was trivial, because we were already computing it. And it was hard to do it initially because people were shocked when they found out that they didn't understand how the interactions and all these things affected the real operations and the system. And if we didn't have the real prices, the correct prices, then the market wasn't going to work.

Speaker 2: It's very interesting that we did have the machinery in place because of optimal load flow dispatch that was an objective at the transmission level. We don't have the equivalent at the distribution network, but it is not too different, actually, in terms of the computation scheme that one needs, if one understands the load flow of the distribution network, and it's fairly reasonable to assume that the flows and reactive power can be measured with new nonintrusive monitors that are technically becoming available.

And once you can measure the flow of real and reactive power at enough locations on the distribution networks, you don't have to have extremely advanced volt/VAR KWK wire meters in every home, and so on and so forth. You can, at key locations, let's say in front of a high rise or a building or a supermarket or a McMansion or a sort of a feeder that goes into 20 homes that are served by the same transformer, you can measure there the flow of real and reactive power and come up with its marginal costs. I mean, that's doable. That's the ex-post marginal cost. So the ex-post marginal costs is easy to calculate which is sort of an approach that people took in Australia and New Zealand and so on when they were first interested in implementing marginal prices, right? You see what the load flow was, and you can impute what the marginal costs are. It's the same thing as the ex-post, you know the five minute type of market…

So I think the same is possible at the distribution level. So you have these prices, you can make them available, you can broadcast them, you can put them on a board that people can look at, and if you have small responses in the beginning, they're not going to change that much. If you have very small penetrations of distributed energy resoures that are responding to these prices, you know, these marginal costs don't change. The price and prices don't change so much, or at least they may change a little bit locally, but they don't affect everybody else. So that's a way to start, and that's something that suggests that you could have sort of a la carte selection to participate into this process, by accounting for the impact that you have on the cost at this specific location, as opposed to some sort of an aggregation of locations. So I think that technically that's possible.

Questioner: I agree with that, but you know we're not doing that, and the sequence that we're having now is we're running around trying to find new products that we can sell in the market and find their hidden values that we can pay them, and all this kind of conversation. And then the discussion about how to price all those kinds of things is kind of being put down as a secondary problem that we're going to deal with later after we get all this important stuff done first. And I wonder if it isn't the wrong sequence. So maybe the implication is that we should take a pilot program like, you know, some distribution utility and we should take the full blown Speaker 2 spiffy AC power flow distribution system, and do the ex post calculation that you talked about, and publish the prices as advisory information. We're not going to use them for settlement purposes, so there's no incentive for people to actually start screwing the system up, because they're not going to make any money by exploiting these kinds of things. We're just going to start publishing those prices, in order to see what they are, because I don't know what they are. I mean I can make up cases, but I don't know how frequently these things happen, and all that kind of stuff. And people can start getting a better intuitive feel for how important this problem is, and whether, when you start saying "We can aggregate across these regions," does that make sense? Or is it something that's actually going in the wrong direction? And that would actually make me more comfortable. I think that's kind of a pilot scheme.

Speaker 2: I agree hands down. That's the equivalent of when Andy Ott analysis type of thing. It may take more than two weeks. It may take some deployment of some sensors, and so on and so forth. But, you know, these real time, real studies are the first step. And I hope that we go ahead in this direction. And that would allow us to familiarize, to do computer simulations, and et cetera, et cetera. Absolutely, the technology is not ready, and you know we're not ready to launch a market right now, but we can certainly carry out the studies, and I think the studies are doable in the horizon of one or two years.

Question 6: I think the last questioner has raised a lot of important points here about how we get this. And I think the necessary condition is to actually get the prices right first, and then let's worry about the rest of this. Let's see what happens.

I have a couple of comments and then questions. The first one is that, you know, we talk about PRD (price-responsive demand), and I think about when I used to teach Econ 1101 at the University of Minnesota. And I'm like, wow, technology's actually caught up with basic micro economic theory. We actually can see what the prices are before we make consumption decisions.

On the governor response issue that came up, Speaker 4 is right. We don't pay for it, but it gets even worse in some contexts where there's a complete disincentive to respond, because you have to stay on your schedule, otherwise you're subject to deviation charges. So it actually goes in the opposite direction until you actually get a signal to say, "Please respond."

So we've done a lot of institutional things here that, you know, have not always helped us. But, the question that I have is, why can't we drive places down to the distribution level? Why can't we drive prices down to the distribution level from transmission, almost top down, so you actually have a price at the transmission substation where it interfaces with distribution? And then split the problem up, rather than a top down solution for the entire system, transmission and distribution together. And then you use an optimal, you know, dispatch power flow model, where the generator in that model is actually the transmission bus for which you have an LMP price. And then solve down to the distribution level. That's where I think, Speaker 2, you're going on this. And that way you can get LMPs down at the distribution level.

Why don't we split that problem up? Or would it be faster to run it in parallel or run it at one time?

And I think this helps us in a couple of ways. To the point that Speaker 3 brought up, we have similar problems in PJM. In September, 2013, we had exactly the same issue. If we had visibility behind the wholesale meter we could have avoided shedding firm load locally for the same reasons. But that's also because we're not getting the prices right. Rather than actually pricing out transmission, the transmission supply curve, we're basically saying, "We're not going to price that out, we're just going to issue a post contingency load relief warning. And if the contingency occurs, then we shed load." Why not price that out, send that back down to the distribution level, then if there's anything behind the meter, they can respond and they can actually help the bulk power system at the same time? Because at that point they become one and the same.

So really that's the ultimate question. Computationally, what's the best way of going about this? I think we can do this, but the question is, do you do it as one big problem, transmission and distribution together, or do you split the problems up separately to take advantage of either parallel computation or quicker sequential computation?

Speaker 3: I'm just going to give a practical take on this. I'm not sure about the algorithms and the computational needs. As an ISO, for us to model the distribution network is a challenge. Both in terms of getting good data as well as policy issues.

The other response is that what we're proposing in ERCOT is that we'll map the DERs to the closest transmission. We're already pricing out all the transmission nodes. We'll give them the same price if they're separately metered, right? Now, the question is, if you're wanting to have a market inside the distribution grid, right? And the different players have different perspectives. I mean, from what I can gather from what New York is talking about, the DSO (distribution system operator) is going to optimize along one feeder, and they are serving that load, and that seems to reflect that kind of mentality. But in ERCOT, along the feeder you might have six different aggregators, because we have retail competition. How does that play into the picture? And if you have a separate market, is there going to be arbitrage?

I guess Speaker 4 has said that you can't have a joint optimization between MISO and PJM. Now you're talking about every distribution utility. I mean, that's going to be a nightmare. And people are going to advertise between the two markets. So looks on the surface as if it's better to have a single market, but I have no idea how to do that. I mean, you took the easy way out, which is that we model under the transmission, and the people participating in the wholesale market will get the closest transmission level pricing. And that's what's being debated right now. We just started the process in the ERCOT stakeholder process. I don't know if that answered your question.

Speaker 2: Well, sort of going from the zonal pricing, which is there for purposes of fairness I guess, or whatever, smoothing, to actually having the LMP that is relevant for a substation is something that we can do. Right? Or, at least we can sort of monitor what the impact of that would be. And then from there on, having this as a composition in translating this LMP to DLMPs at the specific distribution network is certainly something that's doable. And eventually, of course, if the distribution network responds in ways that change very radically the energy demanded, then one would have to address that, too. But certainly you don't have to solve sort of the whole system, and going the distributed approach allows you this sort of adjustment type of process that certainly is compatible with the what you suggested.

Question 7: You know, when I hear all of this discussion about structuring the distribution system to be better integrated with organized wholesale markets, I naturally think about the distinction between retail and wholesale. And I think that, you know, the history of the Supreme Court jurisprudence on this has been to some degree to defer to the engineering expertise and economic expertise about the evolution of the grid. And I'd just be curious to hear your thoughts about, you know, looking forward to 2020, 2030, sort of the planning horizon, how you think that distinction is likely to evolve in practice over time. Forget about how we define it in terms of the legal questions, but in practice, as these technologies become more commonplace, as storage falls in price, as we see more distributed energy resources in the system, and this kind of computational possibility comes to fruition. You know, what does that mean for that distinction?

Speaker 3: In ERCOT, in the competitive areas, we have retail electricity providers. And right now they primarily serve load. Now, if we get increased distributed energy resources, which could be a combination of PV storage or individual stuff, and they can monetize it somehow, they will jump on it. I mean, we have an extremely competitive retail electricity market. So the question is, what is the value? How will I monetize it? And I think the structure is already in place. You don't have to wait until 2020 or anything. The setup is there. The question is, will I make money? And if there is the potential to make money, you will just see an explosion of people doing stuff.

Question 8: Speaker 4, to the extent that you're comfortable commenting on this, I was wondering if you could just give some thoughts on whether you saw any issues with the state of the art of both sort of software and hardware capabilities as limiting, and any of the concepts under the energy price formation discussions that have been going on, starting with the technical conferences and then the comments afterwards. Are there any kind of issues there that we just couldn't get to, couldn't solve, even if we all agreed on what we think should happen, just based on where the technology is now?

Speaker 4: I think the answer is yes. But it's more on a conceptual level than on a computational level at this point in time. And I think the whole interplay between the way the models look at voltage constraints and reactive power which don't formally appear in any of the dispatch and pricing models is a challenge. They sort of sit in the background with these closed loop interface constraints and, you know, just the operator turning on generators because they think they need them. And then trying to jam all of those issues into an LMP that has classically been thought of as a real power price, when, in fact, some of these prices could be more due to reactive power than they are to real power. But, we don't, again, do much with reactive power prices, although the reactive power prices show up in uplift allocation. For example, if you're starting up a whole bunch of units for a local voltage problem, the old strategy would be to spread the cost of that across the very broad swath of demand. Whereas now, almost all the ISOs are moving to a strategy that says, "Look, if I'm starting up a generator to support…" (well, let's take for a random example… "the Upper Peninsula of Michigan, maybe most of the costs of starting up and operating that generator should go to the Upper Peninsula of Michigan, you know." The same is true for units on Cape Cod. They may be there to support Cape Cod, but I don't think they're there to support ISO New England. So a lot of those things come in, not in LMPs themselves, but in getting the cost allocation right. Now, you know, the standard strategy has been to jam this stuff into an ELMP or something like that, without regard to the fact that that RMR unit who is now setting the price because it's relaxed its minimum operating level was started up for reactive power. So yes is the answer.

Question 9: Thanks. This has been a great panel and a whole lot of fun. To the questioner who talked about history, I remember back in the day that when we said, "You know, it's simple enough, let's just go forward," and we were exactly wrong. So I sort of support what you're saying, that, you know, we say the distribution network, but it's a distribution system, and most of it is radial, and we don't really have a good way to solve radial LMPs on transmission systems. So I'm still worried that we don't quite know where we're headed.

I'd like to change gears, though, because I work with a lot of advanced technology companies. And I think it's terrific that we're still trying to move forward, and I love that we're saving a billion dollars by trying to open some breakers, and so I have a question for you, Speaker 4, and anyone else on the panel, because what I see is that there's a conflict between opening breakers for efficiency's sake, and then you wander into the NERC violations of a million dollars per day, per violation. And that math can get pretty complicated when you're deciding if you're going to open breakers or not. That's versus what I would call topology control. Which is a lot of solid state devices that do what I would call feathering and fine tuning, and there's a lot of good work being done in that area. I can count on one hand the utilities in the U.S. that are actually doing helpful things to advance that technology and incorporate it into their grid. And I want to say thank you, National Grid, because they've been really helpful with some of this advanced technology. How do we break that log jam? How do we get these feathering controls and the things that are going to save us billions without the risk of violations? Is it through incentives for utilities to sort of get those 30 year engineers who are really good at rates and rate base to be more encouraged to try some new things?

Speaker 4: Yes, so you have the problem of getting through the bureaucracy also.

I mean, there's nothing here against having you know feathering technology. As a matter of fact, in some sense that's what you would want, but what we have today is that we're faced, not with feathering technology, but abrupt shifts in the topology of system. I'm all for, you know, putting in more controllable devices and things of that nature. Although we don't yet have a good way to figure out how to put them into the optimization. But, the interesting thing is that the corrective switching is all about reliability. After a contingency, you reconfigure the network to get back to your reliable state. And, believe me, although I'm not personality involved, the stories I get back from the people that are working with the ISOs is that you've got to convince them that everything is reliable and copasetic.

Questioner: Yes, and actually working with the ISO's, they'll tell you they don't have any money, so you have to go find a utility partner. Yes, it's pretty Byzantine. But, thank you for thinking about it, and thanks for the good work on it, because I think it's quite important.

Question 10: Bringing this back to the earlier question about how demand response aggregators can be accomodated, I've often thought that in thinking about responsive demand as a resource, that the whole meta-model of demand response as something that needs to, "participate in the wholesale markets," is to some extent asking an elephant to enter the house through the bathroom window. I mean, if you look at the hurdles that have to be crossed for demand response, for instance, even in the past participating in capacity market auctions and certainly now, with the pay for performance requirements, it really does constrain it to maybe a very small percentage of the potential for demand response.

And so my question is, if you think of it very differently, think of the business model very differently, which is as a decentralized business model, which is not "participating in wholesale markets," but actually a business model that says that you are going to monetize your investment by actually arbitraging tariffs, assuming accurate LMP signals at the distribution level and real time volume based distribution tariffs, then my question back to the ISO's in the room is, how does that change the way you think about this if that were the business model? Does it make your life simpler, because you're not having to model the entire distribution system? Or does it make it more difficult, because now you have to go back and completely rethink your data algorithms about scheduling and load forecasting?

Speaker 3: Actually I'm not sure I understood the question. Today we do have distributed load resources that participate in one of the products, mainly the responsive reserve, the one I was talking about where they have a high under frequency relay. We map it to the transmission model. We don't model the path all the way down to the distribution. And even a retail electricity provider, if he hedges his consumption bilaterally or in the day ahead market, if he manages to suspend consumption, he gets paid at the real time price for the amount of curtailment. So that avenue is there right now. That is what is driving a lot of the price sensitive demand response. So those avenues are there already. I'm not sure if I understood what you were saying in terms of what other avenues you might be thinking of.

Questioner: It's this much smaller you know, 10,000 customers question. It's not something where they're going to bid it into your SCED and you're going to say well, I need it at 2:00--it's just happening because their DLMP's that smart devices or aggregators are…

Speaker 3: I may not be sure what the DLMP is, but if I'm an REP, it is really based on the wholesale price typically at that load zone. The wholesale price.

Coming back to the aggregation, yes there is a hole in the thing, if you're aggregating across an entire region and you have a constraint, and I'm talking about on the transmission level. If there's a constraint between the nodes, we'll probably back your resource down all the way, instead of bringing up someone over here and pushing down someone over here. Our philosophy has been that ERCOT will be reliable. We will manage the constraint. The person who is harmed is the resource. Because if he had disaggregated into two resources, he would have been better off. So I guess our answer to that kind of thing is that the resource, the aggregator, should be kind of be able to manage those aggregations and figure out what is potentially a reasonable aggregation to offer up as one resource. So you're doing a tradeoff between, "Hey, I just have to send telemetry and information for one resource, but I might get hammered if there is condition between all my nodes," versus "Hey, I know that this is based on history. These kind of constraints normally pop up. It's better for me to have two resources." Something like that.

Quesiton 11**:** I'd like to make a friendly amendment to the earlier suggestion, which was that we should also publish the prices at the individual transmission busses.

Speaker 4: Yes, but there may be some low hanging fruit to start out with. We don't have to do this all at once and have 10 million LMPs running around the system, but certainly at the end of these long distribution feeders, where the losses are 30 percent or more, locating, you know, storage facilities and solar facilities there could be something you could create an incentive for and watch how the system develops. I'm not sure, you know, that this is a big bang type of project.

Speaker 2: But what he's suggesting is doable right away, right? So if you're transacting from the distribution network with the ISO, that transaction should be based on the proper interface, which is the LMP.

Speaker 4: Yeah, talk to the California ISO on that.

Moderator: I'll give Speaker 1 the last word here.

Speaker 1: Yes, I asked for a minute to be able to say one or two things. I'm a bit at a disadvantage here because I'm not an expert on these markets. I'm more of a consumer actually. I have a pretty big woodshop at home, with at least one tool that has a maximum consumption of like 260 amps of three phase power. So there is probably something I can learn here to reduce my cost. [LAUGHTER]

But commenting on optimization, one of the things I'm hearing here corresponds, at least as I understand it, to a very sort of natural evolution that we see in a lot of industries that use optimization. Namely, that they have gigantic problems that they would love to be able in some way to optimize globally, but they can't do that. They're too big. They're too complicated. So they decompose them into individual problems that they can handle, but as time goes on they get a better handle on those individual things, and they realize maybe the next step is to take two of them and put them together. And they benefit from that. I remember seeing this in the airline industry. They've been solving what's called a seat assignment problem for years, which is the assignment of airplane types to flights. And the input to that optimization used to be a given schedule. And at one point they realized, you know, we can do these fleet assignment models, maybe not perfectly, but very well, and clearly the schedule and the assignment interact with each other. Why don't we put those together into a single optimization model? That was a struggle. The initial models were intractable. But in the end they got tremendous benefits from doing that, and you get better quality solutions. You think you're getting the best possible solution by doing these things separately, but when you put them together there's synergies and things that you don't recognize when you decouple the computations. And they saw, I think, 20 percent improvements on the bottom line for that part of what they were doing. So I see, at least from one point of view, a real potential there, but it requires some effort and some patience with these models. That was my comment.

Moderator: I think everybody now has to go back to their advance mathematics text books and understand this, but seriously it's been a very interesting panel showing the way to the future.

Session Two.
Free Renewables and Electricity Markets: Can Renewables Thrive through Markets?

Advocates suggest that we can move fully to an electricity system with only renewable sources of energy. Many counter that it is virtually impossible because of the intermittent nature of wind and solar. Even with a solution for the intermittency problem, however, are there other inherent economic constraints on renewable penetration? Are free renewables, that have near zero short-run marginal costs, a special case that undermines the electricity market? Will subsidies be required in perpetuity, particularly if the value of the energy produced decreases faster than the cost as renewable capacity increases? Does high market penetration of renewables lead inexorably to declining marginal values, leading to rapid growth of subsidies? Are the social benefits associated with high penetration of renewables sufficient to justify the subsidies? Are subsidies best provided through mandatory financial arrangements rather than by a voluntary equilibrium of the market? Why is electricity market design important? With high renewables penetration, what are the implications for electricity market design?

Speaker 1.
I'm happy to be here and grateful for the invitation to join you today. I was struck by the title of this panel when I first saw it, and my immediate thought was, the best things in life may be free, but electricity is not one of them. And I think it's just good to call that out, in the sense that we may have episodes of zero or negative marginal cost in certain markets at certain times, but the ways in which those costs are recovered are much more complicated than that simple story would tell. So I would avoid, if I could, the word free. I think the question is really who pays and how do they pay, and, most importantly, what do they get for what they pay.

We were posed an interesting set of questions for this panel. I'm going to try to address most of them. The first question has to do with whether zero marginal cost resources, renewable resources, are a special case, and I would argue that, no, they're really not. At times throughout the last several decades (I've been involved in this industry for 30 years) we have had examples of zero cost resources time and time again, in a system with a high contribution of nuclear, such as the Electricite de France system. They often have zero cost periods. I lived through a period of time when I worked at the Wisconsin Public Service Commission where we had utilities that had take or pay fuel contracts. And those were treated as kind of capital items, and they were dispatched at zero cost, because they were stuck with the cost of that fuel, whether they burned it or not. I worked as a project developer for a subsidiary of Pacific Gas & Electric, and we had fixed cost fuel contracts associated with some of our projects, and so the dispatch cost for those was zero or near zero. I would argue, then, that this is not something that is uniquely related to variable intermittent renewables, but is a phenomenon that we have seen time and time again in the past.

What is interesting is what happens when you build up the contribution from any particular resource, what that zero cost phenomenon means. Oftentimes from renewable advocates we hear that the solution to the problem of meeting our electricity supply reliably and cost effectively is that we just need to double down on renewables. But what that means from a cost standpoint is that you wind up having twice as much electricity at times when you don't need it. And not very much more electricity at times when you do need it. So you actually exacerbate the low marginal cost problem by doubling down. The more you add, the more you are going to create this low cost or negative cost problem, and you can drive that to the point where those periods become very frequent.

I think the questions that we really need to answer are, so, in order to kind of keep the train going, would a market solution allow the continuing penetration of variable renewables without subsidies? And I would say the answer's no. The answer's no, because without the subsidies, the developers would very quickly realize that there is no way for them to get their money back, as these periods of low cost, negative cost, zero cost extend and get larger and larger. So, without subsidies, I think it's unlikely that we would continue to see growth in intermittent renewables.

Are the social benefits associated with high penetrations of renewables enough to justify paying these subsidies? As I think about the social benefits of renewables, I think that traditionally, they have been put into two boxes. One of them is an environmental box, and one of them is a sort of fuel substitution, fuel savings box. We like renewables because we don't have to depend on limited or expensive fuel. We like renewables because their environmental attributes are better than other resources. What I would say regarding environmental attributes is that if that's what we care about, then we ought to begin to price those environmental attributes into the market, rather than a priori selecting certain classes of resources that we believe to be better from that standpoint. So we see lots of states around the country with renewable portfolio standards, mandating a certain percentage of the resource mix to come from a class of renewables, defined kind of differently in each state, if you look around. If what those states really care about is carbon, for example, I would argue that it would be much better to build carbon into the price in the equation, rather than to favor a particular set of resources.

The last thing that I want to say is from an overall standpoint of sort of carbon mitigation is that we look at high degrees of carbon reduction. We've done a number of studies. We've looked at Germany, we've looked CAISO. We've looked at ERCOT. We have looked at Upper Midwestern Utilities. We find that as we push intermittent resources up to very high levels, the amount of carbon reduction that we're able to achieve tops out at about 70%. That is, it tops out at about 70% without some kind of almost unimaginable innovation and storage. Storage is a solution to some problem, but it is not likely the solution to these very, very large seasonal imbalances that we would see with 50, 60, 70% renewable portfolio standards. That seasonal problem is not about moving energy from today to tomorrow, but it's about storing energy in June against the periods in the winter, in the case of California, when the wind and the solar resource are down. We have no technologies extant that can begin to store the amount of surplus that we see in some of these things. So, that said, these high renewable scenarios seems to top out at about 70% reduction. So if we need to get to 100% reduction or 80% or 90% reduction, it's not going to do the job. We believe that there is a critical role for zero and low carbon baseload resources, and that if you think about the load as a layer cake, and you believe that the first couple of layers of that layer cake ought to be built with zero or low carbon dispatchable resources, and that the intermittent resources can then be built on top of that, we believe that that balanced system both yields better economics, and we believe that that system yields better carbon results.

Lastly, in terms of market design, and I think the discussion this morning leads to this very obviously, and this is a group that clearly gets this, but we think it's critical to include the things in the market that you really want. And so, if carbon reduction is a thing that you value, then include it explicitly in the market design, instead of adopting policies that are sort of proxies for that. So that, I think, is the last of the comments that I'll make.

Speaker 2.
Good afternoon. I slightly amended the title of the session to say can *low-carbon* resources thrive through markets, because to some extent, the idea that a resource has zero or extremely low short-run production cost is hardly something new, and it's also something that's quite common to a number of resources we're talking about, including, for instance, nuclear.

But there are also some pertinent issues that that bear on the question that are common to all of them.

So the quick answer is, sure, why not? Of course they can. In fact, I will argue, as you'll see momentarily, that I think the issue is not whether they can thrive through markets, but whether or not you get the markets right. But it's perhaps a little more complicated than that.

So this is a very conceptual presentation. It's one that comes from a little more of a European perspective, although I think it's applicable to a number of regions here in the US, perhaps not in ERCOT, but in many of the other regions. And it touches on a number of issues. It touches, first of all, on the fact that we're looking at markets almost everywhere in Europe, I would even argue everywhere in Europe, and most places in the US, that are actually currently substantially oversupplied with resources.

So what you see here is a graph that conceptually shows a mature 200 gigawatt system. The green bar is the pace of investment in low-carbon resources, whether it's renewables, nuclear, fossil with CCS, whatever you want to choose. That's the pace of investment in low-carbon resources that is implied by an objective that perhaps I don't share with everybody in the room, but that I think is rather self-evident, which is the need to substantially decarbonize the power system by sometime around 2030 if we're to achieve our current energy objectives. So there's a pace of investment that needs to take place in low-carbon resources if you want to have any chance of doing that.

The red bar is the incremental amount of capacity resources that the system needs. And as you can see, for some time there's actually a need for disinvestment, a need for retirement of stranded assets or assets that are the walking dead. They're stranded, but they don't know it yet. And the black is the consequences of those two bars added together for the balance of, shall we call them, non-low-carbon resources. And so, what you see is actually a period during which, I don't care what your market design is, there's no market in the world that's worthy of the name that's going to attract the investment in low-carbon resources that is projected in order to achieve our larger policy objectives.

So there's a period, and I'm calling it the transition period, during which the question of investment in low-carbon resources is not in the first instance a market question. It is a market question in this sense, that the decision to invest in low-carbon resources should be seen as something that forms part of the envelope within which markets need to work effectively. There's some point in the future, probably beyond the scope of any useful discussion of market design (and I say "useful" because it takes place in the absence of or in the place of what we don't know about technology context, about political context, about resource context 15 to 20 years from now), but there's a period of time at which we perhaps will see, taking all things into consideration, a net incremental need that an effective market would drive in net new capacity resources. That doesn't mean to say that there isn't investment that needs to take place in the meantime that can and should be market driven. That gets to the question of how the turnover in conventional or dispatchable resources takes place during this period. But, broadly speaking, the question of low carbon investment, during this transition period, whatever it is, is fundamentally not a market question. It's a policy question.

So this slide just further illustrates the point. This is actually an image from a study that I led five years ago, called the Roadmap 2050 Project in Europe. And this is a particularly severe example. It illustrates the 80% renewables case. We looked at 40%, 60%, and 80%. In this case, it's 80% renewables, 10% nuclear, 10% fossil with CCS. I'll talk in a moment about the 60% case, which is the one we sort of ended up focusing on. This is a somewhat extreme, but only a slightly extreme, depiction of what we're talking about here. I mean, we are talking about a substantial turnover in power system assets over the next 15 to 20 to 25 years. Substantial. And that is not a transition that is going to be driven by the market. It's going to be by policy.

So the conclusion, therefore, that I'm suggesting is that low carbon investment decisions during the transition period cannot and will not be driven by the market.

But that's a very different question than asking can they and should they increasingly adapt to or assimilate into market conditions once they are built. And I think the answer there is clearly yes. Locational pricing signals, imbalance responsibility, real time price exposure, economic curtailment in real time, and we got into this this morning, so I won't talk about it, but for distributed resources like rooftop solar or even commercial ground based solar, volume based, real time tariff structures in order to incentivize the right operational behavior. I mean, I think it almost goes without saying that of course, these things taken together will probably add to the costs or the all-in costs of owning and operating intermittent renewable resources. They will probably add to the cost of owning and operating inflexible baseload resources like nuclear. And that's tough. That's life. It doesn't make any sense to put it differently. If we accept that we're going to have to support upfront investment decisions in low-carbon resources over the next 15 to 20 years, we should also be willing to accept that that support, for the sake of the rational operation of the overall system, should not be delivered through special treatment of these resources once they're on the system. There are other ways to support them, and I would argue that they are far more suitable, as we go forward, especially since, at this point, some of these resources have become quite mature technologically.

This is the piece where the efficiency or the effectiveness of the market becomes incredibly important. Because, of course, the market signals, and not just the market signals, but everything in the rest of the system should be screaming, "More flexibility!" And what this slide shows (this is from the IEA's power transformation report that was issued last year) is two systems. Both of them have the same amount of renewables as a percentage of the annual energy production. The top one is a system where, alongside of those, you have a very sort of a traditional legacy mix of conventional resources with a lot of baseloads and a very small amount of peak. And the bottom one is one where, with the same amount of total demand, you have a transition to a system with a smaller amount of baseload, a larger amount of merit, and, again, a small amount of peak. And you can see the differences in the utilization rates of the different resources. That's sort of striking, I think, in one sense. But it really means, if you translate it into upfront capital cost, that the cost of building the system at the bottom is up to 40% less in capital costs than the cost of building the system from the top, because you're getting resources of higher utilization, and you're actually getting a mix of resources that is less capital intensive as well. And this is a job that the market can do and should do, if it's working effectively.

The market should also work in a way that it accesses all viable sources of responsiveness to the efficient needs of the system. And these are, to some extent, interchangeable. There's investment in grids. There's investment in interconnectors. That's a more European term. There's how you operate the market geographically, and the market rules that you use, whether it's a fast market or a slow market. Is gate closure time an hour ahead of real time or five minutes ahead of real time? There's demand participation, electricity storage (to a much, much smaller extent--we're not big buyers on electricity storage, at least just yet). And so on and so forth.

We also think that, and this again reflects, to some extent, the environment I'm steeped in at the moment in Europe, where you could attend a conference where people scream at each other about capacity markets pretty much every day these days in Brussels. And we think that not just from a market efficiency perspective, but also from a decarbonization perspective, forward capacity markets are antithetical to an efficient transition. And what you see here is data. On the left is weekly average prices, price formation in three markets with, we would argue, relatively effective scarcity pricing, or effective price formation in the energy reserves markets. And on the right, three markets that are starting to do a little bit better, but to varying degrees have used forward capacity markets as an excuse not to fix what's wrong with their energy reserves markets. The difference, what you're seeing there is that the difference in one context is that the value of flexibility comes close to being fully expressed on the left. It just disappears on the right.

And so I've been spending a lot of time lately taking a Bill Hogan idea and running around Europe and repackaging it in a way you probably won't like. But we're referring to it as a climate friendly capacity remuneration mechanism, which is a reserve shortage pricing instrument. And if we had two hours to talk about it, I have a number of arguments why it is, in essence, a capacity mechanism that simply operates four hours ahead of time instead of three years ahead of time. But in many other respects, it operates exactly the same. And if we're going to intervene in markets to make sure that the investment in capacity that's needed actually comes forward in order to meet resource adequacy targets, this mechanism is the way it's got to work.

So, just quickly, to wrap it up, I find this a very interesting example. This is the Nordic market. This is Nord Pool generation in 2013. 65% of the annual energy came from resources with zero marginal cost production. Another 23% came from resources with less than 10 Euros per megawatt hour marginal cost production. So 88% of the energy production in Nord Pool, in 2013, came from resources with marginal cost production of less than 10 Euros a megawatt hour. And 2013 was a very typical year. That's the way the Nord Pool market is. Only 12% came from resources with significant short-term marginal cost. And yet, what was the average market price in Nord Pool that year? 35 Euros and 74 cents a megawatt hour. So there's this myth, and it's particularly powerful in Europe, that energy markets don't work, and we need these big forward interventions, because energy markets price energy at the short run marginal cost of production. Well, you could have a theoretical argument till the cows come home, or you could just look at Nord Pool. Clearly, that's not the case.

And when we look at a balanced decarbonized system or diversified decarbonized system, on the right, you see the 60% case, which we've always said is, from a risk management perspective, clearly the best case. It's the case that is easily the most diversified of the three cases. 40% renewables, 60% renewables, and 80% renewables. So on the right is the 2030 to 2050 95% decarbonized, 60% renewables case. And on the left is Nord Pool. Clearly, we're not entirely in uncharted territory here.

We've faced these problems before. We're facing them today in some markets. There are ways to deal with it. The market is going to play an absolutely critical role, and it needs to more and more dictate how low-carbon resources, whether they're renewables or nuclear or whatever, play in the market. But the question of continuing to invest in those resources really needs to be seen as something that is outside of market design, at least for today. It's a policy-driven decision.

Question: Just quickly, in the Nord Pool example, if you have all that zero to pretty low short run marginal cost production, why didn't it crash the energy prices? Was there an element in the design of the market that allowed the fossil generation to set the price for everybody, or am I missing something?

Speaker 2: Well, they co-optimize reserves in energy. It incorporates the hour by hour opportunity cost of generating energy, as opposed to providing reserves to the system. And that's not a particularly volatile system. And a system with much more volatility would see an even higher average price, most likely.

Question: What were your capacity reserves during the period that you looked at?

Speaker 2: Well, in the 60% case, I couldn't give you a percent number, but we we did a full unit commitment in scheduling the dispatch model. It didn't get into issues like inertia, and I think there was a question about whether there are economic limits, and I think there probably are, on the penetration of renewables today. There may not be by the time we get to 2030, depending on what happens with technology. But sitting here today, there are. And we shouldn't plan on the assumption that there aren't. However, if I had to bet, I would say that the binding constraint on penetration of renewables, which will probably continue to be the case in 2030, is system inertia. So, anyway, we didn't look at inertia. But we maintained a system reserve level and an hourly reserve position in that model across Europe that would deliver the current loss of load expectation on the system. So it was 12 to 15% system reserves.

Question: So you think Nord Pool probably has only 12 to 15% installed capacity in excess?

Speaker 2: Oh, no. I think Nord Pool's probably closer to 20%.

Speaker 3.

I'm, of course, delighted to be here. It's a great privilege to be addressing this audience.

So we know renewables are coming to the market. I don't know about the US, but in Germany, renewable energy is very important. Just to give you an order of magnitude, the price of power right now on the wholesale market is 30 Euros per megawatt hour. So $35 a megawatt hour, or whatever. Every retail customer in Germany pays 60 Euros per megawatt hour for the subsidies to renewable energy. The subsidy to renewable energy is double the wholesale price of power. So in Europe, renewable energy is important. It's important in terms of its role on the wholesale market. It has moved the supply curve, but it's also important for customers.

So what we tried to do is two things. The first thing is, we tried to write out the equations of what happens when you plunk renewables into the market. There have been lots of studies, and you were alluding to some. There have been great studies by the Lawrence Berkeley Laboratory in the US, where you actually add renewables into the power markets, and you compute the outcome for many, many scenarios and you say, "Oh, this is what happens and this is what we see." What we tried to do in our model is actually to write down the equations. So we make a few simplifying assumptions to be able to write the equations, but, as usual, once you have equations, you understand better what happens. You understand better the economics. You can do comparative studies, all that good stuff. So that's what we did, and I was perfectly happy being the first guy that worked out the math, so I was happy. And my co-author, who's British, who's more pragmatic, said, "No, no, no. Now we need to test those equations on the power system in the UK." They have a big renewables program, a big windmill program. They want to build 60 gigawatts of wind in the UK. So my co-author had all the data. He had data on wind penetration. He had data on a lot of factors. And he said, "OK, let's just do that for Great Britain."

So what are the outcomes? The first outcome of the study is that in fact, in the UK, the more renewables you add, the less economic the baseload is. So, in other words, in the UK, the renewables (essentially wind) are pushing out nuclear. There is a substitution between wind and nuclear. And the model, when you start playing with it, explains to you why that is the case. I do not believe it will be the case in other countries. I think that in the US, it will be different, but in the UK, very clearly, the more wind you have, the less nuclear you get. And that's a problem, because if you want to have a low carbon economy, and you want to have a low carbon nuclear baseload, well, the more renewables you put on it, the less thick that baseload slice becomes.

The second outcome is that the renewable subsidies are not going away. You had a question about a transition phase. The premise of subsiding renewables is as follows. The cost of renewable is going down. The more you build, the less it costs. So you're going to subsidize the first unit, knowing that the second one will be cheaper, and then you subsidize the second one, and the third one will be cheaper, all the way down to the point where actually the cost is so low that now it matches the market value. When you do the math, you realize the market value of renewables is going down in general, and therefore you have a race between the cost going down and the market value going down. And what we find in the case of the UK was that the cost was not going down fast enough, and you still need to subsidize that forever.

That doesn't mean you shouldn't do it. There may be some security reasons why you want to do that, maybe some good arguments why you want to do that. But the economics suggest that you will never get away from a subsidy.

So how do we analyze this problem? So, this slide shows a demand function. I guess in Texas, this low demand portion would be in the winter, or an afternoon when there's not that much consumption, and the high one would be in the summer, in the evening where everybody has their AC on. So demand is downward sloping on the X axis (the quantities), and the price is on the Y axis. The more expensive it is, the less you consume, and demand rises across the states of the world.

For demand like that, we know what the optimal generation mix should be. This is something we've known since 1949. The first paper was in 1949. A French guy, actually, who solved that problem cleanly. This stairstep line is a supply curve. So this is the marginal cost of the different technologies. Nuclear, and combined cycle gas turbine, and open cycle gas turbine. The price is set by the marginal cost here. When you get here, the price is set by the marginal cost. And then, we understand why the price rises here, because you need to cover the capital cost of those units. So, to your point, the price is not set by short term marginal cost. No, it's not. Because if it was set by short term marginal cost, people would not make money. So you need somehow some money to be had, and you have that in those hours. And that's the entire capacity, and that's the split between the different gas technologies, and I'm assuming that nuclear is inflexible. You want to run your nuclear all the time. So that's the old model.

Now, when you have renewables, what happens? Well, when you have renewable, you move your demand curve to the left. And it's not a symmetric shift. In some hours, there's a lot of wind, so you move a lot. Some hours, there's little wind, therefore, you move less. So once you move your demand, your supply adjusts. Because if you don't, you have over supply, and that's exactly what your chart was showing was over supply in Europe, so they lost money, so they shut down their power plants. And you have a tax to finance that. So that's what we saw. We ask ourselves, we have renewables progressing into the system. Let's solve the equations and find out what's going to be the impact on the generation mix, and what's going to be the impact on the subsidies.

So we did that, and we have a nice equation. So I put in an equation just to show you that we actually solved it. I'm going to explain it another way easily, but I just wanted to convince you it's real. We have an equation. The second thing which is pretty neat is that the equation is fairly simple. You don't need to be an operations research specialist to understand the equation. I would never understand a word. I would never understand the problems you were explaining this morning, but this means I can figure out.

So, what happens to the capacity of technology N, when you increase a renewable technology, I? Two things happen. The first thing is that, as you increase renewables, you need to subsidize a bit more. So if you increase the subsidy, people pay more for power; therefore, they demand less. So the first thing is kind of the tax effect of the renewable. And the second thing is the substitution. If you put more wind on the system, the wind is going to blow, so there'll be less need for other technologies. And the more you have wind, the less you will need other technologies, because you have the energy produced by the wind. And this is what this expectation of the availability of wind on the vertical segment captures.

So this is the result of the analysis in terms of what happens in the UK. So, we increase the wind capacity from zero to 60 GW. This is the plan from the British government. They say, we want to have 60 gigawatts of wind production on our system. And on the vertical axis we show the total capacity on the system. So, as we increase the wind, you see that the nuclear is going down. And that's the first effect I was describing to you. The wind is simply pushing out the nuclear. The CCGT growing a little bit. The open cycle is growing slightly, and of course, the wind is going up. So that's what we see.

Now, why do we see that? Think about a system when you have two states of demand, high and low. High's 100, low is 50. You have two periods, high demand of 100, low is 50. So you're going to set up your system where the baseload technology's going to produce 50, and the peaking technology is producing the other 50. In the UK, you have layer at 50 and another layer at 50. Now, if you add wind, as you do in the UK, and the wind blows all the time (at least it blows similarly on peak and off peak), so let's say the wind blows at 30. So now your peak demand is 70, 100 minus 30. Your off peak demand is 20, 50 minus 30. So your baseload is only 20, because you have only 20 off peak demand, so your baseload capacity's only 20, but your on peak capacity remains 70 minus 20, 50. So that's exactly what you see here. You're pushing the nukes out, because the wind in the UK is blowing the same way on peak and off peak. That doesn't mean it's blowing all the time. It is blowing equally when demand is high and when demand is low. So that pushes out the nuclear. Now, for the UK, it's a big problem. It's a big problem, because they are subsidizing the nuclear power plants. They're offering contracts for different nuclear power plants, and they're subsidizing them. And they're subsidizing the wind. So the more they subsidize the wind, the more costly the subsidy for the nuclear is. So that's a bad policy decision for the UK.

In the US, I think there will be a difference. Because, if I understand correctly, in some systems in the US, the solar production is highly connected to demand. So the demand is high, but solar production is high. So here what's going to happen is that the renewables are going to substitute for the peaking units. Because, again, if you do the same process, you reduce your peak demand, you don't push too much your off peak demand, so your baseload remains constant, and what moves out is your peak capacity. So you won't have a problem in those systems with the baseload, but you will have a problem with peaking capacity. And you will have the problem of flexibility you were alluding to and a ramp up and a ramp down rate, and all that good stuff.

Some guys did an analysis of the European power system, and they found that we didn't have any stability problem if we increased the wind penetration to 30 or 40%. So they confirmed numerically by doing the detailed commitment problem, the kind of findings we had. OK, so that's the first result. We can trace what will happen to the mix in the future.

A second observation. When you add one technology, what happens to the value of another? So, let's think about onshore wind and offshore wind. So if I have onshore wind, it's going to reduce the value of offshore wind proportionate to the covariance of the availability of onshore and offshore. So, again, I was kind of pleased that it was such a simple result. I was expecting some nasty stuff. But covariance is pretty straightforward. So what does it mean? It means that if the onshore wind is blowing at the same time as the offshore wind, adding the offshore is going to reduce the value of the onshore. But if you have two technologies, like sun and wind, and if the wind is blowing at night while the sun is shining during the day, in fact, increasing the capacity of wind is going to increase the value of the sun. So you get different results that you wouldn't have otherwise expected.

What else? This is a graph of the value of the onshore wind and the offshore wind. They are fairly correlated, so they go down, both of them together. And you see that they go down as you increase the capacity of wind, and here it gets crazy, because you lose nuclear and then it gets completely crazy. But you see that it goes down nicely. Now, the question is, does it go down faster or less fast than the cost? So, the cost is going down, right? This is the traditional learning curve. The value of renewable energy is going down, too. In that example, the cost is going down faster than the value of renewables. At this point, you stop subsidizing, right?

There could be another case where those curves never meet, and the cost is always higher than the value of the renewable, so you keep subsidizing, and at some point, the subsidy even increases. In the UK, with the numbers we had, we found ourselves in the second case. So that's for offshore wind. Offshore wind, the subsidy goes down because the costs are reduced a lot. This is very early-stage technology. So as you increase offshore wind, the cost is going down, and then it gets crazy when you lose the nukes. But for the onshore wind, there's not that much in the way of economies of scale, because already the technology's fairly mature, and the subsidy keeps going up. So, again, it doesn't mean you should stop subsidizing renewables. It just means that, and that's the point you were making, the market will not take care of that by itself. You have to somehow subsidize. And if you want to subsidize, you've got to understand that this thing may last longer than you expected.

With respect to the cumulative subsidy, the interesting thing is that when you increase renewable energy, you reduce the value of the last unit, but you reduce the value of all of the infra- marginal units. So increasing a subsidy is not only this little bit, but it's also that bit. So when you add more windmills, you increase the subsidy you should give to the other ones. And when you do the math, you see that the subsidy goes up to about 20£ per megawatt hour in the UK.

So one final thing, the solution. The solution is, I think, that instead of giving physical priority to the wind, instead of letting them run all the time, one solution is to tell them, "Look, we're going to have to shut you down at some points. When price goes to zero, we shut you down. Because there's no point having negative prices. It's not efficient. So we shut you down. Even if we still pay you so that you don't complain, if we still pay you for the megawatt hours you could have produced, it is much better for society than just having you run and get negative prices." And that's the math behind the story.

Question: I have a clarifying point. Actually, in the US, peak solar is not coincident with demand. It's almost always the opposite, actually. Sometimes it hits the shoulder, but almost never hits peak demand.

Speaker 3: I thought, naively, that it was, OK, thank you.

Question: I have a clarifying question about the intuition behind renewables pushing the nuclear out. This is like a long-term view? In the short term, there would be minimum generation conditions. They would just push out something else, because the nuke is going to stick around. In the long run, the economics of nuclear deteriorates.

Speaker 3: Exactly. I'm sorry, I should have been clear. It's the long run, because if you do not cover your marginal costs, your capital costs, at some point, you have no way to exist. And in Europe, I think we have retired 40 gigawatts of capacity over the last few years. That was just economical.

Speaker 4.

I am in the fortunate position of being a generalist in a room full of experts, and agreeing with basically everything that everyone on my panel has already said. So I will try and move through my comments really quickly.

So just to start, this is the big global picture. This is wind and solar as a percentage of total electricity generated on the planet. So, as we can see, wind and solar are still small bit players. Wind in 2014 was about three percent of global electricity generation, solar was about 0.7%. So if we're talking about global decarbonization, we still have a long way to go. But variable renewable energy sources, wind and solar in particular, have made much bigger strides in certain jurisdictions around the world, which we hear about a lot. We think Denmark. We think Germany. We think Spain. We think certain states in the US like Colorado, Iowa, Texas most certainly. Those are all political boundaries, not grid boundaries.

So what I want to look at today is the grid boundary. What are wind and solar doing when they're setting records on grids around the world? So, the American Wind Energy Association, AWEA, has celebrated Iowa in particular, among other states. And in 2014, AWEA celebrated the fact that Iowa generated 28.5% of its electricity from wind. Of course, we know that Iowa is connected to the MISO market, which itself generated 5.7% from wind, and MISO is connected to the PJM market, which is 3.7%. So this just illustrates the big variability in what penetration we're talking about, depending on where we draw the boundaries.

Denmark is another example. The blog, Climate Progress, this year celebrated that in 2014 Denmark generated 39.1% of its electricity from wind. This is a couple graphs that I made illustrating the electricity mix in the Nordic synchronized area, that's Denmark, Germany, Norway and Sweden. Across that whole system, not that it's all one huge homogenous system, but across the whole system, it's about eight percent, not 40%, wind. Denmark is also a member of Nord Pool Spot which includes Denmark, Norway, Sweden, Lithuania, Estonia, and Finland, and in that, wind is about four percent. And I bring this up not to denigrate wind or to belittle its impact and the penetration and the strides that it's made so far, but just so we're very clear what penetration we're talking about, and what we're talking about in reality.

So, again, we hear a lot about Germany, we hear a lot about Denmark. Where are the countries and regions and grids around the world that are really setting records? So we see in the Eastern Interconnect, wind is is about three percent. In the Nord Pool spot, which is the next bar, it's about four percent. In Texas, where we are now, is about 10%, and, as we saw earlier, it's a pretty isolated grid. The next two are Spain and Portugal. The Iberian Peninsula turns out to have remarkably high penetrations of renewables, particularly wind, but also higher solar than most other jurisdictions around the world. I'm not sure why we talk more about Denmark and Germany than we do about Spain and Portugal, but we do. And then, the red bar is where we want to go with zero carbon.

As we all said, we want to get zero carbon as soon as possible, whether that's by 2030, 2050, or 2100. So the question is, can we get there from where we are today?

So I'll continue this conversation with an exploration of Germany. This is a headline from *The Week*, which is a publication in the United States. It says that Germany gets 50% of its electricity from solar for the first time. This particular reporter reported that without a whole lot of qualification, or explanation of what that sentence means. In this particular case, Germany generated about 50% of its electricity for one sunny afternoon on a national holiday in Germany sometime last year. Over the course of the whole year, Germany generated about five percent of its electricity from solar. Again, not to denigrate solar, but just to illustrate the numbers that we're working with here.

So this actually illustrates the dynamic that I really want to focus my comments on today, which is the difference between peak generation of variable renewables and annual generation. So in Germany last year, 2014, solar generated about five percent of total electricity over the year. But as *The Week* headline showed, peak generation of variable solar was about 50%. So with a very simple mental model, that tells you what happens when Germany goes to 10% solar one year in Germany. Sometimes they'll be generating close to or over 100% of load. And for an extreme case, if German PV were 50% of annual generation, then sometimes they'll be generating 500% of load, which is obviously a situation that would never arise.

So what do we do about this? What do we think about this? And it turns that the capacity factor, the actual generation of solar in Germany divided over the rate of capacity of the panels installed, is about 10 to 11%. And that led my colleague and I to postulate this very simplified heuristic rule of thumb, the capacity factor threshold, which states that it's increasingly difficult for the market share of variable renewable energy sources, wind and solar, at the system-wide level to exceed the capacity factor of the energy resource. So if the capacity factor of solar PV in Germany is 10%, then once you get to 10% penetration on the year, then occasionally you'll be having solar meeting all of load, occasionally be having solar meeting zero percent of load (obviously every night), and you'll have these huge swings, resulting in a non-linear increase in costs or decrease in the capacity value of the resource to the grid.

So why does this happen? Again, I'm talking to a roomful of experts, so I'll move through this quickly, and my co-panelists have already addressed much of it. The first is the merit order effect as variable renewable energy resources increase their penetration and they displace resources on the grid that are of lower cost, thereby lowering the capacity value or the value factor of variable renewable energy. And as we get to higher levels of penetration, approaching 10% solar in Germany, or approaching the capacity factor threshold for technologies like wind in Spain (for which capacity factor is usually much higher, 20 to 40%, depending on the jurisdiction), then what we will start to have to mitigate these high levels of penetration. We've heard a lot of solutions for mitigating this, and oftentimes it can be done at very low cost or even with some kind of system wide benefit, but there is a declining value factor to wind and solar that we've seen. And just to give you a couple sources, this is a study done in 2012 by Mark Mills and Ryan Weiser at the

National Renewable Energy Laboratory at Lawrence Berkeley Labs, that shows the value factor of wind in different models that they used. This is similar work done by Leon Hurth, who works at a think tank called Neon in Germany, who used both modeling and real world data to track the value factor of wind and solar as they increase their penetration on the grid. And we see a similar shaped curve in the very recent MIT *Future of Solar* study that they published earlier this summer.

So this is, I think, an increasingly accepted finding of the technical literature around variable renewable energy. What my colleague and I tried to do was put this in sort of clearer conceptual terms. This is why we tried to coin this capacity factor rule of thumb, which I think gives us, and hopefully you all, a helpful way to talk about this in the most, maybe simplified and simple, but helpful, terms possible.

So what are the conclusions? Wind and solar will be economically constrained below their capacity factor thresholds. There are constraints to variable renewables, wind and solar, that can be mitigated through storage, demand response, ancillary services, markets, things like that. These are all mechanisms that can help mitigate the limitations, but the limitations do exist and we have to think about how to mitigate them. And most importantly, I think we have to address how these limitations interact with the other zero carbon dispatchable and baseload sources that we want on the grid to complement wind and solar. And that's going to be nuclear. It could be fossil with CCS. Obviously, you have other renewable energy sources like hydroelectric, bioenergy, all of which have their pros and cons in and outside of market design. And so, we really do have to think about not just the unit costs of wind and solar, which are obviously going down, not just the cost of building a power plant, which, in the case of particularly nuclear, is proving exceedingly difficult in the developed world, in the US and in Europe. We have to think about the system cost of a fully, or very close to fully, decarbonized electricity system, and we have to think about how all these pieces fit together. So those are my slides. Thank you.

Question: You went over quite quickly the comment on your last slide, where you talk about storage being no panacea. Can you just explain what you mean by that?

Speaker 4: Right. So there are a couple different techniques, technologies, and mechanisms that you can use to fix or mitigate or exceed the capacity factor threshold. Storage is one of them. If you have over generation, which will happen once you get to high penetrations, then storage is one way to tap that over generation and arbitrage and sell it later. But storage has a cost, as will demand response in many circumstances. Obviously, curtailment has an economic cost in terms of lost economic value of the resource. One solution is what my co-panelist Speaker 3 was talking about. Other solutions certainly exist. I think that for the most part, they're still not well understand by the academic and theoretical community, let alone by regulators. But the solutions to these problems are not particularly well understand yet, and we don't know which technologies, techniques, mechanisms are going to be the best ones to help mitigate the value factor loss of variable renewables. We don't yet know how to optimize fitting these puzzle pieces together. I would just say that the reason I have this bullet point is that I've talked about this a fair bit in the few months since my colleague and I have been talking about this capacity factor rule of thumb, and often I am met with the comment that storage is going to solve the capacity factor threshold problem, and I think that's overstating it. Does that make sense?

Question: Yes, but just to be clear, then, is your argument more economic than operational, or is it a bit of both? Is your argument more that based on current economics, storage is no panacea?

Speaker 4: Yeah, my argument in general here is more economic. We could get in to a conversation about operations.

General Discussion.

Speaker 2: Just to clarify, the problem you're talking about, the problem of declining value, is essentially negative prices. I mean the main driver, when you start doing the math, is you get into negative prices when demand is very low. So you have more wind production than you have demand, so the only way you can sort that out is by having negative prices, as we saw this morning. And in that case, demand response cannot do anything for you. What demand response works is precisely on the complete opposite. When demand is very, very high, you have very, very high prices and demand response helps you sort out the peak. What drives the declining value is the opposite of the peak. It's actually the anti-peak, in a way. And then, there are operational issues. That was just the economics.

Speaker 2: Well, I'm going to respectfully slightly disagree. When you say no panacea, I agree with Speaker 4 in principle. It depends on what level of penetration you're talking about. At the current levels of penetration, it's just not an issue. There's not a system in the world that has that issue at a system level. But at a moderate level, sort of 10, 15, 20% of system penetration by intermittent renewables, there are probably ways in which storage is a "panacea." It's a big part of the solution, and it doesn't have to be battery storage.

And part of that is in the demand side. There's a lot of potential for temporal shifting of excess energy production using thermal storage technologies. In fact, there are systems that do it today. I mean, Denmark does it with district heating systems. There are coops in the Midwest that give away free storage electric water heaters and use them to manage their system peaks. I mean, there are ways to manage it, up to certain levels of penetration.

It's when you get to the really high levels of penetration that it becomes, at the moment, technically, an unsolvable or economically difficult problem to solve because of the cost of battery storage and other technologies you have to start getting into once you work your way through the cheap options. It also becomes technically a very, very difficult problem to solve that storage doesn't help you with, because of the inertia issue. There, you're not trying to solve the problem of over generation or generation shortages. You're actually trying to solve the problem of having too much asynchronous generation on the system and not enough inertia to maintain stability. But also, the other problem that storage has at very, very high levels of penetration is that there are seasonal transfers of over generation. At the moment, the only way we have of doing that technically is through pump storage hydro. And even if you could do that everywhere, and you can't, because there are just physical constraints on where it's feasible and where it's not, it's also not cheap. So, again, it all comes back to what level of penetration you're talking about.

Question 1: I want to understand the definition of baseload. I think there are two definitions that are commonly used. One of them is low operating cost, high capital cost, typically. And the other one is inflexible, preferring to run continuously, 24/7. I much prefer the first definition, because I think it's a much more economically sensible one, but the effect of renewables on the net load curve is to significantly reduce the need for baseload, as Speaker 3 implied, perhaps to zero. Nevertheless, there are other panelists who seem to think that there is still a need for baseload, and I'd like to understand the continuing love affair with baseload, as opposed to flexible resources, because it seems to me that with the renewables, we're not going to need any more baseload. What we need is more flexible resources to deal with the variability. And I just don't get why there's a continuing enamorment with baseload that seems entirely superfluous.

Speaker 1: I'll give you my answer to the question. Of your two competing definitions, I don't care which. From my standpoint, it's kind of immaterial. But if you think about the layer cake, and you think about the decarbonization problem, and you think about typical capacity factors--let's just restrict the discussion to nuclear for the moment. Let's say we have a 95% capacity factor resource. You solidly fill in that layer. The only reason renewable energy displaces nuclear is because we have a convention that allows that to happen. That's all that is. That's an economic system operation convention. We say the renewable resources are first in the dispatch deck. There's no reason that has to be. You could just as easily say we're going to dispatch the renewable after the nuclear has been dispatched. So I just make that point.

Build a system that relies heavily on intermittent renewables, and you have a lot of interstices in that layer cake that you have to fill. From a decarbonization standpoint, we don't have good options for how we fill that layer cake with a zero carbon option. Right now we're doing it with NGCC, and, in fact, in all the modeling that I've done, I've used NGCC as a proxy, and I realize what I should really be doing is using simple cycle gas turbines, because you wind up creating a system that is entirely populated by low capacity factor resources. The entire system is made up of low capacity factor resources, and the flexible ones that we have today can't be easily decarbonized. We're very interested in figuring out what are options. Hydrogen is one option. We're actually spending a lot of time looking at ammonia as a possible zero carbon fuel for dealing with that. So our sense is that the decarbonization job is easier if you can build that big fat layer of unvarying generation. We also think the economics work better.

Speaker 3: I'd just like to react to that, because of two things. First, the two definitions are equivalent. If you have a technology that has high fixed cost and low variable cost, economically, you want to run it all the time. So one definition implies the other. So baseload, which is high fixed cost, low variable cost, economically should run all the time. Point one. And the second point, is that wind is zero variable cost. So, again, from a pure economic perspective, as long as the price of power is positive, you should run wind as a priority because it has zero variable cost.

Except for the cases you mentioned, where for some reason, the opportunity cost of producing power using gas, because you already bought the gas or something like that, was zero, except for those cases, you should, in the merit order, run the wind at priority because it's zero variable cost.

And the last point I made about the baseload, and I'm sorry I was not very clear, is that you do not choose your mix. It's the correlation between demand and your production of renewable energy that drives the economics that determines your mix. So in Europe, the way the correlation works out, the economics of it, the way the prices shake out, it moves out the baseload. I was thinking that in America, it may be different, but based on what you say, it actually may be pushing out the baseloads. What I'm trying to say is that there are economic forces at play. Politically, you may decide not to follow the economics. It's a free country, you can do it. But the economic forces drive the composition of your mix, is what I'm saying.

Speaker 2: I'm going to play my old power systems engineering card. The high capital cost and very, very low marginal cost resources, traditionally, are referred to as "must run" generation. Baseload generation is generation that economically and technically doesn't like to cycle. Those are kind of the two basic differences.

But anyways, I havbe a slight variation on Speaker 1's response. To me, it is a risk diversification, risk management decision. I would much prefer, cards on the table, that renewables and load following resource world. Because I think it's going to be socially, technically, and economically very difficult to have a significant buildout of new nuclear. I mean, I think that's just the political reality. But that's a high-wire act, because at the moment, we don't have a technically and economically viable solution for a very, very low carbon, very flexible, load following fossil resource. Gas fired CCGTs with CCS are just beyond the horizon right now.

The fact is, with respect to storage technologies, whatever. We don't even know how to store all that stuff just yet. So I just look at developing some sort of very low or zero carbon baseload option as a smart policy risk diversification bet. I don't think there's room for a lot of it in a decarbonized system. I think it doesn't make sense to have it as much more than 15, 20%. But I think it makes sense to plan on the assumption that we probably should have between 10 and 20% of it somewhere.

Speaker 1: I just want to make one more comment, because I think it's easy to confuse accounting and engineering. So, for example, we say wind has no variable operating cost. Well, that's not true. Any piece of machinery that has moving parts has variable operating costs. They're just low. The thing about nuclear is that for a long time in the United States, and still in a lot of jurisdictions in the United States, we treat the fuel in the nuclear power plant as a capital asset. We don't treat it as a variable cost. It's a capital asset. That's an accounting convention. That's not an engineering reality. And so, if you count it as a capital asset, because those fuel assemblies are long-lived, variable operating costs of a nuclear plant looks an awful lot like the variable operating cost of wind.

Question 2: I would like to make a comment on Speaker 3's presentation and Speaker 4's to some extent. I appreciate very much your analysis, but it holds for a very (just to be a little bit controversial, so you can have a lively discussion here) old fashioned and unrealistic model of demand. Demand and responsive demand should not be seen as a myopic price elasticity. The way that we are moving forward and the way that loads and demand changes is to have a higher and higher presentation of demand which is time shiftable and whose response has to do with the ability to move around.

And storage is not the only way to deal with the volatility and the non-dispatchability of renewables, but storage-like loads may be. For example, we see almost every major car manufacturer introducing a plug-in hybrid vehicle and electric vehicles. Of course, nobody knows that this will be the case, but it's quite likely that 20 or 30% of increased demand will be absorbed by electric vehicles, if that's the option that we go forward with. Then, the picture is quite different. Then, distributed energy resources are not for sure not a panacea (that is, we can't be sure they are not a panacea.) They may not be a panacea. "May" I will accept, but not sort of a foregone conclusion that they are not, the way you present it. And then, the analysis that we saw very nicely with your co-author, whose work and yours I follow and I appreciate very much, is based on this sort of myopic, non-time shifting demand functions.

Speaker 3: You're right. How can I put that? The way we modeled it is assuming that, indeed, the demand for every hour does not depend on the demand for another hour, that you cannot shift demand across states of the world. And we did that because it felt like the reality of today, but I completely agree with you that over time, as the ability to shift demand develops…but we have to be very clear. I'm not consuming today. I'm shutting down my plant today at 4:00 because the price of power is high, so that I turn on my plant at 10:00 at night or tomorrow or next week. So that ability to shift consumption across periods will be there in 20 years, and that will change the economics. But as of today, we felt that the first order approximation that that kind of shifting is small today sounds reasonable. It's not perfect. It's not forward looking, but it didn't sound like an egregious oversight to make. We can disagree on that, by the way.

Questioner: I absolutely agree, but we are looking at renewables in the next five or 10 years, so, therefore, we should be looking at the way demand evolves.

Speaker 2: I'm going to throw my hat in with you. I think, clearly, there's a lot of storage-like demand responsiveness that will it take us a long time to access for some of the reasons we talked about this morning. But we're still at very low levels of penetration, and it's going to take us quite a few years to get the levels of penetration where we eat through the potential we already have. And just as an example, the installed base in the Southeastern US of electric water heaters, if you add commercial hot water storage systems to the installed base electric water heaters, that would levelize or would manage the production from something like 45 to 55 gigawatts of solar. And that would cost about $50 to $100 per household to do that. Could you do that overnight? No. And do we have to go out and convince millions of people to switch from gas fired or propane fired water heaters? No.

So there's a lot of potential to use demand effectively as storage today to manage levels of penetration of renewables up to where we're going to going to get in still years from now. It's just, again, at some point it's going to start to get very much more expensive to deal with it. But there's a lot more potential for demand to deal with this today and for the next few years than most people realize, and I agree with you on that.

Question 3: I heard Speaker 2 say that markets in the near term aren't going to be very good at inducing the entry into the market, the construction, of zero carbon resources. I guess my question, bluntly would be, well, what do you have in mind for the long-term procurement of these things? I mean, it seems to me that we've had a subsidy regime where you've caused these zero dollar variable cost or very low variable cost renewable resources to enter into the market, and that already creates a kind of distortion that depresses the wholesale energy price. But, in a way, some of the subsidies that we've had almost double down on the distortion, because they're volumetrically expressed, like the production tax credit. And so the revenues are hinged to these units' marginal performance, which has sort of a further interrelationship with the wholesale market. So, I mean, what do you have in mind for the long-term procurement of low-carbon energy? Is it a subsidy regime, where these people are paid for performance, or just given sort of a big grab bag of money, or is it more of a command and control model of utility integrated resource planning from a state actor level? I just didn't understand the implication of your comment. And I'd be interested in other panelists' view about long-term procurement mechanisms as well.

Speaker 2: I suppose on one level it would be nice if we had a world where we could politically get away with putting a price on carbon that would take care of this problem for us. Although I would imagine that the price of carbon that would drive that level of asset turnover in 15 years is beyond even the wildest dreams of carbon market developers. So what I have in mind, I guess, is, first of all, it is in pursuit of policy objectives, climate and energy policy objectives. It's going to be policy driven. We need to move away from production-based support and move more towards capacity-based support, investment support, rather than supporting them through special treatment and operations. Other panelists have talked about that. And if we're going to bite the bullet and accept that it's going to be policy driven, we should accept a couple other things. First of all, as in Europe, and most places here, we're talking about adding quite a substantial amount of new capacity to a market that, generally speaking, is already fully served, and fully served with assets for the most part that are not going anywhere anytime soon, unless someone pushes them. And I get into this discussion with people in Europe all the time. "Well, if there's all this over capacity, why aren't people retiring assets?" Well, there's two answers to that. One is that people are taking assets out of the market. You refer to retirements. Actually, they're not retiring them, they're mothballing a lot of capacity in Europe. Some is going away, but most of it's being mothballed. Mothballing's not retiring. Mothballing is sitting on the sidelines ready to jump back into the market any time, and if I'm an investor (and I was an investor for 30 years), I wouldn't touch a market like that with a barge pole. Because I know exactly what's going to happen when prices tick up just a little bit. That mothball capacity's going to be brought back. They're going to remove the nitrogen blanket, get it fired up, bring the staff back, and put it back online. So there's that. There's a lot of mothball, in addition to the visible overcapacity, and this has been an issue in Texas for a while now. There's a lot of shadow capacity in the market that just seems to come out of the woodwork every time there's a need for capacity. It comes and goes, absolutely, yeah.

Comment: If it's out too long, it starts to be cannibalized.

Speaker 2: It starts to be cannibalized, yes. And we actually owned one of those plants back in the late '90s. And we cannibalized it a lot. Used it for parts.

The other answer, of course, is the prisoner's dilemma. If you're a generation owner, and you're sitting around in Germany with other generation owners, and you're all sitting on gigawatts and gigawatts of what is effectively stranded capacity, who's going to jump first? Because the first guy that takes five gigawatts of capacity out of the market (and we and others have done these studies) will cause wholesale prices to recover quite nicely. In the meantime, you will give up market share and all your competitors are sitting there enjoying very healthy prices. So no one wants to be the first one to go out and do this.

So there's a lot of walking dead capacity in the market. So part of the answer to your question is that one thing I have in mind is that we may need to think about a managed disinvestment, stranded asset settlements. We've been there before. It's a nightmare. People think, well, there's surplus capacity now, but there's going to be load growth and some plants are going to retire, and we're going to need capacity in 2025. Maybe. Maybe not. If we keep adding, if UK adds Hinkley, the nuclear plant. UK's also trying to call for CCS and gas fired CCS, and there's biomass, there's other stuff coming into the market. And if they meet their current policy objectives and what's actually written in the legislation, they're going to continue to add gobs of capacity to a market that's already oversupplied.

So when is this going to resolve itself? Well, unless somebody gets in and does something about it, I'm not sure it's going to resolve itself anytime soon. So stranded asset settlements are probably one part of the issue, because there are people who are legitimately going to have an interest in being compensated for what's going on. Although probably not as much as they seem to think they should be compensated.

The second part of it is, again, I talked about non-production based supports. And, again, if that's going to be policy driven, further to a previous question, it shouldn't be obsessively focused on intermittent resources. We need to get a lot more serious about CCS than we have been, and we probably should think about doing something to try to bring down the outrageous cost of new nuclear. I know Speaker 1 and I had this discussion back in July, and everyone loves to sit around and look at what the Chinese say they're building new nuclear plants for, which they claim is $3,000 a kilowatt. Not in a thousand years, as far as I'm concerned. At least not in this part of the world. It's going to be seven, 10, $12,000 a kilowatt. Until we figure out how to do it better. And I've been in this business for 35 years. I worked in GE's nuclear business. There are a lot of really difficult issues to get at, of trying to figure out how to do nuclear cheaply, more cheaply and more reliably than we have been. And they don't have a lot to do with regulation. They have a lot to do with the structure of the industry. So that's maybe not a terribly crystal clear, sharp answer to your question, but those are some of the things I had in mind.

Speaker 3: One thing that the Brits have done which I thought was very good is learn that you're going to subsidize the renewable industry for the foreseeable future. They set a cap. They said, "The subsidies we're going to give to this industry are X billion per year." And once you set a cap, that drives what you're doing. So, as opposed to saying, "Come and be on the windmill and we'll guarantee your rates no matter what," you say, "OK, we want to distribute no more than four billion, two billion is already eaten up by the guys already installed, so we have so much left to give, and we're going to run tenders for whatever next we want." And I thought that was a fairly, at least transparent, way to do that. And you can have an adult conversation with the public and with the voters about whether it should be four billion or 10 billion, whatever. And then you run tenders. That way you hopefully get the cost down. So it sounded like a reasonable approach to solve that problem.

Speaker 1: I want to just respond a little bit different way. You've asked the most important question, and there's not a very good answer to it. And it's especially hard in the United States, because we are this incredible patchwork. I'm from Wisconsin, where we have more or less a traditionally vertically integrated system. And we've got everything between an even more traditionally vertically integrated state like Georgia, for example, and then the far end of the competitive spectrum. And so there's no single answer, I think, that fits all of those different contexts.

I delved back into this stuff about three and a half or four years ago, and began by spending a lot of time in Europe and a lot of time in Germany in particular. But the sense has grown, and I think that this is a big problem, that we have lost the ability to look at the system as a system. So we've very much gone in the direction of picking out the part of the system that matters to us. So if we're AWEA, clearly we care about the generation side of the system and we care about getting more wind on the system. Or if we're the ISO, we care about the questions that pertain to transmission. Or if we're the local distribution utility, we care about other things. I think it would be very helpful to begin to kind of try to put some of those pieces back together and get an integrated look at what different policy and economic options mean, and to sort of ask ourselves what we want. What is it that we want as people who are concerned with the electric system?

And I sort of said this at the beginning because I think it's important. We think costs matter. We think costs will always be the primary driver. We'd like to think environment would be the primary driver, but the reality is we think costs matter. And the analysis that we've done suggests that you can pick paths that have radically different cost implications, and those paths lead to the same kind of carbon implications. That being said, we think we ought to try to go for the cheaper path. We think reliability matters.

The other thing that I think is important is that there are some secondary factors that are beginning to bind in Europe, and I think they will begin to bind here. So, Germany, in my opinion, has run out of terrestrial resource to build wind machines on. The German public is kind of tired of waking up every morning and no matter where they look, all they see is a wind machine. Speaker 2 was a project developer, I was a project developer. And I've built coal plants. I've built wind plants. I've built gas plants. Nobody likes anything. [LAUGHTER] Nobody likes anything in reality. I think the footprint of the system and striving to minimize the physical footprint of the system is something that matters.

So I think we sort of add all those things up, and we try to generate a system look and say, 'What is it that we as a society want, and how do we get there?" And I think markets are underutilized, and I think we've gone a long way, but I think we can go a lot further. But I also think that there are some things that are going to be very difficult for markets to solve, and we're going to have to be prepared to have policy interventions. I just hope we can do better than the production tax credit kind of things. When we talk about economic subsidies, I'm always immediately reminded of St. Augustine, who said, "Make me chaste, Lord, just not now." Once we put the subsidies in place, we have very little evidence of ever taking the subsidies away. And I'm not going to pick on the wind industry, but the ethanol production tax credit--I mean, most sane people look at the ethanol production tax credit and say, "Boy, this is really dumb policy." But we haven't had much success in getting rid of it. So to think about things that are not as intractable as those kind of blunt mechanisms, I think I would be looking in that direction.

Question 4: Speaker 2 tossed out the idea that we need solutions by 2030. Speaker 4 makes a good point about the limits to wind and solar. There have been discussions about limits of solar. When you put this all together, it looks like, without dramatic demand side flexibility changes, flexible nuclear is an important piece of the solution…and there are systems that have lots of renewables and nuclear, but no one talks about those…no one focuses on getting over challenges of making nuclerar flexible preserving what's out there.

Speaker 2: During the coffee break I did say that if we accept this will be policy driven, the smart thing to do would be to do for nuclear what we've done for renewables

Questioner: How to you explain Germany?

Speaker 2: It's a cultural thing. Germany was traumatized by Chernobyl. The other piece is that if you talk to people in Germany, they will admit that Germany is part of a much larger system. There's nuclear in the system. So they have it on the system. I'm not here to explain Germany or France, but from my perspedtive you should be doing what you can to bring forward more flexible, economic nuclear technology. That would be a wise risk management policy commitment. And I think we should do more on CCS. It's more likely we'll be in a world with intermittent and load following resources, in which case we better have an option. That could be a few things. If we're smart about this, we'll be bringing forward, in the next 15 years, alternatives to renewables.

Speaker 3: Nuclear is a tricky thing, and it comes down to cost. It costs a fortune to build today to safety standards we expect. Just volume of concrete, for example. Plants to be built in England will be very expensive. New plants will be very expensive.

Speaker 1: The nuclear industry and people in nuclear nnovation are keenly aware of the need for more flexibility. Speaker 2 pointed out concerns about Chinese plants. I agree it's difficult to swallow economic data from China whole. I take data from Korea more seiourly. There is more transparency in Korea. The delivered prices for reactors they've sold to the Gulf states are dramatically less than what we're seeing elsewhere. Discounting for all the things we want to consider, it still seems like we can do a better job.

And on the systems point, we're modeling systems with nuclear at $8000 /kw and solar and wind at $1000/kw. That thousand dollars is quite a bit lower than delivered prices we're seeing now. A nuclear-based system comes out to be slightly cheaper than a heavy renewables system, even with those generous assumptions. So we need to look at full system implications. The LCOE metric is at best potentially miseleading and at worse completely worthless.

Question 5: With respect to the rationality of Germany's abandonment of nuclear power, rationality is an interesting concept. The Germans think we are crazy.

I have two comments. With respect to low capacity factor concerns about renewable energy, that's fair, but we have a lot of expensive infrastructure in our economy with a low capacity factor in order to deal with swings in demand (roads, housing stock). So we should keep that metric in perspective.

Second, the perceived need to look at things from a systems perspective is interesting. The Germans think this is Communism. The electricity system is in transition, such that system-level planning is increasingly an illusion. Consumers increasingly drive things by buying what they want.

Question 6: With respect to the interatction between renewables and markets, it seems like the focus is almost entirely on short term hourly markets. There are other markets. But I think it's important to ask whether there are markets more relevant to investment decisions. To the extent renewables are fixed cost driven, investment is were the action is. Once you build a plant, it will produce. So when we think about the role of renewables and markets, wouldn't it make sense to think about the whole set of markets involved? We are stuck with a set of technologies on the renewables side which are largely fixed costs. There are other low-carbon technologies that are more traditionally split (eg biomass). To what extent would we use market structures to affect that?

Speaker 2: On load capacity factor, I agree. We built several large gas fired power plants that have been operatig at low capacity factors…

Speaker 1: When you produced your finance documentation, you didn't foresee that capacity factor…

Speaker 2: It's a question of cost—compared to what? I've lamented for a long time, the fact that we continue to exist looking at electricity infrastructure in a fundamenatally different way than we look at consumer electronics. Perfectly good stuff gets thrown out or retired and replaced. But with electricity infractucture, it's like we have to get every second of useful life out of it. That's not especially rational. It's worth rethinking how we think about this.

With respect to the system perspective part of your comment, I co-wrote a thing for Shell recently, where we talked about peak centralization and whether we've reached peak centralization, and the internet of things. And I think it's a great idea, and I think it's going to happen over time. But I think between now and 2020, 2030, 2040, we in the developed world will still be relying to some extent, I think to a great extent, on a centrally operated, synchronized, alternating current grid. And we've got a lot to do while that is still the case.

And then, markets for investment. Don't get me wrong. Hopefully, from my presentation, it was clear that I do not subscribe to the view that competitive wholesale markets cannot support investment. I do not subscribe to that view. But as I said, the market doesn't need new investment right now. So whether you look at ways to focus markets on driving low carbon investment or not, we still have a problem, because we need more low carbon investment than the market is going to demand. And I think getting away from volume based support schemes is part of that. Let's make the decisions we want to make about how we're going to get things built. Once they're in the market, we need to operate the market the way it should be, and the market should be sending the signals for assets. That means economic curtailment of renewables. Absolutely. No question about it. That's much cheaper than the alternative.

Speaker 3: This kind of thing about the renewables is that when you think about the market, you think about short-term market, the spot market, but you think also about long-term markets where people decide to invest, and so on and so forth. And in renewables, we didn't have long-term markets. We had long-term subsidies. Bring it and we'll pay you. And if five of us come and bring, we'll pay five of us. If 20 of us come and develop, we'll pay for 20. So what we need to do instead is create a market for investment. That is, say, "We want to build five and we'll take the five best." And that's a long-term market. And that generates all the good stuff you want, which is efficiency, the best technology, the innovation. And if a guy says, "You know what, I can do better than the other guys, because I have the right mix of fixed cost or variable cost…" and so on and so forth. That's what you want to create, is that auction mentality that gets you the best project for the long term. And somehow, we do that for a lot of things, but for that particular technology, which is renewable, we just completely forgot that and we just say, "OK, let me just throw money at you and just build it."

Speaker 4: I agree with what's been said. On the point about systems versus customer driven approaches, I think that we are obviously seeing a lot of action happening on the edge of the grid today, on the distributed energy edge. I think the illusion, though, is that that is customer driven and not system driven. The reason that we see, I think, EVs, PV being deployed at the distribution edge is because of policies, for the most part, and markets to a lesser extent. In Germany, it's the feed-in tariff, and the United States, it's net energy metering. My parents have solar power on their rooftop and talk about producing their own power, but they're producing their own power and selling a lot of it back to PG&E, Pacific Gas and Electric, which is how we make these technologies competitive today. I think that will continue to be the case going forward. I think that's to the benefit of distributed energy resources. I think that decarbonization as a mission will be more successful if we're all in it together, as opposed to this idea that we're all going to be producing our own power and storing it. I think the system costs and the efficiencies work out much better if you actually treat it like a system.

To the point about non-variable renewable energy that you were making, I think that's absolutely essential, and I think that's why what the four of us have said on the panel today is not actually very controversial among anyone who knows anything about power systems. If you look at actual carbonization pathways with a lot of renewable energy, like the study that Speaker 2 worked on, like the National Renewable Energy Laboratory, or *Renewable Energy Future as of 2050*, there are only about half variable resources, and the other half is some combination of baseload dispatchable.

And, again, here, I think it's important to look at what our objectives are. Are our objectives to use as much renewable energy as possible, no matter which technologies we're talking about? Or is our objective something closer to what Speaker 1 was talking about, which I wholeheartedly agree with, which is very low cost, very low carbon, very low footprint, which, in particular, I think would make us think twice about technologies like bioenergy? We can sort of go back and forth for a long time on the footprint differences between wind and nuclear, which are large, but bioenergy has an order of magnitude larger land impact. And as a representative of an officially environmental think tank, I thought it important for me to bring in land footprint a little bit.

Speaker 1: I wanted to add one thing to the last comment. Biodigesters, I think, are a technology that is much neglected. I did some research for USDA three or four years ago. I've been in and out of the biodigester world. What I would say is that the worst thing to do with biogas is to generate electricity with it. You take an expensive piece of equipment, you add another expensive piece of equipment to it that's inefficient, and you ask somebody whose primary job has nothing to do with making electricity to run a complicated piece of equipment. I think the very best thing you can do with biogas is turn it into CNG (compressed natural gas) and use it as low carbon transportation fuel. And in fact, I can think of four projects in the Midwest that have put biodigesters at CAFOs (concentrated animal feeding operations0, produce biogas for transportation fuel, and they are in the black financially, and they receive no subsidies at all. It is one area where you can make real money today. So I'm all for it. I think we've got a lot of CAFOs in the United States, and I think every single CAFO ought to have a biodigester.

Question 7: I think that certainly implicit and I think explicit in some of the comments here, is that a policy element that we would all agree on is that we should be spending a lot more money trying to develop breakthrough technologies that really turn out to get us something that we actually want, and that we don't actually know what they are today. So it's not like we've got them sitting on the shelf and we just need to figure out a way to get them adopted. It's just, we don't know what they are. So I think we need a greatly expanded investment in that component, and I think we all agree about that.

The second comment I have is that I was very happy to see from Speaker 2 that the operating reserve demand curve is widely accepted. [LAUGHTER] I think that's a really good idea. And I'm fully in favor of, and always have been, not surprisingly, about getting a price on carbon. I have a different view of this than Speaker 2, which is that I haven't given up yet. [LAUGHTER]

Speaker 2: I've spent more time in Europe. [LAUGHTER]

Questioner: If you ask me if we're going to do a carbon price next year, that's a different question, but this is a decades long process. If we don't do that in the end, the rest of this conversation is just talk, because we're not going to get the incentives out there for people to respond to.

The place I get concerned is with what to do when you go beyond putting a price on carbon. And there are a few things that I would do in terms of subsidies, for example based on the learning by doing argument for early deployments of technology. But I think you would take a short pencil, and I'd have to look at this problem, and you'd come up with that number which is pretty small for that. So the kind of subsidy that you're talking about there is maybe a third of the production tax credit. Something like that. And only for a little while.

Now we get to the point where, after I've adopted all those policies, I agree with the general sense of the analysis that it's not going to get us anywhere near eliminating carbon from the electricity sector any time soon. And my reaction is, if that's true, and if we've got the right price on carbon, which I'm assuming for the purposes of this policy discussion, that's OK. Because my objective is not to eliminate carbon from the electricity sector or the planet. My objective is to internalize the cost of carbon.

And there's uncertainty about what that actually means in terms of what the costs will be and what would I do. Where it will come out, I don't know. And we could have a conversation about what's the appropriate price, but what I get here, is that really the source of the conundrum of "Say we do all these things and then we haven't gotten there. And now we need to figure out something else even further," has to do with the framing of the problem. And I think what this is revealing, is that the objective should not be framed this way, as eliminating carbon from the electricity sector, or any of those kind of quantitative pre-fixed goals. I don't know if 450 parts per million is too much or too little. That's all, to me, an issue about setting the proper price on carbon, but once I've done that, I don't have to worry about these other problems, and it turns out we get a lot of renewables, that's good. If we don't get a lot of renewables, that's good, too.

Speaker 2: Well, I'm just going to bask in the ORDC comment. I guess my response on carbon pricing would be threefold. First of all, I'm not against carbon pricing. I think it's a terrific idea, but I think that, at least for the time being, the main value of carbon pricing in practice has been what you do with the revenues, not whether it's necessarily driving the desired reductions in carbon emissions or the necessary level of carbon emissions. So we're recycling the money from carbon, whether it's revenue recycling or it's goods, tax and refund, or whatever.

But in an ideal world, I agree with you. If you actually had a market that applied to all sectors of the economy, that prevented carbon leakage, that dealt with trade and competition issues, and that literally progressed to the right level, then I wouldn't care whether the carbon came out of the power sector or not, in theory. As long as the carbon emissions go down, you're right. That's the objective.

Questioner: Emissions coud go up over time.

Speaker 2: Well, then you haven't got the right price of carbon.

Questioner: And that's the issue. The goal is not the trajectory of carbon. It's to internalize the social costs that are associated with it.

Speaker 2: Well, OK. That's the tax approach, as opposed to the cap and trade approach. The cap and trade approach controls volume. The tax approach says, "We're going to price it and if people still want to emit, then they emit." OK, fair enough. I mean, with the tax approach, you wouldn't necessarily care what the volume was, as long as people are internalizing the cost. So I accept that. Presumably, if you really were internalizing the appropriate cost, the emissions would go down because it may be —

Speaker 3: It depends on the growth of the economy. You could have models where the economy grows so fast, that actually you would want to consume more, and things like that. But that's a sort of theoretical side argument to the main one.

Speaker 2: The reality at the moment is that we don't have a carbon market that applies to all sectors of the economy. And it's not clear that we could get one that applies to all sectors of the economy. And at the moment, they're markets, they're not tax approaches. So they are focused on volume, as opposed to price.

I talked to the guardians of the ETS (Emissions Trading System) about this. And they freely admit that, at the moment, the trajectory through 2030, while it would be consistent with economy-wide decarbonization by 2050, it doesn't get anywhere near where most people think we need to get to by 2030. So the trajectory is not steep enough in the European ETS, and I would suggest it's certainly not steep enough in RGGI (the Regional Greenhouse Gas

Initiative), and it's probably not steep enough in the California market.

So, in theory, possibly, yes, you're right. But in practice, we haven't yet been able to demonstrate that we can do it. And then, finally, and probably from an analytical perspective, my biggest issue with that is that carbon markets are not very good at pricing cross-sectoral impacts. So, for instance, we could end up with price that drives a number of decisions between now and 2030 that leave us with having not brought forward the options we would need to get to where we need to get to beyond 2030. And the reason is, the technical analysis I've seen, not the pure economic analysis, but the technical analysis, has led me to conclude that there are a whole host of reasons why, from a long-term economic perspective, it is critical to decarbonize the power sector first, because the lowest cost long-term options, at least as far as we know today, for decarbonizing the transport sector, decarbonizing the heat sector, have to do with electrification. And so, we could end up with a lot of, for instance, gas fired heating systems in 2030, and a relatively high carbon power sector, and that would have gotten to us where we thought we needed to get to by 2030, and leaves us no way to get to where we need to by 2040. And you could say, "Well, you just got to trust the technology's going to be there and we'll figure that out in 2030." I think the stakes are too high. I think that's a high-wire act. I think we need to recognize that there's a risk management part of this that long-term carbon markets don't do a very good job of. They're not good at looking long term. Partially because there's just a very low level of confidence in the political will to stay with them. And especially with markets. There's a very low level of confidence in predicting what the price is going to be five, seven, 10 years out. Especially with carbon leakage and cross-border trading of emissions. So all that brings me back to the fact that if we think the stakes are high enough, and I do, to get serious about decarbonization, carbon pricing is a valuable piece of it, but it's just too risky to rely entirely upon it.

Speaker 4: I basically agree with what Speaker 2 said. I think I have what I have estimated to be a relatively unique view on carbon pricing, so let me work through it pretty quickly. First, to your point about the social cost of carbon. We don't know what it is. I think mainstream estimates of the social costs of carbon vary between, maybe it's a couple dollars a ton of CO2, maybe it's a couple hundred dollars a ton of CO2. The US government's estimate is that it's about $35, $40 a ton of CO2.

I think we can say from, as Speaker 2 said, a risk management perspective, that a reasonable goal, my goal, is zero carbon all energy as soon as possible. I wouldn't say by 2030 or 2050, because I don't think targets and timetables really work. And I think that it's guided mostly by technology. What do I say is as soon as possible.

To that point, I also agree with Speaker 2 that carbon markets probably aren't going to get us there, both because of the inherent inability of them to do a lot of the technology policy we need, and also because of the willingness to pay of most consumers. We do see something like 25% or 30% of all carbon emissions around the planet today priced at some level already. That's impressive. It's a lot more than it used to be. But they're priced at a couple dollars a ton of CO2, and it's just not having that big an effect on aggregate emissions. And when we try to raise those prices, then we see what happens. We see that Australia just repealed its carbon tax. We see that Europeans, where they used to have 20, 30 Euros a ton, now it's seven, eight Euros a ton, and it's not going up. We see the United States can't pass even a low carbon tax.

Some work from my colleague, Jesse Jenkins, has analyzed the willingness to pay for the social cost of carbon, and in the United States and Europe, it's something like $8 to $12 a ton, based on hedonic pricing and stated preference and things like that. So we don't see willingness to accept very high carbon prices that would drive either merit order transition or big investment in new infrastructure.

So leading back a little bit obliquely to what this panel is, what it was designed for, what does that tell us about transitioning to zero carbon electricity systems? I think it tells us that we need to rely more on technology policy, whatever that's going to be, and I'm as skeptical as others of things like feed-in tariffs and net metering and portfolio standards. They all have their pros and cons. But I think we're going to have to rely on technology policy more than emissions pricing policy, due to the constraints that we have on emissions pricing policy, and the fact that we know that technology policy works in creating new policies. The reason that France has lower emissions than it would otherwise is because they decided they want to build a ton of nuclear plants. The reason that the US has seen emissions fall dramatically in the last five, 10 years is due to decades of public and private investments in fracking that have now replaced coal. That's technology policy first, not pricing policy, which is just sort of the overarching view that I have about carbon pricing.

One other related point, to respond to something you said, Speaker 2, with just pure conjecture, is a question that I have, which is whether it does make sense to decarbonize electricity first. I agree with the fundamental intuition there, that compared to transportation, compared to heavy industry, obviously, you would go with electricity first, because there's the most economic and high performance zero carbon alternatives. The question that I have, and again it's pure conjecture, is, if we decarbonize electricity first and maybe in the process make electricity a little bit more expensive, do we actually slow the electrification of everything else--industry, transportation, and lock those systems out of electrification? That's a question that I've had, and I just wanted to raise it. It stumps me. I'm not quite sure how to think about it, but I just thought that I would put that on the table as well.

Speaker 3: OK, now this is going to be exceedingly ironic, because as a French civil servant, I, am going to tell you that we should use markets and not planning. I mean, I'm a French civil servant. I come from the country of central planning, and I can tell you, markets and prices work a million times better than anything else you can invent. Let's look at your question. You don't know whether we should decarbonize this, this, or that first. It's a legitimate question, and none of us has the answer. But collectively, if there's a price of carbon at 60 bucks, now there are millions of people who are going to try to do this, to do that. They're going to try a million things, and somehow, through pure haphazard, we're going to fall around where we need to. The beauty of markets is that you do not need you, Speaker 4, to have the brain, to have the answer, and to know everything. Just let a million people sort it out for you.

Speaker 4: It's a good thing we're not relying on my brain.

Speaker 3: It is a good thing, but like a million people, you see what I'm saying. And that's a legitimate question. We don't know the answer.

Now, the thing you said about carbon markets is very true, but carbon market are not exogenous. The fact is that if carbon markets are unpredictable, if they are flawed, it's because, as a society, we chose not to make them reliable. We didn't give all politicians the mandates to actually design carbon markets. If they are not working well, it's just because we didn't decide to make them work well. And one of the greatest fallacies I see is that people do not want to pay for carbon, therefore, decarbonization, at $12 bucks a ton, but the Germans are paying 60 Euros per megawatt hour for the subsidies. So when you subsidize, people pay for it.

Comment: 400 Euros per ton of CO2 –

Speaker 3: Exactly. Exactly.

Speaker 4: That kind of proves my point. They're paying for technology policy.

Speaker 3: But, in other words, it's not fair to tell them, "You're not going to pay for carbon directly," but then it's going to be hidden in something else. You see what I'm saying? It's just not fair. So the right answer is just put a price on carbon, and once you have a price on carbon, lots of things will simplify themselves, and maybe we decarbonize the transportation first, maybe we decarbonize electricity first. I don't know. But it blows my mind away that there's no more consensus towards just getting there. And I don't underestimate the political difficulties and so on and so forth.

Speaker 2: I think my very short response to that would just be you're probably right, and it's never going to happen.

Speaker 2: Yes, exactly. That's where I am as well. I'd love to see it happen.

Speaker 3: But the only way you can make it happen is just try to make it happen. And, again, I realize I'm a French civil servant in Texas, but, still, if you say it's not going to happen, I can assure you it's not going to happen. [LAUGHTER] Let me finish. Because it's really important. I mean, it's the core of it. The reason why we're academics, we're intellectuals, is because we try to make things happen. That's what we try to do. That's our job. And I agree with you, it's hard. But, hey, America put a man on the moon, and it was not particularly straightforward either. So getting a price to carbon, it happens.

Speaker 1: To the questioner, subject to the constraints that you laid out, I agree. If we got the price right, if we implemented it comprehensively, I think that would be enough. I also agree with what my colleagues have pointed out about the difficulty and the prospects for doing that. I want to emphasize the points that you made about the sort of level of subsidies and the need for technology policy in a surgical way. Because I think a price on carbon makes a tremendous amount of sense. I think it's a big ask at the moment, although I can see pathways where it might become a little bit more doable. But I think we can do more on technology policy, and I think we can be a lot smarter about the way we incentivize things in the electric system. So I just want to kind of pile on to those two things that you said, and then agree with your theoretical constructs that you laid out at the end.

Speaker 2: I also wanted to agree. One thing we can all agree on is maybe some of that recycling of carbon revenues should be going to ARPA-E, rather than going to subsidizing efficiency programs. [LAUGHTER] Yeah, I mean, we need technology badly for all these pathways. And I think carbon revenues are probably a pretty good source for that. But Europe has more or less constantly over the past five years been trying to reform the ETS. And they finally passed the reform earlier this year. It's pathetic. It's not going to get them anywhere near 20 Euros per ton, much less 40 or 50 Euros a ton.

Speaker 3: That's something different. If you want 20 Euros per ton, you don't set a market, you set a tax.

Speaker 2: [OVERLAPPING VOICES] But they tried to reform and they didn't do a tax.

Speaker 3: It's the important point.

Speaker 2: It's a theoretical point.

Speaker 3: No, it's not. You say you want a price of 20 Euros per ton.

Speaker 2: No, I want a price of 60 Euros.

Speaker 3: So put a tax. If you take a market, let the market give you the price.

Speaker 2: Sure, go ahead, magic wand, boom, 60 Euros per ton.

Question 8: I have a few concerns. When we overemphasize these complementary policies, they have unintended consequences. For example, say we subsidize nuclear—then we get "me too" subsidies that aren't quite so benign. Or take high volumetric rates for energy efficiency—yes, that's good for efficiency, but bad for electricity transition. Unintended consequences. We might price out what consumers are willing to pay for technology policy without getting ourselves where we need to go.

And what you see with deployment subsidies is incremental learning by doing, but less long-term emphasis on break throughs and innovation. And this is a global problem, not just in the developed world. We need much, much better technology. It is hard to see how we get there as long as the advocates for carbon action focus disporptorionalitely on technology policy as opposed to carbon pricing. Because we don't really know what the right technology will be.

How do we change the direction we're going and pick up on willingness to talk about revenue rom carbon taxes vs. subsidies for stakeholder groups?

Speaker 4: I think that equating technology policy with deployment policy alone is dangerous and bad. I'm not opposed to deployment policies for solar. I'm not opposed to deployment policies for nuclear, but I agree that, in general, those do incentivize the technologies we have available today, when we know that we need better technologies in the future. We know we need next generation solar. Probably we need next generation nuclear, to be building plants in Europe and the United States, but I wouldn't say that deployment policy is the only kind of technology policy.

Look at the history of the shale gas revolution that I alluded to earlier. That was three decades of public and private investments in shale gas exploration and diamond studded drill bits, and microseismic imaging, and horizontal drilling by the public and the private sector, including a 20-year tax credit for exploration of unconventional wells. That's a deployment policy that, believe it or not, we did get rid of, in contrast to Speaker 1's point about getting rid of subsidies, which I agree with generally.

So, really, I just want to emphasize that we do want ARPA-E. We do want some deployment policies. We do want, as Speaker 1 said, to make sure that the technology policies we have in place are being designed and executed as best they can. I think the shale gas revolution happens to be a particularly outstanding case study of well-executed technology policy. I won't belabor my previous point about carbon pricing again. I think that it has defects, both in terms of political economy and in terms of actual efficacy.

To your point about how, if you have a goal, then you should set the price at that goal, I say, sure, but from my perspective, if I have a goal which is a zero carbon, high energy planet as soon as possible, then I'm going to advocate for and invest in the things that have worked in the past to get us technologies, which is public and private investments and groundbreaking innovations.

Speaker 2: We're big advocates of carbon pricing. I mean, absolutely. And the ETS is still one of the great political accomplishments of the past 15 years, in terms of climate policy. There's no question about that. And RGGI and the California effort, combining California with Quebec… It's a critical piece. But I'll just cite the UK as one example. With respect to the earlier questioner's point about carbon price, basically the treasury in the UK saw a carbon price floor as basically a great tax opportunity to bring money into the treasury in the UK. So they implemented this carbon price floor. It had an increment ratchet which was meant to sync exactly with the UK's climate change committee's targets for carbon abatement by 2030. And it would have risen from, I think, 12 pounds a ton steadily each year, to something like 35 or 40 pounds a ton by 2030. And they made a big fanfare of it as part of electricity market reform. It took them six months to come out and say, "Oh, sorry, actually what we meant to say was that we're going to cap it at 15 pounds per ton." Done. Finished. And this is one of the most conservative governments in the developed world in terms of climate policy and fiscal policy. They just couldn't bring themselves to do it. I mean, I think carbon pricing is an incredibly important piece of this puzzle, and I'm not ready to give up on it, but I am certainly long past the point where I think it's realistic to rely on it on its own. We can disagree about that, but that's where I am.

Question 9: I'm going to pile on. I've heard this before. PURPA, anybody? We decided to pick tech winners and losers because we thought we could outguess the future….how's that worked out for us? What happened in the wake of PURPA begat wholesale competition as a reaction to that because of our efforts to outguess markets. Now wholesale markets serve about 2/3 of US load. So it took us 20-25 years to come to our senses.

And here we are again talking about huge issue of climate change. But zero is not the rght objective function. And now we're trying to pick winners and losers (wind, solar)…So, given the lessons of PURPA, why don't markets work again? And with respect to hiding the true costs, (the 400 euros a ton implied carbon price in Germany, for example)—how sustainable in the long run is it to hide these things?

Look at wholesale markets in the US today. Prices are going down. But, in retail, prices are going up, due to renewable portfolio standards and other issues. How sustainable is that?

Third question: aren't we creating a new class of winners and losers, and the winners will hold on desperately. Isn't it just better to fight for the carbon price? To not abandon the right thing? Otherwise we're creating all knds of market problems. What's the ultimate end game?

Speaker 1: So, in order of the questions raised, the similarities to PURPA are well taken. There was a lot less money on the table with PURPA projects than there is today with all of the infrastructure that we've put on the ground through the production tax credit and the investment tax credit. I mean, it's not even in the same universe. We're getting a lot better at it, and I think about that, because the PURPA backlash was really focused in three or four states. That wasn't a national phenomenon. In the Midwest, we just fought like hell to keep PURPA machines out of our states and we were largely successful, but it was New York and it was California, and it was just a few states that really created the backlash that unleashed John Anderson [LAUGHTER] and that changed the way we do things. It's not that way with wind and solar at this point. What's that?

Questioner: At this point. That's why I said 20 to 25 years.

Speaker 1: The answer that I would give to the German situation is, number one, when the policies were implemented, they had no clue that the uptake was going to be what it was. And the train was really far down the tracks when, all of a sudden, people started complaining pretty significantly about the implications. I think the politics are really interesting in Germany, because in the last election, Angela Merkel's party won, formed a coalition with the Social Democrats, and she gave the responsibility for fixing the problem entirely to the Social

Democrats. Nobody from her party is involved in any of the ministries that has to fix this problem. What has happened is that development of both wind and solar in Germany has stopped, in comparison to where it was. I mean, it has ground to a standstill because they've turned the spigot off. But the parties recognize that the level of electric rates right now are socially unsustainable, and they are struggling internally to figure out how to address it. Because they've realized, and this is what happened with fixing PURPA, there is no way to fix the problem without creating losers.

And what happened in the United States when we fixed PURPA was, there were all these people who had investments in PURPA machines at 10 cents in New York, the famous 10 cent rule, and finally, the policy makers just said, "Too bad, we'll see you in court." So this idea that the sanctity of the contract is going to protect you…go back and look at this history of PURPA, because the sanctity of contract is only as good as the government entity on the end of the contract that made it. There were a lot of contracts broken as those PURPA machines got unwound. So I think, absolutely, costs are binding, and I think Germany is at the cutting edge of it. And the government, the German government, both members of the coalition are doing everything they can do to systematically keep the discussion of this very, very quiet. I mean, this is something that nobody wants to talk about in Germany, because it's very difficult to resolve.

Speaker 2: Maybe my microphone was turned off when I was talking, but I think I was talking about system reliability and a policy driven risk management approach to decarbonization. I spent 35 years in the power industry. I'm an engineer. I worry about things like reliability and levelized cost of power for customers. And the scenario that I put up there, that portrayed a 95% mitigated power sector, had about 60% from a mix of dispatchable and intermittent renewables, 20% from nuclear, and 20% from low carbon load following resources. None of those, by the way, involved quantum leaps in technology. You could argue maybe fossil with CCS is a leap, and I used to run into that argument all the time when we talked about that scenario. So I, at least, very much talk about reliability, talk about cost.

And all of us were talking about the fact that the whole point here is that if you accept that a significant amount of carbon abatement in the power sector should be a priority, and I feel pretty strongly that it should, then there are smarter ways to go about that than a lot of advocates seem to think there are. We haven't mentioned the unmentionable here yet today, Mark Jacobson. But the idea that we're going to get there with 100% renewables or even 80% renewables, at least based on everything we know today, is cloud cuckoo land. So you're not hearing that from this panel.

As far as picking, not necessarily picking technologies, but picking winners, I think part of the answer to picking winners thing is that the smart thing, if we're going to have a policy framework around this, is to diversify the resource and technology bets that we're making. So, no, don't bet everything on solar. Don't bet everything on wind. Do more with ARPA-E to develop nuclear technology. Do more to develop CCS technology for both coal and gas, but also, don't sit around and wait for that stuff to appear magically, sometime in the next 15 or 20 years.

But if you want to talk about picking the power sector, as opposed to picking a particular power technology, that's where I start to dig my heels in. Because in the years that I've been looking at this, I completely defer the academic economists in the room about what the right economic theory is. But I will tell you that based on my analysis, the right technical analysis is that ignoring significant carbon abatement in the power sector will probably leave us in 2030 with very few viable, reliable economic options looking beyond 2030. That may turn out not to be the case. I'm not prepared to bet the farm on that. So I do think we should pick the power sector, but I don't think we should be picking technology winners. I think we should be diversifying our technology bets.

Speaker 4: Just very quickly to agree with Speaker 2 again on this question about picking winners and losers. I don't think it's a question of picking winners and losers. I think it's placing many bets on promising technologies, like we always have in technology policy, including energy policy. I think Speaker 2 and I would actually differ in our respective enthusiasm for renewables and nuclear. That doesn't mean that I don't want to see more investment in renewables. It doesn't mean Speaker 2 doesn't want to see more investment in nuclear. I think it's safe, prudent, smart, ambitious, and proactive to be increasing investments in ARPA-E and demonstration and smart deployment of all these technologies.

And I would just, again, push back on this idea that picking winners and losers is bad, and that we should just put a price on everything. I think a great way to pick natural gas as the winner is to put a $15 per ton tax on carbon dioxide in the United States. Gas beats coal, but the ta does nothing for renewables and nuclear. That's picking gas over, and –

Comment: You put a price on carbon. The whole idea is that the most efficient technology's going to come to the fore, period. So it turns out that gas is really low cost right now. It was not always low cost before. And not only that, if you actually put in a price of CO2 into the market that's reflected in energy prices, guess who benefits? The zero carbon resources like renewables and like nuclear.

Speaker 4: Maybe if you put $80 tax on carbon, I agree with you, but, again, the taxes that we're talking about in the United States certainly…I think a carbon tax is going to do a great job of accelerating coal to gas. Great, we should do it. But in terms of zero carbon incentives, I actually don't think that you can get there with a carbon tax. And I would just emphasize, again, that when you look at the history of technology policy, we've always picked winners and losers, and we've done a pretty bad job of it at the outset. You mentioned that the reason that wholesale energy prices are going down today is because of shale gas. No one in the '70s thought that we should invest in shale gas, including the industry. In fact, the big enthusiasm was for coal gasification and for syn fuels, and for coal bed methane, none of which turned out to produce anything. Shale gas received maybe a tenth of the actual dollar support of those technologies, and even after proving the technology in the late '90s, it wasn't for another 10 years or so that we saw the shale gas revolution actually materialize in the United States. What that tells me is that we don't know, to somebody else's point, we don't know exactly what clean energy technologies we bet on today will be the big breakthrough in the future. That doesn't mean that we should have technology neutral policies. That means that we should have aggressive technology-specific policies on a portfolio of technologies. I don't want to be combative against carbon pricing. I just want to be very clear what I mean when I say technology policy, and I think we need to be careful about the language around picking winners and losers.

Speaker 3: Just a few words. The thing is, when you take a step back, there are two constraints that are binding. One is the carbon constraint, and we had a conference about that. When you talk to the climatologists, it's really not funny. I mean, the carbon constraint is now there. And it feels also like there's some sort of a budget constraint of the consumers. And the problem we have is that we spend a lot of money on existing technology, and if you do that already, you don't have much money left to spend on other things. And I'm very happy that we have renewables, and it gives me an opportunity to write nice papers, I'm very happy about it. But I have the feeling that that money, because it's gone, because the customers already pay 60 bucks per megawatt hour, it's hard to ask them for more. And that's the substitution that I'm concerned about for our collective future, and that's how I feel about it.

Speaker 2: Can I just add one quick thing? Just on the carbon price. If you want to go out and advocate for $60 a ton carbon tax, I will be right there with you. I'll be holding up placards in front of the White House. In the meantime, I think we need to be pursuing other options. In the meantime. And the more likely scenario that we see most places is carbon cap and trade, where it starts out at a small volume and grows over time, and, yes, eventually, the carbon price will reach very high levels. But in the meantime, you're starting at low levels, $2 a ton, $5. I don't want to put any words in your mouth, but I think what we're talking about here is maybe we should just set a price on carbon that's going to grow over time, and for now, what we'll see is a big conversion from coal to gas. Meanwhile, we'll slow down on all these stupid renewables, and God knows we'll never build any nuclear plants, because at $5 a ton, they don't make any sense. And so we'll have this massive conversion to gas and we'll be sitting there in 2030, and whatever progress we'd made on renewables in the past 15 years will have evaporated, because all the cost savings coming from renewables now don't have to do with technology advancements. They have to do with all the balance of plant and the industry that's built up around them, and that will all die. And so we'll be sitting there in 2030 with carbon prices still inexorably rising because the ratchet is increasing on the carbon cap, and we've got a hugely gas intensive energy sector, and no alternatives to turn to. And, I'm sorry, I'm just not ready to make that bet. So, yes, let's go out and get the highest carbon price, whether it's a tax or cap and trade, that we can. In the meantime, we should be developing a portfolio of low-carbon resources that can be deployed. Reliably, economically, practically and politically.

Question 10: Just two very quick comments. As someone sitting here who also cares about climate change, I have to say it doesn't hit me well to hear about some drastic change in the fleet of power plants to be made by 2030. It's just not going to happen. It just can't. So you can talk about some gradual glide path for the next 15 years, and some more drastic change in the subsequent 30 years, but to say that we have to hit some drastic target in 15 years, frankly, as an audience, you lose me right there.

The second comment is, not one of you mentioned anything about emerging markets. It seems to me that if we contribute, in the United States, about 13%, I think that's right, of the carbon emissions worldwide, that the key thing that has to be focused on is how you're going to have an effect in India, in China, and other countries. And I have to wonder whether the most effective policy of all wouldn't be, not a carbon tax on ourselves, but a subsidy to India to encourage them to build more nuclear power plants or do something else. In other words, at the margin, that strikes me as perhaps the most important thing to do in terms of curbing carbon emissions.

Speaker 4: Just to put a few numbers on that. By 2030, the emerging markets will be seven billion humans to one billion in the rich world, and emerging markets will be 70% of emissions to 30% in the rich world. Just to emphasize that that is exactly true.

I don't know whether it's the rich world transferring money to the Annex II countries for incentivizing zero carbon innovation and deployment, but I do absolutely agree with that, just to put my flag down. I absolutely agree that it's going to be countries like China and Korea that are doing a lot of the deployment and innovation in technologies like nuclear. Those power markets do want investment. Those consumers do want more energy. And that's, I think, where we're going to see most of the innovation happening this century. I didn't bring it up in my presentation because we were talking about transitions in the rich world, for the most part, but I absolutely agree that that's where the money is.

Speaker 2: I've got to respond to one thing he said. I just spent my time defending my position that despite what the right thing to do is on carbon pricing, I'm not prepared to assume we're going to do it. And this gentleman said, if it's the right thing to do, we ought to be advocating that we do it. And I say, "Well, it's probably not very realistic." You say that changing over the asset base, the power asset base, a significant percent by 2030 is too hard, and we're not going to do it. We should do it. And if you put the right price on carbon and if what happens is what I think would happen, if it's the right price on carbon, there will be that asset base turnover. And I can guarantee you that we'll turn over the asset base in consumer electronics in this country five or six times during that period of time. And I don't see any moral argument for why you should treat one differently from the other.

Moderator: That'll be the last word.

Session Three.
EPA Clean Power Plan: What Now?

After receiving a huge volume of comments on its proposed rules, EPA issued its Section 111(d) final regulations in the Clean Power Plan. The agency's pronouncements are already being critiqued substantively and challenged both politically and legally. The final rule setting emission guidelines includes important changes from the proposal. In looking forward, it would be useful to first look at what changed from the proposal the agency first published and the final rules, and why. What motivated the changes, and what, if anything, did they accomplish? What is the significance, for example, of the reduction of building blocks from 4 to 3? Is the impact on the various states different from the original to the final version, and what is the import of that? Going forward, what are the relative strengths and weaknesses of the rules from a substantive point of view (i.e., how effective will it be in cost effective carbon emissions reduction)? What are the most significant legal vulnerabilities of the rules, and what are the probabilities of success for such challenges? If successful, what remedies are the Courts likely to impose? If upheld by the Courts, what will be the main implementation challenges? How should electricity market participants respond in this new world?

Moderator: Good morning everybody. The topic this morning is the EPA Clean Power Plan. What's next? What now? A very critical issue. I think when you look out over the next 15 years or so in the power business, this is going to be one of the things that really shapes the power industry in the coming years. We're going to talk about what is, I think, a very complex piece of environmental policy that's come out of the EPA. It kind of breaks some new ground in the way the approach was put together. We've seen a major pivot from what the draft proposal looked like, which was really kind of a bottom-up state formulation, to something now that's a national and regional kind of top-down approach, but it's produced some clarity about what states are going to have to try to do going forward. There's a lot of flexibility in the state implementation plans, so it's going to be important to think about what's ahead from a legal perspective--is this really going to fly? From an operational perspective--how's this going to affect the way ISO's power markets work? And also what the economic impacts look like.

Speaker 1.

Thank you. Here we go. I was thinking this morning that, I don't know if Bill or Ashley will remember this, but before the 20 years of the HEPG, we actually had a policy group that met at the Kennedy School on energy and natural gas issues. I can't remember if it had a name. It was something. It was before the HEPG was formalized. One of the first meetings we had of that group was a debate on whether Congress should repeal the ban in the Fuel Use Act on using natural gas for electric generation. That was one of the first ones we had, and here we are 22 years later, and we're about to discuss whether the Environmental Protection Agency has basically ordered and mandated that you can only use natural gas for electric generation. Twenty-two years. It's amazing how much change has occurred. I have a fairly big deck here, and I'm not going to run through everything. My view of this rule is basically that this is a market share rule, at the end of the day, and you'll see here that the EPA has effectively dictated the market share of each type of generation that each region of the country can have. They use the Eastern Interconnection as their modeling input, because they candidly admitted in their preamble that if they had used the Western Interconnection or ERCOT, the numbers that you see here on the bottom of the screen for the shift in generation would be far more dramatic.

So, as you see here, for the Eastern Interconnection the current split is 64:36 coal and oil and gas and NGCC, and after the rule, under EPA's own projections, the new mix will be 22% renewable, 48% NGCC, and 30% coal. These are EPA's numbers just for the Eastern Interconnection. If you put up the numbers for the Western Interconnection and ERCOT, the split would be dramatically different.

One of the things you all have asked us to discuss is what are the changes, so the changes in the rule have to be understood in this context. They were all designed primarily to address getting past what will be state petitions that at least 30 states, it could end up being as high as 33 states, will file within two days after the rule is published in the Federal Register, which could be any day now. At least 30 if not 33 states will file petitions for immediate stays of the rule. We will also have a group of utilities, a group of coal companies, and the Chamber of Commerce and some other individual entities file. There will be a number of stay petitions.

The EPA has designed its changes in large measure to try to avoid getting the Court of Appeals to issue a stay, and what they have focused on in a lot of the changes is two things. One, they've sought to eliminate what they thought was their most significant legal vulnerability, and we'll talk about that in a minute, which is when they eliminated Building Block 4 in the original proposal, which I think is what you were alluding to a little bit, when they explicitly removed as one of the requirements that states implement demand side initiatives, because that was the most stark, outside-the-fence measure that they had imposed.

Interestingly enough, they didn't really eliminate demand reductions. In the baseline that they have picked for each of the three interconnections, they've assumed a 1% yearly increase in demand, and 1% every year demand side reductions in the base case, so if a state doesn't ultimately achieve that 1% reduction, they have to find the emission cuts somewhere else. So, even though they have eliminated Building Block 4 explicitly, demand is still very much part of the rule.

The second thing they did was they've changed the initial implementation dates, so now, instead of September of 2016 being a hard date, now it can be a hard date, you can still submit your initial state implementation plan then, but EPA has also now said they will give waivers and extensions of that date up to two years based upon certain showings, and we'll talk about that in a minute.

Does anybody remember the mercury rule was struck down by the Supreme Court about three months ago? By happenstance (she obviously was getting bad legal advice) Gina McCarthy went on national TV two nights before the Supreme Court issued it's MATS ruling. She went on the Bill Maher Show. I don't why Bill Maher even knew what the mercury rule pending was, but obviously they had fed this to him, so he would ask the question, "How bad will it be if the Supreme Court strikes down the mercury rule?" On national television, she says, "It won't make a difference. We got past the stay, and because we got past the stay, we've had three years of forcing compliance on the utilities. We've gotten the reductions in mercury emissions we wanted, so it won't have any impact at all. As long as we got past the stay, it's fine." She actually said that on national TV.

There's a link to that video, maybe in the first paragraph of one of the stay petitions, interestingly enough.

So, when you look at these changes to the rules, you see what the EPA has done here. I don't want to go through all of these changes. I put these here so you can see what the changes have been, but you'll see that one of the big changes in the rule is that they've now gone from, as the moderator was alluding to, state-wide targets, and they've now done regional targets.

You'll see here that there's both a rate-based and a mass-based approach, so you can either cut emissions on a CO2 per megawatt hour basis, or you can have state-wide what's called a mass-based program, where you can eliminate CO2 on a state-wide basis.

And you'll see on this slide some of the numbers of what has to be done, showing the difference between the proposed rule and the final rule. Some of the other changes in the rule were, as I talked about, you'll see they changed some of the initial compliance dates, again designed to show that there's no immediate irreparable harm to get past the stay, and they've also, as we talked about, deleted Building Block 4.

Some of the other things that EPA did was that they increased in some ways and decreased in some ways the utilization rate that will have to be done for natural gas. There was a lot of criticism of the original proposal, saying that a 6% increase in heat rates was unachievable. EPA, in great bureaucratic speak, said the "refinements" of reducing those were based in significant part on the comments. But, in reality, because that original 6% number was a national number that was built up state by state, these new numbers for each of the interconnections, as you see at the bottom, as a practical matter, are no different than the original number when you actually apply it on a regional basis. Now, instead of a 6% national number, you have, as you see on the bottom, a 4.3% increase for the East, 2.1 for the West, and Texas is down to 2.3%.

Again, another change that they made that's pretty significant is in the original proposal, they had said that the utilization target for natural gas combined cycle was 70% of nameplate capacity. They've now changed that to 75% of summer rated capacity, which is about a 10% difference, but what's interesting is whether, in fact, as you see on the bottom of the slide, whether even this new number is achievable on any kind of a national basis. You'll see that in one of its technical amendments that they attached to their proposal, EPA itself admitted that only 67 of the units that were operating in 2012 could actually meet the 75% utilization rate. Why they put that in is interesting. I'm not exactly sure.

Again, another key difference was in the proposed rule, nuclear was explicitly mentioned and assumed. Nuclear is not explicitly mentioned at all in the final rule. It's assumed to be treated like any other type of generating capacity, and if there are certain units, for example the one that Southern's building, that now can be used, not explicitly but by application, in meeting Southern Company's, Georgia's or Mississippi's, baseline, because it's not considered to be an eligible unit as of 1/1/13, but it's not explicit. The way EPA dealt with nuclear was interesting in that sense. They had explicitly tried, in the proposal, to talk about nuclear as a way of obviously trying to get some of the utilities to be more favorable to the rule. Of course, the environmental community got very upset about anything that appeared to be pro-nuclear in the proposed rule. What they did was they eliminated the discussion of nuclear in the final rule, but the treatment actually turns out just as favorable to nuclear, if not more favorable.

The other interesting thing they've done is, because they've now changed some of the targets and they actually increased the national emissions target from 30 to 32% by 2022, it assumes that renewables will increase on a yearly basis between 2024 and 2030 for everyone in the country, so if you look at these numbers on the next page, the highlighted yellow is the numbers that EPA has assumed in its base case for each of the interconnections and it assumes for those four-year periods the highest number, which is the number all the way right, but in each category it takes that yellow number, and it assumes that that level of renewables can be added each year, not cumulatively, but each year between 2020 and 2024. Just look at those numbers for a second.

Now, what's interesting is, here's the numbers that they picked for how much renewable energy can grow. For example, when they picked the year 2012 for wind, that was the year in which the production tax credit was about to expire, so you see the big yellow bump there. That was the year we had this enormous amount of increase in wind because of the production tax credit--then look what happened a year later. What EPA has assumed in their base case for renewables target in order to comply is the yellow number that was achievable in that year and that is the number that has to be added for wind for every year between 2020 and 2024 in order to actually make compliance.

We talked about demand for a second. This is really the guts of it. It is a market share rule. If you think about what Pat Wood tried to do a number of years ago with standard market design, this would make standard market design blush. This is, as you go through what EPA has done, this is a market share rule. This is EPA dictating the fuel use market share. So, you see on the left, (this is the Eastern Interconnection again) what the status quo is in terms of generation market share, and then look on the right. That is what the end result will be as a result of the EPA rule for market share for fuel generation. Here it is again on a national basis. Here it is for the Western Interconnection. Again, all we're doing here is using EPA's own projected numbers in their technical appendix and applying it to the Western Interconnection. Here's ERCOT. These are EPA's own numbers. I did a couple of states. Here's Indiana, a red state. Here's Pennsylvania. Here's Maryland. I just picked some random states so people could see how the rule is going to affect the market share of generation in each state. Here's North Carolina; I picked that because I'm a Tar Heel. Here's Ohio, Michigan. I picked important battle ground states so that I could then do some fundraising when this was over. Here's Tennessee, and then here you'll see, in the final rule, 15 states had their emission reductions increased from the proposed rule and nine states can actually emit more than they did before. If you look at the nine states on the bottom and you look at the 15 states on the top, there's a pretty easy trend to spot. It's kind of interesting.

Turning to legal issues, dropping Building Block 4 was clearly an attempt to shore up the rule because 111(d) only speaks to stationary sources and reducing reductions of emissions at stationary sources. When EPA originally proposed explicitly including demand side reductions, they were quite sure that that was their most legal vulnerability. So they dropped that.

We also talked about the delay on compliance and the argument about the stays. We don't have to go through that again.

They've also tried to address the argument that the 30 or 33 states will be making under the 10th Amendment that the EPA is commandeering state legislatures by forcing state legislatures to enact new legislation in order to comply with the law. By moving the compliance dates back and saying, "You have all this flexibility to implement the rule," they're trying to address the 10th Amendment issues.

There's also this whole question, we could have a whole other HEPG session on whether the so-called reliability safety valve that they've included has any real effectiveness.

You'll see here that we have this official standard, so at the end of the day, what this rule really comes down to is whether the EPA can restructure. This is an electric restructuring rule. It's based on EPA's interpretation of five words in 111(d). "Best system of emission reductions." Five words. It really turns on one word, "system." EPA has taken the position that the word, "system," enables it to effectively go outside of the fence, beyond the stationary source of each electric generator, in order to impose these market shares. Ultimately, what the Court of Appeals in D.C. and the Supreme Court will have to resolve is whether those five words and that one word enable EPA to restructure the electric industry in a way that clearly FERC and the states could not do on their own. Thank you.

Speaker 2.

First, I'd like to thank Ashley and Bill for the invitation to come here and talk. One of the things I want to do before I dive into my presentation is to refer you to something that Bill has posted on the HEPG web site, but it also happens to be tucked way in the back of your folder. There's a paper, about 30 pages long, talking about a lot of the dangers that lurk in the rule and how states could really implement this and make a mess of things. I think it comes down to one thing—in order to not make a mess, put a price on CO2 emissions, but to get through the details, I strongly urge you to take a look at Bill's paper on that.

So, with that endorsement, let me go ahead, and I just want to step back for a second rather than diving into the rule. Let's think about the final Clean Power Plan, and let's think about the context. I'll put this in a PJM context. As many of you know, my first degree's in history, even though I am a bit of a math geek, but I think it's important to understand history and what the forecasts are.

The first thing is we had this thing called shale gas. It's not just in Pennsylvania and Ohio (and New York, if Governor Cuomo ever decides to tap that resource), but you've got shale gas everywhere. You have it in Texas, Oklahoma, Louisiana, Arkansas. We are probably going to see more of this coming about as time goes by. If you look at the forecast for natural gas (and the forecast I've got here is from HIS), you see under $4 dollar gas out to 2025. If you look at the forward markets, you don't see over $4 dollar gas until January of 2024. EPA, in its analysis, used well over $5 dollar gas.

In our initial analysis that I'm going to show you of some of the results from the proposed rule to kind of just give you some intuition, our gas price in 2020 was $5.25. If you think about what's going to happen with this, gas is truly under $4 dollars. Some of these new combined cycle technologies, like the 501J Mitsubishi single-shaft one-on-one combined cycles, have a stated LHV heat rate of 5800, and they could probably get down even lower than that, judging from what some of the people testing this are saying. We're talking about gas being dispatched ahead of coal at some point in the future.

Obviously, we all know about coal retirements. We've had about 26 gigawatts of retirement notices, not necessarily all coal. Some of it's been old oil-steam, gas-steam units, stuff in New Jersey for the high electricity demand day rule, but effectively we've weathered this without any major resource adequacy issues or anything of the sort. Now, a lot of those units probably would have disappeared in the current economic environment, with low demand and low gas prices, rather than just MATS. To Speaker 1's point about Gina McCarthy, yeah, I kind of wish Gina hadn't said that, but she wasn't speaking out of school. Everybody and their grandmother knows that a lot of the units that were retiring were going to go away anyway, in large measure because the economics had simply turned against them. The vast majority of the units that retired, contrary to popular myth, were subcritical coal built before 1970, so they were grandfathered under the 1970 Clean Air Act. They had high heat rates. They didn't run all that much. It really didn't hurt the system all that much to lose them.

However, going forward, the Clean Power Plan, that's going to be probably a little bit different. Now you're going to start having to go after the more efficient units, some units that may have already done MATS retrofits, things of that nature. Just something to keep in mind.

Obviously, we've had the changing resource mix in PJM. We now have, for the first time, more gas-fired capacity than coal-fired capacity going forward. We still have a lot of nuclear capacity in the ground. You've got demand response. You have some renewables. (By the way, the renewables on this chart are nameplate capacity, not the capacity value. The capacity value on those renewables is a drop in the bucket, maybe, if you're lucky, a shade over two thousand megawatts), but the changing fuel mix is different. As of 2015, gas is about 21% of total energy. Coal is still 40% of total energy, actually 39.5%, to be technical. Nuclear's still solid at around 35-36%. The rumors of coal's death, to paraphrase Mark Twain, have been greatly exaggerated to some degree. Take some of the slides that Speaker 1 showed, for example. Contrary to popular myth, in some of those key battleground states, you didn't see coal disappearing in Ohio. You didn't see coal disappearing in Kentucky or West Virginia or Indiana necessarily. Coal is still going to be around.

Finally, just to kind of give you the context, what's been happening since 2005? We've had declining CO2 emissions rates along with criteria pollutants, NOx and sulfur dioxide, largely because of changing resource mix but also largely because of the so-called Building Block 1, the heat rate improvements. There's probably not a whole lot of heat rate improvements left. Yes, EPA went back and revised this. Now it's about 2%, maybe up to 4%, but the truth is, in wholesale power markets, there was a great incentive to get those heat rate improvements. I think you're seeing that in the CO2 emissions rates here system-wide. It's not like we saw nuclear jumping up. We saw a little bit more gas, but that doesn't explain those declining emissions rates in 2005 to 2007. The heat rate improvements have already been done.

When you really look at the goal of a 32% reduction of CO2 emissions from 2005 levels, we're about halfway there already, so, really what we're looking at is somewhere between 15%, 16%, maybe 18%. We've already gotten a long way there. There's the headline number and there's the reality of where we go from here. That's the context for this.

What are the details? I'm not going to get into some of the deadlines. By the way, for those of you who haven't noticed, nothing's been published in the Federal Register yet. Think that has anything to do with the Conference of Parties coming up?

Speaker 1: No. No, it really doesn't.

Speaker 2: You don't think so?

Speaker 1: No.

Speaker 2: OK. I'd be interested to have that discussion.

Speaker 1: They're engaged in a battle royal with the Federal Register people over getting it published, but that's not a Harvard-level conversation.

Speaker 2: OK. Anyway, I've listed some of the changes. Speaker 1 has gone through a lot of this stuff. I don't want to get into it. There are just some other changes that I want to highlight that are actually a little bit more institutional and that I think are important here.

One is that there's multi-state compliance under the guise of plans being trade-ready, which didn't exist in the proposed rule. The proposed rule almost looked at multi-state compacts of some sort. That's gone. We're now looking at states that can act independently and be trade-ready and let markets evolve on their own.

There's a big emphasis on trading, something the proposed rule seemed to avoid like the plague, and I'll get into that a little bit more.

Halleluiah, they did actually put the words, "reliability safety valve," in the rule. I'll explain kind of my interpretation of EPA's thinking on this and what's OK and not OK about what's actually in there with the reliability safety valve.

So there are those issues, but there are a few other nuances here. One is the way the goals were set, which was on an interconnection-wide basis rather than on a state-wide basis. The other thing is that combustion turbines, just simple-cycle CTs, are gone from the rule completely. Can you see an incentive to run a bunch of CTs that for compliance purposes have zero emissions? That's probably not going to work out terribly well.

There are other things that have changed here. The compliance dates, Speaker 1's gone through all of this stuff. I don't want to belabor the point, but there is one thing that he did bring up, and that is that there is a deadline of September, 2016, for initial state plans or requests for extensions. Previously, under the proposed rule, those requests for extensions hinged on trying to work with other states in a multi-state plan. Now, you could pretty much ask for an extension for any reason, because you're working on it, you don't have time to go through the stakeholder process, you're doing analysis on it, and so forth. I think there's going to be wide latitude in states getting the extension, because the reality is, no one's going to do a state plan in 13 months. It's not just feasible. It's just not going to happen. What's somebody going to do, choose a federal plan that's not even finalized yet? They don't even have that option, so I think extensions are going to be fairly easy to get.

Here's where we kind of hit the "best systems of emissions reductions" concept. It's interesting. I've gone back and re-read that section in the rule fairly carefully recently. What is striking about the best systems of emissions reductions and the changes to the rule, going from a state-based setting of the emissions rates to an interconnection-wide setting of emissions rates. EPA is actually recognizing, to their credit, finally, that, yes, electricity knows no state boundaries. There are RTO markets. There's interchange between RTO areas and non-RTO areas in each interconnection, except for Texas, which is its own market in interconnection, but they understand that everything happens interconnection-wide, that there's trading. Moreover, they also, if you look at the best system of emissions reductions and you read the language carefully, they're almost assuming that emissions trading is going to take place in order to get the best system of emissions reductions. They make no bones about it in that section of the preamble, that emissions trading is really implicit in all of this.

Another change is to how nuclear is treated. The existing nuclear was taken out because 1) you're going to have varying state impacts, but 2) because they claim to want to be fair, because they're only using incremental renewables, so that's how they got rid of the existing nuclear problem, so to speak. On the new nuclear problem, they looked at nuclear as a compliance option and said that, as part of the best system of emissions reductions, it's not a cost-effective compliance option; therefore, we will not put it in the best system of emissions reductions. If you get it, great, lovely, but we're not going to bake that in to setting the requirements because it's expensive. That's another interesting feature here.

Finally, new gas combined cycle could have been part of the compliance option, but there are two problems. EPA kind of waves its hands and says, "Oh, by the way, it's regulated under 111(b), and we can't put it in here," which is true, but then they make this big production about how much more expensive it would be to build new gas combined cycle as a compliance option to go forward.

The changes to the final emissions targets Speaker 1 has gone over, but it's basically adjusted for renewables and zero-emitting resources across the interconnections, and it's going to be based on the least stringent of the interconnections, as Speaker 1 has talked about.

And there's the proposed federal plan, which is basically saying to the states, "If you don't do something, we're going to do it for you." The proposed federal plan is an emissions trading program, whether it's a mass-based trading program similar to the SO2 trading program, or it's a rate-based trading program, something we haven't had much experience with since the phase out of lead in gasoline back in the 1980s.

Then, of course, there's the reliability safety valve in the final rule, but it's been excluded from the federal rule. Why? Because the federal rule as it's proposed is an emissions trading program. EPA's logic is that if you're in a trading program and a unit is needed for reliability, say a specific unit wishes to retire, that we can still run the unit; it could go out and buy allowances and continue to operate until such time that it is ready to shut down. There's no problem with that. As opposed to what states could do under the final rule, which is set an emissions rate target, I would refer you to Bill Hogan's paper here, for each specific unit and once the unit hits that limit, it's done. You can't run it anymore. The only way you can run that is by changing the state plan.

Some other fun facts here. New natural gas combined cycles and CTs can't be used for compliance in a rate-based program, so for all those people that think, "I need load growth, so I'm going to go rate-based," not so fast, my friend. There are no new gas combined cycles in the rate-based program, which means that if you're a coal-heavy state, say, like Ohio, like Kentucky, like West Virginia, and you retire a unit under the rate-based approach, it doesn't help you, because you've still got a bunch of coal, so your rate's still going to be high. If you build a bunch of new combined cycle gas, that doesn't help you, because it doesn't count.

Under the mass-based program, ironically enough, the EPA wants people to include new gas combined cycle somehow for the so-called "leakage" issue (leakage from existing combined cycles to new combined cycles). They've got a couple of funky ways to get around that. One is to expand the program to bring the new sources in. There's a question of whether anybody can actually do that. I guess states could opt to do that. It's technically more stringent than the EPA rule, and that's always allowed, to have the new source compliment, or you could do the 5% set aside to subsidize investment in renewables and, of course, those renewable resources, once built, will then have to monetize that to accept the subsidy. You still have the same amount of allowances in the system.

Oh, by the way, the new natural gas combined cycle still helps you, except now you've actually reduced the price of those allowances with all of the renewables, and supposedly you're going to reduce new natural gas combined cycle dispatch, except there's one problem. Even though the new natural gas combined cycles were more efficient that the existing, it's still going to run more. A bit of a flaw in the logic.

So let's talk about the reliability safety valve. As I mentioned, there is one. Now, EPA has really hung its hat on trading avoiding the need for a reliability problem. That's probably true in most cases, but I can't unequivocally say it's going to be true in all cases. What EPA really has envisioned with the reliability safety valve is a very stringent, almost unit-specific command-and-control type standard, an emissions rate standard of mass limit one-time restriction that exists for a lot of units today under their Title 5 air permits for criteria pollutants. That would make it very difficult to operate the system. Under the terms of the reliability safety valve, there's a 90-day grace period, I'll call it a forgiveness period, where any emissions from the unit needed for reliability would be exempt from the Clean Power Plan, or exempt from Clean Power Plan compliance. There is a provision tucked away into the preamble to the rule, saying that states could then automatically, very quickly, revise their state plan. EPA doesn't address how state EPAs will actually do this in a 30-day period, but they mention a 30-day period, and that without EPA approval, but the the new state plan to address the reliability problem will presumably be approvable by EPA. It kind of stops there. So, there are a lot of details to be worked out.

Anyway, at the end of the day (and PJM states are mostly better off, except for the coal-heavy states), you'll see that with the final and interim targets, the coal-heavy states, the Kentuckys, the West Virginias, the Indianas of the world, Ohio, are going to be worse off or slightly worse off than under the proposed rule. Actually, we have a less stringent emissions target overall, on a mass basis, within PJM.

Now, there are some things I want to point out here and just mention very quickly. There are some key take-aways as we go through this and we think about state plans. That we're on a regional dispatch-type system, and that if you put in energy efficiency or renewables or any other zero-emitting resource, it's going to displace the most expensive thing on the system, and under EPA's assumptions of gas prices and under our assumptions of gas prices when we did our initial analysis, what's going to be the most expensive unit in the system? Gas. So all those renewables, they don't displace coal; they displace gas--the very gas that you're trying to redispatch to. That's kind of a problem. I mean it's not a problem, but all of a sudden those renewables and energy efficiency don't get all the bang for the buck. And oh, by the way, because you're in regional dispatch, putting renewables in Illinois (as you can see there's a whole boat load of renewables in Illinois) doesn't displace fossil resources in Illinois. It displaces fossil resources that are more expensive on this system. Well, to the east, in Ohio and Pennsylvania, is where they get displaced. So you can't even take credit for it within your own state.

So, when you're devising a state plan, thinking, "Oh, I'm going to just try to keep this all in state," it ain't going to work, because of regional dispatch. Even if you tried to go it alone, regional dispatch will prevent you from gaining those benefits. The same is going to be true with emissions on this.

Now, with respect to regional versus state compliance, all I'm going to say is one thing here. Regional compliance is going to lead to lower overall cost than state by state compliance. The same is going to be true today. It's also going to lead to less at-risk generation. If you're really worried about coal-fired units going away, regional compliance is your best solution. For example, in our analysis in West Virginia (this is probably the most egregious example that I can think of off the top of my head), if West Virginia went it alone, they would face a very high CO2 price. It would actually raise wholesale prices to their customers by more than going with regional compliance, and they would also decimate their coal industry and their coal-fired generation, reducing their coal-fired generation by 25%, versus regional compliance options. That sounds like a lose-lose to me. Yet, the politics are, "We've got to keep it within the state. We can't do this regional trading program. Trading is so bad." Not really. It's going to be that way for many of the coal-heavy states, but West Virginia is probably the most egregious example of that. At the end of the day, regional compliance makes sense.

What's the best way to do regional compliance? Let me come back to the punch line. Put a price on CO2 emissions, not necessarily a tax. Make it cap and trade. Let the price be discovered endogenously through market processes, just like we did with the sulfur dioxide program. Just like we did with the NOx budget program. We have experience with this. People can put that in their offers. We can manage the system reliably. If states go down the road of trying to hide the price and actually try to run time-restrict units, it's going to create and operational nightmare for us that we're going to have a hell of a time handling, and we're probably going to end up at FERC asking for new authorities to make sure we can manage this system. With that, I'm done.

Question: I thought at one point in your presentation you said coal was going to be on the margin, and then in another point in your presentation you projected natural gas to be on the margin. Was I hearing you right, or…?

Speaker 2: I think you were hearing me right. If you think about gas prices and where they're forecasted to go today, a lot of those gas units are going to be inframarginal; the newer gas units will be inframarginal and the coal units will be on the margin more often.

Questioner: So they'll get displaced?

Speaker 2: They'll get displaced. However, if gas prices are higher, which is the assumption that we did our study under and what EPA did for its study, gas is marginal.

Speaker 1: Hold on a second. Let me just clarify one thing. The EPA in its rule listed four criteria that a state has to address specifically in order to get an extension of the original date. You have to identify for EPA in that extension request what state laws need to be changed and what's the legislature's plan for doing so. You have to identify an initial plan for what units you're planning to retire and where you're planning to build new units and new transmission in the extension request, and you have to have engaged in "meaningful engagement" with the public on those preliminary plans, and that has to be done within one year. So getting an extension may not be as simple as people think. I just want to clarify that.

Question: Yes. This might be a question for both speakers. My understanding, or at least how I view the reliability safety valve, was that it exists in the final rule, and it would encompass either compliance pathway or even if you've been FIPed, you could still invoke the reliability safety valve. Is that incorrect? Speaker 2, what you said is that there's no reliability safety valve in the proposed federal plan/model rule. So, in the event you get FIPed, would you not be able to invoke the protections of the reliability safety valve?

Speaker 2: That is correct as it is proposed now.

Comment: But it ultimately can't be the right answer, right? That is the way it's proposed now, but it ultimately can't be the right answer.

Question: Speaker 2, on page 15 of your presentation, can you clarify what you mean by "compatible rate targets?" Second bullet point.

Speaker 2: OK, so, really what I should have just said here is that the rate-based trading can only occur between states that have a rate-based plan, period. So, mass can trade with mass, rate can trade with rate, but rate can't trade with mass.

Question: Speaker 2, on page 7 there you have the PJM average emission rates. Is that PJM overall, or just the units that are subject to the provisions of 111(d)?

Speaker 2: This is PJM overall, so that also includes nuclear renewables, et cetera, et cetera.

Speaker 3.

Thank you. I'm going to share my perspective, which is broadly similar in many respects to what Speaker 1 had to say about legal risks for the Clean Power Plan, and then provide a little bit more detail on some of the challenges for state compliance that relate to the details of the plan.

A famous Yankee died this week, and I thought I'd just sort of take his words as a way to frame the talk. I'm a Giants fan, but we can share respect I guess. "It ain't over 'till it's over."

One thing to say about this plan right now is that we don't really know what the outcome is going to be in court. I think the approach the EPA is taking creates tremendous legal uncertainty, and that legal uncertainty is unlikely to be resolved until, at best, sometime in 2018. I think this is going to go to the Supreme Court. It's very hard to see, with as many states bringing the challenge as are bringing it, that the Court wouldn't hear this case.

What does that mean? A former student of mine who now works at Citi in the energy group, Richard Morse, said to his clients, this means that the shadow carbon price is somewhere between $0 and $50 dollars per ton, and we're not going to know what the actual price of carbon is, or if states adopt some sort of explicit carbon pricing frame work, for some time.

So I'm going to talk about legal risks and some of the most significant legal risks that I perceive for the rule, and to some degree I share some of Speaker 1's concerns, but I'm also going to talk about some slightly different risks that we haven't focused on so far today.

One is the new source rule. That's a picture of the capture component of the Kemper County facility under construction. The existing source rule, right, the rule that we're talking about today, the Clean Power Plan, is authorized under section 111 only once a rule for new sources has been finalized. Then, of course, the new source rule was finalized on the same day as the existing source rule, and it is also subject to challenge. The new source rule, as probably most people know in the room, requires partial CCS for new coal plants, based in large part on EPA's view that Kemper County and Boundary Dam and other projects that demonstrate components of coal carbon capture, or pilot scale projects, show that the technology is in the terms of the statute adequately demonstrated. Of course, the key language here, as previously mentioned, is that EPA has to frame the standard for an emissions source in terms of the "best system of emissions reduction that has been adequately demonstrated," taking into account costs.

A key legal question: is coal with CCS "adequately demonstrated?" Is EPA's judgment that coal with CCS is an adequately demonstrated technology, taking cost into account, reasonable? I think we don't know on that one. The law on this "adequately demonstrated" language really dates from the early days. NSPS (new source performance standard) is not used terribly often, and the key cases that are the precedents that drive this come from the late '70s and early '80s. I think the court is very different today. Certainly, Kemper County is not painting a picture, currently, of a technology that is adequately demonstrated taking cost into account. That remains to be seen. There are some questions about whether Kemper County can even count as an example. It'll be interesting to see if they lose their tax benefits, as they're likely to do, because of delays at this point. That actually opens up the possibility that it could count as an example somewhat ironically.

There's a real question here. If EPA doesn't have a 111(b) rule to rely on, they aren't allowed, I think, to promulgate a 111(d) rule. That could stay the existing source rule until EPA goes back and fixes the new source rule.

I'm just going to talk about some other key legal issues, some of which you may have heard about, some of which maybe not. There's what I think of as the dueling statutes issue, right, the problem that the House and the Senate versions of the 1990 Clean Air Act Amendments contain inconsistent language about whether or not coal-fired EGUs that are already subject to MATS can be covered by a 111(d) rule for greenhouse gases. I think there the EPA is likely to prevail. There's pretty clear precedent, a relatively recent to the Supreme Court precedent, from this Court, that says that as long as the agency's interpretation of these kinds of ambiguities is reasonable, they win. So, I view this as one that EPA is more likely to prevail on.

Speaker 1 has already talked about the beyond-the-fence-line issue, and I don't have a lot more to add there, except to say that this is uncharted territory. I agree that EPA is leaning very heavily on the word "system." Actually, I'll add one thing, which is that I think a key question, and one that EPA made some attempts to address in the preamble to the rule, is whether they can articulate a limiting principal. If you say "system of emission reduction" is how you're going to define goals moving forward under section 111(d) (and, of course, there are other source categories that are coming down the pike so far as the regulated community is concerned in this respect--you could think about refineries as being the likely targets of subsequent rule making, potentially), and if EPA's allowed to move beyond the fence line in electricity, why can't they move beyond the fence line for refineries, and what would that look like? Would it go upstream? Would it go downstream? What does that mean? I think the key question that a court will have in thinking about the beyond-the-fence-line issue is this: is there an articulable limiting principal that cabins this move to the electricity sector? I think there is, if it's made carefully, and that is that the electricity system is one single machine that is synchronized and operates as a single machine. Most other industries simply do not work that way. Whether the court buys that or not, I think, is a separate question, and I don't want to minimize the risks that exist here, but that's going to be a key legal move that EPA has to make in order to prevail on that.

The other question that is going to come up, and this is in Speaker 1's slides, but he didn't emphasize it, and I think it can't be over-emphasized, harks back to the Clinton administration and attempts to regulate tobacco or cigarettes as a drug delivery device under the FDA Act. This led to a case called *FDA v. Brown and Williamson* in which the Supreme Court said, "You know what? Even though there is ambiguity here, and normally when there's ambiguity in a statute, we'll defer to an agency's interpretation of their statute as long as it's reasonable, in this case we're going to do something different, because the broader context in which the statute was enacted, the broader context in which Congress has made other actions, matters for determining whether the move is a reasonable interpretation of the statute." In that case, as probably everyone remembers, the FDA lost, the Clinton administration lost. That was another case, interestingly, where I believe the states filed in the district court challenging the move when it was announced in a press conference. It sort of reminds me of this instance where there have been so many attempts on the part of the states, sort of a preemptive action before we actually have a final rule in the Federal Register. They lost then, too.

But there's this broader question about whether this is EPA over-reach, right? Is this EPA trying to regulate the entire electricity sector, and even if they can interpret the statute and the ambiguities in the statute in some way you could characterize as reasonable, the Court may look beyond that. The most recent example of this that actually you should look to is *the King v Burwell* decision, the Affordable Care Act decision, where the Supreme Court said, "You know what? There's actually plain language here that means that the Obama administration should lose, but we don't care. Because if you look at the broader context of the statute and how the statute's supposed to function, this can't be right. That result can't be right, so we're going to ignore the normal process for deciding these kinds of cases that are governed by *Chevron v NRDC*, the sort of Chevron two-step that I teach in my administrative law class, and we're going to say, look, this has to be the way that this case comes down." I think there's a real risk, and the Court has been signaling to EPA that this risk exists, that this will be viewed as a bridge too far, that EPA will have gone beyond what the Court views as a reasonable extension of its jurisdiction on the Clean Air Act, but we don't know.

What if EPA loses? If EPA wins, we kind of know what happens. States have to try to comply. I think if EPA loses, they're likely to lose big, in the sense that the rule will be vacated, but what does that mean? Does it mean that power plants won't be regulated in terms of their greenhouse gas emissions? I think not. There's clear law, settled law, on that point, which is that greenhouse gases are an air pollutant. Power plants are a major stationary source of greenhouse gas emissions. Regulation is coming. It will just be that it comes later.

I think an EPA loss implies a delay to 2019 at the very earliest for a final rule, which is significant in a number of respects. Someone mentioned the COP and our international commitments. The Clean Power Plan is a key piece of the INDC (intended nationally determined contribution), the target that the U.S. has submitted leading up to the Paris negotiations. I think (this is my guess and this actually comes from some work that Michael Levy did) that the sort of voluntary early action crediting in the final rule is really there so that the Obama administration can claim that there's some way that they're going to comply with the Copenhagen Accord commitment. Because notice that moving the date for the Clean Power Plan interim compliance to 2022 means that there's no rule enforced to reduce power emissions in 2020, which is when the Copenhagen Accord target applies.

One issue of major significance is the impact that losing may have on U.S. credibility on the world stage. Of course, we will have done the deal in Paris by the time this all comes down, but this should sound a little bit familiar. Have we heard this story before? Think back to 2001 and the damage to U.S. credibility that occurred because we agreed to something in Kyoto and then decided not to do it--a very negative outcome from a U.S. negotiating perspective, particularly if China is seeming to be willing to do things.

I want to change gears and talk a little bit about context. I'm in a room full of energy economists, and that makes me a little nervous, but I'm going to do it anyway. I'm going to say, "The future ain't what it used to be." What do I mean by that? I think the biggest context that matters in terms of Clean Power Plan compliance and the overall stringency of the rule is demand. EPA has made it clear that states can move to mass-based compliance, and that basically means assuming some baseline for 2030 electricity demand. What baseline does the EPA recommend? They say, use EIA's baseline, use NEMS (the National Energy Modeling System).

This slide is just a plot that shows the evolving pattern in actual data, as opposed to an EIA forecast, of GDP versus total electricity sales in the US, and we all know the pattern here. Everybody knows it, but I think it's important to look at it and think about it and think about projecting that forward. What's causing that pattern (of declining energy intensity)? I think there are lots of stories you can tell. The folks that think a lot about energy efficiency will tell you, "Oh, it's building envelope," and there's sort of a technology engineering story about it. That may be right. I come from a place where this story is about, how do you create economic growth? You make apps now instead of building things that are made out of steel. That may be part of the story. Probably there's lots of stories that are true that explain this figure, but the point is the figure. And I'll just show one additional figure. This is annual growth in total electricity sales--percentage growth over that same time period. There's the data in black (a line heading jaggedly down), then the AEO 2013 forecast (which is what EPA's using in the rule) is the sort of light gray there. EIA likes to plot this sort of quadratic fit so that the data and their forecast are consistent, but you could have easily put a line through that data, and probably the truth is somewhere in the middle. NEMS and EIA forecasting is sort of a lagging indicator of reality. That's right. EIA should be conservative, but in this case we're projecting out to 2030 and letting states convert from rate to mass based on that very conservative baseline.

If I were a state that had a lot of coal and I didn't want to do a lot in the Clean Power Plan compliance world, I would convert to mass. Life is good. Take that hot air when you can get it. This is why I actually don't think the Clean Power Plan is going to be tremendously impactful. In terms of its stringency, if it survives legal review, it will be impactful in terms of establishing a framework. I think this is another thing to bear in mind. Once a 111(d) frame work is established, there's a long history of tightening the rules. If you sit down and do the math on the U.S. INDC, we are nowhere near complying with it, so I think there's a reality, a likelihood, that a subsequent Democratic administration might, if this rule survives challenge, think about tightening it. You would be able to justify that, I would say, by the fact that by the time we get there, probably the EIA baseline will be a lot lower. That's just my guess.

"You've got to be very careful if you don't know where you are going, because you might not get there." Let's talk about compliance challenges. One key issue, and I think this is raised in Bill Hogan's paper, and there's some work by Chris Knittel, and there's some modeling work that's been done by Jim Bushnell to look at some of the seams issues that come up when you have an electricity market region in which some states chose rates and some states chose mass. Lots of mayhem in the merit order there. Because recognize that a rate-based standard effectively subsidizes gas, whereas a mass-based standard taxes gas.

There are important coordinating issues that need to occur in electricity market regions. Hopefully, there's regional compliance, but we don't know. An important challenge there is going to be states that want to do more, and this is something we're thinking about a lot in California, a state that wants to do more, but doesn't want to see that effort exported to Nevada. If you link in a cap-and-trade program, it's actually very similar to the UK and the EU ETS, which we discussed yesterday. They have a floor price on carbon that's above the EU ETS price. What does that mean? That means Poland can burn more coal. California doesn't want to be the UK in the West, and there's a real question about how to accomplish that.

There's also a legal question about retaining flexibility in state climate action. That is, not putting everything in a Clean Power Plan compliance plan that's very difficult to change.

My last point. There's a whole set of questions around energy efficiency in rate-based jurisdictions. If that's in the plan, what's the baseline? How do you verify the baseline? What are the strategic incentives to game the baseline in a big way?

Concluding, there is significant legal risk here, and we're not going to know for two to three years what the outcome is. My bias is that low demand combined with a high baseline in the plan implies a low level of stringency, and that's going to incentivize mass-based compliance. Maybe that's what EPA wants, to get everyone in the trading program then lower the cap. That's possible. More generally, there's just a key problem in that we're dealing with sort of two separate sets of policies: the electricity markets, which have been moving toward regionalization for several decades, and the relatively inflexible Clean Air Act compliance structure, which means that EPA sets the goal, and states get to decide how to meet it. States, not electricity markets. Thank you very much.

Question: You indicated at one point that you thought the Court had signaled on the context question that there may be over-reach. Can you say what you meant by that?

Speaker 3: Sure. In the utility or regulatory group case they were clearly signaling. That was sort of a bizarre case in that EPA lost on the merits but won on substance. They got to do what they wanted to do, the Court sort of crafted a new way for EPA to do what they wanted to do, but there's language in that case, with Scalia writing the opinion but multiple justices supporting him on the other side, that EPA needs to be careful about a *Brown and Williamson* problem, about not trying to regulate the entire economy by the permission that the Court has given to regulate greenhouse gases under the Clean Air Act.

Speaker 1: There are three paragraphs in the *Utility Air Regulatory Group* decision that clearly and unequivocally say that we have to look at the context in which congress intended EPA to regulate in this space, and it cannot mean that, given that there are subsequent legislative actions like the 2005 Energy Policy Act that specifically reserve certain authorities to the states, for example, and give certain new authorities to the FERC, it cannot mean that EPA gets to ignore all that. It's pretty explicit and it's very flowery and Scalia-like writing, which is always fun to read.

Question: Speaker 3, if I heard you correctly, about halfway through you said that the big risk was that they would lose, they would lose big, and that the rule would be vacated, and then the next bullet on the slide said there would be a new final rule, so I guess the clarifying question I'm trying to get my head around is, if this final rule falls as not being compliant with 111(d), what new rule would occur in 2019 under what authority to replace it?

Speaker 3: EPA would still have authority under 111(d) to regulate, assuming you have a 111(b) rule. I think the 111(b) rule is curable. If EPA loses on the CCS idea, they're not going to lose on ultra super critical, for example, as the standard for coal, which, given the costs and given the economics right now, might have the same effect--no new coal plants. Then what happens? Then EPA has to take a more traditional approach under 111(d), probably. What does that mean? There are some people that think that means Building Block 1 only. I am not one of those people. I think EPA actually has a lot of room to be more creative about how they interpret 111(d) and stay within the fence line. My guess is, if EPA loses, they're going to lose on the fence line issue, and I think that they have a lot of room there to get creative, particularly given the repeated language in the statutes that they need to take into account the remaining useful lives of the facilities.

Let's talk about that. What is the average age of a coal-fired generating facility in this country? What if EPA were to say, "Look, at age 40 years and older, you have to come up to the new source standard." That would be very similar to how many 111(d) rules work. Like the large municipal waste combustor rule. If they did that, that's going to have a tremendous impact. If you said, every plant that's even 35 years and older has to come into compliance with the new source rule, has to retrofit to ultra super critical heat rates, that's a big deal, and that's a very traditional inflexible, not necessarily as cost effective, but legally defensible approach.

Speaker 1: The way I think about it is, what they could do if they get vacated in large part depends on how big they lose, specifically on what the word "system" means. If ultimately the Court says, "You cannot interpret the word system in any way, shape, or form like you've done," that's sort of one way EPA can go. If the Court says, "You have some flexibility, but you can't go this far," that's another potential scenario. Ultimately, it really just depends on how big they lose and what the Court says about it.

Speaker 2: Let's also keep in mind that if it stays within the fence line, now we create a whole other set of problems for how we actually operate the system, too. If you go down the road that Speaker 3 is talking about and everybody has to, at age 35 or 40, retrofit to ultra super critical, most of those units are gone at that stage, number one. Or one could stay within the fence line, and you do everything within the fence line, like you do under a normal Title 5 air permit for CTs that are usually emissions-limited on NOx and carbon monoxide and so on, and now I've got a bunch of units that are actually going to be run-time-limited. How do we manage that in operations on a daily basis? Be careful what you wish for, you might get it.

Speaker 4.

Thank you. Also, thanks to Ashley and Bill for inviting me. I was a little surprised when I found myself on this very legal panel, but it turns out actually I think it'll work well, since I think the first three speakers have given a lot of detail about what this final rule now looks like as compared to the original. So I'm going to take the liberty to sort of step back even further than Speaker 2 did and relate the discussion to the bigger picture that in some sense was discussed yesterday and particularly yesterday afternoon.

I'll also mostly say some things that only toward the end will ideally converge toward what my slides say. We'll see whether I succeed.

First of all, just some general comments from an economist about the legal stuff. I'm not entirely through the 1500 pages or so plus the 750-plus pages of the proposed FIP, 750. What that suggests to me is a pretty complex set of regulations. I remember the Waxman-Markey bill, which was a little over a thousand pages, was pretty complicated. I make that comparison quite deliberately.

So, one, it's very complex, and it's clearly not optimal. So, for me, one question in all of this is, if it's not optimal, how does it fare compared to the alternatives? An absolute ideal set of regulations is probably a very optimistic standard to compare this against, so in the end, this is the famous sausage-making process. In particular here, and this was alluded to in some sense a few times, it seems obvious that the Clean Power Plan is an imperfect response to not getting comprehensive climate legislation. I thought the Waxman-Markey bill wasn't particularly great in terms of its design, being also overly complex, so I'm not surprised that this is very complex.

It also strikes me that the way this was crafted originally and the way it was modified toward the final rule is clearly constrained by the EPA wanting this rule to survive. It's trying to box it in a way that sort of picks up some of the legal concepts that are established, as opposed to doing the things that make sense if you're doing comprehensive climate legislation, which it is essentially an imperfect substitute for. You mentioned the dropping of Building Block 4 as one important example of that.

That being said, having read part of the, whatever, 1000-1500 pages, plus a lot of sort of analyses around it, it strikes me in many respects that the final rule is a big improvement over the proposed rule. One, even though from a political economy perspective that may not play well, there is a much more significant burden on states that have higher emissions from existing resources. Speaker 1's list of sort of the states that lose…you could lay a political map over that if you want, but you could also just layer an emissions map over that, and you conclude that it actually makes sense. Take North Dakota. Under the proposed rule, they had very little incentive to investigate participating in some regional scheme, because they didn't have to do anything. That was because they decided not to build any combined cycle gas plants at some point. Minnesota, being the state next door, had gone ahead and built a lot of combined cycle plants, and they were being hosed in the proposed rule, so in that sense the shifting of where the emissions reductions ultimately have to come from, in my view, now makes a lot more sense.

Giving a little bit more time, I think, was legitimate. So starting in 2022 and getting rid of this perceived compliance cliff where the first year emissions reductions were very steep compared to the 2030 emissions reductions, so getting rid or modifying both of those elements, I think, responded to a lot of comments that the EPA received from the industry, and is actually sort of legitimate.

What was mentioned about putting the compliance obligation on the individual plants as opposed to on states, I think, is a big step forward. The trading ready option is also a big improvement. I remember us working with a number of companies that were trying to figure out how they would actually establish a regional trading scheme under the proposed rule and it is pretty complicated. I think the EPA, with what it did now, conceptually makes it quite easy. To the extent that you operate in a state that has adopted, say, a mass-based approach, then there could just be trading options that exist, and you don't have to ask the state. The state doesn't have to do anything. With respect to that last thing, actually (and I think, Speaker 3, you mentioned something to this effect), I wonder whether this is ultimately really the EPA hoping that everybody will adopt something like a mass-based standard, and then we basically do get Waxman and Markey. In that case, you would get, through the back door, a cap-and-trade system at the national level, I think.

What I found a little surprising is, it's staggering how complicated it is to figure out the various options that are put on the table. How I as a state would figure out whether to take any of the two to three mass-based options or any of the two to three rate-based options is complicated enough, but then, as I guess some of the papers have mentioned, figuring out how you run the system is another challenge. In PJM, say a third of the states use the rate-based scheme version A and a third of the states use whatever. It gets very, very tricky I think. That's unfortunate. I'm not sure where it comes from.

Now, I'm going to hopefully converge a little bit with my slides. I think a lot of discussion here has focused on the EPA setting the standard, which is legitimate, and obviously there will be a lot of legal fighting over whether that was appropriate or not. I think I disagree with Speaker 1 that it's a program that regulates market shares. This was a mistake that I think a lot of people made at the level of the proposed rule, where they interpreted what the EPA sort of showed and modeled to derive a BSER, they confused that with how the EPA thought the states would actually comply. Those two things are entirely different. There's nothing that I read (I haven't read the entire 1500 pages) that says that you in the end shall comply with the CPP by reducing your share of coal from whatever to whatever. In particular, if in the end there's a fair amount of trading that takes place, there's absolutely no indication and no obligation that you end up with a certain share of certain resources in certain states, so I think I disagree with that.

Now I'm moving to the slides, I think. I'm going to take the bridge to yesterday afternoon and focus a little bit on renewables as an example. The CCP does seem to push an expansion of renewables, particularly early on, unfortunately. This is actually the EIA analysis of the proposed plan. Maybe that's an indicator of the complexity. That was released in May 2015, a couple of months before the final rule got released, so the EIA obviously has not done any analysis yet at the same level of the final rule, but we can talk about what changed.

Here, you see wind on the left and solar on the right. The blue line at the bottom is kind of the forecast base case and the green line above is the change that the EPA assumed, in its modeling, might occur. This is not the BSER. This is the modeling that EIA did based on using NEMS, which forecasts what would happen. You see, all that stuff goes up some. To me, what's interesting is the wind goes up for a few years, and then basically it flattens out, in the original projection, and solar goes up a little bit.

This slide is a little more interesting to me, tying the discussion here to the bigger discussion. This is, again, wind and solar stacked on top of each other. The blue thing is projecting out, if by 2040 we're trying to be in a trajectory to decarbonize the electricity sector by increasing renewables to 80% of the mix by 2050. What I read out of this is two things. One, if EIA's projection corresponded to what might happen under the Clean Power Plan final rule, then by 2030 or 2040 we're going to be way below where we have to be compared to that trajectory of where things need to move. On a slightly more promising note, I think, at least for solar, the rate of change looks OK for a while.

A question that was raised yesterday a lot is, do we find ourselves in 2030 at a place where we have at least a possibility to reach what we may or may not agree is the right target by 2050? For that you have to put yourself on some trajectory. I think it's complicated to understand what exactly that trajectory needs to look like, but at least comparing the slopes of my blue line to the green line for a while, there's something that comes out of what the Clean Power Plan might do that sort of gets to growth rates of renewables that might, if you sustain them, actually get you in the right region.

In this graph I tried the same thing, except I used the EIA's projection. The red line is wind and the green is the solar. Then I tried to lay over that both a solid blue area and some dots. The solid blue area and the dots represent the German expansion of wind and solar, not starting in the same year. I basically went back to when Germany had the same combined wind and PV share that the United States has today and then I moved forward sort of year by year to understand how quickly the capacity for those two resources changed. The little dotted line is the path that the German government has set for itself to reach its own target, which is essentially the same. It also has a target of basically 80-plus percent renewable share by 2050. To get that, you need 65% or so by 2040, et cetera. The reason I did that was just to show how what the Clean Power Plan may impose on the U.S. system compares to what at least one other country has been doing for a while. My reading of this is that Germany has been ramping up renewables faster than the U.S., and faster or comparably to what the EIA thinks the Clean Power Plan will do to the U.S. system for the first few years between 2020 and 2025.

Yesterday we talked a lot about the cost of doing this; maybe there's another session of that at some point in the future. Germany did this with absolutely no impact on things like system reliability. As a matter of fact, it's fun to compare the reliability statistics of the German grid to the U.S. grid. The U.S. doesn't do so well in that comparison. It's an unfair comparison, since there are a lot of wires underground and things like that, but the reliability of the German system has actually increased quite dramatically over the last decade at the same time they have increased their share of renewables. There is a lot of discussion about the impact on reliability of these kinds of things.

As I think over the expansion of renewables that the Clean Power Plan will motivate, it's not clear to me that in general the RTOs, the large electric systems, are not capable with dealing with that expansion of renewables. I think what's actually more critical, and this is where Germany is facing problems now, is, if you wanted to get on this trajectory, then you really have to think hard about investments with long lead times that need to get made. In particular, I think that's investments in transmission infrastructure and perhaps gas pipeline infrastructure. In Germany, gas pipeline infrastructure is not an issue, since they're naturally phasing out gas plants just by retiring them because they're not economical. Transmission investment is a very complicated issue. Interregional transmission investment remains a complicated issue for many reasons that you all know. Germany is experiencing the difficulties that have to do with nimbyism just as much as anybody in the U.S. does.

Another topic that was discussed a lot yesterday was sort of thinking through the longer term, the seasonal storage, issues. Those are both issues that you'll have to face when you're on the top path (of fast renewables growth). I really don't think they're a serious concern if you're on the EPA Clean Power Plan path. Now I come to my final slide which motivates me in all of this. I read yesterday a long article that was in one of the publications about utilities, and one particular state in the mid-west that's lobbying very hard to have their Public Utilities Commission agree to very, very, very long-term PPAs with very old coal-fired power plants. The push back against the Clean Power Plan has not much to do with legitimate criticism of how well the rule is crafted. It has much more to do with the fundamental disagreement about whether or not we should do the bigger thing, which we didn't accomplish through the legislative effort. I'm more worried about what's suggested by this slide. This is kind of a probability distribution that shows the uncertainty about how doubling our greenhouse gas emissions might affect global mean temperatures.

Everybody's talking about two to three degrees' centigrade temperature increases, and that is where the mean of that distribution is, and the social cost of carbon is basically based on that kind of projection. For me, and having this discussion about whether this rule is a good rule or a bad rule, I think of how it relates to the tail of that distribution that shows that there's a greater than 10% chance that a doubling of CO2 concentrations will increase temperatures by six degrees or more. I think the last time temperatures were two and a half degrees higher, sea levels were 60 feet higher than they are today. We don't have a really good handle on the impact, although I do think we probably agree that the impact would not be very good, to say the least. If we wait until 2019, then one of two things will happen: that we are even further behind where we need to be in 2030 to provide some insurance against the risk of this catastrophic climate change might happen, or that CPP is even less relevant than it is today.

I'm not sure where I come out. I really don't know. What I try to say, is I don't find the renewables goals or the renewables projections that come out of the CPP very, very ambitious. I could see the dynamic in the market to be such that if you had no CPP, you would have higher renewable shares by 2030 than the CPP assumes will happen. But I am not sure, so that's why I have this last slide up here. What we do here, this regulation, should be part of an insurance policy, essentially, so in the case that business-as-usual does not get us there, we're having sort of a regulatory or a legal forcing mechanism to make sure we don't stray too far from this sort of path of our emissions or renewables that I think is necessary to provide some insurance against this risk.

Question: You mentioned grid reliability. Are we talking about the high-voltage transmission system, or are you talking about the distribution system?

Speaker 4: I'm talking both.

Question: You mentioned reliability was better in Germany than the United States, and the question I'm asking is, are you referring to reliability at the bulk power system level or at the distribution system level?

Speaker 4: That comparison was based on SAIDI (System Average Interruption Duration Index) scores basically.

Question: OK, so distribution system level,

Speaker 4: That's actually not quite right. The SAIDI scores include blackouts that would happen at the wholesale level, except they're very, very rare compared to the blackouts that you get at the distribution system level. Most of the difference between the U.S. and Germany is due to much lower distribution system outages.

General discussion.

Question 1. On the topic of German reliability, the German system hasn't gone black. But the number of N-1 violations in each of the four ISOs in Germany has skyrocketed. The number of N-1 violations has gotten to levels that in any of the ISOs in the United States would be deemed unacceptable. What's interesting about it is the Bundesnetzagentur, which is the state agency responsible for keeping track of and reporting on system reliability, which used to produce a monthly report on N-1 violations, as most of the ISOs do in the United States, about 18 months ago decided that was no longer going to be published. I talked to my friends in four German ISOs and they said, "Yeah, they really didn't want that information to be getting out, because it's a little bit embarrassing."

What's happening in Germany is the four ISOs are effectively operating in a state of heightened alert all the time. That's not a good thing.

My second point is that at the distribution level, voltage variations due to, in particular, momentary fluctuations in output from DER plaguing many, many voltage distribution feeders, particularly in the southern part of the country, and then to make matters worse, they discovered about 18 months ago that 10 gigawatts of the PV that they had installed, mostly, again, the southern part of the country had rate of change of frequency protection that was not within the limits of system tolerance. Now they are actively and very quietly trying to retrofit 10 gigawatts of PV with rate of change of frequency protection that meets the system criteria.

The question that I had, which was for Speaker 3, or anybody who's got an answer to it, is, Speaker 3, I thought I heard you say that the question about outside the fence was untrodden territory. At least I was under the impression that in the Supreme Court's decision on the tailoring rule, they trod into that territory just a little bit. I'm curious if I'm wrong on that.

Speaker 3: I tend to agree with what you're suggesting that the discussion on *Brown and Williamson* and the tailoring rule case is relevant. Yeah. The Supreme Court has made a sort of signal. On the other hand, the tailoring rule case is not an interpretation of section 111 of the Clean Air Act, so to some degree the reference there to, what is it, "finding mountains in mouse holes," is speculative at this point. Clearly, EPA is thinking about that. That's where Building Block 4 went.

The question is whether Building Block 3 is also vulnerable.

Speaker 1: You can look at the few times where EPA has actually tried to use 111(d) before in other contexts, and in each instance they've always assumed, and used as the compliance mechanism, an actual on-site at the stationary source emissions reduction percentage tailored to specific goals. Every single time they've invoked it, which hasn't been many, that's always been what they've done. So the ultimate issue is, if you read the language in the UAR (Utility Air Regulatory) case and you try to understand the way EPA has historically interpreted that language and the fact that they've now departed from that, that's going to ultimately be the context in which the court looks at whether they've exceeded their authority.

Speaker 3: Can I just make one follow-up point? Actually this is a question for Speaker 1 as much as a follow-up. The one place where EPA has been innovative with the new source performance standards is in their Clean Air Mercury Rule which is the rule that was struck down for reasons having nothing to do with EPA's flexible interpretation of 111 by the DC Circuit. There, EPA did implement a cap-and-trade program for mercury at power plants. The implementing language for section 111 that, well it's a little bit complicated right now, but the implementing language for section 111 allows for emissions trading because of the Clean Air Mercury Rule. We don't know how the court would have felt about that aspect of the rule. We never will. Is it fair, Speaker 1, to say that EPA's never done this before?

Speaker 1: Yeah, I think it's fair to say they've never done this particular, because in the mercury rule the type of compliance approach was because the nature of what they were regulating was dramatically different. I think, ultimately, it's a fair question and it's good to go back. EPA just argued to the DC Circuit…so, there's this big debate now about whether the mercury rule should be vacated, and EPA should start from scratch or whether they should be allowed to have a remand and build upon it. The DC Circuit has heard briefing on this two weeks ago. They're making that very argument that you just said. It's not clear how it happens, but I think that will be a precursor to how some of this will ultimately do, but the argument that some of the states and the utilities made was, with the nature of the regulation, the mercury rule is quite different than what they're doing here. How that gets resolved is going to be interesting to see. I don't know the right answer to it.

Question 2: Thank you for this panel which I thought was very helpful and raises a lot of important questions. I wanted to follow up on something that Speaker 3 said and that I think Speaker 2 also alluded to. I'm going to set aside all the legal issues and assume we go forward. Now we got these standards, and now a state is sitting there trying to decide whether to go rate-based or mass-based. The rule is complicated, but there's a little part in there that if you go mass-based, one way to deal with the leakage problem in new generation is to take an equivalent level of emissions that you would have acquired under the rate-based system, and now you fold in the new generation at this new cap, so everything is capped at this new level, which would be good for a whole bunch of reasons, if people actually did that. It's very hard (how many times have Speaker 2 and I gone around on this before?) to figure out what they're doing, but I believe there's this issue of whether the demand forecast is optimistic, because it's like 12% to 17% total increase in electricity consumption over this time frame. If you think that's optimistic, and if you think demand might be lower than that, and if you think the renewable numbers they've assumed in their setting the standard are high compared to what will actually happen, if you go in that direction, if you don't do anything else, then I believe the way to characterize what the EPA has done is they've said, "If we had a rate-based standard, which was targeted against these demand growth rates, these high renewables that we're projecting, all that kind of stuff, and if you were perfectly successful in arranging a national trading program to acquire renewables from faraway places like Maine so they could be renewables in Arizona, you will be able to increase your emissions under the rate-based system," and they calculated the mathematically highest number that you could actually get and still meet the rate-based standard under that assumption.

So, there are a whole lot of questions about whether that's achievable, if you could actually do it if you had a rate based approach, and all this kind of stuff--how much renewables would be available, and blah, blah, blah. By fiat, they deemed that you would succeed, and that that's the number for emissions that you're allowed to claim as they assigned to you as the equivalent emissions under the mass-based standard, and you don't have to do anything. You get this whole increment in emissions, and fold in the rest of the new generation, and meet the load growth. This looks to me like a very attractive sweetener for states to go to a mass-based standard. Am I interpreting this correctly?

Speaker 4: That's more or less the way I understand it. I think, that being said, the guidance on some of this stuff and the regulations themselves are not crystal clear, so there's going to be interpretation that happens in the implementation phase that will be important, but, yeah, that's my reasoning.

Speaker 2: Given the conversations that you and I have had back and forth on the side, and for everybody else's benefit, it is *one* of the sweeteners to go to a mass-based program. The other one is simply that if a coal-heavy state, if West Virginia or Kentucky or Ohio or North Dakota joined a mass-based program, I can actually take advantage of any incremental retirements that occur from my coal units, whereas if I'm in West Virginia, in order to get any benefit on the rate basis, because I can't bring in new gas now, I have to retire all my coal units in order to get the rate. That's the only way you can do it in West Virginia, period. It is really strongly pushing people into a mass-based program in that way.

Not only that, forget about the leakage issue. The leakage issue, in my opinion, is a lot about smoke and mirrors and trying to satisfy some of the environmental groups by saying, we don't want to push all this generation into the new combined cycle gas because it's regulated under 111(b), but it still has emissions, so we'll this 5% set aside. Immediately people's minds go to, "Ah, a 5% set aside means there's going to be 5% fewer allowances." No, there's not. Because that set-aside is going to renewable energy projects, so it looks like an investment tax credit, or it's functionally equivalent to an investment tax credit for renewables, to bring those renewables on. The only way you can monetize that tax credit is by selling those allowances back into the market, so, effectively, you're not reducing allowances by 5% and, effectively, if gas prices stay where they're at or where they're forecast to be, and actually that materializes, you're still going to shift everything to new combined cycle gas versus existing combined cycle gas anyway, because they're just going to be more efficient. A lot of the existing combined cycle gas fleet has heat rates in excess of 7200. The new combined cycle, as I mentioned, they're under 6000. They're going to run every time much more often than the existing combined cycle fleet, which would be regulated under 111(d). It's a bit of a smoke and mirror move, but I also think that is sort of to placate the environmental groups, to either do that or the new source complement, and it's definitely pushing people toward a mass-based program. Absolutely.

Speaker 1: Your question really raises a larger issue, because you are right. The incentive there is to go to a mass-based approach and a cap-and-trade. It's a palpable incentive for lots of different reasons. The question, ultimately, is if that's what we want to, we have to address climate. Everybody agrees we have to address climate, but is the right way to do it with this sort of buried incentive that is not entirely clear to push people to cap-and-trade, which is clearly what EPA wanted in the first place with Waxman-Markey? The question ultimately will be, Waxman-Markey failed. Disappointed as they are, now EPA has this sort of convoluted process by which the incentive clearly is to get there. The question is, is this really the right way to go about it? That's the larger public policy question. Is this sort of convoluted Rube Goldberg approach to get cap and trade really the right way you should go in addressing climate? That's a rhetorical question, but the answer's obvious.

Question 3: I have a few questions on "trading ready." At a meeting earlier this week, I thought I heard the Agency say that all it would take for a state to be trading ready would be to designate a specific tracking system. I want to get the panels' thoughts on that, and just other challenges you see to states getting to a point where they are trading ready and can work with other states on that.

Speaker 2: To me, "trading ready" requires not just a tracking system. It requires denominating what the commodity is. Is it going to be tons, under a mass-based program, or is it going to be an emissions rate, so pounds of CO2 per megawatt hour? I think that's a necessary condition. Yes, you have to have a way of tracking it, but also there has to be a compliance mechanism that says that you have to simply hold enough of these allowances or emissions reduction credits.

Let's assume for the sake of argument that it's a mass-based program, and I'll make no bones about it, that's the best way to go. You have to hold a certain number of allowances to cover all of your emissions, and the other thing that has to be put into the trade ready program is that the EGUs within the state can trade with each other and with EGUs in other states that have the same common characteristics in terms of the same tracking system, the same commodity type, et cetera, and be allowed to trade. It's really as simple as that. With respect to the tracking system, use EPA's tracking system. They've offered it up for everybody to use. Heck, it's a beautiful thing. Why not use that? You don't need to reinvent the wheel. That's easy. That's hitting the easy button. Then it avoids the whole interstate compact issue, trying to coordinate in meetings with other states. If everybody just does that, then it can easily take form.

Not to mention the trade ready concept also solves a lot of the seams issues across RTOs and non-RTO areas. Illinois is the perfect state for an example. You probably have heard me say this before. Suppose that the Illinois EPA and the Pollution Control Board come up with a rule, and it's trade ready; they say, you can trade with each other, and you can trade with any other state. All it requires is Illinois to do this and to trade with any state. It could be in MISO; it could be in PJM; it could be SPP; it could be in a non-RTO area. It could be California, for all we care. Especially between the RTOs, immediately Illinois's created a fungibility between the RTOs, by definition, because it has resources both in PJM and MISO, and it makes things so much easier. Missouri is another state like that, where Missouri could do this for MISO and SPP and make things a lot easier.

Speaker 3: I would just like to comment, and this really comes from my experience working with the California Air Resources Board on trading issues. Legally speaking that's all that's required to be trade ready. I think Speaker 2's response is accurate, but I think that actually to be trade ready, a lot more is going to be required. In particular (and this is something that air regulators are not generally experienced in and don't generally have the human capital to do well), you need to have a market. You need to organize a process for providing information to the market. You need to organize some sort of market surveillance. You'll also need to coordinate with any partners, where you are allowed fungibility of allowances in terms of surrender dates, all those kinds of things, because in the absence of that you create opportunities for problems to occur. I think it's not quite as simple as has been made out, just because from a legal perspective sure, trade ready might be fairly straightforward, but there's a whole set of institutional questions that will have to be worked. They cannot simply be surrendered to EPA's tracking system.

Speaker 1: The other two points I'd make real quick are, one, it's not entirely clear that the interstate compact issue is as simple to solve, as a constitutional issue, as EPA would suggest. That's a whole other conversation, but there's law on how that occurs. It's not obvious to a lot of people who are experts in this that it's that simple to solve. The second thing that's also interesting is there was a paper recently that said that about a third of the states, if you looked at the statutory authority that the air regulators had, they did not have the statutory authority to order cap and trade. I've never delved that deep into what that was, but there's at least some sense that a number of the states have to have state legislatures add to the statutorily delegated authority of their air regulators who have not traditionally had this authority in the first place in order to develop some of the things Speaker 3 was talking about, markets and other things. That's an open question as well, at least in a number of states.

Speaker 4: This is not addressing the legal part of your question, but one complexity relates to what trading approach you ultimately want to go to. So, as we have discussed, there's a choice between a mass based and a rate based approach, and I suspect there's actually an additional variable--I'm not sure whether all mass-based states can trade with each other even if one includes the new source complement and the other one doesn't, so the complexity here is trying to figure out what is optimal for the state to do, and that's an impossible chicken-and-egg problem. We all agree it would be nice to have one national system--then the thing is actually efficient. Ultimately the benefits to Illinois of going rate-based and therefore being able to trade with other rate-based systems depend on the artificial boundary that gets drawn by those states that adopt a comparable system. The allowance price in that system is higher or lower depending on where you draw the boundary, and therefore whether it's to Illinois's benefit to go down that route depends on who ultimately signs up for that specific system. Of course, you can't figure that out until everybody has, so I think that's a very, very complicated aspect of the rule. "Trading ready" sounds pretty simple, but then, ultimately, which path you chose specifically is quite complicated.

Speaker 2: Speaker 4, if I understand your last statement correctly, you're saying that it's possible for not being in a trading system to be better than being in a trading system where you have more options, that fewer degrees of freedom are better than more? That's basically what I understood you to say.

Speaker 4: No, I suspect that it would have always been better to be part of a trading system, but if you have to figure out whether you're going to go down the rate-based path or go down the mass-based path, the trade-off between the two depends on what I assume are my compliance costs, including what the benefit of being able to trade with other entities will be. What is going to be the allowance price in the mass-based system versus the rate-based system? Those allowance prices are a function of who is in those markets. Therefore, the advantages of me being in A or B depends on who else is in either A or B, which I don't know, necessarily, at the time I have to make the decision.

Speaker 2: You're talking about a sequential game, but the point you're also making, which is a good one that comes up, is that there are positive network externalities to everybody choosing a common measure. It's sort of like VHS or beta, yeah, back in the day. I guess it's showing. Cassette or 8-track? Those kinds of things. Once you decide that, there are positive network externalities of everybody going down the same road.

Question 4: My question concerns whether or not the renewable energy growth is ambitious or not under CPP, because comparing Speaker 1 and Speaker 4, I think Speaker 1 conveyed that growth is pretty ambitious under CPP and Speaker 4, I think, conveyed the opposite, but in so doing he highlighted a particular country in western Europe, perhaps being a little parochial. If I were being similarly parochial, I would highlight wind growth in West Texas, and everywhere else would look anemic compared to West Texas. So, really, my question is, what's the right metric of, is growth ambitious? The projections going forward are sort of comparing to business as usual, but how do they incorporate technology growth, particularly in solar? What's the right metric of whether or not the implied renewable growth in the CPP is ambitious or not, compared to what we might otherwise think of as ambitious? Has anybody got any idea of what's the right metric, and, given that metric, are we setting ourselves up for failure or not?

Speaker 4: I think the question actually has two components. Question A is, what assumptions are fair for determining BSER, as EPA has done, and then a second and obviously related question is, all right, assuming some kind of regulation is in place, how expensive is it going to be to comply with that? The natural rate of expansion of renewable energy will play a role here. I think Speaker 1 correctly pointed out, and I was a little surprised when I saw it, that on the BSER side, if you take this kind of approach where you look historically at what has happened, then the final rule is more aggressive than the proposed rule in that it looks at the last few years, and it takes, like, a maximum annual increment and it says, well, you can sustain that going forward. Especially when you pick a year where that has the PTC expiration, so there are all sorts of interesting effects.

That being said, history is not always a good predictor of the future. I think history may be a good predictor on the wind side. We have some empirical basis and wind looks more like other stuff that takes time to build, so it's relatively big things, and they take some time to roll out and develop. On the solar side, I'm less convinced that looking at history is a really good indicator of how fast this stuff could develop. I'm not saying these are all fantastic examples of how to do things, but Italy went from deploying one megawatt a year to deploying 10 gigawatts a year over a five-year span. So, having looked at any two- or three-year history and projecting out how quickly it can grow down the road would have been very, very wrong. Maybe the answer is that it would have to be more differentiated, and just doing what the EPA did works well for some technologies and it doesn't work well for other technologies.

Speaker 2: I was actually going to take a different view and say that, at the end of the day, it doesn't matter. In the final sense that once you've set the target, and let's assume the target is feasible, it doesn't matter, because given the targets, you're now going to find the least cost set of resources and the least cost set of methods to actually achieve that target, whether that's going to be redispatch to existing combined cycle gas, whether it's going to be reducing demand even further through energy efficiency programs, whether its building those renewables out, whether it's building new combined cycle natural gas to make that happen, it doesn't matter at that point. It's the least cost set of resources. In some sense, it's like the horse has already left the barn on that. Now the question is, how do we actually get there?

Speaker 1: The only comment I had was real quick, somewhat ironically when you look at the numbers the EPA picked, the PTC is a perfect example. We got those numbers because there was an economic incentive (I have to use the word economic incentive at each HEPG). There's economic incentive, right? Now the incentive is not economic. It's compliance, and that changes the entire dynamic of how you have to look at things, in context of whether it's achievable or not. EPA just assumes compliance, and therefore by definition it's not aggressive, is the way they sort of think of about it. It completely avoids any connection between an economic incentive and achievability. I come back and say, "We've got to address climate in this country. This can't be the right way to do it." I keep coming back to it, because every time you raise a question like that, that's the answer that ultimately you get to.

Question 5: A comment and a question. The comment, I guess, is, if I understand this, where the EPA is reaching, and where it may well be vulnerable in respect to legality, is actually because it's trying to find ways to accommodate, ultimately, market ways in which their goals can be achieved, which leads me to think there's going to be a paradox, where the people who will be most stridently opposed to and wishing for the law to be knocked down will be challenging it in exactly those areas where otherwise, potentially, there could be market solutions, where normally those people would believe in markets, and people who will very much want this to stay in place will be saying that all that broader interpretation of how the EPA can work should be legitimate, I could use the market structures, and yet they themselves often may not care so much about markets. Anyway, I just posed that as a bit of a paradox related to how our political structure works.

My question is this: really, how much difference does this make? If I understand this correctly, of the 32% that's to be achieved, 15% has already been achieved. Given the gas price forecast, Speaker 2, that you alluded to, and keeping in place the existing programs to support renewables for the renewable portfolio standards, how much of the remaining 17% is likely to be accomplished by 2030 anyway, just because of continued retirement of coal replaced with more efficient gas and renewables? So at the margin, with all the cumbersome difficulties and Rube Goldberg system that, Speaker 1, you correctly identified, how much, at the margin, will all this really accomplish beyond what is likely to happen anyway?

Speaker 1: The price of gas closed yesterday in NYMEX at $2.43, a three-year low.

So there's a strong argument to be made that economics and incentives will continue to drive the shift in the way generation is produced in this country, absent EPA doing anything, which is your point. If the price of gas still stays, and the price of oil plummets, as we all expect now, with who knows how many hundreds of millions of barrels of Iranian oil hitting the world market, the price of oil could be 20 bucks by the end of the year for all we know… What's occurred so far has all been driven by the economics of the different kinds of fuel mixes. We've achieved very significant emission reductions without EPA doing any of this. Your question is right. If your gas price projections are off by 10%, because we see $2.43 for gas yesterday at NYMEX, there's an argument to be made that the process will continue without all this, without EPA doing anything, and we'll achieve a good chunk of these emissions reductions in the same period of time without all this calamity.

Speaker 4: As I said in my little presentation, 1500 pages is large document for ultimately an insurance policy, but my experience with insurance policies is that they are very thick and complicated documents. As I said, I think you're absolutely right. It's quite possible that the paths, both of coal to gas switching and the path of sort of picking up renewables, and perhaps the path to more energy efficiency, are all steeper than is assumed by the EPA. The EPA does think that there would be a deficit, right, without the CPP, but it's quite possible reality will sort of overtake that projection pretty quickly.

From my perspective, I go back to my little probability distribution, and the idea that this is a regulation that functions as an insurance policy. When RGGI got implemented, obviously, it had zero impact other than generating revenues for a bunch of states for a long time, but you could also think of that as an insurance policy, in some sense, in case the economic situation changes. It created the option to tighten RGGI down the road. It's happened. You move forward in some ways that give you more options down the road, even though after the fact they might not have been binding constraints on the system.

Speaker 3: I was just going to agree. This is a hedge, right? We can plot, forecast gas prices all we want that look nice and smooth out to the mid-2020s, but we all know that reality is going to be more complex than that. Experience would teach us that it is very difficult to make long-term gas predictions. So this is a hedge. They took it out of the final rule for the new source, but I really liked it; in one of the early draft rules, they said, "This rule has no costs and no benefits."

Speaker 1: That's still in there.

Speaker 3: Oh, that's great. That's sort of an unbelievable statement in a rule, and the reason is because of the natural gas price assumptions.

They mean that no new coal plants will be built. But that could easily change, right? Circumstances can change, so what this does, is it's a one-way ratchet. I think that's the strategy. I completely agree with Speaker 4's perspective.

Speaker 1: Because they are so sensitive to the cost issue as a result of the MATS ruling, it's buried in there, they have this whole conversation about the costs and benefits. It doesn't say it as starkly as they did earlier, but that's essentially what it says.

Speaker 2: I think it is a Magic 8 Ball issue. Yeah, that's a forecast. Yeah, things look really good. We don't know what's going to happen. Maybe the states in which fracking is taking place are going to crack down on this after all. We're seeing a lot more seismic activity in Oklahoma. There are still fights in Pennsylvania about what's happening with the fracking water and fracking materials and so on. There's lots of things we simply don't know, but if that holds true, then, yes, that would be the case. But is that going to hold true? I doubt it. We all know what happened in the first dash for gas we had in this country. What happened to gas prices after that? They spiked. Production fell off. Then all of a sudden we had shale gas, and now we're in a new boom time. How long is that going to last? Is it really different this time, or are we going to run out of it? The answer is that we just really don't know for sure.

Questioner: If prices stay the same in the forecast that you see, and I understand all the caveats and that's very helpful, but if they stayed the same, would merely the switch to increase fleet use of gas over coal with some additional renewables, would that essentially get most of the rest of the 17% or still fall short?

Speaker 2: Let's put it this way: the other thing it also depends on is the cost of coal, because we've seen the delivery price of coal come down quite significantly in the last few years with the MATS rule. It's not entirely clear. We've seen gas prices come down, but coal prices have come down as well. It's going to depend on how far those coal prices are going to continue to fall, too. It's about the relative cost of gas to coal; it's not just about the cost of gas.

Speaker 1: Even if you assume the gas price, one thing we know about gas forecasts in this country is that for natural gas, they always end up being wrong. People forget that the NGPA (Natural Gas Policy Act), when they put their different categories of what the price of natural gas should be going forward, pegged it to $100 dollar a barrel of oil, which is why the NGPA ended up leading to gas shortages. It ultimately gets back to the earlier question, about whether you believe, in addition to the gas prices staying low, whether that 17% is achievable, it also depends on whether the renewable assumptions are realistic. If those are truly achievable, and they will occur absent economic incentives, and gas prices stay low, you may get pretty well close to the 17%, but those are two big ifs.

Question 6: Speaker 2's presentation did a good job, as Speaker 2's presentations always do, of having a single-minded focus on an economically efficient outcome to compliance with 111(d), but we all know that these state SIPs (state implementation plans) are going to be a compromise between economic efficiency and political palatability, and they're not the same thing. Speaker 2 might think they're the same thing, but they're really not. I say that because under the law it's the governor of every state that submits a SIP. Even in my few conversations with state-level EPA agencies, they tell me, "Well, hey, we got a plan to maybe do this, but really the person who's going to be deciding this at the end of the day is Joe." ("Joe" happens to be the energy advisor directly within the governor's office who's also responsible for economic development of energy projects in a particular state.) Joe's interest isn't in economic efficiency; Joe's interest is in making sure that communities that are going to have a coal plant shut down have something in place of that, so that they're not getting the governor elected out of office next year. It's ensuring that rural counties that are always begging for, like, a wind farm or a solar plant get that investment. It's about appeasing the labor unions, who, of course, want in-state investment. That's the whole premise of a lot of state renewable portfolio standards. It's about making sure the utilities are kept happy through additions to rate base and the avoidance of stranded cost risks. It's about all of those things.

There are going to be a lot of governors who are going to look at the situation and say, "Hey, we're willing to accept the SIP that costs twice what the economically efficient alternative does, so long as it accomplishes these objectives in a kind of log-rolling fashion." I guess I'd turn the question on its head to Speaker 2 and to others and ask you, rather than answering the question of what is the most economically efficient way of doing it, what is the way of doing this that is the most politically palatable from the perspective of the governor who, for reasons of public choice therapy, needs to have and wants to have those levers of control firmly within his domain, possibly to the exclusion of a trading-ready plan that would have leakage to other states?

Speaker 1: Your question is very interesting. The Chamber of Commerce has done some analysis, and I don't know the final outcome of it, but it shows the number of municipalities and counties in the country that get better than 50% of their revenue for funding the fire, the police in that county from a coal plant that is targeted to be shut down under this rule. How they go about replacing that revenue is going to be the very issue that you're raising. That's the very problem. They did some preliminary analysis, and it's not 10 thousand municipalities and counties, but it's a fair number. It's well into the low thousands, which shocked me when I first heard this. I don't know what the final number ended up being. I don't exactly know all the criteria, but we'll see this in a couple weeks.

The answer is ultimately not going to be least cost. It can't ultimately be least cost, given that governors don't chose to put people out of work unless they have no alternative. You know what the answer's going to be? The governors are likely to, as 31 have said so far, push back and say no. Then we're going to have a FIP (federal implementation plan). I think the answer to your question is that there are going to be lots of FIPs.

Speaker 2: Well, that actually might not be the worst thing.

Speaker 1: From the governor's perspective as well. Then he can say, "Those damn bastards in Washington made me do it."

Speaker 2: Hold on a second. The FIP actually has some interesting twists to it. I agree that there's got to be a political pull to do some of these things, but as a former commissioner who knows this very well once told me, "When other states want to do things like this, I'm perfectly happy for another state to spend extra money to cross-subsidize and reduce the rates to customers in my state."

It's a free rider problem now, so the question becomes, how politically popular is it going to be to do all these energy projects, knowing that it's raising the costs in your state and it's benefitting people in other states? Remember what I just said about dispatch, that, hey, I could do all these projects in my state, but it may not benefit my state. We know that a lot of that power from coal strip is getting distributed throughout the western interconnection, being consumed in Washington and Oregon, much to the chagrin of the environmentalists in those states. That's one argument. Do you really want to go down that road and effectively hurt some of your industry because you want to do economic development, effectively raise rates to your customers and benefit the customers in other states? That's a political loser, it sounds like to me.

Comment: It sounds like transmission cost allocation all over again.

Speaker 2: Anyway, the other question is, though, how do you actually make these communities whole? That's a separate policy question. Let's suppose you get FIPed. The FIP actually has a methodology for allocating allowances, but EPA has also slipped into the proposed FIP that states can propose a different allocation mechanism. Suppose, rather than allocating the allowances to the coal plants, or to the existing resources, which is really the default in the FIP, the state says, "No, I want to take those allowances and auction them off." Before you go crazy from that, let me explain where I'm going with this. The state auctions off those allowances to all the affected sources. It takes those auction revenues, unlike RGGI, and says, "OK, I'm going to now make lump sum transfers to these communities whose tax bases have been eroded from the coal-fired power plant retiring or for these other things," and you can actually take those auction proceeds and make lump sum transfers to those local and state governments. They're not going to distort decision-making of any sort, and it accomplishes trying to protect those communities.

I hear what you're saying, and I could still get the first best outcome from a trading program and still find a way to achieve that, but it's thinking outside the box.

Speaker 3: I disagree with what's been said so far. I think that there will be a small number of states that choose not to develop compliance plans, but most states will behave, I don't know if it's responsibly, but in a risk management sense they will prepare a compliance plan. Once that decision is made, all the politics that you're referring to matter, and the reality is that I think most states are likely to offer what's called a state measures plan, where, rather than commit to putting essentially whatever their PUC is doing, a whole set of things, into a federally enforceable compliance plan, they'll kind of cobble things together, and then have a federal backstop. We don't know quite what that means, but let's just assume that means something enforceable, maybe. I think many states will opt to retain that flexibility, and to retain a more traditional role in developing their electricity policy. Is that good, is that bad? I don't know, but I think it reflects a likely reality. It's certainly the reality that's playing out in many of the states that I've talked to.

Speaker 4: I'll say a couple things, too, quickly. I agree with Speaker 3, actually, having presented in some rather more conservative states in the last few weeks and months. There's a surprising amount of hedging. There's like, "Well, you know, we're going to sue, we're going to do this, this is horrible, blah, blah..." But also, "Yeah, I think we're going to prepare a state implementation plan nonetheless, because it would be irresponsible not to do that," so I think that I agree with you.

Two other quick things. Two things are hard. Metric and ergonomic analysis is very hard, so even it if weren't all driven by silly politics, I actually do think losing the local tax base and losing the local employment base is actually a real economic phenomenon that sort of standard economic analysis, as it's being applied, very rarely does a good job sort of estimating and calculating. That's just the reality. The other thing is that change is hard, too. I go back to, what's the impact of the CPP? Many of those coal plants that will go away under the CPP will go away without the CPP, too, so those governors will have to think about the employment impact of those things, whether or not the CPP gets passed, in many cases. Perhaps not in all, but in many.

Question 7: I actually want to build on this topic, because this discussion has given us a lot of reasons to think that EPA wants a mass-based plan. There are the sweeteners. It's easier to comply with. If there's a lesson from the SO2 days, it's that when you have a mass-based system, you get new and interesting ways to comply that are oftentimes less costly. You get more flexibility for planning what goes on in the states, and you actually begin to get people to commit to doing things earlier than they otherwise might commit to doing, because that begins to ratchet down in comparison to the baseline.

But leaving aside that there might be those states where there is an individual actor or community or something that just says, "I have to have this rate-based plan," for whatever reason, I'd like you to think a little bit more and talk a little bit more about what are the other game dynamics that might lead us away from this sort of uniform mass-based plan that allows all this flexibility in trading to something where we have a patchwork of many different types of plans that would make life much more difficult and potentially more costly. What would be the drivers for that, and do you see that playing out, or do you see us moving toward taking advantage of the kind of network externalities that would happen by people generally selecting common approaches?

Speaker 1: The first instance is what we've already talked about. If there are things in your state that don't make much sense for your state and will benefit people elsewhere, you're not going to take those steps, right? Commissioner Clark has been talking about this for months. One of the ultimate problems in the implementation of the plan is that there are a lot of cross-state issues, so nobody's really focusing on the incentives for states to do the right thing under the Act. He's been talking about that for months. I'm surprised it hasn't gotten more attention, because he's actually right. He's absolutely right about that.

Ultimately, not to be a broken record, this has to come back to Congress acting, because the way, ultimately, this gets fixed in a way that makes sense for all the states is to have a congressional policy that addresses this without the sort of Rube Goldberg trying to figure out who's got what incentive to do what to whom. It's a failure of that, more than anything else. It's clearly a failure of that, so the question then becomes, you've got to assume every state is going to act in their own best interest. If that's the case, you've answered your question. It's going to be a patchwork. There may be some states that decide that it's better to try to act in concert with other states, assuming they have the legal authority to do that (and that's an open question under the Constitution). But if that's the case, they're still going to have to decide that's the least cost way of complying. There will be some that do that, but I would take issue with my colleagues here, as I think there's going to be a lot of states that just say, "FIP us," because then they can use the Gray Davis defense, "They made me do it."

Speaker 2: How did that work out for Gray?

[LAUGHTER]

Speaker 1: He was recalled because he tried that way too late in the process. The harm had already been done. I've got to run a little early. Thanks.

Speaker 2: I'm going to take a completely different viewpoint, since Speaker 1 is leaving.

I'm going to actually take the opposite view and say that under the *proposed* rule, I think there was that possibility of a patchwork because of the countervailing incentives. I think EPA has closed a lot of those loopholes and is really pushing in one direction, so that you probably won't have this. At the end of the day, and this is from conversations I've had in various states who have publicly been out there screaming and jumping up and dow--not just, "No," but, "Hell no," but at the end of the day, nobody wants to leave money on the table.

The point I was trying to make earlier is that if people get the sense that rates are higher than they otherwise would have been, and there are going to be lots of studies that are going to show that…(It's not just what we're doing. Other RTOs, other independent consultant studies are going to show this. It's really basic fundamental economics at this point.) Nobody wants to be accused of doing damage to their states that they could have avoided and leaving that money on the table at the end of the day. You don't end up in this Gray Davis situation where you get recalled. That didn't work out too well for him.

So I don't see this as being a patchwork, but for the election cycle for 2020, depending on where the economy's at and everything else, I can actually see states or governors in states saying, "I'm willing to cut off my nose to spite my face and hurt my state to try to prove a point politically, and hopefully people won't catch on." Unfortunately, that seems to work quite well in a lot of places. Have you looked at Kansas lately? OK? Or you look at Minnesota, next to Wisconsin in terms of different political parties in power, different economic outcomes, but right next door to each other. I'm not saying, I'm just saying. (That's what we used to say at home, "I'm not saying, I'm just saying.") The whole point is that that's the only way I can see this turning into a patchwork, because I think EPA's actually largely closed those loopholes that have the patchwork rate and mass next to each other.

Speaker 4: I guess I'm not entirely sure I completely agree with that. The thing is complicated. There are lots of little differences in which path you take, and maybe it was the genius of EPA to make it that complicated, so that, just as a safety measure, most states will go down the path that seems the most obviously easy one, which would be to go a mass-based system. This is going to be great business for consultants. People are going to try to figure out the implications of various paths.

I'm not ready to say there will not be groups of states in regions that might conclude that, say, a rate-based trading system in that part of the country looks better than a mass-based system. I haven't seen any analysis that goes that far, but that is a possibility, I think, under this final rule. Then you would have the beginnings of a patchwork system. I don't know how high the likelihood is, so I would go a little less far than you, I think, in thinking it's not going to be a problem.

Speaker 3: I would just add one thing on the patchwork issue. I think it's important to connect this conversation to the one about the stringency of the rule. If this were a rule that was going to impose something like a shadow price of a hundred dollars per ton carbon, then these costs would be front and center, because you'd be talking about doing material economic damage to your state if you didn't take a cost effective approach. But that's not this rule. This rule still allows for the kind of, "How much will we pay to not know how much we pay for our climate policy in the United States?" It allows for that kind of thing that we have right now. I think there is a potential for a patchwork, because the rule doesn't actually create a kind of life-or-death decision for states.

Question 8: I'd just like to bring some experience from the SO2 trading program into the trading issues here. We all sort of applaud the SO2 trading program, because it brought prices down, but it brought prices down only to the extent that it was more efficient. Given what the states decided to do, the trading program made that more efficient. The example I like is if you're a utility inside a state, and your choice is between building a scrubber and buying emission allowances, a lot of utilities were able to convince their states that they should build the scrubber, and guess what, put it in rate-base, and earn a rate of return, versus buying the allowances, which generally have to be cost passed throughs, so they can make no money on it, and they may have driven the price down significantly, because we may have over-scrubbed the emissions.

So whatever the states do in the interest of their fellow constituents, the trading program just makes it more economically efficient, or tries to correct that, so it doesn't cost us too much. The trading program is good no matter what the states do, although in the case here, maybe the SO2 program, if you consider the success to be the low cost, it may have been the low cost of SO2, but the cost of the scrubber was not really factored in, I guess.

Speaker 2: The truth is, the compliance costs associated with the SO2 trading program in reality were much higher than would have been optimal, for exactly the reasons that you just cited. Because people chose the more expensive option, where you could actually scrub out 95% to 99% of the sulfur dioxide emissions, that crashed the SO2 market, so that when prices were low, people thought this was a success. Actually, it wasn't as successful as it could have been, because compliance costs were higher than they needed to be.

What ended up happening? States like Ohio and Indiana and Pennsylvania that had their rate payers pay for those scrubbers ended up cross-subsidizing states to the south who decided not to put scrubbers in, necessarily. Southern Company was really good at this, actually just engaging in allowance trading to comply, and fuel-switching and rates stayed lower than they did in some of those other states. That's exactly the problem. That's the problem with doing things like renewable energy or energy efficiency. They're capital intensive, say, zero running costs resources, so I can drive the price of CO2 emissions down to zero, and I can make this really, really, really expensive program by doing exactly just as you said, except substitute DG, put in wind turbines or solar PV. It's the same thing.

Question 9: My question really ties some of the discussion we had yesterday into the discussion we're having right now. It really surrounds state RPSes and whether or not the Clean Power Plan in itself is a sufficient economic driver for renewables in a state. Full disclosure, Ohio is in this hold position with the state RPS and EE mandates. There's been a small committee that has been formed which has at least day before yesterday or yesterday released a report saying they believe the mandates should be held in place. They shouldn't progress. They should be held in place indefinitely. The full legislature still has to opine. Governor Kasich has said what's he's said. This is the context in which I'm asking you this question, full disclosure.

I think the CPP, based upon the statistics that we've seen, could be utilized on one side of this argument, as this in itself will be the driver for a robust renewables market in the state of Ohio. So I wanted to get your perspective on that, and also from purely a technical standpoint, when you look at the potential compliance pathways and the CPP, for the mass-based pathways you run into the issue that we've already discussed, which is, let's say the state has a robust RPS, we can't tell if our coal plants are being displaced and thereby reducing emissions in the state of Ohio for the mass-based appraoch. For the rate-based approach, as we've talked about, while I think renewables can generate ERCs (emission reduction credits), the rate-based proposition doesn't look to be healthy for states. Tying these things together, the RPS, the CPP, I'm just interested in your commentary.

Speaker 3: I think it depends how certain you want to be of a renewables deployment pathway in your state, and I think that we've been given a lot of reasons to wonder, at least at this point, about the future of the Clean Power Plan and its usefulness as a market signal. Until the uncertainty is reduced, which won't happen for a number of years, I think other market signals are still probably necessary. I don't want to use California as an example, but that's the California approach. Layer a ton of stuff on top of it to make sure that it happens, because any one thing can be struck down by the courts. The Chamber will challenge everything, and for every measure there's some probability that the Chamber will win. That's the California experience, so for that reason, redundancy in the system is considered to be important. Is that economically efficient? No. Does it lead to artificially low carbon prices at the price floor? Absolutely. But if you're concerned with providing a market signal to developers that induces projects, that's maybe what you need to do until the legal uncertainty is resolved.

Speaker 4: A couple of comments. One, I think the RPS might be binding at the state level even though it's not kind of binding. Here's what I mean. The RPSes are typically tied to physical deliverability, even though, courtesy of the Interstate Commerce Clause, by and large it's very difficult to say that renewables have to be in this state, at least they have to be sort of electrically connected a little more tightly. As opposed to going down, say, the mass-based road under the Clean Power Plan, for everybody that chooses the mass-based system, you could get the same amount of renewables built, but they would be different types of renewables and built in different locations. You could benefit from the renewables by just having a lower allowance price because all of a sudden Arizona builds a lot of solar, or whatever, the mid-west builds a lot more wind, even though these projects don't happen where you are. There's that.

For the country as a whole, it's unclear whether the individual state RPSes are binding, but in individual states they could certainly be binding. You could also end up with certain states not being part of the mass-based system, where then the RPS just forces the renewables to be developed there. They wouldn't have an impact on the allowance prices that sort of function across the larger system. Does that make any sense?

Questioner: It does. I guess what I would say then is, what is the incentive for a state that is presently having this debate, what is the incentive then for the state to push for this enormous RPS when we just actually look at how this is billed to consumers. So you have the one expense stream to consumers, which is the state RPS. You then have other expense stream to consumers, which is whatever is the built-in price, whatever the allowance price is that is built into the energy market. I guess what I'm wondering is, if it's your state that's sort of having this debate right now, and you know that the Clean Power Plan will hopefully drive the marketplace for renewables, why would you just strap those two different cost streams onto the backs of your consumers? Especially if you don't know that the RPS, that line of cost, if it's actually going to help your state comply.

Speaker 2: Right. Awesome. I think you've asked a really good question. I'd like to start at the national level, and then we'll break it down to state by state. If you have a nation-wide RPS, which was Waxman-Markey, and a cap-and-trade program, which was Waxman-Markey, only one of those was going to bind. It was either going to be the CO2 or it was going to be the RPS that was going to bind. They won't both bind at the same time. However, on a state-by-state basis, as Speaker 4 pointed out, and I agree with him, you could be in a state where your RPS bind—because, remember, the commodity being sold with an RPS is the renewable energy attribute. It is not the zero emissions attribute. A renewable, now, with RPSes and now with the Clean Power Plan has two attributes that could be sold, and they could be split apart in fact. You have the renewable attribute that could be sold to a state that has an RPS, and you have a zero emissions attribute that could be sold to somebody else. You can break those two things apart. It gets really complicated in that sense.

In the case of say Ohio, if the RPS is not binding, it actually helps crash the CO2 price. Effectively, all of the costs associated with the RPS are not just the RPS, but also associated with Clean Power Plan compliance, which may be actually more expensive than having gone out in an allowance market. But the apparent allowance price will be zero, potentially. That may not even be guaranteed, because, again, if you're part of a regional or a national trading program, there may be other factors driving that price. You could, in fact, have a binding RPS in Ohio and a binding CO2 constraint nationally with a positive price that may not necessarily help you, and, again, to the point you were making, if you put the renewables in Ohio, it may not reduce generation in Ohio. It may reduce generation somewhere else. Those are the things you have to think about.

Moderator: Well, we've covered an awful lot in the time that we've had. I think we have provided some answers to the question, what now? There's a real clear, I think, identification of this gap between what we recognize as what's likely to be the economically efficient way to approach this versus the politically expedient way to approach it.

I thought it was interesting that the EPA was given a lot of credit for producing a lot of incentive toward a mass approach, because the initial draft proposal left the mass approach so ill-defined. It was very highly focused on just the rate approach. I think the EPA maybe was pushed in that direction from a lot of the comments more than people may realize. I think there's a real need for market institutions to enable all of this. We touched on that briefly.

The other takeaway for me was how much of the outcome that people expect is really dependent on these forecasts of what demand and fuel prices are going to be, and that raises some real interesting risk dimensions to the whole program. With that, I'd like you to join me in thanking our panel for doing a great job.