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Rapporteur's Summary*

Session One.
Electricity Trading: Value Added or Value Removed?

Everyone is involved with and affected by electricity trading. Both over-the-counter bilateral forward contracts and organized exchanges with central settlement are pervasive in the energy industry. Organized electricity markets with coordinated day-ahead and real-time auctions provide the foundation and opportunity for virtual transactions that open up entry for electricity trading that goes well beyond traditional hedging by generators and loads. The prevalence of trading is not matched by a pervasive understanding of the costs and benefits for the electricity system as a whole. The potential benefits for financial traders include profit making opportunities created by inefficiency that would arise if entry were restricted. A fear is that the benefits of improving both market liquidity and convergence could be exceeded by disruption that trading and traders might create, wittingly or not. What is the model to explain the value added of electricity trading? What is the experience to show the benefits and the costs? How should virtual trading integrate with the physical market? How should costs and benefits be allocated? How should regulators approach the oversight of electricity trading? Would the market be better with more or less trading? Does electricity trading add value or remove value?

Moderator: Today's discussion is about the value of electricity trading. What are the benefits? What are the costs?

Speaker 1.
Thank you. I want to start with just the basic framework that we use to think about the question today, and in a sense, the framework evolved in the same way that the market has evolved.

So we started off with a real-time market where we had physical generation and physical load. The result was locational prices in a real time market. Real time market trading couldn't really

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change prices, so real time market trading was trading around the physical assets. But it could transfer risk, obviously. Then the day-ahead market was added and we had virtuals at every node. Day-ahead and real-time trading can affect prices. It does affect prices. It can affect dispatch. It can affect commitment. It does. And day-ahead and real-time price convergence as a metric of whether that trading activity is effective implies that getting the day-ahead prices close to the underlying real-time is the goal. Conversely, when prices are farther from the underlying real-time, there's the potential for market power as a metric of market power or other distortions. Then there were the added FTRs.

One of the things to think about as we're thinking about trading and the positives and negatives of trading is the fact that some trading occurs inside the PJM market and some occurs outside the market. I'm going to be primarily talking about what occurs inside the market, but there's a very active over-the-counter and futures markets for PJM products.

I wanted to start with just a little bit of background about the basic volumes. The basic volumes of trading are being driven in the day-ahead market primarily by up-to congestion transactions. Up-to congestion transactions, following a variety of rule changes, are now primarily internal, as opposed to external. And if we look at the comparison between up-to congestion transactions and other forms of day-ahead transactions, like incs and decs, up-to congestion transactions have largely displaced them. They've largely displaced them, not for a good reason, but for a bad reason, because of a set of rules that favors up-to congestion transactions over virtuals. Up-to congestion transactions don't pay uplift. And for a long time, they didn't have significant or appropriate credit requirements.

Another interesting fact just to be aware of when we're thinking about day-ahead and real-time markets in trading is the relationship between the volumes in the day-ahead market and the real-time market. Frequently, people who are pretty sophisticated about these markets are surprised by the difference. If you look at the blue curve along the bottom of this graph, that's the difference between the physical day-ahead and real-time load and the top is between total day-ahead and real-time load. So the difference between the green blobs and the blue blobs is all the virtual activity taking place in the day-ahead market on the load side. So it's a very substantial amount of activity on the load side that's not occurring in real time. Same thing on the generation side, the same set of curves. So this simply illustrates a very significant role that trading and virtual activity has in the PJM markets.

One final piece of information here is about the role of various forms of transactions that ultimately serve load. This table shows the role of bilateral trades, purchases in the spot market, and self supply in ultimately meeting load. Self supply, as you can see, is about two-thirds. Bilateral contracts are about 10%, and then spot market purchases make up the rest.

Another fact to keep in mind when thinking about all this is the relative role of financial participants and physical participants in the markets. This table shows the level of virtual bids made by what we call physical and financial players. You can see that actually the proportion of incs and decs held by financial participants went down in 2013. But as you can see, that was much more than offset on the up-to congestion transaction side. As incs and decs went down, up-tos went up. And as you can see here, the up-tos are dominated disproportionately, 95% or So by financial players, and in fact, to date, it's a relatively small number of financial players who have dominated up-to congestion transactions. It's very highly concentrated in a very small number of relatively small financial participants.

I have the same information here for FTRs, and if you look at FTR ownership, again, what's interesting both is the role of the financial participants, but also the very significant role of physical participants. Physical participants clearly use FTRs. They have a significant role in FTR ownership, as well as incs and decs.

So one of the metrics of the effect of trading is convergence. Convergence is talked about frequently, but not very specifically or not very precisely. I'm not sure I'm going to add to the preciseness of the discussion, but at least I wanted to mention the fact that there are a number of possible ways of thinking about convergence, everything from hourly to annual. This table shows annual convergence. The annual convergence figures are very impressive. There have been very small differences, on average, over entire years, between day-ahead and real time prices. Remarkably small. In fact, the difference is tiny.

But as you drill down and get more granular, clearly the differences change, as one would expect. This table simply shows the frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference. So what it shows generally is that most of the activity occurs within plus or minus $50 between day-ahead and real-time prices. If you look at the monthly averages, monthly averages are farther apart than annual, but they're still relatively well behaved, relatively small, and relatively stable. If you look at the average differences by hour over the entire year, they are actually, again, remarkably small, even on peak, at least for the first three quarters of 2013, versus 2012. And you might expect bigger differences, given the market activity in the summer of 2013.

If you look at the data at an hourly level, clearly there's a huge amount of variation between day-ahead and real-time. Again, this is not surprising. It's almost impossible to converge most activity, given the lag in information between day-ahead and real-time.

And finally, and not insignificantly, we also have issues at the borders. So there are seams issues, and one of the few places, at least in the PJM market, that truly archaic practices remain, is at the borders. There are long lags. It's old-fashioned trading. It looks very much pre-market. The way it should look is as much like LMP as can be, and we're very far from that. We have persistent differences at the seams. And the trading behavior has not been allowed to affect it, and in fact, trading is probably not the right activity to drive those prices together. What you need, actually, is rule changes and market design changes to permit those markets to solve the way other LMP markets solve.

And this is just a reminder that demand side and the capacity market is also engaged in trading. There has been a lot of discussion about it, but the demand side product looks a lot like an option in the capacity market, without having to have an actual commitment to physical transactions prior to the auction and being able to only go physical at the very end, if necessary, and to buy out of that. So again, it's another form of trading, and it's a form of trading that's caused problems in the PJM markets that are being addressed.

So let's think about the impact of an actual specific type of transaction, and we happen to have some good data from PJM, because PJM did an analysis. They reran the day-ahead market without up-to congestion transactions for five days, and they shared the data with us. And basically what the data showed very clearly is that up-to congestion transactions did affect dispatch, did affect commitment, and did not, in fact, result in convergence. About half of the transactions were associated with increased convergence and half were associated with decreased convergence. Up-to congestion transactions had a very significant impact on congestion. You can see here that the constrained hours they had without up-to congestion transactions looked pretty much like real-time, and with them, they were very different than real time. And there was a corresponding impact on FTR funding. Up-to congestion transactions for the day studied had a very negative impact on FTR funding, and, in fact, produced most of the FTR underfunding in those days.

So one part of the discussion about trading is what are the costs and what are the benefits, and part of that discussion is about uplift. Nobody wants to pay, so uplift is a friction on the system. It's a drag on the system. Its costs are not recovered in price. Clearly, the way to go is to have as much recovery in price as possible, but uplift is an unhedgeable, unknowable price everybody has to pay, or at least most participants have to pay. So any individual participant can make an absolutely logically economically correct argument that they should not have to pay uplift. And anybody could make that correctly: Load shouldn't have to pay uplift. Virtuals shouldn't have to pay uplift. Up-tos shouldn't have to pay uplift. Nobody really should, because it certainly interferes with an efficient outcome in the market. Nonetheless, there are those costs. So our view of it is that, because it can be demonstrated pretty clearly that virtuals do have an impact on uplift, that they should pay part of it. But the primary goal here is to make uplift as rational as possible. It's clearly not rational now. Those costs are way too high. And we've made a number of suggestions, which are here, which would in fact substantially reduce the amount of uplift, driving, for example, the uplift payments by incs and decs from the three dollar range down to 17 to 20 cents, and even in our draconian way, imposing a cost of only about 30 cents on an up-to congestion transaction. So we believe, if done properly, defined properly, without any exceptions, if everybody pays, then uplift can be reduced. Trading activity can pay its fair share of that, but its fair share is very small. The point is to make it as knowable and as close to frictionless as possible. And this simply illustrates the impact of the recommendations.

One illustration of trading activity that has caused issues in PJM, in addition to up-to congestion transactions, is FTRs. FTRs were originally defined as the financial equivalent of what used to be a physical hedge. They were given to load because load is paying for the transmission system. That became converted to ARRs (auction revenue rights) and FTRs in order to sell off the additional FTR capability of the system so that others could have access, including traders and those who wanted to hedge and speculate. The problem is that in doing that, FTRs took on a life of their own, and as a result of poor modeling, cross subsidies, and bad rules, basically, PJM oversold FTRs with the result of very substantial FTR underfunding, which then caused a move to try to resolve the problem by having load pay for the FTRs, having load pay for, subsidize FTRs as opposed to ARRs. So again, in just a very quick illustration, there's no necessity for that. Clearly, trading plays a good role in FTRs. FTRs can be a valuable tool. But the way that they're working right now is not good. So we've suggested a number of possible solutions to this, and in fact, our solution is pretty straightforward, simply removing subsidies, improving the model, which would immediately take the underfunding problem from the 67% range into the mid-90s.

In the interests of not taking up all the time here, let me wrap up quickly. So we think there should be more good trading and less bad trading. [LAUGHTER] Does that sound good? I should end right there. So good trading is speculation or hedging based on the underlying market fundamentals, and seeks to manage risk. Bad trading is what I would call false arbitrage or what someone recently called, I think, a "money tree." But it's basically based on bad rules or modeling issues where the activity cannot cause price convergence. It can't always cause prices to go together. In fact, sometimes it causes exactly the opposite. That's an example of trading which is not bringing anything to the market. It's actually a significant negative for the market. A third principle, in addition to liking good and not liking bad, is that trading should be based on the internal profits and risks associated with activity. It should internalize all of its costs. It should not impose the costs on the rest of market participants, as has potentially been the case for both FTRs and up-to congestion transaction.

One of the things that I think is not well understood about the day-ahead model in PJM is that it's not purely mathematical. It's not purely algorithmic. There are very significant subjective judgments, and a key goal for PJM should be to reduce that as much as possible, to make it as algorithmic as possible, to ensure that the market simply reacts when virtuals are added to it, rather than PJM trying to move the model around to adapt to it.

So I'm moralizing now, but in addition to good and bad, responsible activity and behavior by all market participants is essential on all sides of this market. I think the degree to which the markets are sensitive or more delicate than they may appear is frequently misunderstood. I actually think that it wouldn't take very much to destroy the central markets, and it's important that all participants, traders and load and generation alike, recognize that and try to work within the rules and try to trade in positive ways.

So in summary, we think trading plays a critical role. Financial participants play a critical role in the markets, and we'd like to see trading continue with the caveats I said. Thank you very much.

Question: Were the various statistics on underfunding including balancing congestion? Real time balancing?

Speaker 1: Yes. Absolutely.

Question: On page six, I think it was, you had a description of real-time load versus day-ahead load as being pretty consistent, and then you had, I guess, above that, the chart of another load. I think you called it financial load? There we go, yeah. How do you distinguish what was physical and financial in the day-ahead market?

Speaker 1: In day-ahead, what's physical is basically load put in by load serving entities. So it's everything except for decs, the demand side of up-to congestion transactions, and exports.

Questioner: OK. This includes the demand side of up-to congestion in the green side.

Speaker 1: Yes. Yes. But one of the things to notice about this is that in fact, the mean of this, if you look at it carefully, is slightly below zero, which, again, is a reason that decs can play a positive role in day-ahead market.

Questioner: And later you talked about segmenting financial versus physical participants. And I was wondering how you de-segmented that. How did you determine who was physical and —

Speaker 1: It's a great question. It's not a perfect definition, but what we tried to do is to call physical participants those who primarily engage in physical transactions serving load generation and the financial participants, those who are primarily engaged on the financial side, not actually engaged in physical load, while understanding that there are lots of participants that are kind of at the fuzzy edge of that.

Speaker 2.

First of all, thank you very much for the invitation and the opportunity to speak to the group. My discussion's going to be a little different, in that it's going to be broader and more of a macro discussion.

First of all, we could talk about the benefits of markets, commodity markets and trading and what are the benefits that that activity can bring to the broader market. And the perspective that I think I can bring is that of a bank (and bank participation in physical commodity markets is, of course, a bit of a hot topic), so I thought that might be useful.

Some of the commentary that we've heard from regulators, from market observers, from politicians, is, "Why are banks involved in physical markets at all? We want banks to be lending money. That's what banks should do." And what I'm going to talk about today is how activity in markets actually intersects with that activity and supports that activity, because you've got a tremendous need for capital in these markets and in our general infrastructure, and the role of markets and the management of risk in that context is very important.

So with that, let me return to the benefits of open markets, sort of relatively basic economic benefits. Certainly, the efficiencies that markets bring, optimization, the fact that you convey price signals to buyers and sellers and guide activity using a market mechanism, and then the last, which is one I'd like to focus on, which is risk mitigation and the use of markets as a tool for risk mitigation, particularly in the context of large capital projects. People use risk mitigation for daily events, but I'd like to focus, for this discussion, more on the longer-term markets and how risk mitigation is important in the context of actually developing infrastructure.

But before I get into that, I did want to highlight a couple of points about our market more broadly. We here in North America enjoy a tremendously complex and highly integrated market. We also enjoy some of the cheapest energy on the planet, despite the fact that we're clearly the largest users per capital. The reason that we have that benefit today, of cheap gas and cheap power--and again, relative to the world, when I talk to folks in Asia and Europe, I mean it's a stark difference, the benefit we have here, and the impact on the broader economy of having cheap energy is just huge… The reason we have that is multiple reasons, but in no small part, it's due to the fact that we've had tremendous amounts of capital invested over the decades. So the infrastructure that we enjoy today is a result of large capital investments that have been made in the past. And they've come in many forms, but a lot of it is from investments by profit-seeking enterprises that are investing in seeking economic return. Going forward, you'd certainly have to recognize that this needs to continue. If we're going to continue to enjoy the benefit of the markets and the availability of energy and the favorable pricing of energy that we do, we're going to have to continue investing as we have been.

It's important to note that a lot of these investments are very much impacted by movements in the underlying energy markets, so they are highly risky and they face a risk of market movement, and they're also generally made in response to price signals. So when the market tells folks, based on a forward market, there's a profit opportunity here, if you invest, you can earn a return because of the market environment, we get the capital brought to the market, but then, when that capital is brought to the market in response to those price signals, we want it to be the cheapest low-cost capital that it can possibly be. And that brings us back to risk mitigation again.

When investors look at putting dollars into a project, the return that they want to earn on their investment is going to be a function of risk. A highly risky return needs to be a high return. I think that's again, perhaps stating the obvious, but it's important to understand because when it's possible to take these projects and de-risk them in large part, the capital that can be brought to that project is far lower cost. And in fact, we end up seeing that on the margin, there's projects that proceed or don't proceed, based on the return that is being earned by the investor, and that return is always calculated based on the risks that they're taking. So if it's a highly leveraged investment, if it's one that has large exposure to unpredictable market movements, an investor's going to look for a very high return. If it looks pretty much locked down and stable, then of course, the return they need on the project is reduced.

So this de-risking exercise is very important, and that's a large part of our business and what we get involved in, and we cannot do that on our own. We're in the risk management and risk transferring business, but we're not in the business of taking risk from developers and from projects and just owning it. Our role is to take that risk, transfer it and then disperse it in the market. Our business is not to accumulate all the risks and sit them on our or any other bank's balance sheet. So we need markets and actively traded markets for us to participate in if we're going to perform that function.

So in general, the service that we provide to de-risk these projects and to allow projects that otherwise may not have happened or proceeded to happen is really our function, and with respect to the role of markets and actively traded markets and markets that have sufficient liquidity and participation broadly from other buyers, other sellers, and investor and speculators, it's very important that we have robust markets in order to do this.

I did want to close with a few examples. It's all very good to say this in the abstract, but how does this actually happen? What's the context in which this happens? So I just put two recent examples up, publicly disclosed projects that we've been involved in, where we provided a 10 or even 15 year, in the lower example, offtake agreement. In the first one, this was a wind project in Montana, we provided a 10-year, fixed price hedge, where we said, "We will buy at a fixed price all the output from that wind farm." In addition, we manage the variability, so the real time scheduling group in our office manages the variable generation, and we provide that service as well. As you can imagine, variable generation in Montana--there's not a fungible market for that that we can easily offset, so that's an awful lot of work. But the fact that we were able to provide that hedge gave revenue certainty to that project and made it viable. So they were able to get funding because as a project, they knew what their revenues were going to be for 10 years.

Different example, but same principle. Another wind project in Texas that was just closed very recently. Similarly, we provide a long-term fixed-price energy hedge to that project, and with the certainty of that revenue, they were able to proceed with the project.

I won't go through the disclaimer. But I work in a bank and we have to have a very long disclaimer.

Question: What I was looking for was an example was two additional steps that were in the general presentation. Number one, what you described so far is taking the risk yourself and holding it, as opposed to then finding somebody else on the other side to take some or part of that risk. That's the second step. And then the third step, in addition, is this question of how this relates to the short term trading. As you said, you have to have a very actively traded market. Why is that relevant? Couldn't you just have long-term contracts and be quiet?

Speaker 2: Really, it's just that markets don't work that way. The long-term markets will grow out of the short-term markets, so I guess there are two parts to the answer as to why we need the short-term markets. One is simply that all the markets we have have grown and developed and evolved over time. They've typically started from short-term cash markets, which then become financial markets in many cases. So a robust, actively traded short-term market is the foundation that's necessary for a longer term market. Then also there's the clearing mechanism--what are you going to settle against? So when you have a long term market price, it's going to settle against an index, eventually. If you don't have that foundation, you cannot have a long-term market. So that's part of the answer.

And then, the second part of the answer is that the value of a lot of these assets, when we provide a revenue hedge and say, "We'll pay this fixed price," the expectation that there's some volatility that can be optimized in the shorter term market is an important component of that as well. So if we could take a long-term position and hold it to maturation and just let it price out on a daily basis, we would still need that short-term market to do that.

Now, to the first part of your question, we don't just do that. We need to find long-term buyers in this case to offset our risk, and we'll use other markets. So of the two examples I gave, the Montana one is probably more challenging in that here's a market location that doesn't have much depth, so we have to have offsetting positions in a related but different markets. In the case of Texas, their top market is pretty closely aligned with the gas market, so folks in our business will use gas as a proxy for power in elongated markets, and where those correlations can be much lower in the short term, they'll be much higher in the long term.

Question: I just had a quick clarification question on the Rimrock project. Was there actually a loan?

Speaker 2: Yes in that project, we actually provided a construction loan, which got the project from inception to completion when it's up and running. Then there was a loan from a third party.

We wouldn't have provided the construction loan if we didn't have certainty that there would be somebody else to take that out at the end. They wouldn't take it out until the project was up and running, so they needed bridge financing, which we provided, but that loan that was provided when the project was up and running required the revenue certainly that was provided by the hedge.

Question: Do you know about any commodity market where a five year ahead future is traded liquidly?

Speaker 2: Yes, in the natural gas market, which we're involved with pretty heavily, five year forward markets are actively traded.

Questioner: I must admit I have not looked at the natural gas market, but as far as I see, what is typically traded is one year ahead, two year ahead. For the German power market, it's similar. We are two years ahead. There's no liquidity.

Speaker 2: That's true, and we have long-term markets here in North America in gas and then from those, we developed power markets, really when a lot of the combined cycle plants were being built a decade ago or more. Those projects needed revenue hedges, and off the back of an existing gas market, we developed elongated forwards on power markets as well. But it is something that is pretty unique.

On the natural gas side, there is an awful lot of interest globally to invest in projects here in North America that use natural gas as a feed stock. You've got LNG projects, of course, but then you've got petrochemicals, fertilizer, methanol... These projects similarly benefit from revenue certainty, and in North America, we're unique in the world to have forward markets that extend out 10, 15 years. They're thinly traded, to be sure. I didn't bring a chart of the daily traded volume of the market, but it's extremely liquid in the front couple of months. It tails off pretty quickly, and then, when you get to long term, it's much more difficult. But again, that's what our business is, to find the long-term buyers and the sellers and make use of the existing transparency in the market to try to put those transactions together.

Question: Does it go without saying that none of the examples that you gave are viewed as being subject to the Volcker Rule?

Speaker 2: We're just digesting it. They did a lot of work to make sure that the Volcker rule did not choke off market making activity. My belief--but it's early days, this just came out two days ago--but certainly, the hope and the expectation is that this type of activity can continue, because it is important to the economy, and our customers and industry requires this and wants this activity, and I think the regulators did an awful lot of work to try to craft the legislation such that it allows us to continue in this market making. It's a concern.

Speaker 3.

Thank you. I, too, have a lot of disclaimers, but the main thing is I'm expressing my own views here.

When I started my career in the utility business, the main lesson from back then was the problems caused by the absence of long-term contracts in California. So looking at what banks do, one of the things they do is intermediation, both in a credit sense and in a market risk sense, between load and generation. When we went to competitive power markets, we sort of broke that link, which was the basis of cheap capital, but to have intermediaries who can do those long-term contracts, I think, is very important.

How does that fit with organized markets? And I give the example of how when people come to us and say, "Give us a five-year toll," the market maybe that can do that most easily, perhaps, is PJM. ERCOT was another example, but current uncertainty on some policy issues is a bit of a barrier. Hopefully, that'll be behind us. Banks facilitate liquidity in markets. We do both physical and financial, the types of deals Speaker 2 mentioned. There are lots of other examples—lien-based arrangements where the bank is financing and doing the hedge…The Rimrock project is one example, but there are lots of other examples where there were tax equity investment and the bank came and did the firming and shaping arrangement between a wind plant in the Northwest and the California utility, where you sort of do a locational exchange, take the variability risk, and then find the offsetting hedge. More recently, there have been examples with inventory financing on the coal side. Funding transactions often could involve cleared capacity in PJM. People talk about volatility and capacity prices, so things like that can be addressed.

Now, in the current environment, certainly, there's increased regulation--Dodd-Frank, the Volcker rule, increased capital requirements. And on that, the argument I make is that if people like banks as intermediaries who are credit-worthy and strong and are subject to federal regulation and all of these things, they should probably like banks even more, because now you have all these additional protections. The thing is that it comes at a cost, and time will tell whether that increased cost makes our customers decide to do a hedge with other entities, which may not face the same capital requirements.

There has been a lot of discussion on strong enforcement action, well publicized cases at the FERC, and I think that most of us who run in these markets like strong enforcement because when somebody does something bad, it is disruptive for the whole market. Looking only at the public side of information, I haven't read anything that I would personally be comfortable doing. There was one particular case which others have spoken about, and I think that does raise the point that clarity on what is OK and what is not acceptable is very important for the market. Otherwise, people don't want to get caught up in these really big penalties. The risk-reward becomes just too skewed.

So commodity prices today, relative to back when organized markets were formed, are very different. In contrast, if you look at the piece for transmission charges, the California ISO when I started, had $1.50 transmission access charge. Now it's $6, going to $12, maybe even higher. So that's the cost of all the investment and infrastructure for renewables on the transmission side.

On this slide, I put some of the things that people think of when they think of financial trading and organized power markets. And we certainly do some of them. For example, financial transmission rights. With the rise in renewable energy, even though it's a flat gas world, there has been an increased demand for basis hedges, because somebody has a wind plant somewhere, and congestion patterns have changed. A lot of the long-term hedges are at PJM and west hub, so you want to go and hedge what could be a considerable exposure between your node and where you have the long-term hedge. So that's something that we like to do, and when a client comes to us and we write them a basis hedge, we think of that as market making. In the Volcker rule terminology, and in Speaker 1's terminology, it would be good trading. But then, you want to go and offset that hedge and that risk, by doing a hedge and perhaps using the FTR market. So that's an example of how things that we do for customers fit with things in the organized markets.

Virtual/convergence bidding has been around for a long time. The name convergence bidding came in California. People said, "What is this thing called 'virtual?'" and back then I was working at the Commission and we came up with this name. The idea is to converge the day-ahead and real time. If the day-ahead is not aligned with real time, let's say it's higher, and virtual traders come in and converge, it does create a benefit to everyone, and internally, creates profits for the trader. And when people say, "What do traders add, where's the money coming from?" (and I would get this back in the regulatory days) they think that traders are sucking money from the market. Well, there is a benefit to everyone, and how things are shared between the profit that the trader takes and the benefit to the rest of the market, I think, depends on different examples. But that's the way I see it.

A recent thing that has come up is that there are times when trading in virtuals and other similar transactions results in uplifts to the market. So then it becomes very important to allocate those back to the people who caused them to have that feedback loop. Otherwise, it does become a problem. Up-to congestion transactions are, I'm not as familiar with them, but they're fairly recent. At PJM, they help people align day-ahead and real time, so they're like FTRs, but only shorter term in helping people arbitrage the spread between two locations, day-ahead relative to real time.

This slide shows some examples of disruptions and reforms. PJM had defaults in the FTR market in 2007 and 08, I think $85 million. And these were the days when people would say that somebody sold their Harley and opened up an FTR trading shop in their garage, and then the position turned on them, and they just said, "Socialize the default to everybody else." That didn't go over very well, including at all the places I worked. So FERC, of course, did the right thing. They came up with Order 741, strengthened the credit requirements. There is no unsecured credit for FTRs. There are officer certifications required. The CFTC RTO exemption had certain additional conditions to strengthen participation requirements. And there are things that sometimes have just system limitations or infrastructural limitations, such that if you put in more than a certain number of bids the system chokes. So I think PJM has a 3,000 bid limit on the up-to congestion transactions. These are just some examples. There are others.

And to close, this is an example of an unintended risk, and I give the example of FTRs as something that we use to hedge our basis swaps. And what happens is that when you go and do, say, a 100 megawatt basis swap, you want to go buy 100 megawatts of FTRs to offset that and to manage your risk. It just so happens that in PJM, the problem that Speaker 1 mentioned, FTR underfunding, makes the notional value of that FTR an uncertain value. So it could be that I bought 100 megawatts of FTRs, but they're really 50 megawatts because they got devalued. And this happens for a number of reasons, but one of the biggest reasons of late has been the mismatch in models between the day-ahead market and the real-time market in PJM, and a somewhat peculiar definition of the FTR product in PJM, which mixes the day-ahead and real-time. So if strange things happened in real time, they end up affecting how the FTR settles, and it makes it a very imperfect and risky hedge for people who want to be in that business. For someone who is purely in the speculative business, and says, "I want to just value this product, it may be inferior, it may have these problems, and I'll pay less for it and make money," maybe it's not a problem. But for people who want to do the good trading, in the sense of Speaker 1 and the Volcker rule, it's certainly a product that's not very well-suited.

So this is an example of what happened September 10th and 11th, where in the ATSI Zone, which is in the first energy area of PJM, the load was very high and PJM called about 1,000 megawatts of emergency demand response, which has a two-hour lead time, to reduce demand by about 1,000 megawatts. And demand response of this type in PJM has an $1800 strike price, which means that the demand says that as the prices go to $1800, you can curtail me and I will have an avoided cost of $1800. But the price formation mechanisms in PJM are such that there's uncertainty, and you make this call, and by the time you get there, the resource is no longer marginal, because you didn't actually need that much demand response. So the price was, let's say, only going to be $100. Well, if that is the case, then you have a bit of a problem. Then you called the demand response which wanted to be curtailed at $1800, even though the prices were only $100. So it needs a make-whole payment.

So PJM enforced a constraint called the ATSI interface, which essentially says that the flows coming into this service territory do not exceed a certain number. That number is not specified, so this is a tool where the number can be a fudge factor to make the prices come to the level of $1800, which is the strike price of the demand response. And if you do that, which is shown in this slide, there is no make-whole payment to demand response, but there is an uplift that is caused in the balancing congestion because we have shrunk the real-time transmission capacity, in this case with $23 million in balancing congestion charge over the course of 11 hours in two days, which wiped out the funding of FTRs in entirety, which means that if you were using them as a hedge on a hot day, they were, in effect, worthless. If you were looking at FTRs as a mechanism to value transmission, it gave you the signal the transmission is worth zero, even though it's actually infinitely valuable.

So we had the example of the FTR defaults. Those were worth less than $100 million. If you add up all the FTR underfunding in PJM since 2010, it was close to a billion dollars when I checked before leaving. And it just seems that of all the focus among regulatory agencies in Washington on encouraging good trading, clamping down on bad trading, here's a clear example that is begging for a solution, and there's very little interest in fixing it, so I will stop there. And I have two slides of disclaimers. [LAUGHTER]

Question: Yes, December 10th and 11th is a problem, but I'm not sure it's a financial trading problem. It's a problem with the way PJM sets prices, and it affects everybody. It's not just financial traders.

Speaker 3: The point of that example was that PJM was trying to do the right thing. Prices should reflect dispatch. So they dispatched demand response, and they said, "Prices should reflect that." Unfortunately, the tool they used in this case ended up adversely impacting FTR funding. So that was the only point. And if you're a person who wants to use FTRs as a hedge, tough luck.

Questioner: Well, it's an issue of PJM pricing more so than just the financial trading issue.

And my other question is, how would long term contracts have solved the California problem?

Speaker 3: You're going way, way back. [LAUGHTER]

Question: I think what Speaker 3 was talking about in his presentation is the mismatch between day-ahead and real time modeling. The ATSI interface was modeled for real-time operation only, and was not modeled in the day-ahead market. So to the extent that there would have been congestion seen in the day-ahead market, that could have been picked up. But I think that's part of where Speaker 3 is going, if I'm correct in that assumption. But that's part of the problem, I think, is that mismatch. Back in July, we created the ATSI interface on the fly to manage a lot of the transmission constraints that popped up in northern Ohio. And in September, that was again invoked in real time, but was not modeled in the day-ahead market.

Question: Hypothetical. If there was 1,000 megawatts of demand response buried on the downside of that constraint, that was paying real time prices, that wasn't being paid by anybody, but paying real time prices, that saw those prices, responded and reduced load by 1,000 megawatts, would the same result have happened with FTR? And if it did, would that be bad? .

Speaker 3: Yeah, I think the example with the PJM action is really that PJM has rules on demand response being able to set price only when there is scarcity. In this case, there was not scarcity in the ATSI zone. And the way that demand response..well, someone is shaking his head.

Comment: Speaker 3 is very close to being right. [LAUGHTER] This is a technicality about scarcity. In fact, demand having the real-time price forestalls scarcity. In addition, PJM cannot set scarcity pricing for anything smaller than the entire RTO or a big part of the Eastern part of PJM. That's a separate problem. But it is clearly a PJM pricing issue. And the answer to your question is, it would not have changed the price if people had simply gotten off the system. That would not have happened.

Comment: But it would change what uplift bucket things go into.

Comment: Yes, but you wouldn't have that kind of uplift because the price wouldn't go to $1800, because that's an artifice of the way DR works in PJM.

Speaker 4.

Thank you very much. Well, my disclaimer is listed first. I will say very clearly that the ideas that I'm expressing in this presentation and in my remarks are mine and not those of my employer. They're based upon my personal experiences and observations and not on any confidential information. So I hope that was very clear.

When I got started in the electricity trading industry, I don't know, 16, 17 years ago, it was about the time that the ISO markets were starting to develop. And someone came to me at my company and handed me this stack of paper, and said "Here, figure this out." So I was trying to figure out PJM California, New York and New England all at the same time. And I looked at the stack of paper and I thought, "Job security." [LAUGHTER] And here I am.

When I thought about the topic of this panel, to me, it wasn't a question of, do traders add value or extract value? It's, how much more value can traders add? My point is that I think trading adds a lot of value to the markets that we have in place now, but I think that there's a lot of room for improvement in that value that trading brings to the market.

So I'm not sure that we ask the right questions when we look at the industry and we look at trading activity. I think there are more questions that we have to ask. So if we ever question whether trading is bringing value, it shouldn't stop there. I think that there are obstacles that exist in the market structure and in the regulatory and governance processes that actually prevent the market from realizing the full value of trading, and I'll dive into these. I think we as an industry need to take a harder look at these things to increase the value that trading brings.

So to start, can we all agree that the whole point of implementing these ISO and RTO market structures was to facilitate open access, to increase competition, to bring value to the end use consumer? That was the whole point. Many years ago, when I was looking at this stack of thousands of pages, I didn't realize it then, but that was the intent of putting these markets in place. And hopefully, we can all agree that if we successfully enable trading in these markets, then we're going to get closer to having successful markets. So in other words, being able to transact in these structured markets in a way that's unencumbered and unhindered will provide value and make these markets successful. And it's at all levels of the market. It's at the production side. It's at the end use side, and it's all levels in between. And so that includes all of the things that Speaker 1 talked about in terms of virtual trading and FTRs, but it also includes the over-the-counter markets that exist around these structured markets. So we have to ensure that all of this works together. We can't look at this stuff in a vacuum. It's all very closely tied together. We need to ensure that there's competition at every level of the market, not just at some levels and we restrict it at other levels.

And so I think this side probably has some very obvious points on it about the value that trading brings, and some of the speakers before me hit on some of these points. But we should go through these. Truly, trading brings competition to the market, and it is beyond consumer choice. So if we want value to make its way down to the end use consumer, we need to ensure that there's not just competition at the level of the load supplier. There needs to be competition above and all around that process as well. So for a load supplier to get the best deal for its customers, it needs to be able to go to a whole host of other entities that can provide competition and provide supply to that load supplier.

Traders also bring exposure of opportunities to incent competition, and I think the very obvious example is looking at virtual transactions. So the fact that there are entities that are looking for (and I'll use the word "inefficiency," although I know that kind of cuts both ways sometimes) looking for these opportunities in the market, to the extent that they find one and expose that there is an opportunity in the virtual markets, that becomes transparent to the rest of the market and other people step in and compete it away. Traders are trade partners not just for the physical players, but also for the financial players as well. I think that's pretty obvious.

We provide tailored transactions to customers. So in other words, traders, and I think Speaker 2 hit on this, manage risk, and not every trader has the same view of risk. There's no plain vanilla way to manage risk, and there's no view on what's the right way to manage risk. If you talk to three or four different traders about a potential transaction, I bet you they'll come up with three or four different ways to manage the risk of that transaction.

But as we know, the value of trading is also questioned, and if you read *Megawatt Daily*, you will see headlines of high profile cases of accused manipulation being settled with the commission. And I participate in the governance processes of several of the ISOs and RTOs. You hear it in the hallways, and the discussion that financial traders bring nothing but risk to this market. So whether you agree with the cases, whether you agree with that statement, the fact is the value of trading is also questioned.

But I propose, as I said at the beginning, that the value of trading is hindered. And I think there are certain areas that we need to look at to improve market efficiency, to improve regulatory and governance clarity, and to help increase the value that trading brings to the markets. So there are challenges baked into the market structures that limit access to products; that prevent clear, transparent pricing of those products being sent to the market; and that lead to unproductive cost allocations. There are also in the regulatory process and the governance process, challenges that provide confusion, fear, and suboptimal results that actually prevent the value of trading from being maximized. And I say that until we address these areas, we're not going to get there. So we have to step back and, as I said before, when we start to question the value that trading brings, that shouldn't be the only question. We need to look at the broader picture and address these barriers.

These are some specific issues that I thought of off the top of my head, where there are issues in the market operations and design where markets aren't working efficiently, and therefore prevent trading from happening efficiently. And we've talked briefly about real time price formation. In my opinion, in these markets, there is a downward bias in LMP formation. So LMP is not always allowed to reflect the actual cost of managing supply and demand and reliability on the grids. And I think that's supported by the fact that there are uplift payments that are made in these markets to generators that are dispatched that aren't able to set the LMP, but they're given a side payment, which nobody sees except for the resource that receives it, and therefore, the LMP is distorted in a downward direction.

There are also issues with transparency and operator reliability actions. So in real time, if a generator is called on out of merit, or if it's not committed in the day-ahead commitment process and called on, it may not always make it into the LMP, and that's a problem. And it goes back to the issue of how the structured markets are closely integrated with the over-the-counter markets. So if we see suppression in these markets, well, surely there's going to be suppression in the over-the-counter markets. The prices are going to be distorted there, and, to give a very specific example, in the New England market, and as we know, that's in the crosshairs of the gas electric coordination debate that's going on right now. There is a problem with price formation there, where LMP is not able to reflect the cost of managing the system, and it's leaking into the forward markets. And it's incenting the wrong behavior in those markets.

There are other things, too, such as separation of market components. And the one thing that comes to mind is energy markets versus capacity markets. Now, FERC just recently conducted a technical conference on this issue. And there were several speakers there that said, "FERC, we realize the capacity markets need to be addressed, but, please, we have to keep elements that should be in the energy market in the energy market. Let's not start confusing things. Let's not take incentives that should be in the energy market and place them into a capacity market." And then there was a discussion about FTR underfunding and about the certainty of the models that are used for FTRs, and that's a problem in the market. And I know in the PJM market, that's probably the most high profile case. We're working on it, sort of. But it's a big issue, and it really hinders trading.

So in order to get to a level where we can start maximizing the value of trading, we need to address these structural issues and these operational issues. We need to have clear and transparent price signals that are visible to all market participants, not just a few. It's got to be visible to all market participants so that there's a greater opportunity for competition in the markets.

On the regulatory side, there is a gap in the comfort level that market participants have in understanding what is versus what's not manipulation, against what the regulators feel the comfort level should be. And I think we need to close this gap. And I've heard representatives from FERC address this and say, "What's the problem? There's no problem here. We think it's very loud and clear. And if you need any clarity, you should come into the Commission and ask us for clarity." Well, there's a bit of a challenge there. There is a real fear of going to the Commission, because there's the fear that you're suddenly exposing yourself to scrutiny that you wouldn't have had if you hadn't asked the question in the first place. So it's a problem, and granted, with all of my comments, I know that these are not easy things. They're very difficult things to overcome, but we've got to start someplace.

Another issue that creates challenges for trading is market rule certainty. Again, I'll offer up ISO New England as an example, and I don't mean to pick on them. The focus of my experience over the past couple of years has been on ISO New England and PJM, so to the extent that I use those examples, it's not that I love or dislike them, it's just what I know right now. But in ISO New England's market, we just implemented a winter reliability program where the ISO is going to guarantee payment to oil generators to keep oil in their tanks for the winter as fuel security. This is a one-time program, and this is a distortive to markets. Now, next winter, we don't know what's going to happen. And this is a problem. We're going from one winter to the next, and it's not a very long timeframe. It's a very short timeframe in the spectrum of trading. But we don't have certainty on what's going to happen next winter now. There are already markets that are formed for next winter. People are trading gas and power for next winter, but we have no clue as to what's going to happen with these market rules. So that's an issue. And that's a challenge that we need to overcome.

Clarification of regional differences. I think this is probably my favorite, because I get the fact that FERC allows for regional differences when assessing rules that the various RTOs and ISOs present for essentially the same issue. But I would say that in some cases, we probably shouldn't have regional differences. And the big example that I can think of is in Order 741 compliance. Each ISO submitted their plan for how they were going to comply with the FERC Order. And there were some pretty big differences, and I'll give you two examples. One is the certification process that every market participant has to go through for risk verification. Why not just have one process? Why not have just one entity that we submit our certifications and our verification documents to? Instead, we have to submit to every ISO and RTO. Another point is that there are alternative means for meeting the minimum capitalization requirements. You can present your financial statements, and if they meet certain criteria, then you pass. But if not, then you can post cash. It's basically a set-aside collateral requirement. Well, in a lot of the markets, if you want to participate in the FTR market and you want to submit alternative collateral, it's $500,000. In New England, $10 million. $10 million in a market with very little congestion. It doesn't make a lot of sense to me. So I think this is something that I think in some cases it makes sense. In other cases, it doesn't.

And then, last but certainly not least is the governance process itself. We find that there are times when there's gridlock in the governance process where we simply can't resolve a big issue. FTR underfunding at PJM is the huge example there. We've talked about this for years, and at the end of it, there was no consensus that came out of how we should resolve this issue. And I realize that there are people on both sides of the table that are protecting their interests, but at what point is the value of honoring the governance process higher than the value of having an efficient market with good results? So we need to have stable, consistent, transparent regulations. We need to make sure that market participants can comply with these things easily in order to increase the value that trading brings.

And so hopefully these last two slides will kind of provoke our market designers and regulators and our beloved market monitors to really think about these issues. I think it goes without saying this is the lead-in from everything that I discussed, that I encourage market designers, and I know I'm not alone in this, to improve markets to function the way that they were intended. So we want them to function in a manner that increases the value of trading, to increase the competitiveness of the market, to increase the value that ultimately makes its way to the end-use consumer.

And so there are things that I ask that these folks consider. Is it OK to have a market where the LMP, when it should be screaming, is biased in a downward direction? Is it OK to rely on operator decisions and actions that go unpriced in the market? Is it OK to meet those price signals? Is it OK to have incentives that incent the wrong behavior? And I can give you an example of that. I know you're probably getting sick of my examples, but in ISO New England, with virtual transactions in 2010, they were assigned a large share of the uplift cost. Well, what did we see happen in 2010? We saw virtual transactions virtually disappear. Now, I would contend that because of this, ISO New England has removed a very important tool for ensuring reliability on a day-to-day basis in that market. We find that in that market, in the past, on cold winter days, when we know that there needs to be a very high level of generation commitment and we expect load levels to be high, we find that load actually bids somewhere, in the neighborhood of 85 to 90% of the forecasted value. Now, if virtual transactions were not encumbered with these unknown, unhedgeable costs, they could easily step in to increase the commitment in the day-ahead market to ensure that enough generation is being committed so that there aren't real time issues with scrambling to call on generation. Generators that hadn't been committed are scrambling to get natural gas supply. So it's an issue.

And then, lastly, we need to think about cost allocations that actually harm reliability as well, and I think that example also applies there. We don't want to assign costs in a manner that prevents activity that can actually help an ISO or an RTO meet its reliability goals. We need to be very cognizant of that.

And then, on the regulatory side--again, I think it's pretty obvious. I would ask these folks to consider working with commercial entities to develop the clarity and the certainty needed to support trading in these markets. Now, I know this seems very obvious, and we can argue that this is happening. It happens in the governance process. It happens at technical conferences. It happens with roundtable discussion, but I think we need more. I do. If the market is saying that there are some real issues with understanding, for example, what is manipulation versus what isn't manipulation, then we need to come to some sort of bridge to make sure that that doesn't exist, or at least we minimize that. There needs to be some effort to get industry at a level where this discomfort is at least diminished at some level.

So I ask again for the regulators, the market monitors and the market designers to consider these things, to ask these questions, to say, “Is it OK to have a governance outcome that actually runs afoul of market efficiency? Is it OK for that result to hold? What’s the value of governance, versus what’s the value of having an efficient marketplace?” We need to address these regional differences. And like I said, I think it’s OK in some cases, but I think there are some times it doesn’t make a lot of sense. I think we need to be looking at increasing efficiency, improving things like reporting and compliance to the various ISOs, so that perhaps we streamline those items to, again, improve efficiency, to make the trading community, I guess, more comfortable, and to decrease these unproductive costs that are added to the system.

And so with that, I guess I’ll just finish by saying that I feel very strongly that electricity trading adds a lot of value to the industry, but I think it could be so much more, and I think we need to address these items that I raised to start increasing that value.

General Discussion.

***Question 1*:** So Speaker 1, you had some very interesting charts on the up-to congestion transactions and the adverse impact they have on FTR underfunding. And some of my colleagues have wondered about that as well. And I think that you’re saying that if more people show up in the day-ahead market and schedule these up-to congestion transactions, it will certainly impact congestion. We can see that. But then, in terms of their follow-up impact on creating balancing congestion in real time, to me, it’s a more complicated question, because the underlying cause for that is a mismatch in models. So if you had perfectly aligned day-ahead and real-time models, you could have as many up-to congestion transactions as you wanted, and there would be no impact on balancing congestion and on FTR underfunding.

But then, we know that that’s not true. That’s the ideal case. There is a mismatch in models. And now what you have shown is that on certain days, the up-to congestion transactions were such that they had this adverse impact. So my question to you is, can we take those five days and make that a general conclusion? Or is it the case that there could be other days that you may have looked at or maybe you didn’t look at, where it was the other way around, and they were beneficial? And if So is there a relationship between when these transactions are profitable or unprofitable, and when are they good and when are they bad?

Speaker 1: First of all, there are modeling differences and we need to deal with that, and one of my points at the end of my earlier comments was that the day-ahead modeling and the day-ahead market operation needs to get a whole lot better than it is. It just needs a lot of improvement, and that’s certainly true. So the direct answer is that we didn’t pick those days. PJM picked those days. I have no idea what logic they used, but apparently random. I think it is generalizable. But remember, even based on that evidence, we are not suggesting that up-to congestion transactions be eliminated, which would be, I think, a reasonable conclusion to draw, but we’re arguing first that we should try the uplift method and make sure that they’re bearing the appropriate costs. In addition, you add that to PJM being sure that they are not moving the market around and changing market parameters in order to facilitate any kind of transaction, but simply letting the market work. And that might well mean, as I think you pointed out, perhaps even position limits more so than some of the aggregate limits on up-to congestion transactions, because the model, you know, it cannot handle an infinite amount of these transactions. So I do think it’s generalizable. I think the immediate solution is to move forward with rationalizing uplift as well as making the models much better.

Question 2: I think the question of the panel is an important one: is there a value added by the financial participants, and is there more value, as Speaker 4 put out, that should be had? And I wanted to transform that a little bit. I guess all of you have stated that there's value for the good trading, at least. And there's value in intermediation, and there's a role for markets to play. And I was wondering, given a lot of the remarks today suggesting that there are certain issues or problems with market rules or market infrastructure, whether that might cause a crisis, a crisis of confidence that might be long lasting. And the reason I'm asking this is because liquidity is this thing that, if you don't have it, well, you're done. If you have it, then it begets more liquidity.

So I'm raising kind of a threshold issue. You have a market that works, or a market that, once you start putting enough issues onto it, it just stops functioning. And I wonder if we're close to the latter, where you have enough problems, enough headwind, so to speak, enough both intrinsic and extrinsic issues that are kind of all happening at once, that it stops working. There's actually a potential long-term, I guess, crisis here that could start, or could continue, and beget longer-term problems. And I worry about this a bit, because it takes a long time to set up infrastructure properly for markets, for all the elements to come together, for the expertise, the vendors that are supporting competition, the aggregation of a lot of the tools that are supporting this. And you know, if you're going to a situation where there's lower trading (we've seen this a little bit in some areas of the market), lower liquidity, whether that would start unwinding, and you get long-term repercussions. So that was my question to the panel.

Speaker 2: I think certainly you can hit a point where liquidity has gotten so low that the market ceases to function. I think in the interim, well, first of all, you've got variable liquidity, obviously, in different markets. Certainly we've seen, across all the markets, a reduction of liquidity in the last number of years, and I think regulation's a part of that. I think the financial crisis certainly led to that.

We've had uncertainty of regulation, which is now starting to clear up. And you also had, I think, price stability in a lot of markets that negatively impacted liquidity, just to the extent that stable markets become less interesting, and you don't have as much activity.

So all those things have sort of conspired together. I think the impact of reduced liquidity is really understandable jus in how you define what liquidity is, and it's a obviously variable day to day, but the way I like to look at it is it's just a widening of the bid-ask. So reduced liquidity increases transaction costs. So the thing you want to avoid is the downward spiral where transaction costs just become so large that nobody's going to cross that bid-ask spread anymore.

And I think in some markets, we've started to hit that point, but I remain optimistic. We've lost a lot of our competitors. I mean, I think Speaker 3 and I can both talk about the fact that other banks have left the market, clearly. So there has been a reduction in the number of participants, which is becoming troubling. But the optimist in me says that the recent clarity, with the Volcker rule coming out, finally, will help. Now, at least the uncertainty's been removed, and I think it's a common theme that uncertainty's a really tough thing in markets, particularly in the elongated forward markets. There's always going to be some degree of uncertainty, but when the uncertainty is regulatory uncertainty, it's just adding to the problem. But again, the optimist in me says that we still have functioning markets, we're still able to do long-term deals. We're still able to bring capital costs down. We're still able to send price signals. It's just maybe not as robust as it could be, and I think a lot of what

Speaker 4 talked about was that we need to always be thinking about how we make markets better, because there are lots of things that conspire to make them less well functioning.

Speaker 4: I guess, well, I agree with everything that I said, too. Again, using New England as an example, we've seen for over 10 years now that they've had a less than optimal market design and market operations there. And although I think it's difficult to point to one thing, and say "this one element has impacted trading," we can sort of work down the line of things. There is an issue with confidence there, because the market structure is in question. We don't think that it sends the right behavior signals. Therefore, you get traders that don't have confidence in the long-term value of that market. And so therefore, you get developers that then have a hard time going out and locking up hedges to build power plants in that market. So there is a bit of a confidence issue there, because you just don't believe the prices that are issued in that market, and that trickles down into the forward markets, and trickles out through the forward markets. To me, the issue is that because we hinder these signals, we impact transactions, and when we impact transactions, it starts leaking into physical issues in the system, reliability issues. So that's where I see the issue going. I think I am optimistic as Speaker 2 is, but we do need to take a hard look at these structures. We do need to ask ourselves, are they working the way that they were intended? Are we getting the outcomes that we need to get?

Speaker 1: I would just add that it's a low probability, high consequence outcome that could happen. I don't think it's likely to. I'm optimistic about the markets, but the key point is, it's a reason not to be complacent. These problems do need to get addressed, and we can't avoid dealing with them. We shouldn't avoid dealing with them.

Speaker 3: Yeah, I agree with everything Speaker 2 said, and I think that the point to emphasize is that uncertainty is inherent in markets, but regulatory uncertainty is a different animal that's not something that's helpful, and there are things that are particular to one market or another where liquidity is worse or better, but generally, I'm an optimist, too.

Question 3: So I found these presentations very helpful, and I am concerned about this value-added story. As many of you know, part of the motivation for having this discussion was a conversation with a FERC commissioner who was complaining that there wasn't a good story to tell about the value added and what trading actually brought to bear. There was a constant procession of people from the independent power industry, from the natural gas industry, from the Edison Electric Institute, from all kinds of different participants in the market visiting FERC every month and going around and talking to people about what they're doing and what they're concerned about, but they never saw any traders. And because they didn't have a trade representative in there talking about it, they just basically couldn't articulate the story about the value of trading.

And I was trying to think about what I would take away from this session. And let me try a version of the story. So here we have New Jersey, and New Jersey, a long time ago, had vertically integrated utilities. And the couch potatoes in New Jersey, the residential customers like me, were the people on the other side of the long-term commitments. So the utility would build a generation. It would go into the rate base. The rate payers would have to pay it over the next 10, 20, or whatever years, whether they liked it or not.

And we had a whole bunch of problems with that system. And we came along and we said, "We would rather have more competition, we'd like to have open access…" all the other arguments about the advantages of having markets, and we adopted that as public policy. We did a lot of things, and then we moved forward. And then, today, what's the story for the residential customers in New Jersey? Well, they have a default service. They can opt out of it if they wish, but most of them don't, as we would expect. And there's the Basic Generation Service Auction in New Jersey, which is an innovation which I had nothing to do with, but I'm a big fan of it. I think it's quite clever. And they have a rolling three-year forward contract that they use to buy basic generation service for the residential customers. And that creates two things. One is that it sort of eliminates any further mechanism by which the process is providing longer term demand from those customers for forward hedges beyond the rolling three years. And it creates a group of people who are the three year winners in this auction who are selling forward three years, who have their own problems of trying to manage their risk as they're meeting that requirement for those three years.

And the argument we always had was basically that other parties, intermediaries, are going to come along and they're going to say, "Well, there's nobody who's a perfect replication of year seven through 10 of the New Jersey residential customer base, but we could put together a package of different kinds of long-term hedges," (the kinds of things that we saw from the Montana example). "And we can also do some trading with these people who are doing the three-year forward hedging to help them manage their risk. And we want to have a liquid trading market so that when conditions change every year over the next 10 years, we can keep adapting and modifying and responding to what's going on."

But if we didn't have that basic trading going on in the short-term market, we wouldn't able to write these longer term contracts. We wouldn't be able to give the investment protection for people who want to build generation in New Jersey, if they want to do it in a market basis. We wouldn't be able to provide the counterparties to the people who are doing the three-year hedge that they're providing, and so on. So it's all of those intermediate steps that are needed to provide mechanisms so that we could get the kind of broader, forward hedging and investment that we want, and investments in infrastructure, and that's both, A, very valuable because it is going to work down to the benefit of those residential customers and, B, is a necessary part of restructured electricity markets, and you can't just live off the spot markets alone. So that's my takeaway. What did I miss?

Speaker 1: Actually, the one part of that I don't think we addressed, but I think it's important, is that in contrast to the New Jersey model, which I think was very valuable, but I think needs to evolve, ultimately, you actually have to get pricing all the way down to the retail customer. That has to be the default. When I think about what I want for my default, I don't want a weird rate design from a regulator or a utility company. I want to pay the wholesale power price as my default. That should face all customers as the default, not three-year contracts, but continuously, and then (as I believe is happening in Texas, correct me if I'm wrong) let competitors come in and then you have them potentially being there for the longer term. You don't have the short-term issue about not being able to face a longer term or not having a longer term incentive. So again, that's only a very partial answer, but I think that's a key piece of what needs to happen in the power markets in order to match up wholesale and retail.

Questioner: Personally, that would be fine with me. But that just goes further in the direction that I'm talking about. So there would be even more need for an opportunity for short-term trading and long-term trading hedges through financial intermediaries, because I'm not going to sign a contract with a generator.

Speaker 1: Exactly. Maybe I missed your question, because that does create more opportunity for intermediaries, more opportunity for competitors to come in between the wholesale and the retail.

Speaker 3: Yeah, but I think that's a very good example. BGS is one, but there are lots of places at PJM where we have power auctions and we play the role, either of directly participating, or of helping the people who are winning in the power auction. But I think that's not the only example. There are lots of examples. Like in the West, we don't have retail access. But you could have people doing an M&A transaction. Somebody's taking on a new asset in the Southwest. Say a utility buys an asset, but then doesn't need it for serving their load right now. They'll come and say, "Do a toll. You manage it for the next five years." So we'll take it to California and manage it. We're a financial entity, but it's very physical.

And it's only if you have markets and you have the ability to intermediate that you can have those sorts of things. And if you have people like us leave, then I don't know if it was the goal of FERC to just have people trading next day FTRs and UTCs, and I think that would be my message to Commissioner Moeller if that was truly a concern. And on the comment about why people don't go and visit FERC, I think, having worked at the FERC, people come and visit you because they want something. And if you're in this role of being an intermediary and dealing with both sides, there is not an inherent bias to be on the load side or on the generation side, because you're dealing with both. So we don't quite have a position like, "Make the capacity market stronger, because I've got an asset…" We just are people working hard to manage the risk in a very competitive environment. There simply isn't time to go and chit chat, but I think maybe we should do more.

Speaker 2: I'll pick up on that because I went in the last six weeks or so and met with all the commissioners and did receive that exact response, like, "What took you so long to get here?" And the flip answer is, "I've spent my whole career trying to stay out of this building." But the dialog is important, and I think what you said is exactly the message we got as well, was that this representation of what is the role of the trader and what value do you bring, is needed. If we don't take ownership of explaining that and articulating the value that we add, shame on us, and it should be no surprise that it's not as well understood as we think it should be. So I guess, A, you're absolutely right. There needs to be more of that activity, and I'm happy to report that we have done that. And we were very warmly received, and there was a very good dialog and interest in exactly what our role is and what we do.

Speaker 4: And I guess I would just add to what you said that it's very important to have the full suite of products working as they're intended to work so that they're available to the commercial community, and so that you have options for managing positions, managing risk, and so forth. And, as I said in my presentation, that's at all levels of the market. That's within the structured markets that we have. It's also outside in the over-the-counter markets, too.

Question 4: So my question here goes to long-term liquidity. You described a couple of examples that were relatively complex transactions. You're talking about wind energy that has renewable credits, that has tax credits. A gas plant would clearly be different from that.

So I guess my question has a couple of parts. One is, how do you deal with this question of creating hedges beyond the capacity markets and the BGS auctions for the more conventional generation where you don't have those adders. And number two, and I think the more important question long term for me, is I've always assumed that in order for investment to work, we would need the liquidity, and relatively transparent liquidity beyond the three year time horizon, and that if we're doing this right, we should be able to look at creating market rules in the organized markets and evaluating their effectiveness in part by looking at the extent to which we have that transparent liquidity beyond the three year market. And so am I right in that? And if So what indicators should we be looking at to see whether when we change market rules we're actually improving or not improving that long-term liquidity?

Speaker 3: I think the transparency certainly is nowhere near in the long term where it is in the front. And it probably comes in different forms. So you've got a much, much smaller universe of folks that even really care what that forward market is. So I mean I can tell you, if you're a project developer or an investor looking to find that long-term market, you do get the transparency you need by talking to us and our competitors. It's not an RFP process, but it's more, it's a bespoke product. It's not something you're going to see on an ICE screen, where you can say, "Oh, what's the 10 year forward market for this?"

So I think your transparency, it comes in a different form, and if you need it, it's there. But it's not readily available to the market, because it's a lot of work to come up with that, and these are transactions that will happen once or twice a year.

But I think there is a broader transparency issue. I think a lot of what Dodd-Frank tried to do to bring transparency to markets, a lot of the institutional clients that we have, there was a lot of work in Dodd-Frank to give them more transparency. I think many of them felt they already had all they needed. They could call up five of us and get a bid within a penny. And they didn't need it to be on a screen. So I think sometimes regulators have not understood the degree to which transparency does exist for those who need it.

And the second part of your question was…\

Questioner: How do you hedge when you're dealing with more conventional generations?

Speaker 3: Certainly, the two examples I gave were wind power, because those are very recent, and that's what is happening today. Actually, there's an editorial in the *Journal* today talking about what percent of new generation is wind, and they were against this, clearly, in the article. But the fact of the matter is, the market doesn't support gas generation development today. So you're not seeing those projects, just because the long-term prices don't support it--which is a problem for developers and people trying to build new generation. But the long-term markets do not provide adequate revenues. So again, the wind projects are complicated because they have special tax attributes.

Certainly, the Montana example had the firming and shaping component that we had to deal with. The fact that it's in Montana, where the power isn't required, so we had to move it, meant there was an awful lot of complexity on that transaction. Some of the gas-fired generation projects are much simpler, but then they have the added complexity of the variable nature and the inherent optionality that we all value in those tolls, and calculating that is a big part of the business. So those are also very complicated from that perspective. And the contract--when we do a toll, it could be a 200-page contract. We've got to include the start time intervals, the cost of the start, and how many starts are you allowed to take. These are all terms that are embedded in these contracts, and again, to the point of transparency, you're certainly not going to see transparency in the market on that, because it's a heavily negotiated contract. But again, if you're in that business, there are multiple bidders and there's adequate transparency. I think that people know they're getting market value as defined by the group people are talking to.

Speaker 1: That's consistent with what we've seen from developers. You just said they are lumpy projects. You wouldn't expect there to be a clear market for all that stuff, but nonetheless, when people say, "We need a five-year contract or a 10-year contract," I say, "Talk to Speaker 2 and talk to other people, because we know for a fact that there are market participants out there who are willing to do an energy hedge of the kind you talked about, and willing to enter into bilateral long-term contracts on commercial grounds, which help resolve the problem."

So I think you'd agree, Speaker 2, that the groundwork for those is having as transparent and as liquid, as competitive as possible markets for energy and capacity, and then let these derivative or secondary contracts build on those, but they rely on them. But you don't have to have the second embedded completely in the first.

Speaker 3: I was just going to add that there are examples of long-term hedges for gas plants. Lots of them. In Texas and in PJM, for example. In PJM, when the capacity market was new, there was actually an appetite to take exposure to that. The market since then has evolved, because it became very granular, in terms of locational prices, so in terms of the comfort level in having exposure in terms of tolls to the capacity market, maybe it decreased a little bit, but nevertheless, I think the PJM capacity market does remain a pretty credible component in long term contracts. So I wouldn't go so far as to say that just because there isn't a comfort to go more than three to five years, which is the natural comfort zone, that people who are regulators or market designers shouldn't go and fix something that needs to be fixed. I think at least all the changes I've seen in the evolution of the PJM Reliability Pricing Model (RPM) have been good ones. Eventually, you do settle at a place where the construct becomes stable and, Speaker 2, as you were saying, that's when you go and increase the tenor of transactions.

Speaker 2: And it may increase the value, too, because as buyers, typically, in this context, you have to discount the value for uncertainty. So if there's regulatory uncertainty on capacity or utility services, you value those, but if you don't have certainty that that value has longevity, you obviously have to discount it somewhat. Again, I think the value of certainty is that it increases the value of assets, and that helps generators and new projects get developed.

Speaker 4: Yeah, and I think the previous speaker hit it when he said that if you have certainty in these shorter term markets, then that sort of naturally leads to these longer term transactions. But I think it's a softer measurement, though. It's not going to be as transparent, but it's a softer measurement, in terms of, "OK, are the longer-term structures working?" And I think that's something you gather from information sources of developers commenting on how easy or difficult it is to find these long-term hedges for putting a power plant in place.

Question 5: I have a preamble, and I have a question as well. [LAUGHTER] One of the key elements for us, since the introduction of Dodd-Frank, is really the level of regulatory uncertainty, and how that regulatory uncertainty is affecting the commercial marketplace. We have our own activity to analyze, but we also have other measures. And one of the measures that we looked at recently is federal power marketing entities that are financial, and the level of activity that they've been reporting, and what we found is over the last two years, the total power marketing activity is down 53% for the entities that we can identify as financial. From our standpoint, that's a large decline in activity, in terms of financial entities or marketing.

When we look at the landscape today, in terms of Dodd-Frank, one of the key elements for us is that we still don't have a real definition in terms of what the liquidity definition of a future is, versus a swap. So the market could be faced with a large-scale conversion from futures to swaps, with different regulatory requirements. In addition to that, we have continuing issues in terms of FERC and CFTC interactions and kind of the muddy level of jurisdiction. And then, of course, on Tuesday, we now have the finalization of the Volcker rule. We have five agencies and some interesting issues related to regulatory coverage as that final rule has become implemented.

What I would like to know from the panelists is their perspective on the multi-level regulatory uncertainties affecting your business.

Speaker 4: This is one of the key points that I raised about the uncertainty and the lack of clarity in this area. I mean, having sort of a multi-agency oversight, overlapping oversight, is not easy to comply with. It adds costs. And we spend a lot of time just trying to figure out what exactly it is that we need to do to comply with each agency. So it does create challenges, because you want to make sure that you're not opening yourself up to exposure unwittingly to another regulatory body, or that you're not crossing the line for a rule that's in place. So certainly, it has created some issues, no doubt.

Speaker 2: Yes, we talked about liquidity, and part of that is obviously a function of how many market participants there are. I think an unintended consequence of increased regulation is that it becomes a huge barrier to entry. The costs of compliance are very high. I mean, we've been in this business a long time. We're not going to stop because we have to hire five more compliance people. We've lost participants in the market for a variety of reasons, but I think the barrier to entry into our field that the compliance requirements cause is certainly higher than it was. And that's a balance, I think, that regulators obviously need to achieve, where if it's too burdensome to participate in a market, you're going to drive down liquidity, but you don't want the Wild West either, so how do you balance that? I think when you've got different agencies all doing that calculation independently, and there is really nobody who oversees the whole puzzle and says, "OK, well, in aggregate, between all these different agencies…" and in fact, we know that you wind up with a turf battle between agencies saying, "Well, I regulate this." "No, I regulate this."

So I think that's something that's a bit of a problem. In the last five years, we've had every single regulatory agency increasing its oversight and the amount of information it wants. The burden of compliance alone is large, let alone that we can talk about activities and where folks are nervous about doing certain things or participating in markets because they don't want to run afoul of rules they don't understand. That's an issue. But I think just the compliance work that needs to be undertaken is also a concern. Maybe we've gone through this long rulemaking phase and increased set of regulations, maybe the next phase is some form of coordination and ability to say, "Well, where do we have overlap, and how do we get agencies that are separate but sort of competing for the same role? How do we simplify that?"

And I don't think there has been a concern that we need to reduce regulatory burden so that we increase competition, but I think that is reality. I think competition is lessened by too high of a burden. We've seen people leave our market. I don't foresee banks that aren't in our business opening up shop anytime soon, because they see an opportunity and they're willing to climb that mountain of compliance work that needs to be done.

Question 6: Yes. I think some of us believe that electricity trading has angels and devils. And when I try to defend financial traders and trading in general, I'm not sure I have all the tools to defend trading. I realize that we all have the same liquidity and transparency, but I have no idea when enough is enough, or when there's too much, or as some public utilities say, a case of taking money out of the Midwest and putting it into New York offsets.

So let me suggest two things. Quantifying them. There are very few, and I don't know of any, quantified benefits of how traders increase the value of the markets. We have lots of nice qualitative stories, but we don't have quantitative, and quantitative stories are a lot more forceful. And the second suggestion is this idea that traders can discover design flaws in the market and then become afraid to come in and tell FERC about it. There is a mechanism for that, which is the trade group. Tell your trade group about it. Let your trade group come in and present the problem to the Commission, and you can remain anonymous. So if in fact those two things can happen, you can become even more angelic.

Speaker 3: Let me respond to that. I don't know if public utilities want financial traders out of the markets. At least, I wasn't aware of that, because a lot of public utilities are our clients and we do business with them all over the country.

Comment: As far as public utilities go, I think I would associate myself with Speaker 1's remarks that we've seen good trading and we've seen bad trading, and we don't like bad trading. And we're concerned that there are market loopholes that allow bad trading to take place and take money out of the market. So yes, we are legitimately concerned. We actually issued a press release last summer congratulating FERC and its office of enforcement for some of the cases that it had brought, realizing that some people might not like that, but that they'd been taking a pasting, and that somebody needs to stand up when they do something right. So we did do that.

But Speaker 3 is correct. I mean we do a lot of business with traders, because remember, we're Mr. and Ms. Long Term Contract. We're the ones who are actually still able to build a gas-fired generation plant, and we need the assistance of other people to deal with the volatility that comes with that, so we're willing to deal with people who we feel can provide value to us.

But I wanted to illustrate that, because we have actually gone through the looking glass in a very perverse way, thanks to our friends at the CFTC. Which is, we are considered "special entities," and not in a good way. [LAUGHTER] Under the Dodd-Frank Act, as a special entity--this wasn't required by the Act, but the CFTC went out of their way to "assist us" and prevent us from being taken advantage of by limiting the amount of trading that could be done with our members by entities in any one year to a measly amount--I believe it's $25 million. And if you do more than that with a public utility in a year, you become a swap dealer. So there are a lot of people who don't want to deal with us, because they do not want to become swap dealers, and I don't blame them.

So we're actually in a bizarre situation of being left with pretty much only the major banks as our counterparties for a lot of transactions, because all the regional parties who can provide us longer, frankly, more customized counterparty transactions at a lower cost, are scared to death to deal with us. We're wearing the scarlet letter right now. We have gone to Congress. We have gotten an act passed in the House to reverse this situation by a vote of 423 to zero. How often does that happen in Congress? [LAUGHTER] And we just introduced a bipartisan bill in the Senate which is identical to the bill in the House.

So we're hopeful to get this issue addressed one way or another, but the point I was originally going to make was that we're very interested in having non-bank counterparties in the market. We need diversity, all kinds of financial players, because that creates competition. When we're only dealing with the major banks, they know it. So I guess I would just plead, "Let's look at the flipside." There are a lot of players in these markets who are non-bank parties, and I'd like to give a shout-out to them to continue to participate.

Speaker 3: Thank you. So I think you're in agreement on the enforcement and bad trading, and nobody would disagree with that. To the questioner's points, I think that the trade association idea is a good one, and certainly there are examples where we have gone and filed at FERC on market design flaws that we have seen to get them fixed.

And on being able to deal only with swap dealers, I think that's an excellent point as well. As to why banks are more expensive--I alluded to that earlier in terms of how, when people used to do deals in the past, the way credit risk was measured in banks made a difference. I think probably every deal that we do has a CVA cost, a credit value adjustment. So when things get beyond a certain tenor, some of the charges just become exponentially large. So I think the risk-taking appetite, even within the banks, just because of the capital requirements, has changed, and so I wouldn't disagree with you, and certainly to have more choice for the customer is always a good thing. But we are there, and we want to do business with you and do it in the right way, and don't disagree with anything you've said.

Speaker 2: Yes, certainly you have the credit charges, which is part of the regulatory regime that, as banks, we fall under. We're required by the regulators to assess a credit charge in every single transaction we do, and to manage that separately. So you can argue, and a lot of people do, and I probably agree with them, that the rigor is appropriate, that a lot of credit had been mispriced prior to the financial crisis, and a lot of long-term deals were done by banks, as well as non-banks, that didn't fully account for credit risk. And that's changed, and it has frankly driven up costs for everybody, particularly on the long-term transactions, where obviously credit risks increase exponentially over time.

But to your other point, certainly, there's quite a bit of stuff in Dodd-Frank that has protected people or institutions from things that they didn't really want to be protected from, and I think part of the next phase, is to unwind some of those provisions that maybe went too far, and your action sounds like it's going to be successful, and I think there's some other ones as well, in an industry that feels that they've been prevented from participating in the market in the way they wanted to.

Speaker 1: Just to go back to the original question. Because I haven't been doing my job up here if you thought that everything sounded totally rosy. I don't think it is. And a trade group can go so far, but some of the issues that have been created for financial participants have been their own doing--engaging in systematic bad behavior, defending that behavior in the stakeholder process, and generally doing things that don't reflect well on them and actually are not consistent with competitive markets. So while I am sitting up here with angels, there is non-angelic behavior, and it's important to remember that, and I think it's in everyone's interest, including the financial sector, to do the positive things that the financial participants bring. We've heard about a lot of them here and of course, it's true. But we can't forget that there's some bad activity as well, and it needs to be addressed. It needs to be addressed by improving markets, improving rules, and enforcement. Probably in that order.

Speaker 3: Do you think of Morgan Stanley and Goldman Sachs as financial participants?

Speaker 1: Yes.

***Question** 7*: I probably did my first longer term transaction in 1977, and I am still doing them.

The issue is I have comes from my own narrow perspective. What is different now, and what is harder, is the interaction on the detail level with the RTO rules. On compliance, we want it to be right. We want it to be transparent. We want it to be competitive, but it's also very difficult, because of the way the rules are structured. And just listening to the exchanges about up-to congestion (we could probably spend the rest of the day arguing about the details of the rules on uplift) gives you an indication of the detail level that is going on at the basic building block, the spot markets, that need to be secure for you to get the longer term structure for your origination deal to go all the way through.

And so the question I have (there is a question at the end of this) is that the lack of consistency and the lack of transparency at the detail level of the rules has been amazingly impervious to stakeholder based correction. It just doesn't work. These tend to be winner or loser type things. At least, they're perceived that way, or they're not understood at all. And do any of you have some insights as to how that interaction can be fixed to make your first, your base step of comparability and transparency easier to get by? So that I don't have to spend a week translating between a client and somebody else about things like, "This is the way you should have done this." There needs to be a process for that that I think has to fall outside of the stakeholder process.

Speaker 1: People come to me all the time and say, "Well, isn't the stakeholder process broken?" I don't think it is broken. I think it's working the way it's intended to. There's a lot of offset. There are people who can block other people's actions. That's fine, but that should not be the end of it, and it very often has been the end of it, and we've been as frustrated by it as other people. But the solution there is for, in the case of PJM governance, for the board to make a 206 filing, which they've stepped up to do recently, and the more they do that, the more incentive there is for participants to actually reach a rational compromise before we get there. In addition, FERC needs to step up as well. FERC needs to be prepared to take actions to actually go forward and pick an appropriate policy solution, and the right one, when it's a zero sum game, or, as you said, perceived to be a zero sum game at the participant level.

Speaker 4: I've had the same observation. I mean, it seems at those lower levels, you'll end up with either no solution or a solution in which there's clearly a winner and there's clearly a loser, and it may not even end up resulting in a good market design. And I don't know that I have the ultimate solution, but I think that there needs to be more activity, perhaps from the Commission, in developing a group that looks at these sorts of issues, looking at stakeholder process outcomes versus what's required for good market design, and what's required for good outcomes.

Speaker 3: I would add that everything Speaker 1 said makes perfect sense. And while you know this very well, that everything has a cost allocation dimension to it, and if you're trying to fix something that is going to shift dollars, there will always be someone who's going to…It's like Congress. You have PJM governance and there are people that come with the 40 votes and look at it through the lens of whether or not it is going to benefit their narrow interest. But if you have a 206 filing, maybe, I think maybe that would make a difference. Even there, though, I do have a question. The 206 has this provision about the burden to show that the existing terms and conditions are not just and reasonable. And I think a lot depends on which particular attorney in the FERC is going to work on it. There are some who are very thoughtful and appreciate the underlying substance of the issue. There are some who may look at it through the lens of, "I don't want to do anything," and that is unfortunate. So hopefully, there will be people who will look at the substance of the issue and try to find a solution. That would be my hope.

Question 8: Just to kind of continue that last conversation, there would be one thing from a PJM perspective. Yes, we do have 206 filing rights, and Speaker 3, you're exactly right. The burden is much heavier under Section 206. We do have to show that the current mechanisms in place are not just and reasonable. But there are also large parts of the tariff in which PJM does retain 205 filing rights that do not require such a heavy burden. But I think what we would appreciate, in having discussions with certain members of FERC staff and trying to communicate this, is to say that we'd like to get a much stronger, maybe even more public signal from the Commission to say, "Look, RTOs, if you really feel that there's something here that's wrong and that's broken and you cannot get stakeholder consensus, go ahead and make that filing." And I don't think perhaps we're getting that strong enough signal on that.

So that would just be my request to the Commission and Commission staff, is that if we see something, and Commission staff also sees it, that they try to at least send a signal that this is a good course of action, which would be a strong signal to the board to go ahead and burn that political capital, if you will, to make that 205 or 206 filing.

But that was not my question. [LAUGHTER] The question I had goes to the statement that Speaker 4 made about how LMPs are biased downward, and that there must be something wrong with our price formation. And so to the extent that power systems are not textbook textbook markets, we have non convexities everywhere, we're going to have uplift. Price formation has to be consistent with system dispatch and operational needs. Consequently, a lot of the LMPs you see you may feel are biased downward (in some cases, I've heard loads saying they're biased upward for the same reason), but they're consistent with dispatch needs. I and others worked on a paper over a decade ago showing that for the system of uplift we have, along with LMPs, that you can actually decentralize this and it is an optimal economic solution. Bill, then, later on, with Paul Gribik and Susan Pope, wrote a paper on minimum uplift pricing, and I think the important key here is that word, "minimum." We're not going to get rid of uplift entirely.

So my question to you is, what mechanism do you have in mind? Do you have something similar to what Bill and Paul and Susan proposed several years ago on minimum uplift pricing? Or something kind of halfway in between, in which case we might get higher prices, but still uplift, in fact, uplift to tell people to not generate, as opposed to making people whole for generating? What would be your solution?

Speaker 4: I'm not suggesting that we can do away with uplift. I mean, it's just a fact that we're putting an algorithm over top of a physical system that has lumpiness. It's not going to go away. But my suggestion is that we need to look at how we develop reserves in these markets, how we dispatch units, in terms of when we're calling them on and how long are they on, what are the minimum run times, and we need to incorporate that somehow holistically into the market. And there is a solution that's out there. One of them is extended LMP, which Midwest ISO is going to implement next year (and I understand that it's not quite the complete extended LMP solution) but I think we need to look at those sorts of things. It's new, it has not been tested in an actual market, but we do need to give some inspection of that, relative to what we have now, to determine if there's a better way that we can price the system to minimize uplift. I don't want to suggest that we can do away with it. We can't, and I don't think anybody thinks that we can do away with it completely.

Speaker 1: Let me just add, on uplift, that we have been chipping away at uplift for a number of years, and the key first thing is to make sure that only those payments that belong in uplift are in uplift. So part of what we did was we got black start taken out of uplift. That was a huge, huge improvement. We got reactive taken out of uplift. Those are separate charges, about separate products which should be assigned to the right folks, and they don't belong in uplift. They don't belong in deviation charges. So that's made a huge difference.

There are some additional steps to be taken there in order to take out of uplift things that do not belong in uplift. For example, why is it that certain units have been dispatched for the last 10 years to support the Con Ed wheel, but have not been assigned to that wheel? And there's a very significant amount of money there. The same (and we say this in the SOM over and over again), the same 10 units have been getting most of the uplift for the last 10 years. An additional thing we need, in our view, is total transparency. Every unit that gets uplift should be public. The exact amount and the identity and location of the unit should be public, in order to permit competition, because right now it's non-transparent, unhedgeable, and you cannot compete it away. And we've had the same units sitting there for 10 or 15 years, getting paid massive amounts of uplift, as we've documented repeatedly. So I think if you do those fairly obvious things, you can make uplift a very tiny amount, and something that is noise, rather than a significant impact on market transactions, which is really the goal.

Questioner: Uplift is only about a dollar per megawatt hour out of a total wholesale cost of about $55 a megawatt hour this year.

Speaker 1: But for decs, it's three, four, five dollars, and it's very uncertain. It can go up to $30 and $40, as it did, so it's a huge disincentive to trade if you're facing a $40 risk on a $2 margin.

Question 9: Speaker 1, you talked about trading at the ISO/RTO seams and the lack of trading, and there's a lack of many things at the RTO seams, such that even one of the RTO's representatives described it as "no man's land." One of the other things that affects is transmission planning. But from a market perspective, what are the top three things that you would do to increase trading at the market seams?

Speaker 1: I don't know if I have three, but the first one is, we'd make sure that the RTOs find prices at the seam the same way. So MISO uses 1,000 buses, and PJM uses nine buses, and it doesn't make sense. It's irrational. You're never going to get the right answer there. Second is reduce administrative wait time to transact. The longer you have to wait, the less likely it is you're going to be able to react to the price in close to real time and have a rational outcome. The third really broad goal is actually to remove traders from the kind of process they're in now, what I refer to as the archaic process, and make it look more like LMP, make it more look like a financial market that exists elsewhere, so we're not relying on traders waiting for a long time and having to go through a whole big process to be the drivers of equal prices across the seams.

Question 10: I'm reading the title, and it says, "Value added or value removed." So let's just go to value. It seems that you all agree that liquidity is good, and more is better. The best possible liquidity is the best. There's such a thing as bad and good, but it seems like we're the sole judges of that. So how do you convey this to anybody? How do we measure how liquid a market is now? How do we measure different proposals, all of which have costs associated with them, to make a market better, so that we could say, "If you do X, there are X amount of dollars". And I'll add a third challenge, which is that the metric should not only measure the improvement in liquidity, but it should show the distributional impacts, too, because a regulator may want to know who wins and who loses.

Speaker 1: I would just say that I don't think liquidity has much to do with it. I mean, liquidity is kind of a funny word. As somebody said, everyone talks about it, everyone agrees it's good, but it's pretty hard to quantify, and it's certainly not possible to say what's optimal. I would say that's not the goal at all. It's probably not quantifiable. I can't think of a good liquidity metric. But what we're trying to have is competitive markets. We're trying to have rules that allow participants to trade, given those transparent prices, and do whatever they want, so they don't have to worry about enforcement. They don't have to worry about bad rules. They can see the prices. They can react to the prices and trade on them. And the level of participation will follow that. We ought to remove the barriers to entry to the extent you can, and make the market as competitive and transparent as possible. I don't know what liquidity means, and I don't think it's possible to design a meaningful metric.

Speaker 3: I'll give you a simple example. So we look at the bid-ask spread in the market, and what is the tenor--and this is bilateral. So when I say, "Is the market working OK or not?" I look at these kind of metrics in the bilateral market, and that tells me that the underlying spot market is efficient. I agree with Speaker 1 that liquidity in the ISO market is a different issue, because that's a market in which you have all the generation, you have all the load, and then you have some virtuals, so that's really not the issue. If it's working OK, then you will have people trading forward two, three years. The bid-ask will be small, and then you have a real market.

That was really the goal of setting up markets. This was not an exercise of Operations Research practitioners, to create RTOs. The goal was to set up a mechanism so people can trade. So to me, even asking the question, "We have markets, and are traders are adding something to it?"… I mean it's a strange question, frankly. Why would you have markets if you don't want traders?

And the other example I think of is that back when these centralized LMP markets were being formed, there was this big debate. Markets in any other commodity are not like this. There are buyers and sellers and they come together and there's a bid-ask, and that's how markets work. And then, Bill and others convinced the policy makers that electricity is different. We need a centralized mechanism. But then, of course, what comes with that is that you don't also need just one entity making all the decisions. So in the organized market, I think the role of the virtuals and all these different participants is to bring decentralized information to the market. You don't have just the system operator deciding, "I want to commit 3,000 megawatts more because I think the load forecast is going to be this." That could skew the price in the market. And by having virtuals, you help align what will happen in reality with what is shown and what is the forward market, really, the day-ahead markets. So that's my two cents. I apologize if we didn't live up to the expectation of bringing metrics, but we think of it more conceptually.

Speaker 2: Yeah, I'll just comment liquidity, there are lots of reasons why it ebbs and flows. There might be less liquidity in stable markets where there's not a lot of activity going on. I mean, right now we've got, arguably, an overcapitalized market from a generation side, so you don't have scarcity, and therefore there's less activity. I think some of the signs I look at to decide whether markets are working are, again, the fact that we have very low, stable prices. At the end of the day, markets were developed for the benefit of the consumer, so competition could exist. It clearly has, and we've developed a market that has delivered the goods, in my view, to consumers. And I think another illustration of how price signals are working, is that when we had a whole market change about 18 months ago, when very low gas prices came along, we completely changed the way we generated power from coal to gas, and that was entirely based on the market sending price signals and behavior being modified as a result, and I think many of us were pretty taken aback by how quickly the market adapted to the very clear price signals. And in PJM, you had gas plants running base load—something previously unheard of--because the price signals were transmitted quickly, understood, and people acted on them. So I think that's the type of thing when we say whether the market's good or the market's bad, I think you need to look at the end result and what have markets delivered, and I think those are good examples of markets having delivered lower costs and improved efficiency that I think is very hard to debate.

Question 11: I thought that Speaker 4's slide 8 (on market design considerations) gave a lot of food for thought, and I wanted to follow up on the bullet that talks about ISO practices relying on unpriced operator actions that distort price signals. And it seems to me that if we're going to have virtual bidding or convergence bidding that actually works, we need to be relying on more fundamentals rather than predicting what ISO might do. And I'm trying to follow up on how big a problem you think that that is, as far as allowing traders to add value?

Speaker 4: Sure. I think it's a problem, in that the price signal, the real-time LMP signal becomes distorted when you don't or cannot account for the actions that operators take in maintaining good reliability. And keep in mind that these markets work if and only if that real-time signal works. And as I said, there are relationships between these real-time and short-term markets and the longer-term markets. And so if these signals are distorted, then the formation of longer-term price curves and markets will have some distortion built into them as well. And so as a trader, when you're looking at these markets, when you do a fundamental analysis, and you're trying to calculate your value for a given future time period for a particular location in a market, and you come up with an analysis, and you look back to a comparable time period in the past, and you see that, "Well, we know that these prices are distorted, and by the way, there's a lot of uplift that's paid through these markets, so we know that there's some distortion there…" So then it becomes very difficult to rely on your fundamental analysis in determining what's the value of that market, and then, what you should transact at. So that's sort of a linkage in terms of not getting the right real-time prices, and I say the term, "right" in terms of having it reflect as much of the cost of maintaining reliability that we can.

Speaker 1: I agree with what he said, but it's harder to do sometimes than it seems. So for example, imagine you have a transmission line which has a reactive constraint on a voltage constraint rather than a thermal constraint. If you re-dispatch the reactive constraint, then setting the price properly is more difficult than it seems, because you can end up giving people the wrong price signal on both ends. I think PJM recognizes the problem. I think the stakeholders recognize the problem. It's actively being worked on really pretty much by that very name, which is the idea is to make the prices to the extent that they can be, and operator actions, reflect the underlying fundamentals. I think everyone recognizes it's not there yet and it needs to get better, and I think there are some good ideas being floated about how to get there. I don't think it'll ever be perfect, but it needs to get better.

Speaker 4: I agree with that last point. What I said earlier is that it's not going to be perfect. We're not going to get rid of all uplift from the market. It's just impossible to do. But I will say and PJM is taking the right steps. I mean, they started a process to start addressing this issue. As difficult as it is, they're taking a first step to address this issue.

Question 12: I have two questions actually. The irony of this kind of discussion is that we're focused on the organized markets, and we're sitting here in an unorganized market. And so one of the questions I had is, looking at parts of the country, including this one, that don't have organized markets (there was an example from Montana, which is similarly situated), what kinds of opportunities are there for trading? Are there more opportunities for trading in non-organized markets that we're not taking advantage of? And what are customers losing as a result? And the second question, which relates only partly to that, is, what happens to the trading market, how does it look, how does it change, if we started using dynamic pricing in the retail market, rather than just have wholesale actors participating?

Speaker 3: I'll start with the first part of your question. So outside of organized markets in the Northwest, we have Mid-C, a very actively traded bilateral market. In the Southwest, we have people trade Four Corners, and actually, it's interesting that when people trade Four Corners, it's actually a trading point of the California ISO. So Southern California Edison has ownership in the Four Corners power plant, by virtue of which it owns transmission up to the Four Corners power plant, and there is a transaction where APS is buying from SCE. And when that closes, the old units, one, two and three will retire, and the trading that happens in the bilateral market will have to shift from Four Corners to a location called Willow Beach.

And people trade assets, as I mentioned earlier, where we'll do the tolls. And even though California is an organized market, just by virtue of the policy of the state, which is to do everything through new contracts for new resources, and not really have as much focus on a market mechanism for compensating existing resources, the opportunities in many ways in the West are more outside of California, in the unorganized part. Certainly, there's an interface with California, because that's where all of the demand is. So by no means would we dismiss the regions outside of organized markets.

Speaker 1: I think dynamic retail pricing would be a step forward everywhere, but it's harder to make it seem sensible for customers if the wholesale power price is not being formed in some transparent competitive way. So I have a lot easier time saying in Texas or New Jersey or in PJM or MISO New York or New England that the wholesale price should flow through to the retail customer than I would in an area without RTOs, where it's not clear where the wholesale price is coming from.

Question 13: I don't know if this is a question, but I think it's maybe worth saying, because there aren't maybe a lot of generators in the room. So one of the values that we see in having banks participate in the physical markets is the whole issue of who bears the risk in the markets when there's no rate base to put it through to. So if you're an IPP in that market, what you do on a day to day basis is generate power. You're not as detailed, in the weeds, on the RTO rules. You're not as forward looking in terms of where you see the market going, and it's extremely helpful to have informed people with skin in the game who are well capitalized and well regulated, in order to protect you from unforeseen risk. And at least with respect to the IPPs that we invest in, that's a really significant benefit.

MODERATOR: Thank you. I think with that, we'll break for lunch. Thanks to the panel. [APPLAUSE]

Session Two.
The Electric Utility Business Model Going Forward: Maximalist, Minimalist, or Somewhere in Between?

The history of the electric utility business model in the U.S. has varied from a maximal model where the utility sold not only electricity but sold appliances and even electrician services, to an unbundled model where the utility provided only distribution and back office services. Given the changes in electricity markets today, with a diversity of customer demands and options, what is optimal for the modern electric utility? The emergence of such products and services such as micro-grids, demand response, distributed generation, plug-in vehicles, smart meters, and energy efficiency are posing critical challenges for utilities that relate to competitive pressures, revenue erosion, more complex interface with customers, and a host of other issues. How might utilities respond to such changes? The options range from a minimalist approach where the utility performs only core services (e.g. distribution and transmission) and leaves the remainder of electricity services to other actors in a competitive market place. At the other end of the spectrum, a utility might fight to preserve the maximum level of monopoly it is able to retain, or even if unable to maintain a monopoly, it uses its power of incumbency to compete vigorously to provide non-core services. In addition, of course, there are a number of options in between. What factors are most important in the consideration of a model to pursue? What models will be enabled by the rapidly changing circumstances within the industry?

Speaker 1.
So my disclaimer is, I speak for nobody, and I include myself in that category.

We'll start off by talking about what the characteristics of the old regime, the one that we inherited for the last century or So and what they are, and then contrast that with some of the developments that are happening, and whether they're maintainable on an ongoing basis.

And some of the key characteristics were, first, that the upside potential for the industry, which was largely utilities, was limited. The downside was somewhat limited, although there were asymmetric downside risks like open ended obligations to serve with customers not having an open-ended obligation to buy. There were some regulatory protections, but the upside was clearly limited, and for the downside, there were some limitations. How significant they were, I won't go in to, but the point is, it was an asymmetrical sort of risk scenario.

Another characteristic of the old regime was that customers saw essentially meaningless price signals. There was just average cost pricing and average cost within classes, and average cost didn't reflect what the actual cost of production is at any given moment in time. And there was also a fairly limited spectrum for socializing or privatizing risk.

For the most part, the utility and its investors took risks and gained or lost from those, or we socialized the risk, in which case you changed a little bit of the risk-reward profile. But that was it. Essentially you privatized it on the investor, at least where you had investor owned utilities. Obviously, in 25% of the market, we didn't--we had other kinds of actors, public entities and co-ops.

And another old regime characteristic was bundled services. And so we saw prices that were non-discrete in terms of the services. We saw offerings that were essentially non-discrete, take it or leave it offerings. And utilities were generalists, generalists within the context of the services that they were performing.

Now, how well does that fit an industry that's going through some pretty fundamental changes?

Obviously the markets are changing. Why? Well, there are a lot of reasons. One is, technology has changed, the classic example being smart grid technology, but another example being the prevalence now of distributed generation. The needs of customers are changing. Customers need varying degrees of reliability and backup. As we have more diverse customers, even within classes, the issue about who's going to assume what costs is changed from the traditional notion of categorizing customers as industrial, commercial and residential, to a much more complicated set of scenarios of different customers having different needs in each of those categories. So the traditional class-based cost allocation really doesn't work particularly well anymore.

Consumers have a lot more options than they ever had, whether it's energy efficiency options, or distributed generations options, or, for large customers, going out and essentially bypassing the distributor. And we obviously have more diverse resource options, and people wanting different kinds of resources, whether they want a green portfolio or they want a more traditional portfolio, whether they want to have their own distributed generation, how much reliability they're willing to pay for, whether they want their own backup system. There are many more options that are out there than used to be out there.

And you obviously also have the question of how we develop a regulatory system and a system of incentives and of regulation that basically deals with the industry as if it were an entire entity. You know, to some extent we've already made some decisions, at least in much of the country, not all the country, to change some of that.

And in many places we found it beneficial to spin off transmission into a separate business. Obviously, in many states they made that decision with regard to generation. Other states are still in a vertically integrated mode. But even in those states, a lot of the generation is produced by non-utility generators.

And so some of this unbundling and emergence of competition has happened, and the question is how far down the chain we should go. And certainly in wholesale markets, in much although not all the country, we've opened that up.

But now you obviously have other kinds of choices that customers have at the retail end, and how should we deal with those? I mean, you could have micro generation or continue to buy the large scale generation through the utility. Or essentially the utility could provide no service in terms of energy at all, and you could simply buy from wherever you're going to buy. Obviously, if you want a renewable portfolio, you could arrange (at least in theory, whether you legally can depend on the state law) for a renewable portfolio, and you could decide how much reliability you want in terms of capacity and energy.

When I say you could, I don't mean this is actually happening in a lot of places, but in theory and in reality it could happen. The only thing that would bar it would be policies or laws that preclude it. But in terms of practical ability, it's there. You could do it.

Transmission, I think for the most part, we've decided (although not in Mississippi) that transmission is a separate business from the rest of the business. Obviously you've got distribution, you have energy sales, which in some states are separated. They're not separated in all states. You have metering and billing, which I don't believe in any state is separated from the utility. But it certainly could be (we'll talk more about that in a minute).

And then you've got demand side services--energy efficiency, demand response, a whole series of things for which we might ask whether they fit into the traditional model of what a distribution company does?

The other piece of this is, what perception does the public have of the utility?

One of the things that was really interesting about watching the debate here in Arizona about distributed generation was how the arguments that some of the solar advocates were making assumed that they were the small entrepreneurs going up against these giant monolith electric utilities.

But the utility is clearly more complicated than that. It isn't simply this monolith. But in any event, there's a perception of the utility as this giant entity that you do battle with, and the idea that utilities are looking out for themselves. Well obviously, utilities look out for their self-interests, you expect them to do that. But on the flip side, in reality, they are subject to a lot more challenges than they might have been 20 or 30 years ago, and they're not quite the same simple entity they might've been at that time.

And I think the result is that the customers tend to undervalue the core services. So if you think, for example, about distributed generation, and whether people think about what that costs in terms of taking revenues out of the distribution system, most customers probably wouldn't spend any time thinking about it. It wouldn't occur to them, unless you really remind them.

Why? Because that's not how they see the utility. And part of it is derived from the traditional role that the utility provides all the services and not some discrete subset of services that are deemed core services.

Well, what are core services? Well, obviously the wires. Transmission and distribution are core businesses. You know, they're clearly essential facilities, unless somebody wants to be totally removed from the grid, and they have all the characteristics of a natural monopoly (except in the city of Cleveland, where you've got two different distribution systems running down every street corner, and customers can pick and choose which wire to buy from.)

Other than the Cleveland example, transmission and distribution are clearly classic monopolies. But just about every other service the utility provides is non-core. It doesn't have to be the utility that provides it. Now, you can argue whether it should or shouldn't, but it doesn't have to be.

And the question is, if we start looking at these services from a policy perspective and from an economic efficiency standpoint, who's best positioned? Are utilities really best positioned to perform or manage core services? And, similarly, who's best positioned to perform and manage non-core services? And let's talk about the dangers of mixing the two. And I'm going to use a couple of examples.

My personal favorite is net metering. There's a variety of reasons for why we use net metering in 43 states. But the simple answer is, we had stupid technology, and it was easy. And utilities were largely indifferent, because the number of people with rooftop solar or other forms of distributed generation was pretty small and it wasn't worth fighting about.

And so we've got a very inefficient pricing of distributed generation, which clearly undervalues the core services of distribution, because it doesn't reflect the fact that this causes erosion from the distribution system's revenues. And what that, interestingly, is going to do as this builds up, is more costs are going to be treated as fixed costs, which means the utilities' revenue streams are somewhat protected, and you can defend this by saying, "Well, these are fixed assets you're using."

But from an environmental standpoint, and from an energy efficiency standpoint, you're getting pricing such that, instead of putting the emphasis on the volume being consumed, in other words promoting energy efficiency, you're now putting a greater value on recovering its core. Basically, the revenue is to support the core function.

So it's not clear, even environmentally, that we're getting the sort of result we want. And we're diluting efficiency and green price signals, and the two get very confused. I think at some point the environmental groups are going to wake up and say, "Geez, are we both going to be able to promote distributed generation and get green price signals?" And the answer probably is, the way things are headed, we're not going to get that.

You also get socially regressive allocation of revenue responsibility. For example, the non-solar customers are going to have to assume a greater portion of the distribution system costs than the other customers, who are generally more affluent. There was a recent study done in California that showed this pretty clearly, that net metering actually advantages upper income customers to the disadvantage of lower income customers.

And you get inefficient resource allocation. And in effect, through net metering, we've developed a subsidy for inefficiency. Part of the reason we did that, as I said, is because of stupid technology, but the other reason that we got into this is because we didn't think about it.

We just thought that the utility is going to be there, they're going to provide the service, they're going to provide whatever we need, and we can carve out this little niche for this guy, in solar generation or other distributed generation, without thinking about the impact on the core services, because the focus of the policymakers and consumers is taken away from that.

You also get issues about whether the risks and rewards are aligned. The example here I'm going to use is smart meters. Essentially, changing technology and more dynamic technological change is what drove the changes in the telecommunications industry. Not to the same degree, but there is some conceptual similarity between what's going on in electricity.

And can we fit these technological changes in the electricity industry under the traditional rate regime? And I think that that's a dubious proposition. And recovering the cost of assets whose technological obsolescence precedes their physical obsolescence is inconsistent with the regulatory bargain, traditionally.

It's true, you could jigger the regulatory arrangements, but then you're going to run into inadvertent consequences that haven't really been thought through. And how do we keep pace with rapidly changing technology? And who is better positioned to manage that?

For example, one of the things we try to do in order to reflect the advantages of energy efficiency and using smart meters to energy efficiency, is thinking about decoupling and changing the regulatory bargain in ways that remove some of the disincentives for utilities from promoting or enabling energy efficiency.

But actually, do we really need to change the bargain for that? Or do you get to a more efficient result by aligning the interests of those people who could invest in meters and line up with the customers and do energy efficiency on the customer side of the metering, rather than try to jigger their regulatory bargain for an entity that's largely disappearing, which is the vertically integrated utility.

Now, when I say it's largely disappearing, it's changed in very fundamental ways in most places. However, it shall not perish in Alabama. So you need not worry about that.

Another issue to consider is customer resistance to smart meters. So you've got this question about, are we really aligning the risks and rewards in the traditional bargain consistent with the changes going on in the market and in the industry in general?

And then, who is in the best position to cope with these risks? Utilities or alternate suppliers? For example, if you're looking at smart meters, who is better positioned to do energy efficiency programs or to try to manage the risks of technology whose physical obsolescence will take a longer time than its technical obsolescence? Do entrepreneurs manage that better, or utilities manage that better? We need to get away from the question of systematic payment of stranded costs, because we've changed so much.

If you think about, when it comes to stranded cost recovery, at least theoretically, part of that was driven by the fact that we were changing the regulatory regime. And so therefore were going to compensate people. Well, do we really want to run the risk of doing that all over again? Or do we simply change the market structure, so stranded costs become privatized?

And that also means you would need to change the market structure symmetrically--you would need to increase the possibility of profits in discrete services that are subject to competitive markets. And you would need to try to figure out where the symmetry between risk and control is, and who is in the best position to manage it. And I would argue that for a lot of these non-core services (which means non-wires functions), almost everything else is probably better managed by other people. Not because utilities are incapable of it, but because the regulatory bargain can't be skewed that much to try to get to particular results, without impinging on a bunch of other things that we haven't really thought through.

So the conclusion is that I think inevitably we need to look at more unbundling of services, opening up more of the market, then non-core parts of the market to competitive enterprise, to competition, and more entrepreneurial enterprises. We need to develop basically, service-specific kinds of focuses on a lot of the different elements that go into providing electricity service, which go well beyond just the core services. It's not so much limiting utilities, as limiting the scope of the regulatory market to what are the really core essential services that don't lend themselves very well to competition. And we need to open the market up for non-core services. Thank you.

Question: In your comments on net metering, where do you put the debate that was in, I guess, '77 and '78, on PURPA options? Which, you know, explicitly, as far as I can remember a long time ago, teed that up, and was subject to the usual lobbying of interests with regarding to preserving that option. And this set a precedent for a lot of what we see now, and I'm --

Speaker 1: It did set a precedent. But you know, PURPA was the first modern crack in the regulatory regime but, for those of you that were at our September session, they had no idea what they were doing at the time. Or, they had no anticipation of what would happen.

And I think in part, if you think about it, what PURPA was designed to do was to tweak the regulatory system in ways that would enable new actors to get into the marketplace, but in a fairly limited way. Over time, as that evolved, through, basically, regulators applying it, you're right, it started expanding, and then it forced other changes, like the '92 act, and whole series of things happened.

But you know, all these changes have been sort of incremental. And even the '92 act, it didn't create open access, people in shorthand say that it didn't. On a case-by-case basis, you could go in and apply for access. What FERC did, after

Bill Sherman left, what the FERC did was expand that into more of a full open access regime.

But the point is that these were all incremental changes that happened, that were fundamental. And in essence, what I'm saying today is, when you look at those incremental changes in the transmission market, and in the wholesale market, a lot of the same issues now are present in the distribution market, in this whole issue of, how do you allocate costs? Who should bear what share of the cost? How do you plan the system?

All those issues are now being visited in the distribution system. And I think we need to start thinking about unbundling like we have done in many parts of the country, on the wholesale market.

Question: I just want to point out that there is an important difference between net metering and PURPA, in that with PURPA, you're required to purchase at the avoided cost, which is a wholesale cost. And then with net metering, you're required to purchase at the retail rate. So that's just really important.

Speaker 2.

My disclaimer is that Speaker 1 and I did not put together our slides, I didn't know what his slides were until I just looked at them, and Speaker 1 will say things like, "asymmetric downside risks," and I'll show you pictures. [LAUGHTER]

The way that I think about this (and apparently on the panel, I'll be representing the bad, vertically integrated model who needs a lot of help) is that the first thing you come to from that perspective is the regulatory compact. A lot of things that we have done in the past, have been through this particular model. And I think Speaker 1's question at the end was essentially, "Does this work anymore?" And there are a lot of things that have changed and you have to ask the question about the regulatory compact itself to address those.

And so we have all those things that have been part of the regulatory compact--the duty to serve, cost of service pricing, etc. These are the rules by which the utility operates.

And so when you say, "Well, the utility can't possibly address some of these questions, the utility can't do these things," well, you're right, because there are some things that I'm also not allowed to do. Think of any other commodity you can think of, where no matter where you are in the service territory, no matter when you want it, you can have as much as you want.

How do you get the pricings right? I mean, that's a crazy thing. If you live on the edge of my service territory and you want the hundred megawatts at four in the morning, you can get it. And I have to provide it. We have to build it. It has to go out there.

I will point out, on this slide, that we talk about reasonable return--and it's always the <u>opportunity</u> to get the reasonable return--but you've got the regulatory compact. So think about that. Also think through the historic test years.

And guess what? Historic test years work when retail sales and GDP go up together, when you're growing.

So when the buildings are going up, and when everybody moves from Michigan because they come to Arizona in January and they think they like it, and they didn't visit us in August. But they come here, and you get to use the historic test year, and, you know what, it works out, because your sales are growing.

Well, guess what happens when it doesn't? And guess what's happened in the last five years? It doesn't work. It creates a lot of problems. The historic test year model is very, very difficult to work from, because your sales are flat lined, essentially. And they flat line for a number of reasons. And the economy is there, but there are a number of things that are going on: energy efficiency, distributed generation, you can go on and on.

But it's not going to grow like it once did. I think we all realize that, but the time it dawned on me, was when the DVR, when it went to the power save mode, it didn't go up there and say, "Power save mode, because we hate Tucson Electric Power." They went to a power save mode for a reason. Mostly, because of the components inside there that they didn't want overheating.

So there are a lot of different reasons besides energy efficiency that are flattening out our load. And when you have this particular conundrum, you arrive at the problem that Speaker 1 was talking about, which is, we as the utility, and through public policy, have done a lousy job on price signals. Especially the one price signal, which is that about half of your bill is access to electricity, not actual electricity.

That's what really half your bill is--depending on where you live, but in our service territory, that's about right. And if I went to my mother and I tried to tell her that, she'd look at me like I was crazy. "Why am I paying for that? That makes no sense to me." But that's actually what it is, is those infrastructure costs that are there, that you have to deal with.

And it's gotten worse, by the way. Because the federal government has essentially said, "We're going to do a number of things. We're going to retrofit coal plants, and we're going to do it in every way, shape and form possible, by the way, and we're going to use the Clean Water Act, Clean Air Act, and all that."

Everybody's for clean water and clean air and all those other things, but we are going to add capital costs, and we're going to do so in a way that you don't traditionally do in the utilities. We're not going to help you with your asset utilization, we're actually going to impede it. So we're going to put things on the generator that, when normally you do things, like the Henry Ford model, you put stuff together so you get that lower priced, you know, Model T.

Here, you're going to add those costs on, and you're going to get less kilowatts out of the plan. Or you can. But in any rate, the price per kilowatt is going up, and it will go up.

So you have that situation. You add on top of that cyber security, with China and Iran pinging us, and all those other things... And then there are policies. And then you turn around and you basically say to the utility, or to the core, "Spend as much money as possible on this. That's what we want you to do. We want you to invest like crazy." And then, we turn around and we hear things like this: "We want energy efficiency. We want distributed generation." And then, we get the, you know, presidential memorandum, which was issued in I think either June or July, which starts off with about 13 pages of, "This is why we need to get away from coal." But if you read the back half of that thing, it tells you what they're going to do on public lands. They're going to put 10 gigawatts of renewable energy on public lands. The military, the Army, the Navy, and the Air Force, the Marines don't have this, they already are under one, I think it's one gigawatt, that they've got to get done, and I can't remember the years, but that's happening.

It goes on to talk about more aggressive standards. And they bumped up, I think, from 7% to 20%, and then they talk about how all federal facilities will be energy efficient. So you have this interesting situation where, at the same time we're supposed to be investing like mad, they want you to invest in that, and then they say, "but we really don't want you to really use it."

And for those people who have to raise capital and go to people and ask that question, that is becoming a harder and harder question. So when we go back to the regulatory compact of, how do you do these things and how do you provide all this stuff, and what should your return on equity be, I don't know that we have evaluated all the risks that are out there that others who have to fund this stuff have identified and are going to make some of our costs go up for those things.

So this is the old retail revenue and rate formula. I'm going to click through this really quickly, but the point of this slide is to say, growth is the thing that really helped out. Capital expenditures are going up. O&M is going up. Those things are not going down. The thing that traditionally would offset that, if you were setting rates, would be growth. Use per customer is not going up. The number of customers, yes, you know, hopefully if the economy comes back and people start moving back to Arizona, that'll be helpful. But you know, again, transmission and wholesale growth, we're not seeing those things.

So what I'm suggesting is that the old regulatory model was essentially to be low cost and be reliable. That's what they wanted. And it was pretty much that way in all 50 states. Be low cost and be reliable.

But at some point, that changed. And it changed, and the new regulatory model said, "We want you to be low cost, we want you to be reliable, and now we want these public policy things as well." But the interesting part about some of those public policies things is then they said, "But we don't want to pay for it."

And I'll give you an example of that. When you have some of the standards that you have, and we have them in Arizona, if you really want those things, you should really, really pay for it. So if you really want to have 15% renewables by 2025, then why don't you pay the utility for the production of that asset, which has more risks, which needs more things? Right? You've got to firm up the power, it costs more, and there's a reason why there are renewable developers. It's because it's risky.

So if you're going to pay me a regulated rate of return, why would I ever take on that risk of development? I'm not. But yet, you want to pay me that way. So instead of having a 20 year renewables plan, why don't you say, "Here's what we want, and if you do those type of projects, here's your percent"?

What if you said, "We're going to treat the projects differently, instead of treating all the projects as if it's this average rate of return that you should get." So then you start moving towards having to change some of the regulatory constructs. But you also have to start doing some other things, like actually listening to your customer.

It's kind of neat to see Speaker 1 talk about the customer in his presentation. That's the thing that has to happen. So we're still going to have to be low cost. You want to have this reliability. But you're also going to have to have that customer satisfaction.

And how is that going to happen? Well, you're going to have to work on changing the rules. So if you've got the customer, and you've got a competitive advantage (and in our case, the competitive advantage is generally the system that we have, the utility system, the grid) you've got to get the rules right.

So you start looking around, and you say, "OK, what are the things that are out there that we should be thinking about?" Because traditionally, here's what we've done as a utility. We've gotten our rules from our commission, and our customers have said, "We want to put a thing in your service territory". And we go, "Great, here's our tariffs, pay up--Oh, and by the way, you've got to gross it up." That's a fantastic economic development policy, right? That has to change, because growth hides a lot of things. It hid Bernie Madoff for a while. And what growth hid from us is the fact that we really didn't have to listen to our customers.

Our true nature, our Frankenstein, is that we are an infrastructure company. And we have to get paid for that, but we also have to figure out what our customers really want.

One of the examples that I'll give to you has to do with the military. The militaries I talked about, they have a want, they have a desire. They want to be more energy efficient and they want to be more sustainable. They talk about energy independence as well, and we'll see about that, if we ever get moved to storage or micro-grids, but for right now, they are very concerned about meeting certain targets.

If I can go to the base commander and solve that for him, so that he doesn't have to worry about it, and so that he can actually do the things he or she is supposed to do, like protect our interests, be the listening post, fly the drones, whatever it is… You know, that's a good thing, but I can't do it in a way that I traditionally done it before, which has been kind of just to tell him, "Here's what we've done."

We've got to go to the commission, and we've got to change the rules. Because one of the things that we've done for a long time is that we have taken our customers' needs and desires, and we have said, "Adapt those needs and desires to our rules." We have to do the reverse. We have to figure out what they want, and we have to change our rules to meet those things that they want.

You want guaranteed reliability? You're a mine, you don't ever want to go down? Hey, we can do that. You want to have all of these other things that I've put up on the slide? Hey, we can do that. But if we don't have the changes, from my perspective, on the regulatory side--I mean, is it OK for us to go dark? Is that OK? Can I do that? Can I now put together a pricing plan where areas in neighborhoods can be off-line for a little while? But at least we need to have that conversation.

The other thing we need to talk about are economic development tariffs. Another big thing they like to talk about politically, is "Jobs, jobs, jobs." How do we get some of these things done? What I'm suggesting is that using historic test years is using the old ways of doing things.

Think about a line siting 20 years ago. How did that go? The engineers got the room, they drew a line on a piece of paper, you went to the commissioner, it was a three hour hearing, and you had a line. It's nothing close to that today. And people are expecting that. But if I'm going to compete in Speaker 1's world, then let me compete. Don't hold me to the same rules and regulations and all the other things -- let me adjust some of those things so that I can do something about it.

The other thing I think we need to talk a lot more about is value of service, as opposed to cost of service. And here's what I mean by that. If I have a mine, and the mine produces revenue at half a million dollars a day for the utility, and one of the transformers at their substation, which we own, costs two and a half million dollars, if the mine says to me, "We want to have guaranteed reliability," I say "Great, it's two and a half million dollars, here you go, and oh, by the way, here are the rules and here's what you get to pay for," as opposed to somebody sitting there and thinking, "If the mine goes down for five days, that's two and a half million dollars. So if we have an outage and it could have been fixed by having that spare transformer there, we could have avoided the entire investment. Or, have a mobile transformer there. Why don't we have a mobile transformer there?" And we may have some sort of a security pricing for the mine, but we also socialize some of that, because if something goes wrong within the city of Tucson, it's mobile and I can bring it in and use it in different areas.

So I know I'm running out of time, but the focus that I wanted to bring to this panel was the thought about the customer, which I think Dilbert does the best, and he's far more eloquent than I am on it, [LAUGHTER], but that's kind of how we've been. We've been saying, "Well, yeah, we want to do everything to satisfy you as our customer, except when it's hard, or we don't make a lot of money, or we're really kind of busy doing other stuff."

The perspective that I wanted to bring is that some of the reasons that you may perceive utilities as not being competitive in those non-core functions is because of the rules that we have been used to. And if we can change some of those rules, then I think that there are areas in which not only can the utility be competitive, but it can be the best provider, and also we can actually do something for our customers, besides send them bad news every month about how much money they owe us.

Speaker 3.

I'm going to give a slightly different framing for this. I'm going to give an investor perspective. I want to frame what the challenge is in the industry, looking at the utility business model.

I'm sure everyone's seen the death parables out there. The industry is described as "dying," there's a lot of death imagery. Energy efficiency, distributed generation is "killing" it. There's this notion of "grid citizenship," and there's lots of talk of transformation. The question is, what are the facts out there?

We've talked a bit here already about some of the things. These quotations on my slide represent two views on change, to me, that are quite interesting. One is David Crane's, which is that you'll get rolled over if you don't adapt to the technology. And then the second one is from EEI (the Edison Electric Institute), which I thought was interesting. What EEI is saying is that the analysts are not taking disruptive challenges, in terms of the impact of technologies, into account in the valuations of the utilities. So just hold those two thoughts. I'll come back to these.

So let's think about what really is driving the change. There are a set of technology drivers: we've talked about distributed generation, centralized renewables, and energy efficiency, and then there's the customer. This whole theme of the customer and the customer experience, it's very different than it's been in the last 50 years.

I add to that, of course, unconventional gas and oil, which has killed gas prices. So you get that set of technology drivers, and to it you add a set of trends. Now, I've got a starter list here. I'm sure with this room we could add more things. But you combine those two things, and there are really two questions at least a lot of my utility clients are asking.

One is, how bad is it? How concerned should we be? And what should we do about it? Meaning, what is the threat? If you put all these things together, what is the threat to the utility model?

So on this first question, the sub questions we typically hear are, what is really the threat? Are we talking about solar disintermediation? Are we talking about CHP? Is this micro grid thing really going to be real? Is it going to cut me off? And how immediate is it? How real is it? How impactful is it?

And I would say the consensus, and this is really in the last year I'm finding this, is that if utilities, and IOUs specifically, have focused on 4% to 6% percent EPS (earnings per share) growth, that is the North Star that they're trying to deliver to the market, then the changes we're talking about, in terms of the technology, are really going to drive against this 4% to 6% target. I think now we've got a consensus that this 4% to 6% is under threat.

Then, there's the question of, what do you do about it? Is there a defensive play? Do I become a Georgia Power and block a bunch of solar? Do I become an FPL and through a solar water heater program do a bunch of roof installs? Are there certain ways I can go about defensively still using my model, and prevent the technology from attacking my load?

Or, offensively, what can I do? Can I actually start an unregulated subsidiary and go for these businesses? So those are the two questions.

The answers I'm hearing from the conversations are extremely variable. One set of folks say, "It's a disaster, we're just going to lose load." I mean, if you looked at Speaker 2's charts of declining sales… Others say, "This is a transition point, this is the transformative point, and we're going to reenergize ourselves and we're going to get into these businesses." So that's sort of a big question about what is the future.

So you could say glass half empty or glass half full. You could look at it this way. But let me give you an example of what kind of damage you could see from an investor-owned utility perspective.

This is work we just did for a large utility working with them across several jurisdictions. We did a sort of a base case and a high case forecast of looking at DG, energy efficiency, LEDs, appliance standards, building standards, et cetera, and what that's going to do to their load. They're vertically integrated in most of their market. And what this shows is a 10 year load forecast. The base case is the light blue, the high case is the dark blue. That's the load impact from energy efficiency and solar. Pretty damaging.

And, in fact, if you think about where they were expecting their load growth to be, which was about 1% CAGR (compound annual growth rate) for the next 10 years, in KWH, they would be negative in the high case. And this would impact their margins by 25% in five years. So they'd be losing gross EBIT (earnings before interest & tax) by 25%. So this thing is real. It's happening.

And if I can give you some solace, I'll turn to Europe and show you the disaster that's happening in Europe. This is a chart that shows EBIT in Euros in 2011, broken down by value chain. And then, if you look at the forecast to 2020, generation is losing value, and I know that tomorrow there's going to be a conversation around this.

There's some growth in T&D. But a lot of the growth is happening in centralized renewables, which the incumbent utilities have basically been very slow in getting into. About 20% of the existing renewables that have been built, has been built by incumbents. So 80% has been built by new attackers.

And then there's growth in new downstream--new services, DG, those types of things. So value is shifting downstream for the utility model. And if you look at North America, this is U.S. specific, if you look at today's EBITDA (earnings before interest, taxes, depreciation, and amortization), and you look at growth rates in the next five years, generation is red. Gas is killing it, and T&D is where people are putting money--that's the rate-based growth that's happening, for resilience reasons (if you look at Illinois, all the Smart Grid investments, et cetera). But really the growth is going to happen in the downstream side.

So in some ways, when you have these conversations, some utilities will say, "Well, we have had to adapt in the past. We coped with retail, we cope with centralized renewables. We'll do it again." In my view, the coping in the last 10, 15 years has been very different. It's still based on large capital investments. It's still based on regulatory knowhow, which utilities know how to do. The adaptation in the next 10, 15, 20 years is going to be very different.

So let's now turn to the question, what does it mean when we think about what's going to happen in terms of the impact of these technologies? We're going to see a relocation of generation from high voltage to low voltage. Customers are going to become part of the supply curve. We're going to have grid complexity. I think T&D lines are blurring. The need for data from T&D is increasing. The grid will become a backup machine, especially if storage takes off. You go from lumpy to modular-shaped investments. And you get this proliferation of new products and services.

A lot of the conversation are around that second question of growth, this offensive play--as a utility I'm going to get into DG, I'm going to provide micro grid services, those types of things… Well, other people are coming to eat dinner, too. And they're all attacking that same value pool that we talked about here, downstream.

And this is not just a bunch of logos that are doing small things. People are making very big bets on markets, on technologies that are very thin margins right now, and they're expecting, in five years, six years, seven years, to actually make money on these things.

So then I go back to the question of what is the core utility model? And grossly generalized what it means to be a utility. You have your basic customer experience back office. You've got a set of distribution things you are doing, and with transmission, whether you are in an unorganized or organized market, there are a set of functions that are being performed.

In this new space, again grossly generalized, what we're going to see on the customer side is the larger set of innovations. This is the behind-the-meter definition that people talk about in the industry. You will have third party interfaces, we see it all over in retail markets. You're going to have on premise products for single premises. This is a combination of DR, DG, a bunch of different things. And then multi premises, this is where we get into micro grids. And then questions about security at the residential level.

In distribution, you'll see the need for intermittency planning and balancing. I have technology clients who are looking at micro EMS systems, working with distributors on balancing at the LV (low voltage) level. In security, there are a lot of offerings out there that will continue to mature. And OT/IT--operational technology/information technology. That change is so significant that we're seeing a lot of outsourcing that's starting to happen, from core utility IT departments to vendors.

And on the transmission side, there is a need for coordinated balancing between high voltage, medium voltage, and low voltage.

The color coding here is my view of where third parties are really going to dominate, versus the utility. The orange is, in my view, where we're going to see a lot more outsourcing, and the light blue is where I think a lot of vendors are going be in the space, selling big systems.

So I go back to the conversation that Speaker 1 and Speaker 2 were having about what does it mean to be a core utility. To me, if you are focused on those boxes that are remaining white, the rules still have to change. So harking back to Speaker 2's comments about the changes in rules, even before you consider the color boxes to play in, you've still got to change the rules in the white boxes.

So let's now focus for one minute on the question of, as a utility, if you're going to get into some of these new segments, what other capabilities do you need, and do you have them? Utilities say they have scale. But you need national scale for a lot of these markets, a lot of these technologies.

Utilities may also have access to low cost financing, but there's a double edged sword. Can you finance a micro grid equitably with prudency? Utilities may have customer intelligence. My sense is that utilities have vastly underfunded that. If you look at e-programs, a lot of that customer intelligence is actually outsourced.

Customer access is another question. There's a fundamental question when you get to smart metering and smart grid technology, this channel of business to utility to customer. Are we breaking this model? Is this B to C direct model actually going to happen?

Quick and effective execution. Utilities say they do it. The question is, we're talking about a very different profile of capital. We're talking about very different technologies, as I talked about.

Risk profile is another issue--can you handle the risk profile, which is going to be different? Remember, we're going to be on premise, and we're talking about very volatile returns. Even no returns, in some of these businesses, for five years.

And partnerships. Utilities do partnerships, but you really are going to be an EPC (engineering, procurement, and construction) company--are you ready to handle that?

And regulatory know-how--yes, regulatory know-how is there, but again, there's a double edged sword to that.

So I will just very quickly go through this final thing of, So if you take all of that in synthesis, the conversations we're having are along these dimensions. One option is, you stay core to the grid. And you say, "I'm just going to be small, I'm going to communicate that to my investors, it's not going to be a 4% to 6% growth company anymore, it's going to be a 2% to 3% growth company, and I'm going to take it, and that's it."

Or do you do the M&A play? You're growth focused, but you're just going to expand, and you're going to use M&A as the growth driver, again, solving for the 4% to 6% in the market.

Or do you become an infrastructure player, which Speaker 2 was talking about? Do you, like Vectren has done, do infrastructure services like gas and pipelines? Do you take the plunge, like NextEra is doing, NRG is doing? Or do you become a holdco, like Fortis is doing, or like Mid-American is doing? You know, investing in different pieces.

So no conclusions, really, but I just wanted to throw a bunch of things out there for provocative discussion.

Question: When you're talking about the data, is your sense that the utilities haven't spent enough on aggregating the data, or they have the data, and they just don't know what to do with it; or they've got it, but they just don't use it adequately?

Speaker 3: Yeah, I think they have it. For the most part, they don't know how to use it. And some of the data that's been collected is being collected by vendors without giving back to the utility. So I'll give you an example. If you're looking at an HVAC penetration program for residential customers, if you do proper segmentation, needs-based segmentation, you can double the participation rate. That data is sitting partly with ICF or Honeywell or some contractor, and partly with the utility. But knowing what you're putting together to increase that penetration rate is the strategy. So the data is there, but it's kind of a question of designing it so it is useful.

Speaker 4.

You see from the title of my presentation here, "The transmission-distribution interface in a distributed energy future," that it picks up on themes that the other panelists have talked about.

But the transmission-distribution interface is something I want to focus on, because, frankly, the ideas here started from looking at it from an ISO operations perspective and how these changes may affect us. And then it led, through a change of reasoning I'll explain, into a discussion about the utility business model.

My disclaimer is very brief and in large print, so you can all see what it is. Basically, it says that I am, today, being the lunatic fringe of the ISO and not the ISO as a whole.

I'll go through the first few slides fairly quickly, because my co-panelists here have covered a lot of this. The proliferation of diverse distributed energy resources is challenging the traditional model. And I'm focusing on the ISO/RTO context, where you have an entity whose role it is to operate the transmission grid. And that entity is independent of the utility distribution companies that operate from the point where the transmission and distribution grids intersect on.

Conventionally, the transmission-distribution interface in the ISO market, which is based on locational marginal pricing, is a PNode, or pricing node, which is typically a transformer that steps down from the meshed network to the radial transmission grid, and the ISO's role is to reliably operate the system in the wholesale market, deliver energy from generating facilities up to these PNodes, and then the distribution company takes energy in one direction from the PNodes down to the end use customers.

The list of potential distributed energy resources is by now well known. We've gone through them a number of times today. They're growing in volume and diversity in response to basically three groups of factors, those being policies; greater availability and declining costs due to technological change, which makes things more feasible; and customer desires for greater choice and control--and in that category I emphasize desire for local resilience to major disturbances, because we are seeing disturbances that are more unpredictable and more severe than they've been in the past, so that changes our thinking about what reliability means.

It's changing the industry in some significant, unprecedented ways, and at California ISO we're seeing that smaller DG resources now are going to be counting as resource adequacy capacity, participating in the ISO markets and in our dispatch. So we could have sheer numbers in the thousands of resources down to some relatively small size threshold, maybe a hundred kilowatts or so.

And then we've got to think about, well, how do we meter those things? How do we model them in our optimization? And as they get more complicated, like virtual power plants that are comprised of a variety of different types of resources, how do we model them in the optimization?

So these things become challenges, and as I started working internally with the groups, trying to figure out answers to some of these questions--how do we deal with things coming online tomorrow or next week--it occurred to me that, gee, maybe there's a simpler way to have the ISO simply hand off that responsibility to somebody else. And that's what led me in this direction of thinking.

We'll also see an increasing share of end-use energy being produced locally before too long--who knows what the percentage will be, but it could be fairly large. It never touches the ISO grid, so the volume of megawatt hours travelling over the high-voltage grid may be an awful lot less than it is today.

And then, finally, interest in islanding capabilities will increase. And, by the way, along this line of more local control, the ISO does have a model right now called "load-following metered subsystems." Primarily, in fact, exclusively, the players in it are municipal utilities who want to use their own generation to follow their own load.

But we've got capability, and we've been operating for a number of years in our systems, with a metered subsystem that does load following and by issuing five minute dispatch instructions that are processed through our systems. So this is not too far-fetched, it's practical and it works.

Things that have been mentioned here today as well, are the facts that revenues based on kilowatt hours and megawatt hours are declining, part of it due to simply the declining marginal costs of large volumes of renewable energy, but also behind-the-meter and net-energy metering. So that's the obvious economic challenge.

Infrastructure challenges include planning the redesign of distribution systems to meet the high-DER (distributed energy resources) future.

I heard a statistic the other day that the average age of facilities on the distribution system is something like 42 years, which is higher than the expected lifespan of 40 years. And I've heard, anecdotally at least, that there is need for major infrastructure restoration.

And it seems to me that with the proliferation of distributed resources, we don't simply want to rebuild the distribution systems as they are designed today, but we have to think about redesigning them for a world in which the whole nature of power flows on the distribution systems is changing.

And so that leads to the focus on the transmission and distribution interface, where today, the pricing node, or PNode, is both an operational boundary and a market boundary, and where do we want to go with that? Also then, the regulatory challenges if we were to rethink how that all works. There are a lot of questions that I'm not even trying to answer here. This is really just to get some initial ideas out for discussion.

So in the high DER electric system, resources on the distribution system are more diverse and variable. The flows on the distribution system are more complex and bidirectional. And then, net flows across PNodes, those nodes on the ISO grid, will no longer be exclusively a load node 100% of the time, exclusively a gen node 100% of the time, but we may be seeing net flows that change direction fairly often, depending on the build-out of resources on the distribution system below that.

So the question then is, should the PNode remain the operational boundary and/or the market boundary? If we're going to get rid of that boundary, if we're looking towards a more integrated transmission and distribution system, both from operational market perspectives, then we need to answer a bunch of these challenging questions.

For example, is there a minimum size threshold for a distributed resource to be in the wholesale markets?

And then, we have must-offer requirements. If a generator sells resource adequacy capacity, then it's got must-offer obligations to participate in the wholesale market. That's what it's getting paid for, with its capacity payment.

So how is net qualifying capacity calculated? It has to do not only with performance capability but also with something we call deliverability, which is availability of grid capacity. And there are other RA (resource adequacy) rules that right now don't exist. We would have to, in our design processes, come up with all those rules for these small resources.

Do existing RA concepts work in a high distributed-resource world? Do we need some more fundamental rethinking of resource adequacy? Traditionally calculations of resource adequacy involve looking at peak system load and adding a 15% planning reserve margin. Well, now, 40% of the megawatts never touch the ISO grid. And they're all going to be produced and consumed locally. Plus there's the fact that generic megawatts of capacity aren't just what we need, we need certain types of capacity that can be flexible. So all of this is begging some further inquiry into the nature of the RA paradigm.

What about more granular LMPs within the distribution system to reflect the actual locations and potential constraints on the distribution system? That was a question raised in a widely read report by Resnick Institute. About a year ago, they started talking about a number of these issues, I thought very well, and I highly recommend that if you're not familiar with it.

But the notion that the LMPs stop at the pricing node, but if we're looking at resources that are in the wholesale market, and especially if they're providing resource adequacy, we're depending on them to be there, we're depending on them to deliver. Well, then, does our optimization need to look at where they are on the distribution system?

And then, what about some kind of joint distribution and transmission system planning? How might that evolve? As far as I know, people are thinking about it, but not much has been done yet. So it gets back, then, to the question I'm starting with, which is how to redefine roles and responsibilities of the ISO RTO versus the distribution companies.

And I've laid out two conceptual bookends here, just as kind of food for thought and to create a framework. Bookend A says, essentially the boundary goes away. Transmission plus distribution comprise a fully integrated system. There's a system operator that performs scheduling, real time balancing, integrated markets, planning, et cetera, and the traditional boundary is largely irrelevant for purposes of markets and operations.

And it's a whole system, and everything down to some small size threshold is now in the optimization and modeled. On that trajectory, potentially, an entity like California ISO is facing tens of thousands of resources in the not too distant future that are in the optimization.

But part of what gave me concern as I started working along this line was the sense that we're kind of going in that direction largely because there hasn't been an alternative put on the table. Because the ISO given its role of being responsible for reliable operation of the transmission grid, obviously has to think about the impact of these things on the transmission grid, so the natural tendency is to want to see everything, have it visible in the markets, and be able to dispatch it.

So I found a certain sense of alarm that we're going down a certain path, but it's only because it seems like the only option that's open. So that led me to put bookend B on the table, and say, "Well, suppose we keep this PNode as the boundary and really reinforce the notion that transmission and distribution are completely separate systems, then what happens?"

The ISO or RTO has its role, down as far as the pricing node, but below that, we create a new entity, or a new role for the existing utility distribution companies, and they're going to operate and balance their distribution systems, perhaps even create markets at a local level to do some of these things with the diverse resources that are participating at those levels.

At this point, I just painted a couple of extreme concepts here so that we could really contrast them and think about their differences. Both are potentially plausible futures. They may even coexist for a while. Some areas of the grid will have a greater build out-of distributed resources, maybe suitable for option B. Others may have less, and may not be suitable.

And again, thinking about conceptual end states for purposes of this discussion, admittedly to move towards, especially, option B, requires a lot of rethinking of some of the institutional and regulatory structure behind the existing paradigm.

Bookend B essentially, then, shifts distribution level operational market roles and responsibilities from the ISO or RTO to the DSO I'm using that term, Distribution System Operator. Under bookend A, the ISO or RTO schedules and dispatches the entire integrated system to maintain real-time balance and reliability, and it has visibility and dispatch control all the way down to a pretty low size threshold.

Under bookend B, the distribution system operator takes on responsibility for everything below the PNode. And so in a certain way, the pricing node now looks kind of like an intertie between the distribution system operator and the ISO. There is a net interchange that occurs in every interval, and it could switch directions from one interval to the next.

The DSO is also perhaps similar to a large micro grid or to a load-following metered sub system. So these are models that not completely unfamiliar, but it's taken up to the point where the entire set of facilities below an individual PNode on the ISO grid is now managed in some unified way by the distribution utility responsible for that area.

And then, finally, on the bottom right, I'm throwing in the idea here that the distribution system operator at a PNode is also comparable to a scheduling coordinator. That's the entity in the ISO market that actually submits the bids and schedules on a day-ahead basis. The idea is that perhaps they function as a kind of market aggregator of the facilities and the loads that are on their distribution lines.

Put all that together in order to create a net interchange, day-ahead schedule at the PNode and real time energy bids, say, that could be dispatched. It may have excess in some intervals and want to sell into the wholesale market. It may have deficiencies in some intervals and want to buy from the wholesale market.

So there's that kind of a relationship that could potentially unfold here.

Other features that are part of this--the first main bullet goes to the point about declining revenues from kilowatt hours and megawatt hours, and this is both on the ISO grid because of distributed resources now not having to touch the ISO grid in order to get kilowatt hours to customers, but also on the distribution systems, as we've talked about for net energy metering.

So what replaces that revenue stream of kilowatt hours? Well, in California, we've talked about balancing services and what that costs, and how those costs should be allocated. For example, we have an initiative that will start up next year to create something we call a flexi ramp product, which is flexible capacity that is purchase like another ancillary service on a day-ahead basis. So you buy a certain amount of flexible capacity, and you reserve it for each hour in the next day as a kind of load-following reserve that has fast ramping capability.

How do you allocate the costs? Well, the question on the table is, can we allocate the cost of that service to entities that are adding volatility to the system, instead of, like we do with all the other ancillary services today, allocating the cost all to load?

So the idea here is that instead of the settlement between the ISO and the distribution system operator just being based on the net energy flow one way or another in each interval, we're also looking at the volatility or variability of that net energy flow from one interval to the next, and the more stably and predictably the DSO can manage its net energy flow, the less it's paying the ISO for balancing services, and otherwise it is paying more for balancing services if its interchange is more volatile.

Then, in the same way, the DSO can have a relationship with the entities that are connected to its facility, where certain things like very fast response storage may help to manage volatility. Other things that are connected to that distribution system area would be adding to volatility and would pay some for the service of balance the volatility, as well as whatever net kilowatt hours they may be consuming.

Also what we're seeing, and this is probably California-specific, because the ISO has been the only market in the western region for a very long time, in a sense of a real-time spot market. We see real-time imbalance energy markets now under development, with PacifiCorp going into operation next October. And if that's successful, that may spark other interest in creating more of that.

So the idea that the ISO can, by focusing just on the transmission system, stopping at the PNode, not getting down into the distribution system because another entity is going to do that, enable a greater focus on west-wide coordination, which could bring a lot of benefits to the region through imbalance energy markets, through the ability, perhaps, to access renewable-rich areas elsewhere in the state without having to build a lot of new transmission.

So the future system may look a lot like the internet. And I use that metaphorically. I realize there are a lot of ways in which that's not a good analogy, but it goes to the idea of more distributed, shared resources at the local level, decentralized, et cetera, due to policy initiatives that expand both renewables and energy efficiency.

The demand for and performance of these DER are increasing while costs decline. Customers get more services without using kilowatt hours. Kilowatt hours are consumed locally, and more systems become self-optimizing and resilient. The Hurricane Sandy effect has a great influence on how communities or large facilities, like campuses and industrial parks, want to manage their energy.

And the ISO grids and markets can then coordinate and balance multiple of these areas across a large geographic area, without actually getting down into the nitty gritty details. So there you have it.

Question: Could you clarify how your Bookend B is different from what an unrestructured utility has today?

Speaker 4: If you mean a vertically integrated utility, it might not be much different, which is why I'm focusing on the ISO/RTO context, where we have these separate entities today.

Questioner: Right. Well, that was my conclusion, that it probably isn't much different than you have for a vertically integrated utility type --

Speaker 4: Well, except that it need not go that far. I mean, this distribution system operator option B might not own all the generation and have a monopoly over the customers and all of those sorts of things. So I think it also has a number of important differences.

Question: Option B was fascinating. So in an ISO market, let's take New Jersey, part of PJM, the Option B could actually be these small little pods, almost, that could be, you know, just one neighborhood of the distributed generation, including DR and energy efficiency and behind-the-meter generation that would roll up behind a pricing node, and all the ISO or the RTO would see is the pricing node, so you could have many of these in a particular area? Is that what it would possibly look like?

Speaker 4: Potentially, each pricing node could be its own sub system, in a way. But a distribution utility with a service territory may operate all of those pricing node distribution areas that are its present service territory.

Question: Just a small question on your slide 10. You are talking a low size threshold in kilowatts. Is it meant 50 or 100 kilowatt, or how many kilowatts?

Speaker 4: I was just thinking of installed capacity size. For some of these, say, commercial-scale or community-scale solar facilities, they may have an install capacity in that region.

Questioner: And a related question, how many PNodes do you have in California, and what is the typical energy transmitted through one PNode per annum?

Speaker 4: Well, there are about 2,500 on the ISO grid. And of course the amount of energy is going to depend on whether you're in a rural area or in a highly dense urban area. But if our peak load is, like, 45,000 megawatt hours, you can divide 45,000 by 2,500 PNodes and get an average there.

Question: For your A bookend of the system, assuming that's today, in the day-ahead market, against the full network model, how much of that do you actually monitor and secure today?

My understanding is there's still some interaction with the distribution level, in terms of securing and monitoring the system. So what I'm trying to understand, is your A sort of assumed there was not, and maybe I'm wrong, so --

Speaker 4: I'm sorry, I don't under-, what's your assumption?

Questioner: How much of the actual full system are you securing and monitoring day-ahead? That's a better way of doing it, versus how much interaction do you need now --

Speaker 4: Well, in terms of what we're securing and monitoring operationally, essentially it goes down to the PNode, but on the distribution system there are resources that are participating in the wholesale markets, and we have telemetry, and we have participating generator agreements, and they get dispatch instructions. We're not looking at actual flows on the distribution lines or any of that.

Questioner: That's what I was trying to get to. I'm trying...OK, we can get to this later, as to define that split between your A and B a little more clearly.

Speaker 4: Yeah, well again, A is also another conceptual endpoint. It's not meant to express exactly the way today looks. But it could be on the trajectory of where today is going, potentially.

General discussion.

Question 1: I'm actually struck by the whole conversation here--we're talking about distributed resources, energy efficiency, and so on, but rarely have we actually gotten to the question of, why are we actually doing this? Is this environmentally driven? Or is it reliability driven? And Speaker 3 answered some of the question when he mentioned Superstorm Sandy. So I don't know if we have a good answer to that question, "Why are we doing this?" yet. And I think it's important for us to understand.

I've got several questions here. One is, has anybody really done a study about the cost effectiveness of the smaller-scale resources versus the economies of scope and scale of central power stations and centralized grid? Have economies of scope and scale entirely disappeared? Last time I checked they hadn't, but maybe I'm missing something here.

The other question I have is, do we actually know what's led to the decline in load growth that Speaker 2 showed on his slides? And by the way, this is not something that's just happened recently. If you actually look at total load from 1950 to the present and you segment it by decade, and then you just run a regression of load versus real GDP growth, you see a constant decline from the 50s, the 60s, the 70s, the 80s, and so on. But what's driving that? Is it efficiency? Is it that we've run out of penetration of electricity appliances and we're just looking at new toys that are even more efficient? No one's really answered that question either.

And then, finally (this is really triggered by Speaker 1's presentation) don't we have some lessons from Europe and Latin America on regulatory regimes, in terms of price cap regulation and revenue cap regulation? And then in this country, with two part tariffs, especially on the gas side, with Straight Fixed Variable rate design that could solve a lot of the problems here. And if they're so unsatisfactory, why are they unsatisfactory?

Speaker 1: Let me talk about the last part of your question, about the straight fixed variable rates. (By the way, Europe is the topic for tomorrow, so we'll leave that virgin territory to cover tomorrow morning.)

There are a lot of different things driving the push for solar PV. I'm not sure economic logic is driving it, as your question implies. But clearly there are some environmental objectives in mind.

Those objectives can become very twisted when you start thinking about the fixes for utilities for the erosion of distribution revenues from a substantial market penetration by the distributed generation. And the fixes go to what you're talking about—things like moving more costs into the fixed category, which (forget about the economic efficiency), from a purely environmental standpoint, is completely perverse, given the objective of having the solar units there in the first place.

And so in some ways, what we've got is a kind of paradox, where I think distributed solar has become the enemy of energy efficiency. Because in order to compensate for distributed solar and what it does to the erosion of core services by the utility, especially the distribution system, what we've done is we're now sending price signals that don't discourage inefficient use of energy.

And then, what makes it a little worse, is we then throw piles of subsidies at this generating source, in addition to just net metering subsidies, which in many cases, not in all cases, but in many cases, it doesn't even meet peak. So it has no capacity value whatsoever.

So I mean, there's a real paradox here. But I think the real question is, from an environmental standpoint, do we want green results, or do we want green technology? So the extent to which the environmental objectives are driving it, I'm not sure it makes a lot of sense.

You could also argue that there are other benefits, like transmission savings, and that may or may not be the case. It's certainly theoretically possible that there are transmission savings. So there are some economic arguments, but a lot of it, I think, is driven by environmental values.

Speaker 2: I think one of the things I said was, that we all used to be just focused on reliability and low cost, and that's just clearly not the case anymore. You know, from the regulatory side, our commissions are driving policies--I mean, they're more like legislators.

And so on the resiliency side, I think you're going to see more and more of that. Obviously the White House released its study in August about the economic effects of Superstorm Sandy. Besides a lot of the environmental benefits of distributed generation, I think that there is going to be a resiliency discussion coming up.

I mean, what I heard today, and what I'm seeing from Speaker 3 a little bit are somewhat different. Even in the vertical world, there are rate cases that are going to be more about the money we spend on distribution assets and improving the distribution system in the future than they have been in the past. They're not going to add large coal plants.

I mean, we'll have fights about stranded costs, I'm sure, which is another thing. How can you be innovative when you think about things as stranded costs? That's something else about the utility that we need to change. But I think that you're going to have to place a value on resiliency, and I think the policymakers will put a value on it.

As to a study of economies of scale, I don't know, I will always argue that a central station solar plant is more cost effective and/or doubles the emissions reductions, as compared to the current market price for distributed generation.

With respect to your second question, as to why the load goes down, I don't mean to be pejorative, but do we make anything here anymore? I mean, we don't have a lot of large manufacturing…from the 50s on down, what's happened to the car industry? I mean, the basic financial underpinnings and economics of our country is changing and we've got to adapt to that as well.

Question 2: If I understand, Speaker 3, the proposition that you have for bookend A, it's really that the RTO/ISO functions go deeper into the value chain, down to the distribution level. And then, with the bookend B, you would have two organizations, one doing more of the regional, traditional RTO/ISO functions, and then one doing more the regional distribution function for both planning and for the dispatch. Did I get that?

Speaker 3: That's a good rough idea, yeah.

Questioner: OK, well, I want to know about a bookend C, which would be near and dear to my heart, which is separating the transmission planning function and oversight from the market oversight in the RTO. Even if you go down into this distribution level, could that be done? Where you separate all the transmission services, planning, everything away from the markets?

Speaker 3: What are you including in transmission services? Just planning?

Questioner: Planning as well as transmission service access, dispatch, et cetera, by using the market functions as a completely separate entity.

Speaker 3: Well, in the ISO's LMP-based market, transmission access is inseparable from the market. The market is the mechanism by which you allocate use of transmission grid. So there --

Questioner: So if we came up with an alternative to the LMPs?

Speaker 3: So have two parallel, separate systems?

Questioner: Yes.

Speaker 3: Well, I think that goes back to what the ISO tried to do with its zonal markets originally. It tried to have a market that had no connection to the physical realty of the capabilities of the transmission grid. And then you end up with totally bogus financial transactions, where parties can sell things that are not feasible to be dispatched or be delivered in real time, and then they get paid again in real time to buy them back.

So I think we were there, with zonal markets. And to me, the LMP-based markets really solve a problem. Trying to separate them again, I don't see a value in doing that.

Question 3: I'm still thinking about Speaker 3's option A and option B, which I thought was a really good way to think about the challenge that we have ahead. Because it's hard to go to a conference nowadays where someone isn't telling you that the world is changing. And I was a little depressed after Speaker 4's presentation, thinking that maybe I need to find another industry to work in.

But certainly, we have seen a significant interest in micro grids and distributed generation and a continued growth in energy efficiency. And it is not being implemented, at least from what I see, in a manner that is helpful to the system. It is almost like building generation just where you can find the cheapest location to build it, without any consideration of, how do I optimize where I place these things and do it in an efficient manner?

Your bookends really attempt to address that problem, I think even more than what you described. You were focused on the RTO or the ISO view, looking down. I'm looking at it more from the distribution level, looking up. Having either option A or option B does seem to me to allow you then to create those rules which would allow price signals or restrictions. You could go the carrot or the stick approach to ensure that you're trying to optimize where you place these distributed generation tools.

And I just wanted your thoughts, Speaker 3, on how you would go about imposing those price signals, or whether you would just leave it to the states and the distribution operators to come up with ideas.

Speaker 3: Well, I think a lot of the questions that you're raising are really going to have to be faced, irrespective of whether you go in an option A or an option B direction. Many years California, did this Renewable Energy Transmission Initiative to identify renewable zones for the development of grid-scale solar. But we never did something comparable for distribution areas. If we're going to have a state goal of 12,000 megawatts of DG, what are the optimal areas for doing that, from the point of view of environmental impact, and from the nature of the customer base, in terms of who's more likely to adopt it? So I think there's a need for that kind of planning, irrespective of which model you go with.

Similarly with planning the redesign of distribution systems for a world where energy is flowing all over the place instead of one way from the grid to customers. So I think that's all part of the complex of issues to be addressed. And under the option A or option B choices, it's really a question of who does what? But it all has to be done.

Question 4: I'm an old pipeliner from back when we used to have to buy our own gas, and So since we went through the initial open access, the pipelines now have had to come up with new services and prices accordingly. So the variety of services that the pipelines have in their tariffs, is now just tenfold, whatever, compared to what we used to have.

So I'm wondering if a model like that could help with what you were talking about, in terms of the ramping services, and maybe the distributed solar services, where you actually have services where they're priced at the micro level.

Speaker 3: Well, yes. I didn't go into a lot of detail on it, but I think as part of the revenue model, when kilowatt hour sales are not really the core strength anymore, and if the distribution operator now has financial consequences on how stable and predictable is its net interchange with the ISO then it will have incentives to get the set of resources on its system that will enable hopefully an optimal tradeoff between buying balancing services from the ISO or buying them locally and being able to maintain more of an independent system.

So I don't know that much about the gas market details, but there probably is some useful analogy there.

Questioner: For Speaker 2, I just wondered if that's something you all have looked at, to get some additional services?

Speaker 2: Absolutely. We're trying to find revenue anywhere, right? And the thing is, if you don't realize that solar is going to be on your system, it's coming. You can fight it, we can play regulatory games, we can do a whole lot of things, and utilities are generally good at that, too. But it's coming. You are going to have to integrate that into your system.

So from my perspective, why wouldn't I do that in the most cost effective way possible? And if you want solar to succeed, that should be your goal too. Because otherwise we get the Speaker 1's of the world who come in and dump all over it. [LAUGHTER]

So from my perspective, absolutely, you have to have those services. Micro grids are the same thing.

That stuff is coming. You can't stop it. And if you don't do something to adopt it and to change the way that you provide those services, then your customers will go elsewhere. And one of the things that will happen is that people will get in between you and your customers. And that's what's happening on the data side, on energy efficiency.

So from that point of view, if the utility doesn't adopt some of that, it will be a problem. And it will be a problem whether you're in a market or you're in a regulated area, and I'd argue that if you're vertically integrated, it can be a bigger problem, because if those problems aren't heard by the utility, then they will go to the regulators. And the regulators will give you things.

And sometimes the regulators (all due respect) will give you uneconomic things. And they'll put those rules into place, and they'll say, "I don't care, I'm just going to do this, and I like what it looks like in the newspaper," or whatever the reason is.

So I think one of the lessons that no one talks about with respect to net metering is that you have to get out in front of that issue. Otherwise, they will solve the problems for you. So an unqualified, absolute yes.

Question 5: Thank you. I think, as others have said, it's clear that things are changing. And so the electric companies, or distribution companies, whatever we want to call them, need to adapt. And some are adapting and changing and some are trying to hold on to the last century.

It's clear to me, though, that customers are in fact walking, and we have to figure out what to do about that, and how the distribution system and grid system, which will still be necessary, has to be funded, probably in a different way.

It's clear that cyber security, cyber terrorism, is an issue--that electric companies, probably all of them, and certainly other utilities like water, as well as other major corporations have been accessed, and some have been compromised. And it's also clear that climate change, extreme weather, like Sandy, are an issue. New York and New Jersey, business and small businesses, and individuals are all going now to look to island and to micro grid, to use things like combined heat and power...

Our governor, our administration in New Jersey is working now on combined heat and power for all over the state, on a pilot basis, initially. So this is happening.

So I guess the question is, how do we keep the distribution and the grid system operating? How are they funded? It's got to be different than what we were doing now. And then also with Speaker 1's minimalist approach, with just the core functions, how does that company make money? In both cases, you're going to need it, however we do it, whether it's the minimalist approach, which I think makes a lot of sense, and we might end up being there because of how other entities like the Microsofts or Googles and your cable and telecommunications companies, or whoever, are getting into this stuff.

But how are they going to make money? How are we going to do things differently? Who, if anybody, is actually trying to do this differently and getting into that gig? Because it's coming, it's happening, and the next extreme weather event that happens is going to push it even further. If it's not on the East Coast, other places in the country are going to jump on.

Speaker 1: Well, if the utility just did the core function, the way they'd make money is probably the way they traditionally made money.

What you won't have is, you're not going to have the kind of growth--although there may be actually a whole lot more investment to be made in new infrastructure to deal with Superstorm Sandy types of events, but, basically, I see that as still being subject to some form of traditional regulation, whether it's cost of service or price cap, however you do it.

But it's going to be slow growth. It attracts different sorts of personnel. But even in concept, although it's smaller in scale, it's not that different than what the traditional utility was 30 or 40 years ago. It just is not vertically integrated anymore. It's much more of a minimal function. It's hard to see, other than that, how that works. Although I guess there might be a basis for arguing that you need more public power, because they don't worry about the profits, they just worry about covering their costs. But I think that's how it works. What you've eliminated, however, is a whole lot of risks associated with the non-core services. You're not looking at huge stranded asset possibilities. You've eliminated a whole lot of risk, which is going to have an effect on the return, but the fundamental proposition is, that's still the regulated piece, and a regulated return is where the revenue comes from.

Speaker 2: My question back to the questioner would be, you have integrated resource programs in New Jersey, right? Do you have the same thing for distribution? You might have to start looking--those rate cases are going to be more and more about distribution and those things than ever before.

And I don't know how many times you've asked your utilities questions, other than smart meters, about what is your plan for replacing your meters? Why do you do it this way? How is that going on? Because those things are going to become more and more important, because if we are the people who do that, if we have a traditional plan of replacing X thing every three years—well, guess what, this is a new system.

And if there's more energy efficiency happening in the area, maybe every three years is wrong. Maybe I'm pulling capital incorrectly. On the other hand, maybe more demands are being made of the system and I need to deploy more capital every two years. And so with respect to that pie chart that you traditionally see when you talk about rates, I think the distribution side is going to grow more and more.

And we're going to have to know the data portion of it, the engineering portion of it, who has the reliability portion of it. If we own all of that, I think you're going to have to move more towards, if you will, an integrated distribution planning session, where you have all of those things and those stakeholders and you have to talk about those things and those costs, and, from a vertically integrated side, I need to get some direction from the commission as to what's going on or how we should go about this.

Should we be planning events where we overlay the grid over our service territory, and we say, "These are where the wires are. These are some of the places that we should be putting more wires or other infrastructure. Commission, are you good with that, and can we move forward like that?" That might be something that future commissions might have to deal with.

Speaker 3: Just one thing to add here. I sort of separated this out into three buckets. There's the bucket, what are you trying to do with the investor community and growth, right? So I don't want to exclude the 4% to 6% rate of return goal--that's a very real push that utilities are aiming towards. That then has to translate back into rate increases.

So what's the allowable rate increase? That's the second factor. And the third factor is, what do you do with your set of charges? Do you go to a straight fixed variable charge?

So you can change all these factors, you can get additional services, et cetera. At the end of the day, from an advocacy perspective, are you increasing your rates beyond what is allowed? And if that's acceptable, then are you hitting your 4% to 6%? So to me, it's sort of solving those three things in line, if that makes sense.

Questioner: I obviously did not express myself correctly (which is not unheard of). Customers are going to be buying less electricity from the electric distribution companies. That's a fact, because they're going to be doing combined heat and power, they're going to be doing mini micro grids, not real micro grids, but like, Princeton did, or co-op city or that kind of thing, during Sandy, where they literally went offline and operated fully, for seven to 14 days. Other places are doing that.

In fact, New Jersey is planning to do that throughout the state. Which means the electric companies, who still have to have the grid and the distribution system, they're not going to be selling the energy that they're selling now. Customers are not going to want to pay the way they're paying now. It's got to be done differently. How is that to be done? Has anybody come up with the actual way of doing it? Because it's happening, and it's happening sooner than we think.

Speaker 2: I don't know. But one of the things that you start thinking about when you start talking about stuff like that, is monthly charges. Why does everyone pay the same monthly charge? Speaker 1 will tell you, because it's easy, right?

But you can adjust it on usage. You can adjust it for people who say, OK, we want to do this, we want to be a part of this (and use less electricity from the grid), but we still want to have that safety net. OK, here is what the safety net costs. And that's how you're going to have to do those things, through rate design. And I know Ohio has done some impressive things for low income customers--you know, you can adjust those things for low income customers.

It's kind of like the return of the guys who built Y2K, right? It's going to be, "Return of the rate design folks."

And it's one of the things that we are going to have to adjust. And not only just simply because the utility says So and quite frankly because the commissioner says So but because of actually what the customer wants. And don't ignore the customer's customer as well. Sometimes customers are doing things because they're trying to meet the expectations of someone else as well.

Speaker 1: One of the things that is interesting is that as customers are exercising their own choices for all kinds of services, the rate case becomes less and less controversial to the public, because it's a smaller and smaller component of what they're paying for, because they're going to be buying what they used to buy from the utility elsewhere.

So rate cases themselves actually should become less contentious, because there's less at stake for consumers as a whole.

Question 6: So I want to repeat an earlier question, but I would like to ask it of Speakers 3 and 4, who didn't answer the first time. And let me rephrase it a little bit.

Everyone says, "Change is coming, and this is all inevitable, and it's going to happen," all that.

But it's not quite as obvious to me, and maybe to the earlier questioner, as it is to everybody else. If the economics aren't there, and there are regulatory mandates, well the regulatory mandates will survive for a while, but if they're going against the fundamental economics, I'd be surprised if they were permanent changes.

So the question is, do you or do we collectively have any reason to believe that micro grids and distributed solar PV are actually cheaper and more reliable than buying from the grid? Because after all, the reason we had networks was to precisely get away from super decentralized unreliable power. I mean, that's why we went to a grid. And just to comment about micro grids and reliability, I think part of the reason that there's an issue with reliability at the distribution level is precisely because distribution reliability has been underfunded post restructuring.

I think that's a fact, and now you're paying the price for that. You have a less reliable distribution grid, and of course people want to be reliable, so we're thinking about backup. But the question is, do you think the fundamental economics are there for distributed solar power to undercut costs from a brand new, hyper efficient, gas fired combined cycle? Same question for micro grids.

Speaker 1: You're asking a fundamental economic question. But the way we pay customers to put on solar PV, we've thrown all fundamental economics out the window and said, "We want this technology and we're going to make it in your interest to do it." So we don't do it institutionally in a way that gets to the question.

Questioner: Right, and I agree that's a question, and the fact that people want to do bad rate design, at least initially, in order to subsidize a particular outcome, is probably not going to survive long term, because people have talked about what that does to other people's rates, and particularly even a redistribution of wealth between higher income and lower income customers. But if you don't charge solar PV customers for the full cost of the backup, someone else is going to have to pay for it, and eventually the regulators will not want to live with that. Again, I think the fundamental economics is going to drive it.

But again, just back to the simple question, do you really think that solar PV and micro grids are more efficient than a brand new combined cycle distributed over a network?

Speaker 3: Let me separate those two things out, and I'll talk about EE as well. For solar PV, going from $5 per watt peak, to two and a half in five years--if you look at hard costs and soft cost compression, that's just happening. Hard cost is global scale. Soft cost is all in the push that the installers are doing in the U.S. So I think the economics are there, and they're going to drive it.

To me, the net metering thing is interesting, but it actually just delays the point of adoption by a few years, depending on your starting point, your retail rate, all those types of things. If you look at adoption rates, when a customer is in the money, if you look at Hawaii, if you look at New Jersey, if you look at Germany, adoption rates are increasing. This is the whole awareness piece of it, so --

Questioner: Yeah, but you can't separate "in the money" from the rate design. That's why I'm just asking the really simple question. Do you think it's actually cheaper on a dollar per megawatt hour basis than a brand new gas fire combined cycle --

Speaker 3: Not right now. No.

Questioner: OK. But do you see in the next five years?

Speaker 3: Probably not in the next five years, but it's not going to affect the level of adoption that you're going to see, I think.

So just on micro grids. To me, micro grids are over hyped. I think it's very hard to pull a micro grid off, unless you have, like in New Jersey, a push. Siemens, Lockheed Martin, all of these guys are pushing it.

I mean, during the stimulus time, I remember doing a lot of work around micro grids, because there was a lot of excitement. And it's failed. And the reason it's failed is because it's a two year sales cycle. You have to customize each deal. It's an escrow sale at the end of the day. Plus O&M contracts. So you add that all in, and then you go to the university board and they say, "Well, we're getting cheated."

So you go through this circle for two, three years…I think micro grids is a very hard sale, and no one does it for resilience reasons. Very few people do it. They do it because of onsite generation economics. If that works, then you talk about demand side, all of that, on the premises. So to me, the micro grid piece is a lot slower in development than people think, unless you have regulatory money being thrown at it in a push.

The one other thing I'm going to say is that you haven't really mentioned energy efficiency. To me, energy efficiency, with LEDs, with appliance standards and building codes--forget the debate on solar, just think about what EE is going to do to utilities. Let's not ignore that, because that's going to have a pretty big impact.

Questioner: Just on the last points. You think, and it seems to me it's true, but do you think that EE is right now a cost effective substitute for a megawatt hour of a base load, gas fired super-efficient combined cycle? On a pure cost basis, holding aside the rate design question.

Speaker 3: Yes, if I'm saving a kilowatt of electricity from not using it, yes.

Questioner: Right. But excluding the distribution charges. Only compared to the wholesale price of power.

Speaker 3: I guess so. I'm not sure.

Question 7: Speaker 2, you and Speaker 1 both alluded to customer needs and that we have to pay more attention to that, all of which I agree with. And then you went on further to say that the regulatory scope has to change to accommodate this new phenomenon of customers actually have a role in deciding how you're going to operate and move forward. Much like an earlier questioner, I'm going to ask you, do you have examples, suggestions of things that have to be done in that arena to be ahead of the curve, as opposed to being responsive, as a regulator?

Speaker 2: Yes, I do. One of the things that we try to talk about are some economic development rates.

So for example, think about a mine. A mine operates 24/7. Should we have a mine on an inclining rate block structure? Or should we be incentivizing a mine to produce as long as its economic, so that they hire more people, so those people have better wages and better jobs and the community does better, and so on.

We don't talk about any of that at all. We don't talk about what happens when the mine runs into hard ore, for example. So when they're digging in (and I don't know much about mining) at some point they have to continue to dig down in order to dig out. And generally the easier ore is on the outside and not on the downside.

But when they have to do that, what that means is they have to use more electricity, either for crushers or whatever, but whatever they do, they have to. But here is the real problem. When they hit that bad ore, guess what? They don't get the efficiencies. They don't get the product out of the ground. So they use the same amount of electricity, or more, and they don't get the same product out of the ground.

Why don't I have a program to incentivize them, to add that crusher, add whatever it is, so that they can get through that hard ore in a more efficient, cost-effective manner? But we don't do that. Here's what we say. We say, "Here's the tariff rate."

And there's no flexibility inside those tariffs at all to do anything like that. We just simply say, "Well, this is what we did in the last rate case, and we'll be in our next rate case cycle in another two or three years, and thank you very much and see you later."

So there are a lot of things that we talk about. Because the mine is looking at it, and from their perspective, you know, they too want to get through that hard ore, but electricity is their largest O&M cost, and they want to address it. So there's an example of something for us perhaps to think about.

Speaker 1: That's part of what I was talking about and one of the things that's asymmetric. You've got an open-ended obligation. That mine, like mines everywhere in the world, is part of a volatile market. I mean, the copper market is volatile. So if you're building at capacity to serve that mine, and the copper prices fall, and whatever production they have, they get from Zambia, what do you do with that?

So that's why I think we need to move away from the open-ended obligation to serve and have everything much more on a contract basis, so there's some mutuality. Otherwise, I think it's problematic. Well, if you get the ability to negotiate flexible contracts, you can address that issue, but you can also try to cover yourself from potential stranded assets or delta revenue issues.

Speaker 2: One of the things that the utilities I think they're going to have to do is we're going to have to get a little bit more used to risk. And our regulators are going to have to understand that and adjust the ROEs accordingly. It's not just that were going to do a simple discounted cash flow model on everything, and get the return on investment directly from the price of inflation.

There are risks associated with doing these projects, and for us to be that flexible, then we need to be treated a little bit differently than just our standard ROE.

Speaker 1: The question is, how far do you socialize those risks? That's the problem. That's why I'm talking about customer-specific contracts as a way to deal with this asymmetry within the contract, as opposed to saying that the utility has to pick up the delta revenue on the copper mine use.

Question 8: As I listen to this debate, I think about how it compares to the other large, disruptive thing that has gone on, at least in my lifetime, in the electricity world, which was the opening of competition.

And in that case, you had Congress with PURPA, and then the Energy Policy Act of 1992, and some seminal FERC orders that drove this, so you had some structure--whether it was a good parent or bad parent, you had some parentage around this transformational policy. And with this, what I hear is something that is organic, mutant, spontaneous occurring without the same sort of directive policy leadership.

And you've got FERC and RTOs and state commissions and potential DSOs, and all sorts of players in this, that seem very fragmented, decentralized, ungoverned in many respects.

I guess my question is, does this worry you? Or does it make you feel better that we don't have FERC and Congress involved? Who is ultimately responsible for the reliability of the system and for this coming together in a way that works? Do we need that?

Speaker 4: All of us.

Speaker 1: It's interesting, though, because if you try and think about the question, does the policy drive what happens, or do policymakers simply respond to what's actually going on in the marketplace? I think I would argue that even in the case, when the questioner was pointing to PURPA, and also similar to the '92 act, I don't think policymakers were sitting there thinking about, "Gee, what can we do?" It was more that they were watching what was going on, watching the pressures, and that they had to make some changes.

And so they try to put some policy guidance around it. And in essence that's what we're talking about here. There are a lot of changes in the marketplace that are going on. And they cut in a bunch of different directions. And it's a question of trying to develop policies to deal with it.

So, you know, the fact that it's not being policy driven is hardly surprising. I mean, I think most of the policy changes are market driven, rather than the other way around. And I think that's what's happening here. Of course, the prospect of Congress coming up with a rational solution is certainly an optimistic one.

Speaker 2: The quick answer to your question is, yes, because ultimately, as I sit here today and look at the Energy Policy Act of '05, the utility is responsible if people lose power.

So when you start thinking through some of these things, you say, "OK, that's a little bit unnerving." If you're reliant more and more upon a number of things to ensure the reliability of the grid, but yet you still rely upon the regulatory compact to get paid, some of those things going wrong can affect your regulatory outcome in a negative way.

And so you can put liquidated damages in a contract to a supplier or this or that, but…I mean, I hadn't really thought long and hard about it, but those are the first two things that popped into my mind on the vertically integrated side, which is, first, that they're always going to blame me. And, second, the regulator's going to take it out of my hide. So both of those things do concern me if we don't have some rules of the road.

Speaker 4: I wasn't being completely tongue-in-cheek saying "all of us" in response to your question. I was recently at a symposium where a state regulator whose name I won't mention said, "Don't worry about a thing, the adults are in charge." And I thought, "Now I'm really worried." [LAUGHTER].

And I kind of think that in this situation, any attempt to have some sort of umbrella policy that figures out this whole thing and where it's going is more likely to make a botch of things then to be helpful, at this point.

Maybe at some point in the future, as we learn a little bit more and things progress a little bit more. But as I understand it, when there's a period of really dramatic change, nature updates and experiments in the most diverse ways possible. And I think we're seeing some healthy innovation and experimentation right now, to see what's possible and how can we make things better than the way things are now.

Question 9: I want to concentrate on the core services, which I think is the more interesting policy question, setting aside the non-core services. And I like Speaker 4's bookends A and B, because it at least helps me think about it. And it should be true that if we do a good job of designing the rules for bookend A and the rules for bookend B, we should get the same results.

And it's easier for me to think about bookend A as the starting point. So we'd have the ISO expand and take over the world, all the way down to my house. And then they would do economic dispatch, and they would worry about the constraints on the distribution system as well as in the high-voltage grid. And they would be charging LMP at my house, and that would include the marginal losses on the distribution line, and then there'd be a mechanism for doing congestion pricing on the distribution line, so that would be part of the LMP. And then there would be an access charge to pay for their rest of the infrastructure hardware on the grid. And if you look at how to decompose that problem, a lot of work has been done on this in the past, because it's just too big to manage, and so you'd have some entities who were managing components of that. And a very nice place to break it would be where the system starts being a radial line.

And so it would be more or less bookend B. But now we tell you what the pricing would look like down in this distribution system, you'd have the variable losses, you'd have the variable congestion charges, and you'd have an access charge for everybody who's connected on the distribution line.

And that gets us to, basically, the same problem we now have, which is, we need a straight fixed variable two-part tariff, with the access charge. We have to divide up the total pie, the total cost amongst those access charges, but we know in principle that what we want to do is set to those access charges just so that nobody gets driven off the system who could still get some positive benefit from staying there. It's a little difficult to do that, but as a proxy for that, we would probably use contribution to coincident peak as a way of doing that.

And we wouldn't have net metering anymore. And then I wouldn't care about whether people put in distributed grids or not. I wouldn't care about whether they put in solar or not. Everything would work out fine, and I would be happy. So it seems to me that the fundamental problem here is the pricing problem, having the access charge, and then charging the variable cost down on the distribution line, and that's what we'd have to fix.

So if we could fix that problem, a lot of these other issues would go away, except the one that Speaker 2 talked about. It would make it a lot harder for the regulators to be legislators, because we'd be constraining the pricing in a way that was efficient, and make it much harder for them to do what they want to do. But that might actually be good, rather than bad. But I think that's the implication of bookend B. That was not a question.

Comment: Can we all just say amen and go home? [LAUGHTER]

Speaker 2: I'm going to add one more wrinkle. I have a hard enough time explaining my rates to my customers, explaining essentially our demand and energy rates.

Questioner: I think that's a really hard problem, but I think that's the problem, and I think most of these other things are derivative from that. And it's the usual thing--get the prices right, and a lot of the problems go away, and if you don't, you have a lot of problems, and then you have to have Band-Aids on top of the problems, and then you have to have Band-Aids to deal with the Band-Aids, and you can see, it just piles up.

Speaker 2: And most of the large customers are demanding energy rates. I mean, the sophisticated people, the people who have people on their staffs actively trying to beat me, and that's what they're paid for, their bonuses are to beat the utility, I mean, that's how you treat them. Right?

Questioner: Which is good.

Question 10: Isn't this a simple issue of, in the future, what are the products the utilities are selling and how are they pricing those products? I mean, core services, essentially wires and meters products, should not be priced on a volumetric basis. That's the simple equation. So if we can come up with a method to price those products that are not based on kilowatt hour sales, and then, let products that are truly volumetric be priced based on consumption, I think most of these conundrums go away.

Speaker 1: That's true. The only thing I would take away from that is that I don't view meters as a core function. In fact, meters could be very much tied, and probably should be tied to ESCOs and energy efficiency services on the utility side of the meter. Otherwise, you end up with the problem that we currently have about how do you provide utilities with incentives or remove the disincentives on energy efficiency, and how much activity on the customer side of the meter do you want the utility to engage in? But if you take the meters out, I completely agree with you.

Speaker 2: Unless you want me to do metering for water companies or gas companies or whatever, to become more efficient about that, and that's OK, instead of the traditional, you know, "Thou shalt not do anything other than electricity," and God forbid you even think about having an affiliate do something.

Speaker 1: Part of the problem here is you get into the debate about whether or not you want smart meters. I mean, it seems to me, if you want an efficient market, that's sort of a no-brainer.

But you get into these questions about measuring the cost benefit of smart meters, and to me, it ought to be a decision that is driven by two things. One is, obviously if you have smart meters, it affects the utility's cost in terms of providing distribution services, because you get a lot of information out of that that lets you be more efficient.

But the other big benefit is on the customer side of the meter. And the question is, how do you coordinate that? There might be economies of scale, if you're doing billing for more people, but that also argues for why it ought to be a separate business.

I mean, there are companies that do billing, and there's no reason why they can't capture economies of scale. There are economies of scale, I agree with that.

Question 11: First, a quick comment on bookend A. If in fact the dividing line between T&D, from an operational perspectives is to become generally irrelevant, I'm not quite sure how the dividing line between FERC and state regulation is going to go.

And then my question. There was some limited discussion, I think also from Speaker 4, about the substantial infrastructure need that is facing a lot of the distribution grids throughout the country, based on the aging of the grids.

And I've seen some reports that suggest, except for areas that have been devastated by hurricanes and have already had that infrastructure replacement, most everyplace else has infrastructure that's in desperate need of replacement. And that's billions and billions of dollars of investment. There was some discussion about how, if we are to do that new investment in distribution infrastructure, then we can plan for the next round of what we need for that infrastructure.

But what I'm struggling with is that unless we fix the rate design problem we just talked about, or unless micro grids actually don't turn out to be on a path to change the way the structure works, and unless some other disruptive technology doesn't come along, is it going to be logical to continue to make fifty-year investments in wires, with all those substantial risks associated with the ability to actually recover the cost over that period of time?

I mean, it seems like we are changing the utility business model in a way that is fundamentally altering that basic risk profile for the wires utility as much as anything else. I'm not quite sure when that becomes such a problem that the billions and billions of dollars of investment in infrastructure that is needed is going to be difficult, or at least more costly, to do. Does anybody have any thoughts on that?

Speaker 4: Well, first of all, in response to your first comment about the boundary, as it is today, interconnection, if the generator is going to be selling power for resale, is already a FERC jurisdictional thing.

So I look at it from ISO perspective. If a whole lot of resources on the distribution side are now providing resource adequacy and have obligations to participate in the wholesale market, that's really largely what I was getting at about how that boundary becomes less meaningful. The market is going to be looking at that level for operational security.

On your second question, about the billions and billions of dollars in investment, I think that's one of the things that I've had some discussions with folks at the energy commission about some collaboration between state and utilities, and who knows who else, but looking at specific areas to designate for distribution system development--if you're going to redesign distribution systems, don't try to think about the whole thing and doing it all at once, but maybe there are some areas that you want to start to upgrade, because they really look like prime candidates to do fairly intensive DG development, et cetera.

Speaker 3: Just building on that, I've seen in Ontario, in Canada, this kind of discussion go on about the future, and what this grid is going to look like to accommodate DG, and starting to make those investments now. So you're ending up leapfrogging, doing some digital investments right now. And in other places like Ohio we're seeing it, in Illinois we're seeing it, so I think some of that discussion is going on.

And on smart metering, one of the conversations I've heard recently between utilities and the commissions is that you don't need a business case any longer. 60% of the country is committed in some form to a smart metering vendor and a solution, and this is now much more of a transformer upgrade question than an NPV question. So those kinds of discussions are already starting, in terms of the grid investments that I'm seeing.

Speaker 2: I'm intrigued by that question, as to, if we add a solar panel to a home, and the owner sells it back to the grid, is that a FERC jurisdictional matter? I know FERC is told it's got to be netting, but to me, that's a sale. It seems to me to be a sale that's gone on. But if netting doesn't count, then bartering doesn't count, and I should be able to barter, and the IRS shouldn't be able to come after me.

But what else is out there? Storage units. I mean, how do those play into your question, as well?

The other thing I would add is, I don't know what's going to happen in the future on the distribution system, but although the sales of electricity aren't growing, people are more addicted to the product than ever.

And if we move to an electric vehicle situation, then we've exacerbated the problem, so we might get to some of the issues that have been talked about today regarding resiliency. And I think you're right, I think when you try to go to the capital markets and say, "We want you to invest in this long-lived asset, and oh by the way, the trend is not so good for the use of that asset," (and asset utilization is important to people like that) that's a problem. And it might be a problem that the government may have to solve. I mean, you may see situations where the government is going to have to come in to say, "OK, we do want these things, we do like this type of society, these costs are getting out of control, and we are going to have to have a program."

I don't know if that happens, but that's one likely scenario, either through policy or actual public/private partnerships. And sometimes, you know, as a former government employee, that's not a bad thing.

There are things that government can do. For example, in Arizona, we don't have natural gas storage. Yet we are closing coal plants. That sounds bad to me. Right? [LAUGHTER] But at $3 gas or $4 gas (I know we went up because of the cold spike), but at $3 gas, who builds it? Who builds that? Who invests in that? Well, no one. Why? Because no one wants to make that investment when gas is at $3. And then, when it goes to $15, we will hear, "Oh, we should have some storage. Why haven't you done that storage before?"

So there are some things where we can turn to the government and say, "Hey, you know, you are sort of an insurance policy, and we need your help to do these things," because otherwise, even though I know the market does do these things, sometimes the market won't drive you into making those decisions that you need because you've moved in the name of efficiency instead of resiliency.

Question 12: Picking up on some of the earlier discussion about getting prices right, I can certainly imagine a way that we can get to dynamic pricing. It's not where we are in most places today, but the technology to make that happen is rapidly becoming more available, and allowing customers to automate their responses.

There is also some very interesting dialogue starting in the Northeast about regulatory models and how to create regulatory models that incent more efficiency and also incent the kinds of performance that we would like to see in this new grid.

But the area that I find still a little troubling, because I think perhaps prior to today it has not been really discussed very much, is this notion of the distribution system operator, which I think is a critical element. I mean, we just kind of lump wires and operations together often, but if you look at Speaker 4's presentation, if you look at Speaker 3's color chart, that distribution system operator is the pivotal monopoly function that has to occur.

And today, I know, in states like California, they're still talking about, "Well, how do we create an integrated model between transmission and distribution?" We largely don't have, in distribution companies, either the software, and maybe not even the personnel, to figure out how to do differential reliability and also real-time pricing at different nodes on the distribution system.

It's taken us a long time to get there in transmission. What's the process by which we began to think about really realizing this distribution system operation function, which seems central to realizing the vision we've been talking about as the utility of the future?

Speaker 1: There are a couple trends that I think are going to force that issue. One was just mentioned, which is the electric car. As the storage technology improves, and electric cars become more widespread, you're going to get into this whole question about how do you plan for them, what kinds of transformer changes do you need, who's going to pay for that? How do you anticipate where these cars are going to be? These cars are both generators and consumers.

And so how do we manage that? How do we get the price signal? You've got, obviously, increasing amount of rooftop solar and other DG. Essentially what's going to happen is, our hand is going to be forced. The question is, does it matter when?

Questioner: But my question is not really, can we do these different things piecemeal? But can we get to the place where we really have an integrated operator that's managing all of these in an efficient way? I can imagine all of these things happening, but they could all happen in a very inefficient way if we don't figure out how to do distribution system operations efficiently.

Speaker 4: I think some of the next steps are likely to be pilot projects. There are companies that are working on these things. The Resnick Institute has been doing a lot of research in this area, you probably know about that. Siemens, OATI, they're all working on software and algorithms and ways to optimize and dispatch and monitor in real time, et cetera. So I think capabilities are being developed, and I think at some point a combination of an ISO/RTO, with the distribution utility and a software company, will get together and pick a PNode, and try a pilot program, and demonstrate that it's feasible. I think that's probably the near-term step that we'd see. And once that feasibility is demonstrated and that software gets tested, perfected, improved, and so on, then it becomes something that's real, that people can actually imagine implementing.

Speaker 3: One of the technology companies I've been working with has been developing this micro EMS software that they are now piloting with the utility on a number of nodes, at the distribution level, interfacing with the ISO. And so they're kind of working that out.

In the UK, there are some pilots going on that are interesting. In Japan, there are some interesting pilots, which I think are irrelevant in terms of transferability, but still, the concepts are being explored. So I think in the pilot stage, the technologies are being invested in.

Speaker 2: I'll just add, from the utility side, this data thing is going to catch on. I mean, using data to do this stuff is not one of the real core competencies of utilities.

And whether we build it as a core competency or we buy it as a core competency, we've got to get a better handle on basing our decisions on the data, as opposed to having our customers call and say, "Hey, do you know my lights are out?" Right?

And quite frankly, without making too much reference to yesterday's events, consolidation will help you do that a little bit. Because as a small utility, right now as I sit there, you know, serving 400,000 in this community and 100,000 somewhere else, and 100,000 somewhere else, I have to prioritize my IT budgets, and innovation is more difficult when you're smaller, because you can't afford to make a mistake, so therefore you tend to be more conservative. So that's another thing that might help as we move towards changing that.

Question 13: The distribution systems today, as I'm learning more and more about them, are essentially run by the seat of the pants by a bunch of engineers. And to get it to the state where you have to do LMP and actually dispatch electric vehicles and things like that, is a big investment, and is going to take time.

And I'd like to make one other point, at the ancillary service level. Ancillary services are about 20 years old, so it's probably time to revisit them. And we've added a bunch of ancillary services. So I would hypothesize that there are really only two ancillary services. One is frequency regulation, and the other is voltage.

And you could think of it as saying that the non-dispatchable resources have to pay the dispatchable resources. And when you say non-dispatchable, you mean residential generation that isn't dispatchable. Solar, wind, nuclear is not dispatchable, and self-scheduled generation is not dispatchable. And so anybody who wants to do self-scheduling and can be dispatched goes from one side of the equation to the other, that is to say that the non-dispatchable now has to pay to have the system balanced for it.

So when you do that, a lot of these things start to iron out. And quite frankly, we've just gone an era of trying to subsidize these non-dispatchable generation sources to get them into the system. And when you think about lots of them, and when you think about the fact that you're going to have maybe a very small set of dispatchable, generators, you have to really get the pricing right in order to make the ancillary services work.

Speaker 4: Hear, hear!

Session Three.
Reliance on Renewables: Clash Between Expectation and Reality?

Advocates for renewable resources have long contended that expanded deployment of wind, solar, and other carbon free generation will enable society to reduce emissions while keeping prices reasonable. For many renewables both the marginal cost of producing energy, as well as the carbon emitted from such facilities, is zero. The theory is that both the economics and the environmental benefits would enable the retirement of older, "dirtier," fossil plants, and perhaps even enable the phasing out of nuclear units. Countries such as Germany and Spain have opted for such a strategy and several U.S. states seemed headed in the same direction. Early results from those countries furthest along in implementing such plans suggest that the results are at significant variance with the expectations. In Germany, for example, it appears that both prices and carbon emissions have risen significantly. It also appears that older, coal burning plants, rather the being forced into retirement are being relied upon to maintain reliability in meeting peak demand. Are these early indications a momentary "blip" or an indication that the strategy is seriously flawed? What has caused these results and what should be done about it? What do these experiences tell us about the future of such plans in those U.S. states that are inclined to adopt similar strategies?

Speaker 1.
Thank you. I want to share with you some ideas about what has been ongoing in Germany over the last ten to twenty years. So first, what are the key lessons from what we have observed? What were the key drivers behind what happened? And then also talking about the economic rationales for feed-in tariffs, which have been the main support instrument in Germany for renewables, and also directional for not doing them.

So the first key lesson learned is that feed-in tariffs are effective, at least the German ones. We started in with a feed-in tariff more than 20 years ago. At that time we had 3% renewables in the electricity generation mix, mostly hydro, and now we are at about 23% of electricity consumption coming from renewables. And as you may note, the development has been more or less in three phases. First it was wind which was taking the lion's share of new installations, then biomass came in, and it is only over the last five years that we have seen an important increase in the electricity production from photovoltaics.

The second key lesson is that things are getting expensive, and especially the way Germany did it with unlimited, unrestricted support, has driven costs up. And what is very noticeable on this slide is that costs went through the roof, especially when photovoltaics came in on a larger scale, from 2010 onwards. Nowadays, photovoltaics account for roughly half of the subsidies, but it only accounts for roughly one quarter of renewable electricity produced.

Put differently, if you look across the border to Austria, they have a similar scheme, different shaded feed-in tariffs, but they have limited from the outset the annual support volume to new installations. And so they are not facing the same problems that Germany is facing.

The red line in that graph illustrates the market value of the produced electricity. And you see that until 2008/2009, it was growing proportionally with the support payments, and then with the economic crisis hitting, and also some further developments, the gap between the market value and the cost has consistently widened over the last years.

Since it was stated at some point, also apparently in the press in the US, that carbon emissions in

Germany are rising, I have just a small correction. Emissions have been decreasing by roughly 25% over the last two decades. Germany has been over fulfilling, if you go to its Kyoto goal, which was minus 21% for all greenhouse gasses.

Yet you can see on the chart the preliminary value for 2012 (slightly higher than the previous year). We have seen a slight increase in that year, and expectations for 2013 are another slight increase over 2012 levels. Why this is, I will come back to in a minute.

One key point, clearly, is that we not only have the renewable support scheme, but we have simultaneously the European Emission Trading system, which limits the overall emissions from electricity generation in Europe. It's a ceiling, but the ceiling is as the same time also fully used, and if you increase the share of renewables, we do not decrease overall emissions.

Obviously, we are doing this in the German context because we have ambitious targets for 2050. Limiting global warming to plus two degrees as compared to pre-industrial levels requires, according to European and German and IPCC understanding, that industrialized countries cut their carbon dioxide emissions by roughly 80% by 2050. Therefore you see also we have seen a considerable decrease. We are far from reaching the objectives that the government has set for 2050 or even the 2020 target.

The third lesson learned is that there is not one type of renewable electricity. This has been reflected in the German feed-in tariffs by a broad variety of support levels, which moreover have been changing over time. Just to give you an impression how broad the variety of support levels is, you can see here lowest ones found for landfill, sewage, and mining gases, and the highest for photovoltaics installations. And when designing specific schemes for renewables, we have to take into account heterogeneity, not only in the status quo, but also the dynamics. And this, in fact, is a major reason why things have gone differently than originally expected. Photovoltaics costs have gone down dramatically. They have been cut by a factor of roughly four, and the feed-in tariffs followed, but only with some delay. Whereas you can see that for wind, the feed-in tariff over the two decades has remained more or less stable in nominal terms.

So those are the key elements of the German situation.

One of the key drivers of German policy, clearly, is public opinion. We still have 80% of the voters who are in favor of increasing the share of renewables, and so any government will take into account this public opinion. If you ask people whether they are willing to pay more themselves to increase the share of renewables, then the share of positive votes drops considerably. Depending on how you ask the question, you have between 20 to 50% positive opinions.

And you have a further strong sentiment, which is that all those exemptions for industry make things expensive and are unfair, whereas government officials and economists tend to say this is necessary to keep up competitiveness of Germany. So from a policymaker's perspective, you have no clear mandate from the public, and we have a tendency to muddle around.

At the same time, the feed-in tariff has been remarkably stable. The first feed-in tariffs were put in place more than 20 years ago, and the basic principle has not changed. And one reason why policymakers have been able to stick consistently to that policy is that it is a policy where they make contracts at the expense of third parties. Feed-in tariffs are not paid out of the federal budget, but they are paid through a lift up on electricity prices. And so if there is some budget deficit, that's not helped by changing the renewables policy.

Self-binding of policymakers frequently is seen as a prerequisite for time consistent policy, but as you see, they also have the adverse effect of sticking too long with a policy that gets too expensive.

Let's move on to the third part of my presentation, where I try to identify the economic rationale behind feed-in tariff policy. What you see here are the commonly discussed objectives in German policy, and obviously if you take only the first two ones (reduction of greenhouse gas emissions and low overall economic cost), you end up with some greenhouse gas certificate trading as first best instrument to cut emissions at the lowest cost. But Germany and other European countries, and also the European Union, have target deployment rates for renewables, and they have a focus more on low cost for electricity customers than on the overall social welfare impact. And they have a concern about costs for energy intensive companies.

Let's leave aside those supplementary objectives of going towards a more distributed energy supply structure and the creation of jobs, but keeping all the other objectives in mind, you end up, if you could do it right, with a system of differentiated support by technology class and a focus on consumer rents instead of total welfare.

This is just illustrated here. If you have a uniform regime, like a quota system for renewables, then the cheap renewables will reap heavy producer rents. For example, the good onshore wind sites close to the coast, whereas the marginal sites will just recover their costs. And that is one major argument brought forward in Germany policy debate to maintain the feed-in tariffs. Another major argument is the risk reduction effect of having fixed feed-in tariffs. You lower the risks for the investors. This lowers their capital costs, and you end up with a lower cost for the lift up. Yet this obviously is a risk transfer to government or to the other participants in the electricity market.

So these were some reasons that can be invoked for going forward with feed-in tariffs, but obviously it went not as expected, and you may classify the events of the last five years as a perfect storm for the German policymakers. The consequence of the 2008 financial and economic crisis was both economic recession and extremely low interest rates. This led to a decline in demand for electricity, and the CO2 certificate price dropped. At the same time, we had overcapacities in global PV manufacturing, so PV producers were selling below their whole costs. And we had at the same time, with the low interest rates, the opportunity costs for the private investors sink.

And this together led to the huge investment into PV systems and the huge increase in the renewable subsidies. That can be seen in this graph. The yellow line is the annual new installations in PV, and they go up in the year of the recession. And at the same time, both the carbon prices and the electricity prices collapse, and this drives up the support costs.

So to come to a conclusion, we perceive the situation in Germany as a triple challenge. We have long-term climate policy objectives, and as we discard nuclear for good reasons or for bad ones, it is clear we need renewables to get to the 2050 objectives. Renewables are relatively expensive. And my opinion is that they will remain more expensive than other sources of electricity generation. So you would need some comprehensive CO2 certificate scheme to achieve your climate policy goals. Unfortunately, neither at global scale, nor in many of the important economies of this world, do we see that this will be achieved within the next ten years.

So renewable support schemes are certainly not the first best economic solution, but in my opinion, well-designed schemes could be an interesting complement. “Well-designed” means, in my opinion, calculated investment risks, limited additional costs for electricity consumers, limits on quantities to be installed, political stability of the schemes (because obviously it has taken years for the uptake of both the wind and photovoltaics industry in Germany), and in case of a weak grid, you also obviously should implement locational incentives.

Feed-in tariffs thus may support renewable development in the early stages, but for more evolved markets, other support schemes are certainly more advantageous. And be aware that if you combine feed-in tariffs with a certificate trading system, as long as your expectations are met by the actual development, this may function, but the German example shows that it may go terribly wrong if you have a recession.

Speaker 2.
Good morning. It’s a pleasure to be discussing with you the renewable energy story in Spain, which runs quite parallel to the German one, so you will see a lot of similar slides, but there will be a few twists. This story of renewables in Spain had a rather happy or rosy start. I remember the times where President Obama was mentioning Spain as a good example. But it has ended rather grimly, and at the end, I can mention to you the latest developments which just took place yesterday with what is going to happen with renewable energy policy in Spain.

So just to set you up with what is the electricity system in Spain for some context, we have a liberalized generation market and a not so liberalized retail market (we can discuss that later, but that’s a different story). And in the generation market, we have two large firms, and some smaller firms, and there is some possibility for market power, which will have some interesting implications later when talking about feed-in tariffs and premiums.

Basically, we have a rather mixed electricity generation mix. We have hydro, nuclear, coal, natural gas, wind, solar/thermal, and photovoltaic. Comparing installed power with electricity production in the last couple of years, there are some interesting relationships. It is interesting to see, for example, the relationship between the installed power for combined cycles (24.8%) and the actual production (a smaller percentage), and that is one of the elements that we should keep in mind when looking for explanations for what has been going on in Spain. Also, the role of coal is interesting.

So let me give you a very brief overview of what has been going on in Spain for the last 20 years. We started in ’94 with a feed-in tariff very much like the German one, which was referenced to the retail price, and was an obligation to buy. This was very similar to the German system. But then things started moving, and then in ’98, we introduced the possibility to choose between feed-in premiums, that is a premium that you get over the market price, or to stay within the feed-in tariff. And there was this possibility, of course, to bid into the markets to get the market price plus the premium.

In 2004, we introduced an incentive for market bidding, too, because there were not that many producers that were choosing to go into the markets, so an incentive was introduced, basically 10% over the market price, and we also coupled it with balancing payments. So we required wind, basically wind, to go into the market and to go into the balancing markets, which developed quite quickly production models, for example. There was also an increase in the allowed maximum PV size. So this is what created the push towards photovoltaics, basically from moving from roofs to on-ground installation, big installations up to several megawatts. And we also introduced, for those renewables that chose to go into the market, priority dispatch.

In 2007 we introduced a cap-and-floor for wind, because in 2005 and 2006, market prices were very high. Wind was actually getting a lot of money, those who chose to go into the markets, in addition to the premium. So we introduced a cap and floor system for wind, so that even if you went into the market, you had a limit on the amount of money that you could get through the market, plus a premium.

In 2008, you will see later, there was a big explosion in photovoltaics, and a big explosion in the costs. So in 2009, we started with cost containment efforts. So we introduced a kind of tender for photovoltaics, which is not called a tender, but it's kind of a tender. But at the same time, we saw thermal solar expansion, which was not limited. And that is also an interesting story that if we have time we can discuss.

2012, the government realizes that it cannot contain the costs, so they basically needed to set a new moratorium on renewable energy developments, which has not yet been resolved. We expect to have new regulation for renewables in a couple of months, and there are already some drafts that are talking about two elements, which I will discuss later.

In 2012, Spain also introduced new taxes for renewables. And in 2013, this year, there has been a kind of reform of the electricity sector. Reform is not a very good word, but certain modifications in the way renewables are paid. Basically, we have moved to the old system of a regulated rate of return, so the government has said they are going to pay a 7.5% return on renewable energy investments. Yesterday a couple of consulting firms delivered their estimations of what that means and what needs to be paid to renewable energy installations. And now we'll see also--this is interesting—that this is going to be applied backwards. So I guess in a couple of months we'll start to see suits for the Spanish government in front of the international arbitrage courts. And we also introduced in this electricity sector reform a net metering patch, which is quite interesting, and I will talk about that later. So this is a very brief summary, and I'll be happy to elaborate on any of these elements.

So all these developments basically produced significant growth in installed capacity for renewable energy, which looks very similar to the German experience. We have rather balanced growth in wind energy. We have an explosive growth of solar photovoltaics. And, starting in 2008, and contrary to Germany, biomass has not worked, and small hydro has worked very poorly. So feed-in tariffs are good for some renewables only.

It's interesting also to see how the installed capacities for wind and solar relate very well to the regulation that has been produced in the different years. So for example, all the wind started to grow in '98, but it increased very much in 2007 because of the extra returns that they were getting from these very high market prices, then it was cut down, basically, when the cap and floor system was introduced. On the other hand, you see the explosive growth in photovoltaics driven basically by the change in the regulation that allowed very big photovoltaic power plants on the ground, and also because of an effect that Speaker 1 already mentioned, the decrease in the cost of solar photovoltaics.

So what is the level of support? This table shows the equivalent premiums that the different technologies have been receiving in the last years. You see that the level of support, and that is where one of the problems lies, has not been decreasing. And actually, it has been increasing sometimes, because sometimes in the last years, starting in 2008, the wholesale electricity price decreased. So that means that the equivalent level of support required for photovoltaics and wind actually increased, even though you might expect that this support would decrease. If you take all this level of support and multiply by the amount of capacity installed, this total cost graph is what you get. For wind, total costs have been rather stable, growing a bit but not that much, but starting 2008, we have this explosion in costs for photovoltaics. And at the right hand side, you also see the beginning of an explosion in solar thermal, which probably will go unchecked. And again, as I said, that is an interesting story. But basically 2009-2010 is when everything exploded. Biomass, waste, small hydro don't count much.

Basically, the cost of the support for all renewables was around 30% of the total cost of the system in 2012, around 600 or 700 million Euros. And of course, this differs very much with the technology. So you see, for example, that wind has only 5% of the total system cost, but delivers almost 16% of electricity demand. So wind's share of costs per megawatt hour is not that big. But if you look at solar photovoltaics, which accounts for more of the system costs, it only delivers around 3% of the electricity. This asymmetry is probably one of the biggest problems that we are having.

Of course the cost of photovoltaic technology has been going down, because the big investments, for example, in photovoltaics in Germany and in Czechoslovakia, and in the Czech Republic also, and in Spain. But the cost of wind has not been going down. In fact, in some years, it grew. It will be interesting to elaborate a bit on that, because it was not a problem of the technology, but of the rent extraction problem that we have been having from regional governments.

So what about carbon emissions? Renewables have actually contributed to reducing the carbon emissions in the electricity sector. The total emissions are on the right hand side, but of course these are mediated by the decrease in electricity demand that we had because of the crisis. So it's more interesting to look at the left hand side, and this is where you see the emission factor, which has been cut by half, basically, because of the big share of renewables, and also because of the interaction of combined cycles, which have not been working that much (in Spain, renewable energy substitutes for gas-fired generation, rather than coal). Of course, that is not to say that this is an efficient way to reduce emissions. And in fact, when you look at the cost of reducing emissions, well, it's very much higher than the cost of the ETS allowance, for example. So I agree with Speaker 1 that this makes no sense if your only goal is to reduce emissions.

And then we were also asked to address what have been the impacts on dispatching and market operation. I would like to comment very briefly on the merit order effects, which have already been mentioned. Price volatility has increased. We don't have negative prices like they have in Germany, because the system doesn't allow for that.

So when you have a lot of combined cycles plants, basically, you assume that the combined cycles will always set the marginal price in the market. But, in fact, we have been having these merit order effects, so we have been estimating ex ante and ex post the merit order effect for Spain. So basically you see that we have had reductions between two and four Euros per megawatt hour for every gigawatt hour of wind introduced into the system. In some of the markets, these reductions have been bigger. Typically, smaller markets have an increased merit order effect. Large markets that have more possibilities to exchange with others have a smaller merit order effect. And this merit order effect can be also asymmetric. For example, the left hand side graph comes from Italy in a certain year, and there you see, for example, that there has been a reduction in prices at the lower cost hours, but there has been an increase in peak prices. The right hand side graph belongs to the last year, and there you see a uniform decrease in wholesale market prices.

What about balancing needs and costs? Of course, balancing needs have increased in Spain. We have had sometimes almost 60% of the total power that has been produced by wind, and of course that requires a lot of balancing. But, interestingly, the cost of balancing has been reduced, basically because we have a lot of idle natural gas combined cycle plants, which are happy to participate in balancing market and offer the services for very little.

As for the network effects, we have also estimated the impacts on the need for new lines, and the interesting thing is that the cost is not very big, at least for France, Germany, France, Spain and Portugal, which are the countries that we've been looking at.

And just to touch upon a couple of issues that I think will be interesting later, one element that I think is interesting is the conflict between national and regional coordination. Renewable energy support is paid by national electricity consumers, that is by rates set at the national level, but they are governed by their regional governments. So we have one problem here of sub-optimal development (sometimes rushed), rent extraction, and also some difficulties for planning.

Industrial activity is another issue. One of the objectives of the government was to try to create a new industry, a green industry. Well, this has happened for wind. It has not happened for photovoltaics.

And also I would like to touch upon net metering, because, as we said, it has been addressed by the last reform. Net metering has been very much associated with photovoltaics development, just as in the US. And basically you need to correct this net metering issue, because if not there is going to be a cross subsidy between consumers. And in Spain, this has been fixed right now. A tax has been introduced for photovoltaic producers, so that they will pay more of the network costs, because it is impossible to allocate all of the fixed costs to the fixed term of the tariff.

So in conclusion, there are a lot of things to learn from Spain—basically, to have some caution when developing renewables. The system worked quite well for wind. But the PV bubble was terrible for the rest of the system. It also coincided with the economic crisis, and in fact the crisis is one of the drivers for the problems. Feed-in tariffs were good, but only for some technologies. For other technologies they were terrible. We did have a control system, unlike the Germans, but the control system didn't work, primarily because of this disconnection between the regional and national governments, and that is what created basically the bubble for photovoltaics.

Reliability and the impacts on networks has not been an issue, but basically that has been because of the problem we have with overcapacity.

And finally, of course, the question is about the economics. We also have a strong public support for renewables. But when it comes to money, then you know, money makes the world go around. So when you have an economic crisis that is decreasing demand, and also the cost of renewable support is growing, and also you want to cap the tariffs, like the government tries to do--well, the size of the blanket will become smaller, and somebody's losing here. Thank you.

Question: Just two things. One is, I don't know what the current number is, but my understanding is that the cost of the renewable support was not being passed on directly to the customer, but was being capitalized in what we call a regulatory asset in this country, to be amortized sometime in the future, and at one stage, that number was close to the same as the gross revenues of the electricity sector. So that seems like a big number. And then in 2012 there was an effort to retroactively reduce the renewable energy tariffs, which they couldn't do because of the law, so they just taxed them.

Speaker 2: Yes, there are a couple of issues there. The first is about this tariff deficit, the one that you're mentioning. So this is not only a problem of renewables. It's basically a problem of the whole system. Basically, the government was not able to recoup the fixed cost of the system, because we have these volumetric tariffs. So demand was going down. And so one part of the problem was renewables. The other part was network and distribution costs. And it is this tariff deficit that was generated. So the objective of the government in these last two years was basically to eliminate that tariff deficit. That has not been the case. This year we expect to have 400 million Euros as tariff deficit, which will need to be capitalized and passed on. Again, this is a longer story that is only partly related to renewables.

As for the other issue of the retroactivity, in 2012, we set these cost containment measures, starting in 2009 and between 2009 and 2011, we started with the tenders for photovoltaics. Then they restricted the amount of hours that could be paid for photovoltaics, so they decreased the equivalent hours that you could apply for. Then we went to this tax. The tax was applied to all energy sources, to all electricity sources. Nuclear, hydro, all sources. Renewables, of course, was also paying. And now is where the real retroactivity will come, which is this rate of return regulation that we also applied to existing power plants. And they will only apply to renewables. So we have had several measures that have been trying to cut down the revenues. Some of them have been retroactive, but the biggest chunk will come right now if this new regulation is approved, and if there are no conflicts at the court system.

Question: I have a question about the net metering adjustment in Spain. Is that a tax or fee? Is it a variable fee? How is that calculated?

Speaker 2: There are two elements in this correction for net metering. The government realizes, basically, that the right thing to do is to fix volumetric tariffs, to move a bigger chunk into the fixed part. But doing that would increase significantly the fixed term. So they realized that they couldn't do that. So they could only increase the fixed part of the tariff a bit, and that has been already changed. So for the rest they are trying to recover it through this tax, which is a variable tax and depends on the amount of PV produced. So what they are trying to do is to recover the variable part of the tariff that is not being paid through net metering.

Speaker 3.

I know that most of you are familiar with the European situation. And let me just very briefly recall the major milestones. Twenty-five years ago, Europe decided to liberalize energy markets, electricity and natural gas, and at the same time to build one single European energy market. In fact, one market for electricity and one for natural gas. And in 2007, Europe decided to set quantitative goals for 2020, meaning a reduction of CO2 emissions by 20% compared to 1990, a decrease of 20% in the final energy consumption compared to the business as usual baseline, and to have 20% of renewables in total energy consumption, which translates in something like 33-35% renewables in electricity generation. Well, then in 2009, Europe decided to be even more ambitious and to set goals, or at least one goal, for 2050, going towards a low carbon economy, and the goal is to have a reduction of CO2 emissions of 80% as compared to 1990.

Now, where are we in terms of these three milestones? First, as regards to markets, initially the goal was to have a single market by 1992, which was a little bit too early. So since then, things have improved, and since 2003, basically the legal framework is in place, and regulation has become more and more sophisticated. So basically we have no borders. Since the first of July, 2007, almost all consumers are able to choose a supplier from any member state, both for electricity and for natural gas, and, basically, we have the same basic principles being applied in all the 28 member states. So we have the same full liberalization everywhere, full retail choice everywhere. The same basic rules everywhere. And we have some mechanisms for cross border energy trade.

As regards 2020, in terms of emissions, we are, thanks to the economic crisis, doing well for the moment. Last year we were on target. As regards total energy consumption, you see that last year we were also on target. Total primary energy consumption is lower now than it was in 2005. In terms of efficiency, there have been less impressive results. And then as regards to renewables, of course, which is the major topic, we will see later on what has happened.

Now, for 2050, this is the goal, reducing greenhouse gas emissions by at least 80%, and the heads of state and government recognize that it will "require a revolution in energy systems." Now, when we look at what they are doing in individual member states, it doesn't seem that they have really understood what a revolution means. But by 2050 we should be there, as we can see in this picture. The blue area is the power sector, so basically what we need is to fully decarbonize the electricity sector. This has to be achieved by 2050.

Now, talking about renewables, which is the main topic of our session here, ten years ago, people had some curious ideas about renewables and indeed many people thought that they could not provide any kind of significant contribution to our electricity systems. Things have changed, and this is the picture in this century, the 21st century in Europe, in the European Union. As you can see, renewable generation accounts for about two thirds of new additions every year in the EU. So basically it's wind, which is the blue in the bottom, and photovoltaics, the green. And the yellow is combined cycle gas.

If we look at the net changes in generation capacity in the 21st century, we have decommissioned fuel oil, nuclear, and coal power plants, and there was indeed a dash for gas in Europe, 120 gigawatts were installed, but then we have wind with almost 100 gigawatts, and photovoltaics with 70 as well, until 2012.

If we look now at the penetration of renewables, and let's have a look at wind, we see that the penetration of wind is very significant in Denmark, Spain, and Portugal, and is growing in many other countries. But we have, nowadays, several countries where the penetration of wind is about 20% of total energy generation. And, indeed, in these countries, there are now hundreds of hours per year where demand is fully covered by renewable generation. But these are hours, not continuous hours, although we can also see nowadays situations like this one in Portugal, but also in Spain and Denmark, where for one day, 24 hours, that's a picture you can see here, wind covered more than 50% of total demand. So the system operators must be able to manage this system.

Now, when we started some years ago, we started with small amounts of renewables being added to the system, and because our power systems are as reliable and resilient as your power systems in North America, nothing happened. It was relatively easy to incorporate these small amounts of renewables. Now, in some countries, when we are talking about 20% of electricity from wind, when we are talking about 40 or 50% of renewables in electricity generation, it's not as simple any more. But we still have been able to manage it, both technically and in terms of reorganizing the market mechanisms in place. Economically, we have seen that there are some concerns about the rising costs.

But if we look now to the future, if we look into 2050, and if we want to prepare this future now, start preparing it now, then of course we need to invent something different. It cannot be just a small change to a well-established conventional power generation-based system. And increasing even further the amount of renewable generation means that we have to rethink network planning. We have to rethink system operation. We have to fully redesign our energy electricity markets in particular, but we also need to invent a new kind of regulation, because we cannot imagine that the past regulation will be any good for creating an efficient system in the future in 2030 and 2050.

My point is that we are experiencing changes, and we are moving from a world of high concentration of electricity generation to a world of more and more decentralized generation. And at the same time, we are seeing participation of demand increasing. And this, somewhere, will create a shift of paradigm, and we'll need to throw away the concepts we have inherited from the past, and we must design something new for the future.

My point is that renewables is only one of the many challenges faced today by electricity systems, by electricity markets, by electricity regulators. We have demand participation. We have electric vehicles. We have storage. We have many other things. And if we address them one by one, it may be a pragmatic approach, but if we think about these large scale figures of 2050 and 2030, then we can be sure that if we work on this on a one by one basis, we will be far away from the optimum solution. So what I think is that we are now in the middle, we are living with some other solutions to solve these unexpected new challenges facing our power systems. We are making changes to the old regulatory building. But what we need, really, is to invent a new kind of regulation. We need a systemic solution.

And to show it in another picture, we move from the left to the right, and we move from a centralized control to decentralized control, from passive distribution to active distribution, from intermittent demand and centralized firm generation to the opposite, intermittent generation and firm demand. And we must move from other transitional solutions to a new electricity market, which must be very different from the market we have had in the past.

And the question is, when we will be able to move from Newton to quantum physics in terms of electricity systems? I think it's a comparable challenge. Now, I don't know what the market of the future will look like, but I guess there will be lots of solar energy. There will be lots of megawatts. There will be traders and lots of virtual transactions that we can see, probably, and for sure there will be a male or female regulator in the picture. Thank you very much.

Question: Coming back to the question about the tariff deficit in Spain, on Speaker 2's slide number eight, you can see that the cost increase really started around 2006-2007. Now, the freeze on the end user electricity prices was reduced well before that in 2001, and the government at that time just wanted to keep end user electricity prices below inflation. Don't ask me why, what is the theory, but it had nothing to do with renewables at that time. It was just a political decision. And what we see is that five years later, when the increasing costs of renewables and other costs start to become visible, then there was a heavier stock of deficit, and of course things became worse and worse. Initially it was not a renewables problem.

Speaker 2: No, it was kind of the perfect storm that Speaker 1 mentioned, but with different drivers.

Speaker 4.

Good morning everyone. I am speaking from the perspective of a worldwide company. We have a lot of activities in Europe, and the revolution that has happened there--it's been a challenge. It's been difficult, and I think it's important that we convey the message and have some lessons learned.

In the US we are mainly active in the Northeast and in Texas. And I think it's important that I be clear that I'm not, and also the company is not, against new technology. We are not against green technology. Actually, we are active in it. I think it's just important that there's a level of fairness and some level of economics. If policies and economics start to diverge too much, it creates some problems.

Quite often you hear, "Yes, but the US is not Europe. Europe is different." And, yes, Europe is different. Gas prices have been much higher in Europe, and in the US we've been blessed with shale gas. And also the subsidy system is quite different. But in the meantime, as Speaker 1 already pointed out, costs for solar panels have come down. Efficiencies are increasing. Also, the cost of installation is coming down. And in the US, already 11% of the US is at socket parity, where, basically, it's economic already to install solar panels. As costs may come further down, as efficiencies may further increase, as gas prices move up, and power prices move up, as there's more and more and more charges in TDSP (transmission and distribution service provider) charges, the socket parity only gets higher and higher, and more and more penetration can happen. And once you get there, it can go very quickly.

One thing to point out is that in Germany, there is 20 billion euro annual subsidy a year to sponsor the renewables program. So I think it's very costly in Germany. And if we look to what the results are, one of the things that has already been pointed out is that you need more actually service capacity. At the same time (and sometimes it's a little hard to differentiate how much comes from the economic crisis, versus how much comes from the renewables program), there are no payments for the balancing services provided by combined cycle plants. And one of the things that we are seeing in Europe is that a lot of combined cycles are not only being mothballed, but erased, with the sites being cleared. It's not economic anymore to mothball. So it's a thing that is important.

You also have the "green paradox." You have coal plants displacing gas plants, and at a time when you want to show that carbon is important, carbon credits have completely collapsed, so coal plants are running more and combined cycle plants are being pushed out of the merit order and are just used for system stability.

You also have more and more destabilizing loop flows. The transmission grid is not designed for all those extra things.

And on the company side, it's been hard in Europe. Our company saw a 75% drop in stock price. In total, for all European utilities, $650 billion of market cap has been eroded. So it's a very tough time.

And just as an example, in Germany, when the weather is nice, and the load is not too high, you have higher prices in off peak than in peak.

This chart shows the impact on the merit order dispatch, and also the prices. And it's important to note that those prices are around $50 per megawatt hour, and so at the same time, what you're having in Europe is a huge excess capacity, but not necessarily reliability. Just a month ago, Belgium had a very short blackout that messed up the rail transport for a whole day. So on one hand you have huge reserve margins, but on the other hand, you have no reliability.

If we remember the $50 per megawatt hour wholesale energy prices, at the same time we see continuous increase in the retail prices. Retail prices now are around $400 per megawatt hour. That means that you have $350 that is no longer explained by anything. It's just subsidy, taxes, stranded cost recovery…and so it creates a very, very perverse system, because it doesn't send the right economic signals anymore. And in Germany, and also in Belgium and in other countries, with all the increases in cost that are all put in TDSP charges, basically, people are saying, "Hey, my neighbor is green. I'm paying for it. It's actually cheaper if I get off the grid, too, and also install photovoltaic panels on my roof." So you're getting into a vicious circle as more and more people are installing solar panels. You need to recover the costs with fewer and fewer people, and yes, reregulation is a word that is being used more and more.

I think the most important thing is, what can we learn from Europe? I mean, the subsidies and taxes are problematic from an economic perspective, especially if you put them in the tariffs, because that allows people to arbitrage it. But you are not really arbitraging efficiency. You're arbitraging other types of things.

When I grew up in Europe, we were always looking to the US to get ideas about what we should be doing. Now I think it's important that the US looks to Europe, to look at what should we <u>not</u> be doing. But it's important that we start looking at systems more from a macro perspective than from a micro perspective. Most of the analysis, most of the market monitoring, most of the activities are from a micro perspective, but a lot of the long-term costs, a lot of the investment decisions are more from a macro perspective. And I show the example of the CREZ line in Texas. (And I know that all that cost was not just associated with wind, that some of it needed to be done anyway).

But if you start doing big investments and just added in TDSP charges, you create an unfair situation. First of all, the renewables get subsidies. Second of all, the transmission gets to some degree subsidized. And you're also changing the socket parity, because the other generators are getting less and less competitive.

There also needs to be value, and the value needs to be represented correctly, for flexibility and reliability, voltage support, all the other things that in the current markets don't have value. You cannot run a system purely of renewables and DR.

But in the current market, the big differentiators are not there. If you have a very good energy market that reflects those values, you could be there. And none of the markets are fully there. I think ORDC is a great addition, but I don't think we are there.

"Peanut buttering" of costs is a big problem, where we have subsidies, transmission charges--to some degree a capacity market creates some extra peanut buttering. It creates a disadvantage for generation that is needed, that is the backbone of the system.

One of the things we've also seen from Europe that creates a big problem is the regulatory uncertainty. Germany has been relatively consistent, but other countries have not. We heard from Spain. For Belgium it's the same thing where now basically they want to also put a type of connection charge to people that have solar panels to have standard cost recovery. They went to court. The court shut it down. Now they are looking at other ways. But there's a lot of regulatory uncertainty associated with all of that.

Overall, I think in Europe it was too much too fast.

Speaker 5.
I'm going to summarize California's current situation in maybe one or two slides. And that is that in 2012, California achieved a 20% RPS, and approximately a 20% reduction in electric sector greenhouse gas emissions relative to 2005, which is the last year that it's actually easy to calculate these things for. And by 2020, we now, I think, can pretty confidently say that we're on track to meet or exceed our target of 33% RPS. And with that, we'll achieve something like a 30% reduction in electric sector

greenhouse gas emissions, again relative to 2005.

Now, not all of those reductions are because of renewables. Approximately half of them are because of renewables, and the other half is because of a transition away from coal and towards natural gas. And if you were to add other types of resources--renewable resources that count towards RPS compliance, or count towards renewables in other jurisdictions, like rooftop PV and large hydro, we would be at approximately 50% renewables in 2020.

Now, we couldn't always say that we were going to be on track to do this. I think five years ago, when we were looking out at the massive burden and the massive amounts of investment, and all the changes that were going to have to happen on the California electricity system to make this happen, we weren't very confident that we would actually get there by 2020. Now, because of a number of factors, I think we can pretty confidently say that we'll be there. And in fact, because there's been some over-procurement on the part of the utilities, expecting a relatively high rate of project failure, we probably will be above our 30% target by 2020.

And if you look at what the impact of that level of renewables is on retail rates, my firm did an analysis for the three California utilities a couple of years ago, and we came out with a range of something like a 6-8% increase in 2020 from achieving this 33% RPS target, and that includes all the costs that you might imagine of integration and transmission, distribution and all sorts of things.

So if you look at this, compared to where we were five years ago, where we thought we might have been, and I think probably compared to some of the experiences that others on the panel have talked about, I think you probably have to consider this to be a success. It's a qualified success. I wouldn't say that we have done everything right in California, but things have gone, I think, fairly well, again considering where they might have gone.

So I thought I'd spend at least one slide sort of talking through some of the key factors allowing California to be on track. We're not there yet, but we're on track to achieve things by 2020.

The first thing I want to note is that in California, we really are blessed with access to very high quality resources. If you look out the window, you can imagine that this part of North America has probably the best solar resource of anywhere in the world. We also have reasonably high quality wind resources in California and in our neighboring states, and a pretty significant geothermal resource as well. And as Speaker 4 mentioned, we also have access to very low cost natural gas, which has made a lot of the stuff a lot easier, both in terms of integration and in terms of the bill impacts of making that transition from coal towards natural gas.

And we've also had very strong support for renewable policies at the state level, and really all the way down to the county level where things like permitting and zoning laws have to change. Renewable energy is very, very popular in California, and it's been supported really at every level. There's been lots of effort to try to speed the permitting process and help to achieve these policies.

We've been able to have a very active market of developers seeking to bid projects into California solicitations. We literally get now dozens of bids for every one project that's selected in a solicitation. It's a very active market.

This has really been aided by the steep decline in solar PV prices that we've seen over the last few years, and in this sense we're really kind of standing on the shoulders of what our colleagues in Germany and Spain have done. They bore the pain of achieving the scale-up in solar PV, and that was at least partly the intention of those subsidy policies—"If we scaled up this industry, how fast can we drive those costs down?" It turns out the answer is, very fast. And the costs are very low now, and we're achieving some of the benefits of that now in California, and we appreciate and recognize the pain that some of the folks in Germany and Spain have felt, but appreciate what they've done.

We also have a complementary fleet of very flexible natural gas and hydro resources that has helped with the integration challenges.

And last, but certainly not least, is that there have been fairly generous policies at the federal level to promote renewables--tax incentives and loan guarantees and those sorts of things, and the California consumers have benefited from those policies helping to keep our rates low.

This slide just shows you very briefly what our generation mix looks like in California. Unlike in other states and other jurisdictions, we don't have a lot of coal in our mix in California, and what we have is largely expected to be gone by--I think 2027 is the last coal contract that rolls off. But most of it will be out by 2020. What we have is a great deal of natural gas capacity. And there's been a dramatic increase in natural gas capacity between 2001 and 2012. This was a deliberate transition towards a more natural gas-intensive future. If you combine the natural gas resources with the hydro resources, and with our interchange with our neighbors, all of those resources are flexible to some extent. So you can see that the vast majority of our non-renewable fleet has at least some of the aspects of the flexibility that's needed to help with the integration challenges.

So that's what we've been able to do so far. So now the question that everyone in California is trying to answer is, where do we go from here? This slide shows the trajectory of renewable energy installations that are needed to meet our 33% RPS target by 2020. The actual installation isn't going to really look like this. We're going to have a big bulge that happens over the next few years, trying to get as many projects on before the expiration of the federal tax incentives in 2016 as possible. Then it's going to kind of level off a little bit. But you can see that if we were to just stay at a 33% by 2030 goal, that would represent a very, very dramatic slowdown in the industry.

So we're in a position now where we have companies that are very active, and we're getting lots of bids for all of our solicitations. If we stay at 33%, those companies will fold up shop. They'll send their experts off to places like South America and Japan and China to direct projects in markets where there is actually demand for their resources. Even if we stay at 40%, that still will represent a dramatic slowdown in the development industry in California, and there's some concern there as well. So the industry looks at this kind of picture and says, "Well, obviously the thing to do is not to let that happen, to maintain a viable renewable development industry in California, and to continue on that nice linear trajectory, all the way out to 50% by 2030."

Now there a lot of challenges associated with that, which I'll talk about. Before I get there, I think it's helpful to step back and ask the question, "Well, why? Why would we want to do that? You know, why have we been so anxious to achieve a 33% RPS by 2020? Why would we want to go higher?" And there have been a lot of reasons that advocates have proposed for why we should invest in renewable energy--a reduction in criteria pollutant emissions, and the hedging value of having a fixed price resource, and local economic development, and those sorts of things. I tend to think that most of those other reasons are either insignificant, or in some cases just flat out wrong. The big reason why we might want to invest in higher levels of renewables is if we're worried about the potentially catastrophic effects of global climate change, and we want to try to do whatever we can to avert those.

So this slide shows some work that some of my colleagues have done, looking at what the California energy system might need to look like in 2050 if we are going to try to achieve those 80% below 1990 reduction levels that some of the earlier speakers referred to. This work identified three major transformations that are needed by 2050. One of them is energy efficiency. We would need to basically reduce business as usual projections for end use energy consumption in 2050 by half. This really means meeting all increasing demand for energy services by 2050, while keeping energy demand constant at today's rates. We need to do a lot more to make our energy use much more efficient.

We need to decarbonize almost the entire electric sector, squeeze just about all the carbon out of it, with just a little bit left over for integration services.

And we need to electrify. Just about every fossil fuel demand in every other sector needs to be electrified, and that new electric demand needs to also be served with low carbon generation.

This is the technology path towards achieving these types of 80% reductions in 2050 that are needed to avert climate change above the 2 degree Celsius level.

So what are our options for electric sector decarbonization? Well, there are three big ones: nuclear, fossil generation with carbon capture and sequestration, and renewables. And there are issues with all three of these. With nuclear, we actually have a state law in California that prohibits the construction of new nuclear facilities until the federal government gets its act together on establishing a permanent nuclear waste depository. We're actually going in the opposite direction of where, from a climate perspective, we need to go in California with the closure of the San Onofre nuclear generation station last year. Similar things are going on in Germany and on the East Coast and in Japan, obviously. So we're really not going in that direction.

For the second source (fossil generation with CCS), what I have up here is not a picture of an operating plant. I have a schematic. And the reason for that is, there isn't a single operating power plant that captures its carbon dioxide waste and permanently sequesters it underground. The technology can work in theory. There is the plant in North Dakota that injects CO_2 into the ground for enhanced oil recovery. There are lots of questions about cost. There are lots of questions about whether the CO_2 really actually stay underground over the kind of geologic timeframes that we would need it to.

What that leaves us with is renewables. That's the current default option. And that really is the reason why California policymakers, concerned as they are about the climate change problem, are trying to think about pushing as fast and as far as they can on renewables. And so that really is a question facing California today--how fast and how far can we push before we run into some of the issues that we've seen in the cautionary tales that we heard earlier?

I want to talk a little bit about the renewable integration challenge, mostly because this is the subject that I can talk probably the most intelligently about, because we've done a lot of work in this area. We've actually developed a new software tool called the Renewable Energy Flexibility Model that investigates the need for flexible capacity under high penetrations of variable renewables.

This is just a picture of an operating day in March under a 33% RPS. It's just kind of a typical day that we grabbed. There are five challenges. first one is that we need to have fossil resources on at night to serve our load.

When the sun comes up, we get a big influx of solar energy onto the grid. Those resources need to be able to back down very, very quickly. So we need downward ramping capability. We need to be able to turn our resources down as far as we possibly can at solar noon to make room for this big influx of solar. Once we've done that, then we need to be able to bring them back up at night to serve this new peak demand, which on this day occurs at about 8:00 at night. And the big challenge is, can we turn our fossil resources down low enough to be able to make room for all the renewables while still maintaining enough upward ramping capability on the system to meet that 20,000 megawatt upward ramp that we see that occurs from about 4:00 in the afternoon until about 8:00 at night?

Now, we've seen that there are some days, even with our current system, that we won't be able to do that. So the default solution that we think is necessary to maintain reliable operations is simply to curtail the renewables. You can do scheduled precurtailment. If you give the solar a haircut in the middle of the afternoon, I can maintain my fossil fleet. I can keep more resources online, maintain my fossil fleet in a state of readiness to meet that ramping demand. This is actually the default solution that we absolutely need to have available to us, to precurtail renewables when we think they might be able to get us into a situation where we have upward ramping needs that we can't meet.

And the fifth challenge, which isn't really on the slide, it's more of an hour-to-hour challenge. Every hour, we need to have enough operating reserves to be able to meet the kind of hourly, you know, five minute, one minute wiggles that occur. It turns out that probably isn't a binding problem for California.

So we need to be able to curtail the renewables. And as we get higher and higher levels of penetration, we'll need to do more and more curtailment of renewables.

And so this slide just sort of shows what a marginal curtailment might look like as you get to higher and higher levels of renewables penetration. It looks like at 33%, we'll probably see a little bit of curtailment, because the renewables won't fit, and to help soften the ramping needs, but not very much. We think we probably are generally OK at 33% in California at the system-wide level. There might be local challenges, due to transmission constraints and those sorts of things. But as you get beyond 33%, there starts to be an elbow in the curve, and curtailment of renewables starts to mount pretty dramatically. And in this example that we ran, once you get to 40% RPS, you'd be curtailing 16% of the next megawatt hour of renewables that you added to the system, assuming this mix of 55% solar and 35% wind.

So this is a challenge that starts somewhere at about 33%, and it starts to mount very, very quickly. Now, we don't know exactly where that curve starts to bend upward. That's sort of the next set of investigations that we need to do, is to kind of figure out how can we push that out a little bit further in the future. What things can we do to avoid this kind of situation that we're seeing on this chart?

The good news is, there are a number of solutions that are available to us. The most cost effective one, or the most economically cost effective one, but perhaps the hardest to achieve politically, is to more closely coordinate our operations with our neighbors. There's lots of flexibility that exists throughout the Western interconnection. The current way that we do business across the West makes it difficult for that flexibility to be brought to bear to help with the California integration problem.

The second thing that could help is a more diverse portfolio of renewable resources. You'll avoid some of these issues. It will push out the time when you start to see this overgeneration.

If we have flexible loads, things like plug-in hybrids that we can move around--we can do daytime workplace charging of plug-in hybrids, rather than home nighttime charging, which is what everyone has been thinking about with respect to hybrids. If we can move those loads around, that would help.

Flexible generation obviously helps. High ramp rates, lower minimum generation levels, those sorts of things.

And energy storage helps. Now, the interesting thing on energy storage that we're finding is that we really need deep-draw energy storage to deal with this diurnal pattern, if not even longer. So this isn't really the kind of battery technologies that most of the people running around California are trying to sell. It's things like pumped hydro. It's things like compressed air. Those are the most valuable storage technologies.

So just to conclude, as of now, I can say that we're on track to achieve our 2020 RPS and GHG goals at a cost, at that 6-8% level, that's a cost that I think is at the level that most people won't notice on their monthly bill. Reasonable is a subjective term, but to me that seems like a reasonable cost. And we're just now investigating what the appropriate role is for renewables in meeting our future greenhouse gas reduction goals.

Question: Yes, just one. To give people a feel for this 6-8%, what's the tail block rate for Southern Cal or PG&E?

Speaker 5: The average rate in California is about 15 cents. That would include all the residential, commercial, everything else. You're right, though, that as these costs get spread out to rate payers, there isn't any one average rate payer that just sees the 6-8%. Some of them who happen to live in small apartments, like myself--I'll probably hardly notice it even a little bit. The tail block rate for Edison is 35 cents, somewhere in that range. So if you have a large house, and you live in the Central Valley and do a lot of air conditioning, then you'll see a much larger impact.

Question: You had a chart of where your sources are for electricity. I think you called it the net interchange, the electricity coming from other states. Which is how much percentage, and what are the sources of the electricity from those other states?

Speaker 5: The chart I showed is a capacity chart. We have about 13,000 megawatts of import capability in California. That would combine the Northwest and the Southwest. There are some contracted resources in other states. There are coal resources in the Southwest. There's some solar in Nevada and Arizona, and some wind in the Northwest and a share of the Palo Verde nuclear station that are scheduled every hour into California. That adds up to probably a 2,000 or 3,000 megawatts. The rest of it is transmission capacity that could bring in imports when we need them. This tends to be fully loaded during the summer peak hours when we have high demand in California, particularly because the Northwest is winter peaking, so summer is when they have surplus hydropower to sell.

So there's been this kind of mutually beneficial economic exchange throughout the Western interconnection of just really energy and peaking capacity. Now the challenge is, how can we use those same transmission resources to help provide the flexibility services that we'll need to do the hour-to-hour kind of upward and downward ramping? And that's a new challenge that we're only beginning to address in the West.

General Discussion.

Question 1: There were some comments by Speaker 4 which implied that socializing transmission cost is somehow a subsidy for particular renewables. And I would just point out that in Texas, we actually subsidize all the generators with the postage stamp, because they don't bear any of the cost of the transmission system. And so whether it's combined cycle or a wind farm, there's that subsidy. And I haven't heard very many gas generators actually object to that.

Speaker 4: And I agree, and also that the CREZ transmission project was not purely a wind project. I mean, the system needed to become more robust. The only thing is, once you create an LMP system, you're still going to have gas generators that are going to try to build relatively close to the load pockets, because that's also where you would expect prices to be high. Once you start just making it layers upon layers of subsidies that the wind gets from the federal government or other programs, then you have the risk that they can say, "OK, I can build near the load pockets from a value perspective. It really doesn't matter. My revenue stream is going to be relatively the same from a cost perspective. The land is cheaper, and the cost of transmission gets carried by someone else." And so from a macroeconomic perspective, you may get into issues.

I didn't want to put Texas on the spot, because it's a state I like. It's a state I came to as soon as I could. [LAUGHTER] But it's just a warning that things like that that worked in an old world, because for just gas generation, the majority of the revenues were based on the LMPs, and that's also where you make your decision. Once you start making revenues kind of peanut buttered and flat, people may arbitrage that, and then the sad thing is that all that gets put into the rate base and actually changes the socket parity, which should not be changed from an economic perspective

Question 2: Well, my question really follows on the last one. With the exception of what we heard about CREZ and Texas, we didn't hear a whole lot about transmission planning and cost allocation. Now, I know that many of the renewables are being integrated into the distribution system and are going to act as more as changes to load. We talked about some of that. But even when you hook up at the distribution system, you're going to make changes in the overall transmission morphology. And we talked about the fact that this can go across country boundaries, which obviously have different regulatory regimes. How is this move to renewables going to impact transmission planning and cost allocations, system upgrades, reinforcements, to ensure reliability in every area of the country, of each country? And that's kind of directed at everybody but Speaker 4, unless he wants to answer, too.

Speaker 1: Well, perhaps I can make a start for Germany. But part of it, I think, is valid for almost all of Europe. We have no tradition of nodal pricing. That's the first point to make. And the transmission and the distribution system charges are distributed among the customers through a postage stamp tariff. So the cost --

Questioner: A postage stamp across Europe?

Speaker 1: Peanut-buttered among the customers. Obviously the increase of wind is posing increasing needs for transportation north to south in Germany, because we have the good wind resources in the north, and there has been a series of network development plans issued over the past years, both at national and European levels, which aim at upgrading the transmission network to increase its capabilities for transporting renewables and for separating both transnational and national trading activities.

Questioner: OK, so if you build something in Spain that causes an overload in Switzerland, who pays for the upgrade?

Speaker 1: Spain is not the best example, because it's almost an electric island. It's like Texas.

Questioner: Pick anywhere.

Man: Germany.

Speaker 2: I think Speaker 3 has a lot of things to say, because there has been a lot of work at the Florence School of about transmission planning, which is the real issue in Europe. Speaker 4 mentioned, for example, these blackout problems that we have been having in Europe, which are not caused by lack of generation. They are caused by lack of transmission. And this has been on the agenda of the European Commission for a long time. And the thing is, at least from our perspective, we have been working, for example, on projecting what is the cost of these increased transmission needs and transmission investments that we need to integrate renewables, particularly in the north. And the cost is not that high. The problem is how to allocate it, and what is the political will behind it. I think the transmission issue is one that is very highly politically charged, and it's trying to be dealt with at the European level with not a lot of success.

Speaker 3: Yes, I think we have to distinguish between two different cases. One is the case of some cross-border lines. We clearly have a lack of interconnection capacity, both for electricity and for natural gas, at some borders. This is not a regulatory problem. This is not a problem of investments not being properly enumerated. This is a political problem. This happens where some governments don't want, for some reasons, these lines or these pipelines to be built. So it's a pure political problem. If we do not have the degree of connectivity in Europe nowadays that would be necessary to have a fully interconnected and efficiently integrated European market, it's for political reasons, not for regulatory reasons, not because the rates of return are too low or because the incentives are not right.

Answering your question about how planning and cost allocation is done, as regards cost allocation for the use of the infrastructure, this was settled in the year 2000 on a voluntary basis between the regulators and the transmission system operators. And this was later on incorporated into a European directive in 2003. So this has been since then refined, from a regulatory point of view, but the basic concepts of how this is done is in practice have been there for more than ten years.

As regards planning, initially there were no provisions at all in the European directives about planning. When I was a regulator at that time of the first directive in '96, and the second one in 2003, I was insisting with my colleagues that we needed some degree of transmission planning. But this was not very fashionable, because everybody was in favor of the markets, and talking about planning was not at all fashionable. But fortunately things have changed, and in the third energy package of 2009, provisions for transmission planning were introduced. So now we have in place a system by which the transmission system operators collectively, through their official body, have to present an expansion plan for the next ten years, and this gets the opinion of the agency of national regulators, and then finally it is approved, and it is published, and everybody can participate, of course, in this process. There is a public consultation. And I think we have had two or three such plans published. They are updated every two years. So that's about how it works in Europe.

But if you allow me just a short remark about this issue of extra transmission costs for renewables or for this or for that, I'm not sure that I always agree with that approach, because when we say that, we are stating that the existing network is what we want to have. But the existing network is what we inherited from a vertically integrated monopoly. So it cannot be what we wish to have to have an efficient liberalized market, and it cannot also be what we wish to have to accommodate a higher penetration of renewables. So we have to change. The starting point is not the end point. The starting point is not the most efficient one in terms of the future. It was perhaps in the past, not in all the cases, but in many cases, it was the optimum. But it is not anymore. So these extra costs, these extra investments we are discussing, they are necessary, but they are not in fact necessarily inefficient. But what we need is to define very well what is our goal, what is our objective, and then to have the necessary planning to get there in an efficient way.

Question 3: So for those of you who've heard me speak on these matters before, this is a little bit of a broken record, but I'm trying to recast it. First, I want to express my appreciation to the panel, because I thought this was very interesting and very helpful. Second, I want to express my appreciation to all the foreign countries that were represented, because I'm glad that they have run this grand experiment for us, and they're going to absorb the costs.

But I want to make an argument that what we should conclude from this is that the experiment has failed. And what we should learn from it, and what we should do going forward, is to change our policies in a rather dramatic way.

OK, so what is the argument about how it's failed? Well, let's take carbon emissions reduction as the purpose, and what we're trying to do here, and get a lot of this other stuff out of the way. If we're worried about reducing carbon emissions, and we set targets like an 80% reduction in 2050 and so on, then we turn to the question of, "Well, what is the first best policy, the optimal carbon tax on emissions?" And I'll pick a number for sake of discussion, which is about what the US government has said about this, which is that the optimal amount would be about $30 a ton of carbon dioxide. And Speaker 1 tells us that the political economy says we can't do that because it's too high. So we can't actually get that tax put in place, because the population won't accept it. The industry won't accept it. And this has to apply to everybody. So we'll have to do something else.

So what do we do? We adopt these renewable feed-in tariff support policies, and Speaker 2 tells us that the numbers are, well, it's 80 Euros per megawatt hour, or 500 Euros per megawatt hour, in an environment where we're not willing to pay 30 Euros per megawatt hour--but we're hiding it. We're trying to hide the ball by pretending that the costs aren't there, but the costs really are there. And what happens when we implement those subsidy programs? We don't reduce CO2. What we do is we substitute these expensive renewables for cheaper ways to reduce CO2. That's what's actually going on in the European context. That was, I think, Speaker 1's point. So it's not only expensive and hiding the ball, it's not even addressing the problem that we want to address. So I think it's failed.

Now, what do we have to do going forward? Well, it seems to me that there are three possibilities, broadly speaking. One possibility is that we face up to the fact that we're really worried about carbon. It's going to be expensive, but it's worth it. And then we change that psychology and that political environment. We make what is politically impossible possible. And we adopt these carbon taxes, such as they are, and they have to be very high, and we have to live with that possibility. And that's actually my preferred path. A second path, which I would love, but I think has a low probability of success, is we find out a way to really make this stuff really cheap, not actually pretend cheap, and not hide the costs. So this is a technological breakthrough, and this strikes me as basically an upstream R&D problem. It's not like we've got a gazillion technologies that are really cheap that we just can't figure out how to use. We don't have them. So what we need to do is discover them and invent them. So I'd be spending all this money, not on installing expensive stuff. I'd be sending it to ARPA-E and similar organizations that are trying to really push the envelope out there with ideas that haven't been adopted. That's the second path that I think we should go down. And they're not mutually exclusive, incidentally, those two things. We could do them together. And then the third path would be to face up to the fact that we're going to fail to meet the carbon objectives, and we're going to have to do something else like geoengineering, and my colleague David Keith has got a book out on that subject, if you're interested. But the path that we're going down of paying enormous amounts of money for things that are very expensive, hiding the cost, and things that don't reduce CO2, at least in the near term, is a failed policy. What's wrong with my conclusion?

Speaker 1: The point that it does not reduce CO2 is only true if you have the combination of the CO2 emission trading, plus the subsidies. Right?

Questioner: Which we do.

Speaker 1: So in fact, I fully agree for the rest. These are the three basic options. On your second option, I would argue that I don't expect a technological breakthrough. Most of what we have seen is reducing costs through scaling up. And this will not be done in research labs. This will be done through massive deployment.

Speaker 2: OK, at the risk of not being invited anymore, let me disagree. I think it has been a partial failure in the sense that, for example, in Spain, the experiment with wind went quite well, in the sense that we observed a significant reduction in carbon emissions--at a certain cost. I agree with that. But then the cost of that reduction was not as big as the costs associated with solar, so let me differentiate between these two technologies. And I liked Speaker 1's point in his presentation that not all renewables are the same. So there are some renewables and some other renewables. And for wind, for example, we were able to keep the cost rather low. In fact, there were other elements that kept it up, which were not related to renewable policy, but with, for example, these regional national conflicts. For example, one of the explanations of why wind costs did not go down was because the regional governments were interested in keeping high the tariffs so they could extract that amount of money for their international policies or whatever.

So my conclusion is that, first, there has been a failure in some of the technologies. There has not been a failure in the others. So there might be some interesting ways forward. Second, I like very much the way you framed this as a political economic issue, because it is like that. Why don't we go for the first best solution? Well, because it's not that easy. And the second best, which is renewable energy policy, in fact, and this is the story that I didn't tell before, was very much backed by all political parties in Spain, even utilities, because they could make a lot of money out of renewable energy, and this has to do with the intra-marginal nature of renewable energy, which they could profit from. So if you cannot go for the first best, then you say, "OK, let's go for the second best," and if you're able to keep the cost low, like for wind, and you try to eliminate all the other distortions, like the regional versus national issues, you are able to keep that cost low. And you can reduce emissions much faster than in other sectors.

And I think Spain is a pretty good example of that. Spain's emissions have increased compared to Kyoto objective, except for the crisis, which has allowed us to become closer. But the power sector was able to reduce them a lot. Why? Because it was much easier to just switch technologies in the power sector, coal to gas, or to renewables, than to try to reduce the nonpoint source emissions, like in the transport sector, which is much more difficult to address.

The second thing is, carbon emissions, at least in Spain, was not the main target for renewables. Renewables and renewable policy started much before carbon concerns, and it had to do with international policy. It had to do with security of supply. It had to do with regional pollution, in fact. So you can look for other arguments to what's still having the original, this good renewable energy policy, which is not what we have.

And what about your three options? Well, the carbon tax--I already discussed that. Technology breakthrough--I think, as Speaker 1 said, we needed some scaling up, and we had this scaling up renewable energy policy. The problem is that for photovoltaics, this blew up. So as you said, we had a lot of pain in some countries from which the other foreign country, California, profited from. But that was the failure. The failure was photovoltaics, not the others. On adaptation--of course we need to go to it, but again, that's a different problem.

Speaker 3: Well, if you believe that carbon is a problem, then we have to talk about what is more convenient. We know some of the costs of this European approach. Frankly, I don't know what the cost of geoengineering would be, but I guess that if you take into account some unintended effects, they could be even higher. But I agree it must be open to all solutions.

But I don't think that characterizing what has been done as a total failure is correct. There are several failures, parallel failures. But the thing as a whole is not, in my view, a failure.

Some remarks about renewables and costs. Today, for onshore wind in, say, Portugal, the cost for the feed-in tariff is 64, 65 Euros per megawatt hour. Combined cycle, with the gas prices we have now, is about 80 Euros per megawatt hour. Nuclear was published a few weeks ago, the next power plant will be built in the UK with a guaranteed price of 111 or 112 Euros per megawatt hour for 35 years--not for 15 years, as we have for wind in Portugal. So in terms of cost, you cannot say that onshore wind and other technologies are more expensive than conventional sources of electricity generation.

When we talk about renewables, I think it's important to look not only at the cost of the technologies, which is important, but also at other aspects, like more political economic aspects. And one of the important developments brought by the feed-in tariff system in countries like Germany was lowering the market power of incumbents. The incumbents were against renewables. They've been against renewables for many, many years. And this allowed small investors to invest and to build up this stock of renewables that we have seen. And so this really was good, also, in terms of market liberalization, because it reduces the size of the incumbents. And it's good in terms of redistribution for farmers and other activities who would get money from other kinds of subsidies and don't need to get as much money as in the past, because now they are getting this rent for their windmills, and so on. So there are lots of social and economic aspects that we should take into account, and not only the electricity price.

Speaker 4: I philosophically agree with what you're saying. The only thing is, I think it's missing one part. The big problem is, if you would add, like, $30 per megawatt hour for technologies that have emissions, immediately you are changing the socket parity quite a bit. The reason you do it is because a lot of the stranded costs are not treated economically as sunk costs. And as long as you do that, you're going to send the wrong economic signals, and I think as part of your solution, that also needs to be addressed, because, yes, we have stranded costs. We have uplift costs. But if you don't treat them in a decision making process as sunk costs, or you allow people to say, "I walk away from it and put it on the others," you still have a big problem that your solution does not address.

Speaker 5: I'd like to respond to that one as well. In theory, I agree with you 100%. It would be much, much easier if we could just put a price on carbon and let everybody respond to that and make all of the economically efficient operational and investment decisions based on that price signal. That's the best pure market policy. The problem is that we don't live in a pure market economy. There isn't a pure market economy anywhere in the world, and there certainly isn't one in the United States. And the fact is that if $30 per ton were the right answer, if that were the right number to get us to that level of reductions, this would be easy. We would do it tomorrow. And we'd get there nice and easily by 2050. The problem is, it's not $30 a ton. It's probably $300 a ton. And the transfers that would occur in today's economy if you imposed that kind of a carbon tax are enormous, and politically infeasible, and unsustainable, and impossible to do. So that option is not possible. So that one's off the table, at least for now. Right?

So it's interesting to me that the fallback option that you proposed was, if we can't get the pure market solution right, then what we should do is look at geoengineering. Now, geoengineering, that seems to me to be the ultimate central planned solution. We're not just going to plan our economy. We're going to plan our entire climate with human intervention. Now, that's an interesting prospect, and I agree, we need to look at that. And maybe that is the right answer, ultimately. But I think we're a long way from even understanding that option, much less actually trying to implement it.

So what we're left with is, it has to be the inefficient option to lose half of South Florida to rising sea levels, and to have to build 20 foot of sea walls all up and down the East Coast to deal with the rising sea levels. That can't be the efficient outcome, if you take a step back and look at the big picture. Right? And this is also exacerbated by the fact that we're trying to do this piecemeal with only some jurisdictions, and so there's a kind of a mass equilibrium problem going on here, where we have to convince the other jurisdictions that we're serious about doing this, so that they'll start to take steps as well, and not think that someone's going to be able to be a free rider. So what we're left with is a series of very, very imperfect solutions that we have really no choice but to muddle forward with. And that, to me, is where renewable policy fits in.

Questioner: Can I just respond? I would be perfectly willing to muddle through. And I would be willing to pay $100 a ton of carbon dioxide. I'm especially willing to have somebody else pay it. That would be even better. But my concern is, it won't happen, because we keep telling people it's cheap, and then when they find out it's expensive, they just won't do it. And so we won't muddle through. And then we'll waste all this time not addressing what the fundamental problem is. That's my concern. I'm not opposed to second best solutions. We do it all the time. But I'd like them to work.

Moderator: Well, to me, the issue is one that's political in this country, and so we're going to be mitigating, and people work at adaptation mitigation now, because we haven't moved as a country. And I give Europe and the honorary European state of California a lot of credit for at least trying, because we're not, as a country, and we're taking the world down with us. But anyway, that's just my point of view based on climate science. Great question, though.

Question 4: My question is sort of related to both what Speaker 1 and Speaker 2 were talking about in Germany and Spain, and in general in the EU. There seems to be this overarching reliance on putting blame on the recession. But as I see it, there are really two policies that are almost redundant, and one is a renewable policy that's encouraging renewable deployment with feed-in tariffs that are extremely generous, and the second is the greenhouse gas trading regime under the EU ETS. And so, given that the rationale for both of those are the same, one of those is going to be redundant at some point, because if you have too many renewables, it's going to cause the price of GHG allowances to crash. By the same token, if you don't have enough renewables, that price is going to go up. And so the question is, in implementing both of those policies in both Spain and Germany, was it the intent to have that kind of interaction? Or was this something that's like, oops, we made a mistake?

Speaker 1: I think, as Speaker 2 has already pointed out, it was a historical development. The feed-in tariffs were in place before the carbon trading system came. And I put the emphasis on the effects of the recession, because there were wide plans in the 2006-2007 period about how part of the necessary emission reduction would be performed through increasing the share of renewables, and other parts would be done through the ETS. And so there were some more or less equilibrium paths considered.

But what was not considered was that reality sometimes deviates from equilibrium, and so in the equilibrium path, we would have ended up with 20 to 30 Euros per ton of CO_2. Without the additional renewables subsidies, the CO_2 price would have been higher.

One problem with ETS is that it is extremely nonlinear. Between zero and 30 Euros per ton, you get almost no emission reductions, at least with European coal to gas price relations. And then between 30 and 40, suddenly the whole base load, at least in long term equilibrium, shifts to gas. And this makes steering of an ETS, independently of what your renewable policy is, extremely complicated, and if you then add that kind of nonlinear effects on the renewable subsidy scheme, then you really have a system that could work in an equilibrium path, but which has very little robustness against shocks like we have seen.

So I agree, it would be better to rely on one instrument. For policy reasons, that has not been the case. And one part of the policy reasoning was that the CO_2 price would have become too high if the ETS were the only policy instrument used to deliver the carbon reduction. And again, we have the international perspective. Europe is willing to be a front runner on carbon emissions, but only to a certain extent. If we could agree on a global carbon tax or carbon certificate trading system, I think the case for some separate renewable policy would be very much different.

Speaker 2: Of course, if the objective is to reduce emissions, you are right that it is redundant, but then again comes the issue of political economy. Renewable energy policy is a very good way, as a previous questioner said, to hide part of the cost of carbon policy. So that has a pretty clear explanation. That said, the Commission, when they prepared their new plans for the next stages in the ETS system, already took into account renewable energy policy, and they came out with a rather nice price of 35 Euros per ton. What was the problem? The crisis that basically made everything crash. So of course, there is some political economy issue, and then there is also the issue that Speaker 1 mentioned that renewable policy came before climate policy. And there were many other reasons for countries to push them.

Now, again, should we assume rationality in a policymaker? One element that I didn't include was that in Spain in the last couple of years, we've been mandating the use of domestic coal, which does not help for either purpose, but it is helping some small regions.

So now, coming to the economic crisis, why do I place such a large importance on the economic crisis? Because, as I said, the economic crisis basically made everybody's feet come out of the blanket. And one interesting story is what happened with utilities in Spain. As I said before, utilities in Spain were backing up renewables until the reduction in demand that basically compromised their investments in natural gas combined cycle plants. So everybody was happy when there was enough money for everybody. But if renewables, particularly PV, start to compromise the return of the investments in natural gas, which were otherwise clearly excessive, then everything comes against renewables. So I think the economic crisis has a lot of implications towards this analysis of what has happened with this partly failed, as a previous questioner said, policy experiment.

Questioner: There are two observations I would make, given those responses. The first one is, if we had just a single instrument, let's say greenhouse gas trading, then we wouldn't have this perverse policy outcome where coal is being dispatched ahead of natural gas, because you could have the appropriate price on CO2 emissions that would be factored in to the cost of coal versus gas, and you'd see that gas generation running, rather than coal.

The second thing is, from my perspective, suppose the economic crisis never happened? Suppose it was just all energy efficiency? Wouldn't that be then observationally equivalent? And if we just had one instrument that would drive the energy efficiency, would we be having this problem? Just food for thought.

Question 5: My first question is for Speaker 5. I'd like for you to elaborate on the regional coordination issue that you mentioned. Many of your neighboring states (I can speak for Arizona) have their own renewable portfolio standards. And we're also projecting the same operational impacts that you're seeing, where you'll have hours where renewables need to be curtailed. So how you see that playing out in terms of better coordination, when we're seeing the same issues? And then for the European panelists, have you actually had to curtail renewables in certain hours and turn them down?

Speaker 5: With respect to the regional coordination, renewable integration is a challenge which benefits greatly from two things: scale and diversity. So the larger the system that you have to integrate the renewable resources into, the larger the number of dispatchable resources that you can bring to bear against the problem, and the smaller the sort of "lumpiness" issue gets to be.

And with a system, let's say, Arizona Public Service, where I think they have maybe 20 different shafts that they can dispatch, they would run into a flexibility issue much sooner than a system like California, which has 200 and something different generators, just because of the nature of the system. Also, as you spread the renewables over larger and larger areas, you get geographic diversity. The shape of the combined renewable resource output is drastically smoothed as compared to the shape of any one specific resource, especially when you get into things like the Rockies wind and the Northwest wind, which has very, very different seasonable output shapes than Southwestern solar. So that's how it helps.

The reason why it's a challenge for us to access that flexibility now is because the way that we do business across the West hasn't really changed in the last, let's say, 15 years. We have an LMP based market in California. The rest of the West operates on a bilateral trading system, where the products that are traded are 6:00 a.m. to 10:00 p.m. fixed flat blocks, with a minimum size of 25 megawatts, or something along those lines. And then there's a nighttime product, which is 10:00 p.m. to 6:00 a.m. When previous studies have looked at integrating large quantities of renewables in a place like California, they would make the mistake of using a big West-wide production simulation model that would dispatch all the resources in the West up and down, basically exporting our problem and relying on resources all across the West to help with our integration. It doesn't work that way in reality. We can't just take our intertie from zero up to 13,000 megawatts and down to minus 13,000 megawatts in the next hour. There are real life constraints to our ability to do that. If we were able to coordinate our operations through things like an EIM or other kind of sub-hourly scheduling processes, that would allow us to take better advantage of the latent flexibility that exists all across the Western system.

Speaker 2: About the curtailment, let me explain you a bit. As Speaker 1 said, Spain is an electric island. So we don't have that degree of connectivity. But renewables have priority of dispatch. So that means that you can only curtail them for security reasons. On the one hand, we have a lot of idle natural gas, so it allows us to allow for a lot of renewables into the system without any security concerns. Then you have 20% nuclear, which, in principle, you cannot touch, but a couple of months ago, for the first time ever, they were mandated to reduce by 20%, so that can happen.

And given all that, yes, we have had some curtailment, but only for less than ten hours total, probably. However, that is going to change in the future. First, because it's not efficient not to curtail, because basically you're increasing the startup costs of the others, and you need to pay for that. So in the future, we expect much more curtailment, for economic reasons, and also because we won't have the flexibility to allow all these renewables into the system.

Speaker 1: The short answer for Germany is order of magnitude of 1% of energy curtailed, mostly for local grid congestion reasons.

Speaker 5: Just to add one thing, you'll see stats quoted sometimes that this or that small country (I think I saw one for Denmark) had 122% of their load served by wind in a given hour. Well, obviously that can't happen just if you look at that system alone. That's a small country that sits between two giant neighbors, a hydro system in the north in Norway that can store a lot of that energy, and a big giant neighbor in the south, Germany, that they can export some of that energy, too.

Question 6: One effect of the rapid growth or renewable generation in Germany is that natural gas generation is being viewed as subject to an increasingly marginalized environment. And of course there are potential liability issues connected with that, especially during the winter months. There are a number of generators that have indicated that their gas-fired units are not profitable given the current pricing environment. They include RWE, Aeon and Statkraft. The question is whether or not there are concerns within Germany as to the availability of that generation during key time periods, as in the winter, and if there are any efforts to address the potential liability issues, not only from the standpoint of plant operation, but also given the needed imports of natural gas to run the generation, in that there are supply considerations as well, if that generation is marginalized and important to the grid, but only important during certain time periods during the year.

Speaker 1: The short answer is, yes, there are considerations. One consideration is to go for a full-fledged capacity market, something that has been debated over the last two years without a political decision having been taken. So that would be a nationwide or even European-wide capacity mechanism.

But we have specific problems with reliability and grid operation also related to the rapid shutdown of nuclear plants in 2011, particularly in southern Germany, because most of the nukes are concentrated in the southern part of Germany. And so their generation capacity is missing. And for that issue, an administrative procedure has been designed to secure some reserve capacities, especially for the winter months, and also including reserve capacities from neighboring countries like Austria and Switzerland.

Overall, we have overcapacities in the market, partly due to the expansion of renewables, partly due to the less than expected growth of electricity demand, partly due to the increased interconnection with the neighboring countries. And that all contributes to the lack of revenues for the conventional generators, especially for the gas fired ones which are at the top of the merit order.

Speaker 5: We have that same problem to some extent in California, that there are some gas-fired generators that no longer have any kind of long-term contract with a utility, and are not making enough revenues in the short-term hourly markets to be able to cover all their fixed costs. The obvious solution is that there needs to be some type of fixed payment if we want to keep those generators around. There's a variety of different mechanisms that are being discussed in California, including some type of an organized capacity market. The question I think we have to answer first is, how many of those generators do we need to stay around? And that I don't think we quite know the answer to yet. It depends on how significant the flexibility problem ends up becoming.

***Question** 7*: So I would like to go back path number two from the earlier part of the discussion, that is, the innovation and cost reduction path to reducing carbon emissions. Clearly, the experience in the EU suggests that simply doing scale up, while it has had some success in reducing cost, is an expensive way of learning. And I'm wondering, first, if there are any more detailed lessons from the EU that we might take about how we might accelerate our ability to learn and innovate, in terms of bringing down the cost of lower carbon technologies.

And, secondly, for you, Speaker 4, you sit in the middle of a clearly important global electricity company. There will be, over the next several decades, a tremendous growth, globally, in electricity use in parts of the world that don't have stable systems today. If we compare this to other industries--for example in pharma, it's the big global pharma companies that support the commercialization of a lot of new drugs. What conditions would be necessary for companies like yours to play a role in that innovation space in terms of bringing new technologies to the market?

Speaker 1: My impression is that the success of national research and development programs on renewables and energy efficiency has been mixed. Partly, certainly, that's related to the fact that the prices which you would use to try to optimize or identify a startup cost for your technology developments are very unclear, because carbon prices are unclear. Partly because it's government-steered research, where industry is playing an increasing role, but still, setting the right priorities out of a government seat is not always easy.

Just one example, which I would cite as an example of why pure R&D is certainly not all that we need. We certainly need R&D, but we also need a market-driven scale-up. Almost 20 years ago, the first three megawatt pilot wind turbine was constructed with German research funding. It was a complete failure. It ran about 100 hours. One explanation is that that was too large a step. Now, the standard for new installations in Germany for wind plants is two to three megawatts. But this has been growing over the years. They started with 300 kilowatts, then came one megawatt, then 1.5, and so gradually they increased.

So I think there's no silver bullet for R&D policy. And this is especially true in the field of renewables, especially since you don't have the same situation as for smart phones or for other products, where the innovator can get additional willingness to pay from innovators on the consumer side. You're producing a bulk commodity, electricity, and you don't get, typically, a premium for being innovative.

Speaker 2: So I agree on the conclusion that probably innovation in the electricity sector is quite complicated, but still I think there are interesting stories. And again, as we said before, the story is different for different technologies. So for wind, there has been an interesting improvement in the technology at the European level, which started in Denmark, and also continuing in Germany and in Spain. And it was interesting in the sense that these countries were able to appropriate some of these improvements in the technology. What was the problem there? The problem there was that one element, which is environmental impact, that is, the Not-In-My-Backyard, or whatever, drove the industry to build bigger and bigger turbines, which are by nature more expensive than smaller, nimbler turbines. So we haven't been able to see large decreases in the cost of wind turbine technology, mostly because of the push for bigger turbines.

That said, I think there is another issue that we need to take into account, which I already mentioned. That is, all the political economy and all the rent extraction issues, because one thing you can observe is, if you look at, for example, databases like IRENA or Bloomberg, you see large differences in the price of the same wind turbine sold in different countries, produced exactly in the same place, but sold to China or to the US or to Spain. And you see differences of 25%, which cannot be explained other than by these rent extraction issues and badly designed policies that allow manufacturers to have this market situation. So I think there is some potential there, but you can spoil it in other ways.

The solar PV I think is also interesting. When I started working on this almost 20 years ago, we had a relatively high price. And we had that for 15 years, until Spain, Germany and the Czech Republic started asking for more panels, and then the Chinese realized that they could start the first PV grade silicon factory, which would clearly push prices down, and then they got into mass manufacturing. And that is a clear example of how scaling up actually improved prices, because the technology as such did not change. It was still those same monosilicon panels.

Also an interesting story is how, because of the European money, the Chinese have been producing en masse these photovoltaic panels, but the real technology drivers are in the US, companies like First Solar, who have been getting the technological breakthroughs without any big support.

Speaker 3: Well, I believe in technology. I think that the technologies are already there. We don't need to invest public money on that. And I think it will really change the way we think about electricity markets. I mean, I can see that in this moment, in my home in Lisbon, there is 1.6 kilowatts consumption, and now I've decided to frighten people there by switching on a lamp [presses iphone screen], and this is information. [LAUGHTER] So it's information, stupid.

And in fact, I think that's what is going to change the way we think about this industry, because we still are talking only about generation. It's still a supply-side discussion. But the innovation is on the demand side. And until we accept the fact that with more and better information we can design better markets and better regulation, we are not there.

But in my view, the technology's available. We don't need to reinvent it. And that's one of the problems of electricity—we don't need to reinvent some technologies that already exist, are very cheap, are very reliable.

Speaker 4: To the question of whether companies do research, yes, there is a level of research, and a lot of small types of projects that are being done all over the world, most of this coordinated from Paris.

But there are some interesting elements there. First of all, as I mentioned, stock prices have crashed, and a lot of the market cap has been lost. It's a harder environment to spend money in than an environment in which stock prices go up and profits go up. We're still doing it. We're still trying things.

Then the other thing that is interesting is, we are also investing in quite a bit of renewable energy. Even in the US we have some solar investment that we have participation in, and in Europe we're invested in quite a few companies.

Our traditional model is under pressure from all those things. But investing in the thing that puts you under pressure is not going to make up for it. On the new investment, if everything goes well, you just have a reasonable rate of return, but you're still stuck with a lot of investments that are going to suffer.

The other thing is that renewables, especially with the grids that we have, create some issues with pricing, which we already covered. But then, in a way, it's also a blessing. If you look to other places in the world that are less developed, and actually have more electricity needs for their economic and GDP growth, they don't have a well-developed grid--if you look to Africa and things like that. And especially distributed generation there makes actually more sense, because in the US and in developed countries, you already have a grid that has been amortized for large parts, which they don't have. So it may be a little bit like with the cell phone technology where a lot of the poorer countries never went to land lines. They leapfrogged immediately to cellular. And that may be the same with distributed generation. At this point, you see some of the things like that. I don't think things are completely aligned yet to make it large enough of a scale.

Speaker 5: This isn't an upstream R&D problem anymore. That primary research always helps, but we're at a point now where the largest renewable technologies, wind and solar, are commercialized technologies. There's an enormous amount of competition to make them more durable, to improve the performance, to reduce the manufacturing costs. If that was the goal of some of the policies that were put in place in Germany and Spain (and I think that was at least part of the goal), that, you have to agree, was enormously successful, because we've seen PV prices now dropping from the $7,000 a kilowatt when I first started looking at these things, all the way down to $2,000 a kilowatt now for installed PV prices.

So, yes, there's R&D, but it's the kind of R&D that leads to a finished, manufactured, completed product that's ready to install that is the important kind. And you really only get that through scale and creating a market that's predictable so that if you build a better mousetrap, that you know someone will want to buy it.

Moderator: I just want to add my own two thoughts. I think we need a lot more resources in storage research, because renewables will then be much better.

Question 8: First, towards the earlier observation about learning from experience, I think we're going to see the same thing with Order 745 rules on demand response. I mean, the behind the meter impacts, and lack of flexibility that will come by taking away infra-marginal rents from flexible units, will possibly outweigh... So we'll have our own experience that we can, five years from now, or whatever, talk about.

And a question that really goes to the duck curve--obviously storage is a big help. Speaker 5, you mentioned the footprint change. That's good. But I was wondering how much of this could be addressed by tools already in the bag that aren't being used. For example, in terms of offer pricing. I know right now you're limited at 30, and someone earlier said you'd go to a minus 150.

Comment: You're talking about the bid floor.

Questioner: That's right. So how much of that would be potentially controlled by just offer competition, rather than, presumably, all the wind bunching up at a minus $30 bid?

And the second thing is whether or not and to what extent you have look-ahead, so that two hours in advance or an hour in advance, I know that the incremental offer is creating a light load that should be dropping the LMP, making me have to do something either for expensive ramping or some other form of curtailment two hours from now that should be showing up in the spot price at your inflection point in the bottom of the duck curve. And I think those are doable things that we can go off and do software for. We don't have to have any really complicated solutions, other than a better way of thinking about the cost implications on a reasonably short scale, multiperiod intertemporal basis. And I guess maybe you guys are looking at this. So are you looking at it?

Speaker 5: I guess I would say the research that's going on now is just pointing to the importance of those kinds of mechanisms as a solution to make the markets clear and to ensure that we have reliable operations. Now, what types of mechanisms specifically are the best ones--that I think we'll be exploring a lot more over the next few years, reducing the offer floor certainly being one of the mechanisms explored.

In California, renewables are in a little bit of an interesting situation, in that they aren't all by themselves bidding into the market. They typically are scheduled by the investor-owned utility that they have a long term contract with. So if I'm an IOU, I'll have 20 different renewable contracts, all operating at the same time during that hour. I know that some of those might have to be curtailed. Which ones I pick and how I bid those into the ISO market, those are sort of detailed and interesting questions.

Questioner: But on a fixed for variable swap, the purchaser, the IOU, is going to need minus 500 bucks or minus 1,000 bucks if he's doing that. And so if they see that, those fixed for variable swaps are going to start changing. And then, in another world, through a lot of contract litigation, they may be ready to be changed even now, if you're seeing those kind of price impacts. The question is, are you getting the tools to get to see that? And particularly the short term Intertemporal--two or three hours in advance, knowing that you're moving a unit up (or not moving a unit up, depends on where we are on the duck curve,) and that you're going to then cause a cost incurrence an hour later.

Speaker 1: Perhaps just a remark on the contracts. If you would make the contracts, not on a number of specified years, but on a number of delivered megawatt hours, you would remove quite some incentives for bidding when they get negative prices.

Comment: If I can respond a minute. In terms of this intertemporal question, our market optimization already has a multiple interval look ahead. So when we have a 15 minute unit commitment, and it looks forward up between five and seven intervals, only the immediate interval is binding. And similarly the five minute dispatch looks ahead up to 13 intervals, depending on what time and the hour it occurs. So it's looking at a multiperiod optimization, making the next immediate interval the binding one for dispatch and settlement purposes.

Questioner: And I understand that. I guess I'm inarticulately saying, should we be doing that longer in terms of the types of costs that you're incurring when you see that kind of a curve?

Comment: You mean extending that horizon further?

Questioner: Yes.

Comment: Yes, possibly. I don't think we've looked into that particularly at this point.

Questioner: Because that seems like something that you could do tomorrow. I mean, you may not be able to implement it immediately, but you could look at doing that, and it's not technology bound. It's not politics bound. It's a rule change.

Comment: Yes. I'll just repeat something that Speaker 5 mentioned a moment ago, which is, more demand-side responsive things are important, because California does have an initiative to increase electric vehicles. And if we're getting those low midday prices out to the end users, out to the charging stations, then charging vehicles midday brings up the belly of the duck. So I think that angle of it is also very important for the future.

Comment: I just want to add, for the demand perspective right now, the customer programs give you energy efficiency dollars to put in flexible equipment, and then they give you another payment to get off the system in the middle of the day. And so all of these resources that have incredible flexibility, hundreds of megawatts of demand side resources, are unavailable due to the rate pricing policies right now.

Question 9: Clearly, renewables come in different flavors, with different underlying capital costs and operating profiles. And as Speaker 5 explained, to achieve the carbon reduction goals of 2050, it's going to take a mix of decarbonization in the electricity sector, as well as demand side management and transportation electrification. Currently there does not appear to be a common comparison metric, something that compares different alternatives in terms of, let's say, dollars per ton of GHG reduced. Is there any such metric being considered, either in Europe or in other policy arenas?

Speaker 3: There is the well-known McKinsey curve. I think the metric at first sight is clear. It is the Euros per ton of CO2 reduced, but then quantifying in detail using computer models or desktop research to value that, especially the McKinsey curve…there were quite some simplifying assumptions in it, especially when it comes to quantifying the grid costs of one or the other technology. This is strongly depending on the precise location in the grid. So I think you can derive it with some margin of uncertainty, and then you end up with wind onshore being among the renewables in Germany being the cheapest possibility, and then afterwards it gets much more complicated, and then you have to have a closer look what are your resources.

Speaker 3: I would like to very briefly come back to the ETS and carbon trade, because, indeed, if this works, this is the best mechanism that we have to reveal all the prices. And we agree on that. I just wanted to tell you that in my view, the problem in Europe with the ETS carbon trade is not the concept itself. Even if it may seem non-trivial to connect ETS and incentives for renewables, you can do that.

The design of the ETS itself is not bad. What was a total failure was the way the allowances were given. Instead of having a centralized mechanism, which put everybody on the same ground, the governments were allowed to decide on an individual basis to whom to allocate these allowances. So this potentially created huge distortions, and in some countries it favored the incumbent utilities. In other countries it favored other industrial sectors. And to give you a very concrete example, in Germany, the government at that time was extremely generous and gave to the industry, to the incumbents, lots of allowances that they did not need. So they sold those allowances. They made billions of Euros. With these profits, they did several things. One of the things they did was to start buying renewable projects, and by doing this with deep pockets, they increased the market price for renewables. Instead of allowing the prices for renewables to decrease, they increased, in fact, around 2007. So it's more a matter of bad implementation and bad political decisions with regards to the allocation of allowances, than the mechanism itself, the idea itself.

Question 10: On the California analysis, for the projected price increase of 6-8%, do you recall any of the assumptions, or how that was structured? For instance, was there a certain starting point for natural gas and a projected increase? Or was it just looking at above market costs? Can you explain a little bit more on that?

Speaker 5: We did this about three years ago. And so we used whatever the Henry Hub's forward prices were at that time, projected out with a little bit of growth after that. Then we looked at 2020 and compared all the costs of the renewable scenarios, including the fuel savings and the transmission costs. It was a full sort of utility revenue requirement look for the three IOUs combined. The reference case in that one was what we called an "all gas" case, where, rolling back the clock to 2008, if you didn't build any renewables after that, and only built natural gas combined cycle and single cycle turbines, what would the cost of that system look like? So even that system had some level, maybe 10% renewables in it, that are left over from the old PURPA days that we still had online in California.

Moderator: We have a few minutes. Any panelists want to add anything that just popped into your head in the last hour?

Speaker 5: I just note that in the US, where we have this mix of federal and state jurisdiction, and in California, trying to do things at the state level, recognizing that we're only one state out of 50, and there's a lot of these questions that we don't really have jurisdiction over in California, so in the absence of some sort of a comprehensive national policy, we're left with the things that we can control at the state level. And I think that's why there's been such a big focus and a big bull's eye on the electric sector, because the state jurisdiction over that sector is much more extensive than it is over any of the other sectors. But I know that the California Air Resources Board is right now looking at what the goal should be for GHG reductions in 2030, and what types of programs and policies it would like to put in put in place to get to that 2030 goal. And I know that it will be looking at other sectors that it can control and what the cost of GHG reductions will be in those other sectors as well.