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Rapporteur's Summary*

Session One.
Gone With the Wind: What Will Replace the Right of First Refusal?

FERC in Order 1000 mandated the end of the Right of First Refusal (ROFR) to build transmission that many market incumbents had reserved for themselves. Implementing a new regime to replace ROFR now has to be under way. In ending the old regime, FERC indicated that in ROFR, "there appear to be opportunities for undue discrimination and preferential treatment against non-incumbent transmission developers within existing regional transmission planning processes." Can such a non-discriminatory regime be constructed and how? How will decisions be made as to who will build required facilities? How will barriers such as state siting and condemnation laws, which bestow powers on incumbents not available to other market participations, be dealt with? How does the removal of ROFR affect upgrading existing facilities as an alternative to building new ones? Will compensation for incumbents and non-incumbent transmission owners be identical? If so, how will transmission in retail rate base for incumbents be compared against facilities that derive all revenues from wholesale markets? Will reliability standards be affected by the new entrants, and if so, how? Will the elimination of ROFR lead to competition that reduces prices paid by system users? Is elimination of ROFR a disincentive for utilities to join or remain in RTOs and would this serve to disincent the formation of new RTOs? Should "reliability" lines be treated differently than "economic" facilities for purposes of phasing out ROFR? Will elimination of ROFR facilitate grid expansion? How will the entrance of new actors into the market affect the use of alternatives to building new transmission, such as locational demand reduction or strategic location of new generation?

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

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Moderator: Before I turn to the panelists, I did want to address one of the key questions associated with this first topic, which is, “Gone with the wind. What will replace the Right of First Refusal?” We’ve been thinking about this for a while, trying to figure out how competition for transmission will work from a process and practicality perspective.

So what I’ve got up here on the screen are a couple of bookend possibilities for the way this could go. Obviously, this is far from an exhaustive list, but I think it does help to characterize what we’re facing here. The one on the left here is essentially a FERC rate case model, which is generally consistent with the way public utilities do transmission projects today. You face significant possibilities of changes to the project itself, the cost of the project, the timing of the project, from the initial plans and design. The process by which you deal with those changes, particularly changes to the cost of the project, is essentially a FERC rate case process. So the competition, basically, under such a model, is really the ISO/RTO determining, based on a variety of factors, price being one of them, who’s best to build a particular project.

The other side of the coin here is the binding bid process, where the parallel is really what we do for generation competition, for instance, today. A need is defined. The project is defined. In this case, then, people who are interested in building that project would submit price bids to satisfy the conditions of the project. And the ISO and RTO would essentially examine all these bids and, making sure they all satisfy the basic qualifications, choose the lowest-priced bidder to proceed. And the bidder would be limited to essentially the recovery associated with the bid that they submitted.

So these are a couple of bookends of the way one could envision competition for transmission working, and I’ll be interested to hear from the panel sort of where they might fall in this spectrum, and how they think this might work. There are a series of questions that come out of this that I’m hoping to see addressed to some degree. Does either of these models essentially produce customer benefits beyond what we have in the current model? If there are qualifications that are going to be considered for the bidders, which ones should be considered and how? Can a qualitative evaluation be done in a transparent and non-discriminatory manner? Given the nature of cost risk in building transmission, could a binding bid model ultimately really work? Are there too many risks involved with being bound to a bid, to make it be effective, at least in many parts of the country where building transmission is a big challenge? And what happens in either model if the winning bidder ultimately fails to perform?

So these are some of the issues. The topic itself has raised several others, so I’m very much looking forward to hearing what the panel has to say about this.

Speaker 1.

I thought it would be helpful to give you a little bit of background on how the California ISO’s transmission planning process works today, because we undertook significant reforms to that process in 2009, and I think it was informative to the FERC process as they were developing Order 1000. And I think in many ways some of the challenges we went through in 2009 and early 2010 in redesigning our process helped drive some of the outcomes that came out of Order 1000.

If I had to characterize the two big changes we made to our transmission planning process in 2009, it was really to change from a planning process that, under FERC’s terms, would be more of a bottom up process, where we did our reliability assessments on an annual basis, but we had an open window for people to submit projects--incumbents and non-incumbents--proposed transmission projects for us to evaluate. And we really got overwhelmed and inundated with a wide range of proposed projects, and really didn't have a good framework for assessing whether they made sense or not.

So one of the big drivers for reforming our process back in 2009 was to try to provide a more holistic and comprehensive analytic framework for how we plan the system. The other big driver was the state of California's environmental policy initiatives, and, most importantly, the very ambitious RPS goals. We have a 33% RPS goal by 2020. When that directive came out, there was really a scramble for us from a planning standpoint of, "OK, how are we going to plan the transmission system to accommodate that?" And importantly, we really didn't have criteria for approving transmission to help further policy directives. We had criteria for economic projects, so if a project met a cost benefit criterion--it could reduce congestion, provide benefits to the market--we could approve it through that. But with RPS we are really talking about building transmission to meet a state policy directive, where the goal is really to come up with the most cost effective solution for it.

So a big driver in our reform process was to introduce a new criterion for approving transmission, which was to help meet state policies. And obviously, you've seen that criterion get reflected in Order 1000 as well.

The stakeholder process in developing our new transmission planning process was very contentious around the issue of ROFR (the Right of First Refusal), and I see a few faces in the room that were involved in that, including some sitting next to me. Obviously, the incumbents had a very strong view on this issue, and we had a lot of independents coming into the process that really viewed this as an opportunity to really get a foothold for increased opportunities for independent transmission companies. So there was a very contentious debate through 2009 and early 2010, and I think in the end we landed somewhere that struck a reasonable balance, and, frankly, I think where Order 1000 ultimately ended up was very close to where we ended up through our own planning process.

So to quickly review the fundamentals of our planning process, the ISO produces an annual plan every year. It takes about 15 months to get through the whole planning process. We start with what we call phase one, which is really building the study assumptions, assumptions around load forecasts and generation additions. And, importantly, what are the things we're going to look at when we undertake this planning cycle? What are the policy directives that we're going to study? So that work goes on in the first phase, which is really kind of the fourth quarter of the year.

Phase two is really about doing the work, doing the technical studies, presenting the preliminary results to our stakeholders, getting their input. You know, if we're coming up with transmission solutions for issues, what do they think of those solutions? Are there alternatives to a transmission solution? And at the end of the day, what we're presenting at the end of phase two is a comprehensive transmission plan that's very prescriptive. It identifies all the elements that we think are needed to support reliability, to address economic considerations on the system, to support policy directives. So in Order 1000 jargon, this is a top down approach. And we really made the decision that this is really the only workable approach for us. And the idea is to really engage everyone along the way through the study process, including non-incumbent developers, to get their input on, are we missing something? Is there a better solution to the needs we identified? And if so, what is that? So at the end of the day, we produce a transmission plan that identifies specific upgrades and elements that we need ultimately to meet the objectives of the plan.

And then the third phase under our process is, to the extent we have transmission elements that are open to competition (and I'll get to in a moment how we come up with that) then there's an opportunity for people to submit proposals to build those elements, and we have a process for evaluating whether they meet the eligibility criteria, etc. And then ultimately we have a process for selecting them, if we have more than one project sponsor.

So let me talk about, under this process, what the roles and opportunities are for incumbent developers, versus projects that would be open for anyone to build. And I want to contrast what we do today, which is on the left hand side of this table, versus how we envision that needing to change under Order 1000. Under our current transmission planning process, with respect to the incumbents' rights and obligations to build, they have the right to build reliability upgrades that have no "incidental" economic or policy benefits. And this was a recent development that came out of FERC this year, with respect to our planning process, where they clarified that, yes, non-incumbents should be able to build reliability upgrades if they have incidental economic or policy benefits. And then, of course, it begged the question, what's "incidental?" And we made a filing to propose that if a reliability upgrade had economic benefits of approximately 10% of the cost of the project, that that would be considered incidental. Or if it displaced or somehow modified the need for a policy upgrade, that would be considered an incidental policy benefit. And FERC accepted that criteria.

Importantly, regardless of whether they need the project for reliability, policy or economics, in order to be open to competition, projects really have to be green-field, because in our current transmission planning process, we are very clear that the incumbents have exclusive rights to upgrade their existing assets. And this would be even things like reconductoring transmission lines or modifications to existing substations, etc. They maintain that right. And that was something that FERC upheld in Order 1000 as well.

And then the last area for incumbents is generation interconnection-driven upgrades. That turned out to be a big issue in California, because as we were developing this new transmission planning process, we had a huge wave of renewable projects coming into our generation interconnection queue. And under our generation and interconnection tariff provisions, the right to build those upgrades rest with the incumbent transmission owner. So that's the role of the incumbent under today's planning process.

In terms of what's open for competition, under our current tariff, reliability upgrades with incidental economic policy benefits, economic-driven upgrades--if we have projects that can reduce congestion on the system, and/or provide other economic benefits, they're open for competition. And then policy-driven upgrades.

On the right of the table I'm showing is what we'd be looking at with Order 1000, the key difference there being that in Order 1000, they made a distinction in terms of limiting opportunities for non-incumbents to upgrades that are subject to regional cost allocation. So one of the changes we'll be making is making that distinction that the incumbents will still have exclusive right to build upgrades not subject to regional cost allocation. And under our tariff, we have a high voltage cost allocation, which is 200 KV and above, that gets allocated across our service territory. And we have a low voltage, below 200 KV, that gets allocated to the specific transmission service territories. So we're proposing that that will be the distinction for us in terms of what constitutes regional cost allocation or not.

And then, again, FERC maintained the rule that upgrades to existing assets rest with the incumbent. And the Order didn't address generation interconnection-driven upgrades. So under our current tariff, those still rest with the incumbent.

This next slide highlights the way we approach doing this comprehensive plan, where we first look at the reliability needs. We then look at the policy needs on top of that. And then once we identify all the policy-driven needs, we look at whether further transmission modifications or upgrades could help address congestion. And then we have some other special studies that we do that kind of build on each other to produce a comprehensive plan.

We have been undertaking some reforms to both the transmission planning process and our interconnection process that actually are going to provide even more opportunities for non-incumbent transmission developers. Most notably, we're moving the interconnection process more into the transmission planning process, where we're trying to develop a comprehensive transmission plan to support the 33% RPS goal in the most cost effective, sensible way. And then that plan becomes a rate payer funded plan. And generation in our queue that locates in areas where they can utilize that transmission don't have to pay for it. It's funded directly through rate payers. And as such, the development of that plan will all be policy driven. So whereas before, these upgrades were coming out of our interconnection process, they're now really coming out of our transmission plan, where we can look at it more holistically.

And secondly, for projects in our queue that locate in areas that can't avail themselves of that plan, and that would require other network upgrades to ultimately make them deliverable, under our approach those projects would have to build that transmission themselves. They'd have to fund it, and they'd have to bear the cost. And so, we've taken the view in this proposal that if you're paying for the transmission, you ought to get to decide who builds it. So that's yet another opportunity where the generator developers could choose somebody other than the incumbent to build the network transmission to make them deliverable. And those facilities, again, would not be ratepayer funded.

I've tried to capture the process today under our transmission plan for selecting projects through the competitive process here. Hopefully it's not too complicated. But basically, we develop a comprehensive transmission plan, so this is a top down approach. We identify the elements that are open to competition. And then we have a window, an opportunity for incumbents and non-incumbents to propose projects to build those elements. And again, it's very prescriptive. We need a 500 KV line from substation A to substation B, and your proposal has to be that facility. And then we have initial evaluation of, you know, is their proposal complete? Is it adequate? We have an initial evaluation of whether the sponsor is capable of building it. And then we see where we stand.

So if we only have one proposal to build a particular transmission element--no need to do any sort of selection. They can go on to the bottom lane there, which is to get their siting approval. If we have more than one, then we provide an opportunity for the competing sponsors to collaborate, to see if they can come up with a single joint proposal to present to us. So if they're able to do that, there's no need to select. They can go on to the siting approval. But if they're unable, or uninterested in collaborating, then we have a situation where we have more than one sponsor wanting to build the same transmission facility. Then the question is, are they going through the same siting authority? And if the answer is yes, we don't decide who builds under our tariff. We leave it to the siting authority to make that determination. But if they are going to different siting authorities, then the ISO, under our tariff, needs to select who gets to move forward with the project.

I will not go through all of the ISO selection criteria in the interest of time, but I think they will be pretty familiar to you or at least intuitive in terms of the things you'd look at--Their capabilities to finance, license and construct. Their ability to operate and maintain. We're not just assuming they're going to build it and turn it over to someone else. We're looking for them to be the transmission owner that's going to have to operate and maintain that facility, and comply with all the NERC standards on it. We look at whether they have some advantages for building the projects in terms of existing right of ways or existing substations they own. That would kind of give them a leg up on the project. We look at their experience on right of ways, eminent domain authority. The list goes on.

I'll focus on the last criterion, which is demonstrated cost containment capabilities and tying it back to the moderator's slide, where he had the FERC rate case option versus a bid based, price based option. Our approach is more of the FERC rate case option. At this level, the project is so conceptual--even though we've identified that we need a line from substation A to substation B, there's lots of different routes to get there. The idea that you could submit a credible bid that you could be held to at this stage is very challenging, and I'm sure we'll get into that. So rather than have it be a competitive process around their bid, we want to do kind of a qualitative assessment of what has been their experience in the past in containing costs on projects they've built. And we did propose, nonetheless, if they were willing to accept the cost cap, where they wouldn't seek rate based funding beyond a certain dollar amount--we couldn't mandate that--but if they're willing to entertain that, that is something we'd consider.

The last slide I have is what I would call a backstop issue. And this is the obligation of incumbents to construct transmission elements under our tariff. So we do have a provision in our tariff, if we identify a need, and no one comes forward to propose to build it, under our tariff, we have the option of directing the incumbent utility to build it. Or alternatively, if we have a non-incumbent selected for the project, and later through the process, they either pull out of the project or for whatever reason, are unable to build it, we have the option of directing the incumbent to build it. This was a big issue of concern for the incumbents, which I'm sure we'll hear more about. But we do have the option, if we get in that situation, of opening a new solicitation process. And which one we would do would depend in the particulars of the situation and the urgency of needing the particular transmission facility.

Question: I had a quick question about your discussion of how, if generation interconnection is not part of a broader transmission plan, it had to be self-funded. Did that include the potential for the generator to actually own and operate and develop its own transmission? In other words, it could select itself to do that?

Speaker 1: Certainly if they were qualified to build the facility, we would allow for that.

The idea would be that if you had a project that didn't fit within the rate based plan, through our interconnection studies, we'd identify what the deliverability upgrades are that are needed to make it deliverable. And at that point if you had the wherewithal to build those facilities yourself, since you're paying for them, under this proposal, we would allow for that. Or alternatively, you could select someone else to build it.

Question: You indicated in one of your slides that policy driven, and I assume reliability driven, upgrades were ratepayer funded. I assume also that economically driven upgrades to relieve congestion, those would also be ratepayer funded in the model you're moving to?

Speaker 1: Yes.

Question: Does this apply just to California and your region? Or does it apply nationwide based on FERC Order 1000?

Speaker 1: This just applies to the California ISO.

Speaker 2.
Good morning. ITC, I think, is unique in this space in the sense that we're not a pure transmission developer. We are an owner and operator of transmission systems. And I think this provides a good context for what I'm about to say.

ITC was formed in 2003 when Detroit Edison sold their transmission assets and formed ITC as an independent transmission company. Over the subsequent years, we have acquired other transmission systems, notably the Michigan Electric Transmission Company. And then in 2006, we created ITC rate plans to develop transmission in the mid, south central portion of the United States. And then subsequently we acquired the transmission assets of Interstate Power and Light from Alliant. So we obviously have an interest in building transmission, owning, operating and maintaining transmission within our existing transmission territories.

At the same time, we've stepped out of that space to also develop transmission in areas where a need for transmission has been identified through a regional planning entity. Just by way of background, we are the largest independent transmission company in the United States. We own about 15,000 miles of transmission across seven states. We serve approximately 26,000 megawatts of load. About 450 direct employees and about 950 contract employees support our operations across those states. We own and operate these systems with the intent to obviously operate them at a high level of reliability. The systems that we've acquired and invested in over the course of the last few years have moved from systems that operated in the lower quartiles to upper decile performing companies. And our intent, obviously, is to operate those reliably for our customers, do it in a safe and efficient manner, and obviously also support the interconnection of new generation and support wholesale and retail competitive markets.

Over the course of the last few years, as the public policy debate has moved forward, we have obviously taken part in that debate with an interest in supporting state and federal policies around renewables.

Through the trade press in December, we announced an intent to acquire Entergy's transmission assets across their four state region. It's a very similar system in that it also is about 15,000 miles of transmission and it services a similar amount of load across that region. They have announced their intent to join the Midwest ISO. Obviously we today are the largest transmission-owning entity within the Midwest ISO, so it was a logical fit as Entergy moved forward with the transaction.

Having said all that, when you talk about the Right of First Refusal, I am a bit conflicted in how I view FERC's intent with regard to eliminating the Right of First Refusal. I think we all understand their intent was to incentivize transmission being developed across the United States. However, owning and operating these systems, there was really a question in our minds as to whether or not this was the appropriate policy going forward. So I think over the course of the past year, we've had conflicting thoughts in our head about what the proper way to go on this was. And at the end of the day, we ended up in a place where I think the elimination of the Right of First Refusal may incrementally help achieve FERC's objectives. But I don't think necessarily it's going to be the silver bullet that they were looking for in moving forward with getting new transmission actually developed.

I don't think there is much dispute today around the fact that the nation's transmission system needs to be upgraded and modernized. With regard to the systems that we've acquired over the course of the last nine years, every system that we've acquired has been in a state of needing significant upgrades and maintenance to just get it operating at what I would call the industry standard--not even operating at a top decile level. I think there's obviously been a lot of focus on the generation aspects of the market, and obviously, in terms of where you're going to deploy your capital with a lot of vertical integrated utilities, generation seems to be where the focus has been and likely should be. However, as we've acquired these systems, we've obviously noted opportunities to upgrade them and make them operate much more efficiently and effectively. We also believe that public policy should be aimed at improving the grids for competitive wholesale markets. To the extent that we can operate at a high degree of reliability while facilitating the economics associated with competitive markets, we feel that's an important role for a transmission owner. Depending on your perspective, we also believe that without significant regional transmission, renewable energy will be limited as far as where that goes onto the system.

From a barrier perspective regarding what's really holding us back, I think you'll find a consistent message from ITC that the lack of a collective industry vision or a national energy policy on transmission is really probably the primary reason why you haven't seen more transmission being developed. It's hard to know what paths you should be on when you don't know what the objective or the goal actually is. So we've seen over the course of the past few years on transmission an incremental process. Yes, the RTOs have moved forward with their transmission plans, and they've addressed cost allocation. Obviously that's still subject to what the courts ultimately say on those decisions. But I think you're seeing an incremental process in that you're going to see some regional transmission being built that reflects nowhere near the regional planning, both within the RTOs and inter-RTOs and across the country, that I think we'd like to see. I think there is a bit of parochialism caused by vertically integrated utilities and state regulation. (Which is not to criticize state siting, because we truly believe that siting should reside with the states and not be pre-empted by FERC.) There are significant differences between various state jurisdictions. And as we've built projects that traverse from one state to the other, the siting processes can be very, very different and very, very arduous, depending on which particular state you're in, and the perceived benefits of a transmission line that's being developed for the constituents of that respective state. So I think a higher degree of coordination between the states is needed, but at this particular point in time, we don't necessarily see that issue being resolved.

There's obviously always the tension between generation owners and transmission developers with regard to the overall efficiency of the grid. I had a conversation two weeks ago with a generation developer who was making a very strong argument that, "Why would you build a $1 billion transmission line, when I can drop a natural gas unit in for $400 million and solve the problem?" And I think when you're talking about $2.00 gas, I think that is a solution. When you're talking eight, ten, 13 dollar gas, it's a different discussion. So I think, again, at any given particular point in time, there are solutions that can resolve problems on the grid. But I think longer term, we need to have a vision of where we're going, and obviously we need to be looking at where prices are going to be for gas and other aspects of the industry moving forward.

There's obviously the continued discussion around reliability projects and economic projects and public policy projects. I think it's important to be careful when you categorize these and put projects in the different buckets, because you know, I often look out my window and ask people who have this discussion with me--I point at the transmission line that goes outside my window and say, "Can you tell me whether that's a reliability transmission line? Or is that an economic transmission line? Or is that a public policy transmission line?" And it has aspects of all three. And when we start arbitrarily deciding whether something is economic today, which may be reliability tomorrow, I think that could send us down a path that we don't necessarily want to go down.

You know, I always throw in there that transmission financing isn't a barrier to competition. I think we've been able to prove, whether it's the LS Powers of the world, or whether it's the ITCs of the world, or vertically integrated utilities, that you can get transmission built under various regulatory models It's just a matter of which model you utilize and then being able to assume the people that are investing in that transmission line, be it either on the debt side or the equity side, that there's some assurance that they're going to see their returns at the end of the day.

So what's not on the list of transmission development barriers? In every conversation that I've had with policy makers, be it at the state level or the federal level, I don't think we've ever identified the Right of First Refusal as being a barrier to developing transmission. We've been consistent in talking about the need for independent planning for the transmission system. We've been consistent in our discussions around addressing cost allocation issues within the RTOs and across various regions. But the Right of First Refusal has never really been an issue for us. Our model at ITC at least has been one whereby we have a tendency to partner with existing transmission owners in the event that transmission is needed and they're not in a position to actually develop that transmission. Our model has been to work with those transmission owners or those entities that have the right to build transmission and partner with them. And that's the model that we utilize in the Southwest Power Pool very effectively. We currently have three projects in the Southwest Power Pool that we're developing in partnership with existing entities.

You know, when it comes to Right of First Refusal, I think Speaker 1 did a good job of pointing out the various aspects of what will be subject to the elimination of the Right of First Refusal and what won't.

Was this really a solution search of a problem? Because I think there are entities within the industry space that have argued that the elimination of the Right of First Refusal will facilitate new transmission actually being developed. And at least from where we sit, we haven't actually seen that really being the major barrier to moving forward with transmission.

So to get into some of the questions that are on the agenda, can a non-discriminatory regime be constructed and how? And I'm taken by Speaker 1's comments about the California ISO. There are times in this industry where, when people talk about what California's doing (and typically California's not something that we cite as a good example of how you should do things) I think California and the FERC decision that preceded Order 1000 have given us a good indication of where this could go and how this could ultimately work. So I think, yes, FERC made the decision to eliminate the Right of First Refusal. And we aren't the company that's going to be out there opposing that.

I think the question for us today is, now that the Right of First Refusal has actually been eliminated, what's the best system that we can put in place to achieve the objectives of FERC? So can a non-discriminatory regime be constructed and how? And I think looking at what other ITOs have done is helpful. Obviously, California has moved down this path. Prior to Order 1000, the Southwest Power Pool put a process in place to address transmission that needed to be constructed in situations where the transmission owning entity that was responsible for ultimately developing that transmission wasn't in the position to do it. So the Southwest Power Pool put a time constraint on the decision whether or not a transmission owning entity was actually going to build it. And I think that is one step away from the ROFR. Obviously it still gives preference to incumbent transmission owners, and SPP will ultimately have to resolve how they're going to comply with the FERC directives on this.

Regardless of what we ultimately do, a stakeholder-driven process within an RTO probably is the best way to go, one that actually does planning for the particular region in question. I think the worst scenario that we could come up with would be to have a number of entities, all with their own transmission projects going out there, sponsoring their individual projects, saying, "This project should be built," because you're going to end up in situations where companies propose transmission projects (not unlike something called the Green Power Express) and those are going to be competing with other projects. So I think it does need to be a top down process from the RTO--a stakeholder-driven process. It needs to be independent in that the RTO ultimately needs to be in the position of determining which projects need to be built and when those projects need to be built. And then ultimately there needs to be a process in place to make a determination as to who actually gets to build those projects. Because I think if you have the competition on the front end as to what ultimately is going to get built, I think that's where we're really going to run into some problems.

I'm getting my notes here. I need to go faster. How will barriers such as state siting or condemnation laws be dealt with? We're already seeing this in certain jurisdictions in that we've essentially eliminated a federal Right of First Refusal, and we're starting to see an increase in interest in putting state Right of First Refusals in place. We saw it in South Dakota and North Dakota last year, which have now conferred incumbent rights to the existing utilities on the development of transmission. There is legislation in Minnesota, Maryland, and other jurisdictions where, even though we don't have a federal Right of First Refusal, we're going to have a state Right of First Refusal. So did we actually solve a problem? Or did we just create a new set of problems that we're going to have to address going forward?

How does the removal of the Right of First Refusal affect existing upgrades? I liked Speaker 1's list of criteria for looking at who would actually get to build the transmission. I think we have a lot of questions to this day about, "Well, isn't the RTO ultimately going to make this decision that's going to be purely based upon the ultimate cost? Is it going to be the upfront cost associated with that transmission facility? Is it going to be the longer term cost? And how ultimately do you hold to the fact that it's a long-lived asset, and it's going to require not only the upfront construction costs, but also the costs associated with maintaining and operating that line long term?"

Going back to my list of barriers to transmission, the lack of a collective industry vision is a key problem. It's challenging to get there if we don't know where we're going. So to give my final statement on having a national energy policy, it would be good to know where we're ultimately going before we make a determination of what our policy should be. With respect to the problem of parochialism, the elimination of the federal ROFR would just create new states' rights that we're going to address across the country now.

Another barrier is the tension between the particular interests of generator owners and of the grid as a whole--what's good generally may not be good for the individual entity. So we're obviously going to see continued pushback on that.

Transmission financing is not a barrier to building transmission. But could it be? You know, any time you introduce uncertainty into the process, whether it's with a vertically integrated utility or an independent transmission company or a merchant company, it obviously creates questions that we've already been asked a number of times by the analysts that cover ITC—"What does all this mean? Does this call into question your ability to service the debt and such that you're actually being asked to support for these projects?"

But finally, you know, new paradigms will necessarily result in consequences, good or bad, intended or unintended. And I think the jury's still out, ultimately, as to what the elimination of the federal ROFR means long term. Hopefully, I think, it's a step in the right direction, but I don't necessarily think it's going to get us to where FERC ultimately wants us to be with regard to developing transmission. Thanks.

Speaker 3.
Good morning. First, let me provide a little bit of context for my remarks today. The PSEG companies are comprised of three subsidiaries. First, we have PSE&G, which I've provided a little bit of background on. PSE&G is a traditional state regulated utility. It provides electric and gas distribution service in the state of New Jersey, and transmission service. We were one of the founding transmission-owning members of PJM. We are currently implementing a very significant transmission investment plan. These projects come from PJM's Regional Transmission Expansion Planning (RTEP) process, but we also have quite a bit of more local projects that we are in the process of building.

And then also, PSEG has a generation company, PSEG Power, that has about 13,000 megawatts of merchant generation. And most of that is located in New Jersey. But we have other assets in the Northeast. And we also have a subsidiary, PSEG Holdings, which has a variety of investments. I'll mention two of those categories. PSEG Holdings has investments in merchant solar. We have merchant solar generation in New Jersey, in Ohio, Florida, and most recently Arizona. And we just recently won a ten year management contract through an RFP for the Long Island Power Authority company in New York.

I describe this because I think it's really important to understand that PSEG, as a group of companies, has for a long time been, and continues to be, a strong supporter of competitive markets. We supported FERC's efforts to open up access to the transmission grids. We supported federal initiatives to create competitive wholesale generation markets. We supported New Jersey back in 1999 when New Jersey decided to separate out regulated transmission and move it out of the regulated utility and create open access through the New Jersey retail market and provide options for New Jersey customers. But despite our strong support of competitive markets, we don't subscribe to the philosophy that everything is better if you bid it, because that's just not the case. There are some things that rule just doesn't apply to.

I was trying to think last night of what might be a good example for this concept, other than the Right of First Refusal. And I thought about PJM. PJM is a public utility. It provides regulated FERC jurisdictional services, and it has FERC jurisdictional tariffs. There's probably somebody out there who could say, that they're being discriminated against, because they don't get to provide the same services that PJM does. I know in some other countries, those types of services are bid out. But that's not the case in our current system. Neither do we bid out the totality of services that an ISO offers, nor do we bid out new services. There's really an innate Right of First Refusal that the ISOs and the RTOs have. And PSEG supports that. We believe that, just like with the Right of First Refusal, PJM is doing a really good job, and there's no reason to change what's working.

So where do we stand with the federal Right of First Refusal and its implementation? Well, I'm not going to provide too much discussion on this, but you all know that last year FERC changed its longstanding policy and directed that the federal Right of First Refusal be removed from FERC jurisdictional tariffs and agreements for certain types of projects. That decision is pending rehearing. There were numerous rehearings filed. FERC has not acted on those rehearings. And certainly when they do act, there will be appeals. No matter how they act, somebody will challenge this decision, because it's really a significant policy change.

FERC did not find that the federal Right of First Refusal should be eliminated in all cases. Rather, as you've heard today, it imposed a complex framework with conditions and exceptions to be followed by the transmission planners to implement on a regional basis with some flexibility. You heard how the California ISO is going about implementing these new rules. PJM is also in the process of going through the very difficult questions about how to practically implement these new rules.

FERC provided for some very specific exceptions to the rules. Local projects--and every region will have a different definition of what a local project is. Upgrades to existing projects--most transmission I think actually falls into this category. If you look back to the transmission list of projects that PSE&G is building, they're all upgrades to existing projects. And then third, I would categorize as an exception any currently planned project. There are projects that were put into the RTEP with construction responsibility identified for the incumbent before FERC issued its Order 1000 and before the tariffs are changing. Our read of the FERC order is that for those projects, the designation of construction responsibility for those projects doesn't change.

Additionally, FERC was clear that it was not ordering the removal from FERC jurisdictional tariffs or agreements other ROFRs, including state ROFRs or other federal government rights of first refusal. Nor was it proposing to alter the status quo of access or use of rights of way. Rights of way are a very important aspect of building and permitting existing or new transmission. In many regions of the country, the notion of greenfield transmission is a real challenge. In some parts of the country, that may not be the case. But in congested places, where there's just not a lot of greenfield places to build transmission, this will become a very practical challenge.

So with these complex parameters and exceptions, FERC directed the transmission planners to go forth and make these changes, to develop criteria, and also to develop a backstop mechanism, just in case this doesn't work, just in case we have a non-incumbent come forward and be designated with construction responsibility, and then either abandon that project, or the project is delayed, the RTOs and the regional planners are supposed to come up with a mechanism on how to jump in and address that. Well, unfortunately, it may just be too late in those situations. I think that's going to be a very complex process to address in advance and make sure that we can maintain the reliability of the system.

Despite the lengthy explanation in the Order 1000 as to why FERC was doing this, and why FERC has the authority to do this, and why it's going to be a very positive policy change, I was really struck with, and I'm still struck with the question, what was the Commission trying to accomplish? I look back to when the wholesale generation market became competitive, and it was very clear at the time what the rationale and the anticipated benefits were going to be. Risks were going to shift away from customers. Merchant developers were going to take on those risks. And developers were going to be able to be more efficient and operate the plants more effectively than the incumbent utility companies. Some would debate whether those benefits have been realized, and that's being debated in many states today. But it's still very clear that there was an objective that everyone understood, and there was a clear and anticipated benefit that was expected from this major shift. The same was true for merchant transmission. FERC's policies on merchant transmission have really brought forward a lot of innovation. And it was clear what FERC was trying to do there. Same for retail electric and gas restructuring. The intent was clear, and the potential benefits for customers were clear. Even for open access to transmission, there were real examples of discrimination that FERC was trying to address. Here it's just not that clear. It's not evident, at least to me, how the elimination of the ROFR will reduce costs for customers. Non-incumbents (at least the ones that I've spoken to, maybe Speaker 4 will change this) have not, in my conversations, proposed to take on merchant risk, to take the risk of permitting delays and cost increases away from customers. Rather, they're looking for a rate-based rate treatment, the certainty that exists right now in the current environment. Further, it is hard to imagine how a non-incumbent transmission developer could develop the same project at a cheaper price. For the most part, developers of transmission use local contractors, experienced transmission developers. There are only so many of these firms out there. It's not as though there is an abundance of people who are out there capable of building transmission. Perhaps that will change. But right now, if you're going to put out for bid building from point A to point B, it's likely that your potential developers are going to be using the same group of contractors to construct that project. So how this is going to result in a lower cost for customers is just not evident to me.

Perhaps it was the prospect of increased innovation. Certainly competition brings innovation. We see that every day. Right here we have an Apple iPad. Certainly I never anticipated that such amazing technology could exist. And clearly, this type of technology and this type of innovation wouldn't exist today if it wasn't for competition. But will that translate to transmission planning? It's not really obvious to me that it will. And we already have a vibrant competitive marketplace out there internationally on developing the equipment that will be used to build transmission. There are many, many companies out there who are constantly looking at new ways to develop transmission equipment that can be used underground, that is more efficient, that can move more power. And FERC has, through its incentive rate policy, encouraged the use of these innovative technologies and their incorporation into the transmission construction process.

Perhaps FERC believes that eliminating the ROFR was necessary because not enough transmission is being planned. And that can be debated. Certainly I understand that companies like ITC and others are saying that not enough transmission is being planned. I included in the appendix a chart from Edison Electric Institute that shows how much transmission is being constructed and planned across the country. And there's a lot. I mean, at some point, you have to question whether that is the reason for the ROFR. Is there just not enough transmission being planned? Or are there other reasons why planned transmission is actually not being constructed? Is it siting? It is cost allocation? In the Northeast, in PJM, we've actually seen some major transmission projects that were planned, with sponsors, funding, moving ahead with permitting, being suspended, because the load forecasts had declined, and the need for those projects doesn't exist anymore. Further, the EIPC (Easter Interconnection Planning Collaborative) effort is really an interesting development for our industry and the transmission planning process. The EIPC process is a collaborative process with many, many different companies, environmental groups, developers, and customers involved in looking at transmission planning.

Certainly there is a lot of attention in the area of transmission planning. And I haven't even had an opportunity to touch on merchant transmission. Something I just want to close with is that in PJM (and this may exist in other parts of the country as well) we have something called qualifying transmission upgrades. We are actually addressing right now a developer in our service territory who has put an idea into the queue to upgrade one of our existing transmission lines, and to take the incremental import capability from that upgrade and bid it into our forward capacity market in PJM. Ultimately if this project is selected in the RPM forward capacity market, PSE&G would build it, just like we build a generator interconnection project, at cost, no markup. But the developer who came up with the idea would get paid through the forward capacity market.

So in closing, my view is that elimination of the ROFR is really a solution in search of a problem, and it's not going to be, in my opinion, the fix for the challenges that FERC has laid out.

Speaker 4.
LS Power is a major player in the independent power industry, both on the generation side, as well as on the transmission side. We got our roots on the generation side. We currently own and have about 7,000 megawatts generation across the country. We've developed about 20,000 megawatts of generation across the country. Increasingly in the last five years, we have moved into the transmission space. And we currently have about 500 miles of transmission that's under construction today in the state of Nevada, as well as in Texas. We are active across the country in this issue of removing the Right of First Refusal, and we do see that there are significant issues ahead. But we are a major player in this issues, and also a major player in the independent power industry. The next map is just a little map of our national footprint.

With respect to the question at hand and our perspective on the removal of the Right of First Refusal, basically, our view is that the removal of the Right of First Refusal is a very serious issue, and that the ROFR is a very serious barrier to entry for anyone who is attempting to develop in the independent transmission industry. We believe that at its core the existence of the ROFR in various tariffs and agreements is unjust and unreasonable. And that is what has compelled FERC to act, because the existence of that ROFR leads to unjust and unreasonable rates. And at the end of the day, that is what FERC is charged to address. We also believe that this debate about the ROFR is fundamentally not an issue of independents versus incumbents. At the end of the day, it's about who has access to regulated rates of return, and that at the end of the day, that's really what the ROFR fight is about, and about whether or not new entrants would be able to earn a regulated cost-based rate of return. And it's not necessarily about whether or not there should be merchant transmission or regulated transmission. It's about whether or not a new entrant can get cost-based rates.

LS Power has been involved in this issue for some time all over the country, particularly in PJM. Basically, the history is that we filed a complaint at FERC in June of 2010 by an entity by the name of Central Transmission. The complaint was strictly limited to PJM, and FERC ruled on a four-zero basis that independents essentially could receive cost based rates in PJM for both reliability and economic projects. And FERC did not recognize that there is a ROFR in the PJM tariff.

The day after the Central Transmission order came out, FERC basically issued an order nationally proposing that the Right of First Refusal be removed from tariffs across the country. And then, as we've heard from the various other presentations, in July of this last year, FERC issued its final order removing the ROFR. So essentially right now across the country, regions are having to comply and are going through the compliance process for the removal of the ROFR. There has been widespread support for this from many states, as well as from the Federal Trade.

So what's really going on in the practical issues of what needs to be changed? First of all, the ROFR has to be removed from tariffs from projects that will receive regional cost allocation. As has been discussed earlier, tariffs or revisions are required to establish appropriate qualification criteria for new entrants, and that's being discussed in regions across the country. What's also being discussed in regions across the country is that independents and new entrants also have to have comparable opportunities to receive regulated rates of return for their transmission projects when they're included in the regional plan.

So FERC ordered, basically, that qualification criteria should be established for new entrants, that new entrants should be able to get cost based rates, and that the ROFR should be removed. In addition, FERC ordered that a transparent and non-unduly discriminatory process has to be set up in evaluating proposals. And then also the FERC ordered that tariffs have to be changed so that folks know what to propose and what information to submit when they propose projects. In addition, FERC ordered that the various regions across the country have to outline the timing process in when a transmission project needs to be re-evaluated or reassigned.

A few notes on our observations and thoughts about FERC Order 1000. Basically, how we see it is that FERC essentially linked the issues of regional cost allocation and the ROFR. And basically FERC said that if you want regional cost allocation for your new transmission project, then the ROFR must go, and FERC made a very strong legal nexus between regional cost allocation and the ROFR in their order. And FERC said that, unless a project is local, meaning it's paid 100% by one transmission zone, or it's an existing upgrade, then the ROFR has to go. And FERC did not differentiate between reliability, economic and public policy projects. And FERC basically said in this new order that it's all about cost allocation. And if the region pays, then there's no ROFR. If the region doesn't pay, and it's a local project, you can keep the ROFR.

And FERC has ordered that qualification criteria for new entrants also should be established in regions across the country. And that's ongoing. And FERC said that the new qualification criteria can't be unduly discriminatory. They can't be unreasonably stringent. They have to apply to existing utilities and new entrants. And they have to be fair qualification criteria.

So regions across the country are grappling with this issue. From an LS Power standpoint, our view is that these new qualification criteria clearly should be focused on financial and technical qualifications. We also think that in the case of new entrants, if they're not an existing public utility in that particular state, they should be willing to apply for that public utility status in that state. We think the new entrants should be willing to apply for eminent domain authority as part of their CPCN (certificate of public convenience and necessity) application. And we also think that the new entrants should clearly have to comply with existing NERC regulations.

So FERC has said that regions across the country and RTOs across the country have to come up with a new process for evaluating projects. And it can't be biased toward incumbents or non-incumbents, and there has to be an open evaluation process. So then the question is, what does this world look like? Well, the way we see it, you can kind of describe this new transmission planning world in terms of two or three camps. One camp would be a camp of competitive bidding, similar to what happened in Texas. Texas determined what the transmission need was, and then put the projects out for bid, and essentially had a quasi-competitive bidding process. And then the other option is a sponsorship model. And PJM seems to be going down that path in terms of from their standpoint. And that essentially is a model where, if you propose a project, and you are qualified, and it's a good idea, and it gets through the PJM or the regional planning process, then at that point, the project sponsor is assigned that project. But the third possibility is a hybrid sponsorship competitive process. FERC Order 1000 not only said that if a new entrant comes up with a new idea, they should be able to have their project, if it's included in the regional plan. But at the same time, FERC also said in paragraph 336 of FERC Order 1000, that if the RTO or the region comes up with the plan, that there has to be a process where both the new entrant and the incumbent have equal access to those projects. It isn't just an issue of cases where the new entrant comes up with the idea. The regions also have to figure out, if the RTO comes up with the project, how that project is going to be addressed. And LS Power believes that in that scenario, if the region or the RTO comes up with the idea, those projects should be competitively bid, because that's probably the only way to really sort through who should get that project.

So essentially, we support a hybrid sponsorship/competition approach. How this model would work is that the FERC Order 1000 compliance filings are, say, due on October, which is when they're all due across the country. And the various regions would go through a qualification process and come up with qualification criteria that can't be unduly discriminatory. And under FERC Order 1000, this applies both to incumbents and non-incumbents. So essentially we propose that there would be a prequalification process starting as early as this fall. And once folks are qualified, qualified proposers would submit their ideas into the process for transmission projects. The RTO would perform their technical analysis on proposals. And then after that independent cost review and assessment, then the RTOs would assess and decide what the right solution for the system is. And at that point in the process, they would look at the winning project, and if the RTO came up with it, it would be competitively bid if there were two of more folks interested in it. But we would also say that if someone proposed the idea, and they were qualified, and they meet the various rules and exceptions in FERC Order 1000, meaning that it was truly a regional project, and it wasn't an existing upgrade to a transmission system, that we would say at that point, then, the proposer would essentially win the project, and that project would be included in the regional plan for a regional cost allocation.

Just in summary and closing, I know that there's been a lot of information that's been presented here, and a lot of diverging views on this very controversial issue of the removal of the Right of First Refusal. But we believe that at the end of the day, the reason that FERC did this is that they said, "We can't have just and reasonable rates if we have a ROFR in our tariff."

We believe that part of the value that new entrants bring to the table in this discussion is also thought leadership on ROE reform. And for instance, in incentive rate cases that we filed for our PJM projects, except for abandonment recovery, 30 year depreciation, and the 50 point basis point adders for joining the RTO, all other incentives we waived. We believe that new entrants can play a valuable role ahead in this discussion that FERC is having on ROE reform, and that competitive pressures are a good thing for consumers.

We also would point that in Texas, which has had a quasi-competitive process in their CREZ (competitive renewable energy zone) process, the costs of new entrant projects are coming in 20% under the cost estimates. And again, we believe part of that is because in the culture in the independent power side of the industry, on the generation side it has always been about cost and putting together competitive projects, because that's what the merchant model lives or dies on. And what we see is that some of that mindset on the cost side that was on the independent generation side, we see some of those benefits coming in the transmission side in

Texas. And we think that's why those cost estimates are coming in lower as well. And we would just say that as we look at this controversial order, FERC Order 1000, we do believe that it is on solid legal ground, simply because FERC linked the issue of regional cost allocation to the removal of the Right of First Refusal and how they frame the order. Thank you.

Question: Is there any state now where non-incumbents must file as a public utility if they're doing the transmission?

You had said that you think they should have to file as a public utility if they're going in to do transmission lines. Are there states now where they have to file as a public utility?

Speaker 4: They should. I think the issue that's in debate on the qualification criteria is at what point does a new entrant need to apply to become a public utility in a state?

Comment: The answer is, yes. Indiana would be the example that comes to my mind right away, where Pioneer right now is applying for that status, so they can build their line.

Comments: It does vary from state to state…. because in Iowa, we own assets there, but we're not a public utility.

General Discussion.

Question 1**:** I would like to just follow up on the question that was raised earlier about merchant projects. Since 2006, with the passage of Order 679, FERC has approved billions of dollars of transmission projects, and that has raised the transmission cost in retail bills. I think New England probably is one of the extreme cases. In 2006, the transmission cost was less than 6% of the retail bill, and today it is 14%. In two years it's projected to be 21%. So, politically, the visibility of the cost on the regulatory side of the bill is causing some more anxiety.

Now, this may seem to suggest that for various new transmission needs, merchant projects may see an opportunity. Now, this change to the right of first refusal creates another type of entrant. How would that affect the merchant projects in terms of meeting all these policy related goals? I don't see why a merchant project cannot be one of the options. And here there is a question about priorities--whether this affects the priority of a merchant project, whether this affects it from a regulatory and a policy perspective. That's my question.

Speaker 4: I would just say in terms of our merchant projects, LS Power has two large transmission projects under construction today. Our one that's 250 miles, 500 KV in Nevada, is a merchant project, and our partner is NV Energy. In Texas it's a regulated model. We pursue both models, and we look at each region and each market with both in mind. But our general view is that the market should be open for new entrants in the regulated sphere, but that doesn't necessarily mean there can't be merchant projects. But the reality is that the merchant projects are exceedingly difficult to get across the finish line, and it's very rare that those projects come together commercially. And the projects that typically can get across the finish line are those regulated projects.

Speaker 3: PSEG's view is that regulated transmission really is a backstop, and it should be what comes in after demand response, energy efficiency, merchant generation, and merchant transmission. Certainly, merchant transmission is a better option for customers, if someone else is taking the risk. But there are certain circumstances where merchant transmission just doesn't fit, because of the network nature of our system, and we understand that a merchant transmission developer usually has a big free rider problem if they just build an element of a network system. And that's where I think this qualifying transmission upgrade idea that exists in PJM (and I've never encountered it before until I had someone just recently propose a project) is really another interesting merchant model, where someone comes along and is a merchant and proposes a network transmission upgrade. They don't build it themselves. They don't own it. But they get it for cost, no markup, no ROE at all added to the cost of the project. But they get the value. So there's kind of an ideal situation for the customer--if someone really can put their money forward and bring value, and they get paid for it, but we're not compromising reliability. We don't have free rider problems. So I see the regulated and the merchant projects as addressing different problems, but the regulated should always just be the backstop.

Question 2: I just wanted to clarify something with respect to the Texas process. We did make a decision when I first came, I think it was in 2009, to allow companies other than the TDUs (transmission and distribution utilities) to bid on our CREZ process. I wouldn't really characterize it as a quasi-competitive bidding process, because the way it worked is, we had the CREZ lines, which everyone's seen that diagram, and if you haven't, you haven't lived. [LAUGHTER] But what we did was, companies came in and indicated if they were interested in building it. And so then we looked at several factors, including experience in building transmission and access to capital and creditworthiness and cost. But the cost aspect of it was, you know, very loose, because the process is that we awarded those, the building of those, and then the companies had to come in with CCNs (Certificates of Convenience and Necessity), and we approved the route. And then the last thing they do is, after they build and put it in service, they get their rates.

The new entrants did a great job of interacting with landowners. They did a great job with their applications. And they had more outside the box thinking. They brought a lot of new technologies, which was another thing that was interesting to us. And given the fact that we were building--at the time, it was $5 billion worth of generation, now it's more like seven billion. But we awarded them in early 2009, when the economy was not doing well. So part of the reason we wanted new entrants was to spread the risk, to make sure that weren't loading any one company up with such massive amounts of building. So I just wanted to clarify that.

Question 3: I wanted to go back to this bifurcation between a federal and state right of first refusal, which appears to be a situation we're going to be living with for the foreseeable future. And the fallout from that situation, particularly the free rider issue that someone just referenced, where you can conjure up scenarios where one party or the other will be in the position of coming at the 11th hour and basically appropriating value from all the front end work done by the other side, whether it be in terms of the political work that has to be done at the grassroots level to get something done, or the actual cost incurred in planning, development, stakeholder work, all of that stuff… Is there any bridge between that situation that any of you see that is workable in the near term without ultimately getting to where I think is probably an untenable pre-emption from one side or the other?

Speaker 2: Well, I think, in my comments I made reference to the fact that the federal elimination of the ROFR has ultimately resulted in states stepping up--probably not on their own, probably at the behest of their existing utilities--to put in place essentially a state right of first refusal, essentially giving preference to an incumbent, or at least setting up a process whereby there will be a process established within a public utility commission to determine who ultimately could build that. And I think we've seen the actual statutes that were adopted, providing that preference.

I think, with reference to Speaker 4's proposal around the sponsorship models, where you run into problems there is if everybody out there is proposing their own projects--and we've seen this kind of play out with ATC (American Transmission Company) in Wisconsin with regard to the MVP projects ("multi-value projects") that were awarded. We're seeing it, obviously, with the Pioneer complaint and NIPSCO (Northern Indiana Public Service Company) and who's going to ultimately build those projects--if the individual entity is allowed to propose a project, and just by the fact that they proposed that project get rights to build that project, I'm not sure it's necessarily solving the problem.

I'm guessing as to what problem that FERC was trying to solve is, because it doesn't necessarily mean that the project's going to come in less expensive because LS Power proposed a project, or ITC proposed a project. I think ultimately there needs to be a determination that if you're going to have criteria, they need to be objective criteria, and they need to be evaluated at the back end of the process. If you're going to have a competitive solicitation for these projects, then don't bastardize the process by having a sponsorship model whereby, just because somebody proposes it, they ultimately get the rights to it.

Speaker 3: I think you raise a really important but challenging question. I don't think we have figured out what the solution to that is. Every state has a different model. You have some states in PJM that don't let any entity own transmission, unless they also serve retail customers. I like Speaker 4's idea that if you're going to build transmission in a state, you become a public utility. But becoming a public utility in some states means very different things. In New Jersey, they have diversification limits on your holding company. They have pretty significant rules that apply. It's not just that you become a public utility with regard to that specific subsidiary. The rules apply beyond that specific entity. Now, maybe that will change because of this. Maybe new transmission companies will come in and challenge those state laws as being beyond the state's authority. I don't know. But I think it's going to be a real challenge, practically. And when the RTOs have a project, whether it's a sponsorship project or a model where people bring in ideas, if it crosses multiple states, and each of the states have completely different rules, I just don't think we've figured out how challenging this is going to be to deal with. And it's important that we don't allow the development of needed transmission to be delayed by this uncertainty and certain disputes that we're going to face.

Speaker 4: I would just add that LS Power in our Texas project has applied and is a public utility in Texas as part of that process. And as we look across the country at various projects, and when we're studying things, we include looking at the state laws as part of our evaluation process. And we also look to see if, in fact, under the existing state laws we could qualify to become a public utility. And so it is the responsibility of that new entrant to look very closely at that state law before they propose, and to think long and hard about whether that's a good idea from their standpoint. Our perspective is that we think it is a good idea to become a state public utility if we're proposing projects in a particular state, and we would make that application as part of our CPCN application at that time.

Speaker 1: I would just quickly add to that that I think another way to mitigate the concern here that you're talking about is the opportunity for joint projects. And Speaker 4 mentioned her Nevada project, which is a joint project with the incumbent utility there. So if a non-incumbent has a leg up on a project in terms of acquiring right of ways, etc. I think there are opportunities to work together with the incumbent to get the value of that.

Question 4: I've been in the position of advising clients who are similarly situated to Speaker 3 on this issue and around the country, and let me tell you what I'm telling them, and what maybe you ought to think about. First of all, this could have been a lot worse. You retain an ROFR for local projects, for anything that's an upgrade to your existing facilities, for anything that uses your existing right of way, and you retain all of the advantages you have at the state level in the siting process and the like. That's number one. Number two, FERC's not going to change its mind, and I think they're doing this for three reasons. First, they are concerned about utilities that both own generation and have transmission, and that, if there is an ROFR, some transmission won't get built that should. Second, I think FERC believes that there is potentially innovation in the industry, and the 765 kv transmission project that's being developed by Pioneer and other transcos in the Midwest is an example of that, whether you agree with it or not. And third, I think the FERC is under tremendous pressure from many state regulators to do something about costs, whether that's correct and appropriate or not (I tend to agree with you, Speaker 3, that that's not appropriate.) For example, in New England, the gentleman just mentioned the increase in the rates. He didn't talk about the reduction in congestion, which pretty much offsets the increase in transmission costs, if not more than offsets it.

But the problem for the industry is that we've got competitors who can take advantage of double leverage in ways that utilities in their regulated structure can't. And so they will go to FERC and claim they can do it for less, because they can use financial engineering that may not be available. And that's a very serious problem for the industry, if there's going to be competition. So what I've been suggesting that clients focus on is, number one, that you retain the things that FERC has given you, and they are better, for example, than where you might have been under primary power without Order 1000, for example. Secondly, that the process be developed so that the third parties can't take advantage of the transmission expertise that utilities have, because from what I'm seeing, at least in the RTOs, a lot of times the projects are developed sort of jointly by the transmission owners working together with the RTO, and their transmission planning and engineering expertise is brought to bear in developing the right projects. And the last thing you want to have happen is to have a third party take advantage of that and then pop in with their own project and claim that it's theirs, and say that they can do it more cheaply, when really what they've done is taken advantage of the expertise that you're bringing to the table.

So we're trying to consider and think about how to develop projects that protect the advantage that the utilities have in knowledge and expertise, and I think that's very important. And lastly, this whole idea of cost competition is really very dangerous. Nobody knows how much a project is going to cost at the planning stage, until you've been through the siting process. You really don't know. And so we could end up having a real fake competition.

So the bottom line is, I think the decision's been made. Fighting over that decision is really not where I would suggest that utilities should be putting their time and effort and resources. It should be in making sure that the process that comes out of this is one that is fair all around, and doesn't allow some of the sorts of gaming that can take place if the process is not developed right.

And finally, two last points. Number one, a lot of this discussion has been about RTOs. You may think it's hard to figure out how to do this in an RTO, but when you get outside an RTO, you can multiple by 100. If ever there was an argument for RTOs, figuring out how to do this kind of transmission planning when there is no RTO to make the decision is just much, much harder. And we haven't even gotten to that. And finally, I wanted to say something in response to Speaker 2. Pioneer will build that project. [LAUGHTER] OK?

Speaker 2: I think it's a good point, and in my slides, I put this in there. If nothing else, the planning requirements of Order 1000, not necessarily even the ROFR, but the planning requirements, may very well incentivize parties to look towards the RTOs or RTO formation to address some of these requirements that they're going to have to put in place, because I agree with you. Outside of an RTO, difficult is an understatement.

Speaker 3: I agree. It definitely could have been a lot worse. And you make some very valid points. I do want to clarify for the audience, in case people are not aware, that in PJM, at least, the right of first refusal is a 90 day right. It's not a long-term right. For 90 days, you have the right to say you'll accept that project that PJM has identified as needed, or you won't. It's not a right that goes on indefinitely. So I don't think that has been a barrier to entry, and the suggestion that companies that own transmission and generation don't want to build transmission--I think my company is a perfect example to prove that that's just not the case. Perhaps it is true in some places in the country.

I agree with you, I think FERC has set up a process in which companies that have joint RTOs and are supportive of competition are going to be treated more harshly than those who have kept a more parochial approach, and those more parochial companies will probably want to keep that approach to protect themselves in this environment.

Comment: I think my point is, it almost doesn't matter whether FERC is right. Those are very legitimate reasons that they can explain to a court of appeals as to why they're doing it. And so this looks a whole lot like the fight that some people in the utility industry fought over third party independent generation 15 or 20 years ago. So let's focus where we can get a result that is fair to everybody. And if we don't, it won't necessarily be fair to incumbents.

Question 5: There was something in Speaker 4's presentation at the very end that really got my attention. And I have a question about something that's discriminatory but going in the other direction. It seems that under Order 1000, an RTO-identified project, regardless of reason, is going to open for bidding. So there's no right of first refusal. Yet, if there's a project that a sponsor, such as LS Power or any other merchant transmission developer, identifies, they have sole right to develop that project. And I have this question. Doesn't that seem discriminatory, but in the other direction? And what was FERC thinking when it came up with this in Order 1000? I'd like to kind of get everybody's take on the panel.

There is something else that comes out of that discussion that jumped out at me, too. Transmission cost allocation, as much as we try to avoid it, is the 800 pound gorilla, or the elephant sitting in the room, or whatever analogy you wish to use at this point. And in order to kind of draw that out, let me use an analogy from the gas pipeline industry. In interstate gas pipeline development, it's the project sponsor that goes out and makes the statement, "I want to develop a pipeline from point A to point B. I'll have different receipt and delivery points. And let me now go out and look for people who want to take transportation." And if there are sufficient customers that want to take transportation service on that pipeline, then the pipeline developer can go to the commission, can get eminent domain authority, can get that pipeline built with cost of service regulation and so forth. We take care of the cost allocation issue right away, because the pipeline only gets built when there's people that say, "Hey, we want to pay for that." We don't see that in electricity transmission today.

And so maybe there is a halfway house here. Maybe transmission developers, if they identify a project that they think is good, could do the same thing. Let's have an open season. Let's say that we have wind that we want to develop in the upper Midwest, and we want to move that down into the eastern part of MISO or into PJM. And let's see who's willing to pay for that transmission to get it built. And then if the developer can find sufficient interest, much like gas pipelines, they go ahead, and they go to FERC and say, "Look, I've got sufficient interest. The cost allocation question is taken care of, because I've got customers who are on the hook." It could be the loads. It could be the actual generators that are being hooked up to that transmission. And we move forward with that. And I'd like to get some reactions to that potential way of dealing with some of the merchant transmission issues.

Speaker 1: What you described is the merchant model for transmission that is out there. You know, getting that critical mass of subscription to move forward with a project is challenging. And we have a lot of merchant proposals out there in the West. I think Speaker 4's Nevada project is probably the most real one moving forward, because in the West, most of these projects are driven by renewable development. So we have a lot of projects looking to take wind from Idaho or Wyoming and sell it to California. And at the end of the day, for the generation developers, the key is the viability of getting power purchase agreements with utilities in California, primarily. And right now that's just not a very strong market, given where the utilities are currently out in their procurement. But I do think, looking beyond the 33% RPS goal--and certainly in California there's a lot of discussion about, "Well, we're almost there, so maybe we should be looking at 40% or 50%,"--that when it comes to these merchant models outside of California to bring renewables from other parts of the West, I think there's going to be a market for that.

Speaker 4: I'll take on the first comment that you had about the sponsorship model and FERC Order 1000. I think that PJM is a little bit different than some other parts of the country in how they're wrestling through this issue because of the Primary Power order. And just to kind of summarize, essentially the Primary Power order that came out of FERC was related to the PJM tariff. And basically what FERC said in the Primary Power order is, "Primary Power, if you come up with this project, then it has to be assigned to Primary Power," and, "PJM, it has to be assigned to Primary Power, unless you've got a really good reason." That's essentially what FERC said.

In FERC Order 1000, basically what FERC said is, "Region of the country, RTO of the country, you need to decide what your process is going to be. It needs to be open, essentially, in terms of what that process is. It can be competition. It can be sponsorship. It can be a hybrid. There's a range of different models that it can be." And in the context of FERC Order 1000, FERC said, in paragraph 336, "Oh, but by the way, if you go with a sponsorship model, then for projects that PJM or an RTO comes up with, new entrants and incumbents have to have equal access to those projects."

So there are essentially two worlds that are being reconciled on the PJM side, between the Primary Power order and FERC Order 1000. LS Power did notice this difference between Primary Power and some of the issues of FERC Order 1000, and in our clarification request on FERC Order 1000, we specifically asked for clarification that if a region adopts a sponsorship model, that the Primary Power language should also be adopted for that region as well. But the reason we believe that FERC did not adopt the Primary Power language in FERC Order 1000 was that they didn't want to preclude a competitive bidding process. And so, essentially what FERC was doing is, they were leaving open the opportunity for competitive bidding, and not just the sponsorship model.

Speaker 2: Under airline deregulation, if you remember back several years ago, you had a company out there called Braniff. And Braniff had a business model under deregulation of the airline industry that was based on the fact that they didn't believe that deregulation was going to hold. So their whole business plan was designed to enter as many markets as they possibly could, open up as many new cities as they possibly could, because they felt that over time, the regulators would reverse themselves, and then go back to a regulated model. Now, they never reversed themselves, and Braniff obviously went away.

But I think can see parallels to how companies will behave under a sponsorship model, in the sense that if you're going to have a sponsorship model, I guarantee you, ITC, AEP, Cameron, Epsilon, everybody else out there who has an independent transmission company, or at least a company that's focused on building transmission, is going to be drawing lines all over the United States and claiming rights to different projects. I mean, I can draw as many lines on a map as I possibly can. And if, by virtue of a sponsorship model, I hope to get rights to build, I'm going to be proposing projects all over the place, and I think some of them will be legitimate. Some of them may not be legitimate, depending on who's actually proposing them.

I agree with your comment, I don't think FERC's going to reverse themselves on this. This is the policy. So I think we need to embrace it and put in place the best possible structure we can. And the best possible structure we can is going to be one whereby, regardless of whether ITC proposes a project, or AEP proposes a project, or LS Power proposes a project, it's going to be subject to the same criteria to determine who gets to build that project. Because I think ultimately we're going to run into a lot of problems about transmission lines being built everywhere.

Moderator: If I could just quickly follow up, what would that criteria be?

Speaker 2: I think Speaker 1's list that they've developed in California is a very good start. I haven't had enough time to go through there and look at everything that he proposed, but I think there are objective criteria that can be put in place to evaluate these. The reality is, you're going to have to have some measure of making sure that if you're going to assign a project to an entity, they have the capability of actually building that project and offering that project over the life of that particular asset. I think everybody has a tendency to focus on cost, and that's what they know. That's what they go to. And I think if it was FERC's intent to focus on cost, then I think maybe they're a little off. I mean, maybe New England is an exception, but we are talking about 7% of the bill, even if we overbuild the transmission system. Generally we're going to talk about 8% of the bill. So I think again, I think we need to focus on essentially what costs are at what stage of the process, because I can tell you any cost that we give for a project at the beginning stages is going to be quite different from what it is at the end. Often times it comes in much lower, but other times obviously it doesn't.

Speaker 3: And it's not just the building of the project and the operation of the project. It's got to be a demonstration that whoever is building and owning this project is going to have the resources and the expertise to show up when there's a storm, and there are trees down, because customers have very little tolerance and patience, as I think most of us in this room know.

They really don't want to hear, "Well, you know, I only have one project in your area, and I've got other projects somewhere else." So I think that has to also be considered in the criteria. And whether it's someone having a contract to say, "Hey, I've signed a contract with some local company," [to maintain the transmission], whether it's a local utility, or it's some other firm that offers contracts to show that they can show up when there is a problem, and not only operate the line, but be there to take down broken trees within a certain number of hours, because when it comes down to it, at the end of the day, when the lights are not working, and the governor's office is saying, "Exactly when is the power coming back on?" Somebody needs to be able to answer that question with some reasonable answer. Maybe that's a new business opportunity.

Speaker 1: I would just quickly add that one of the criteria we have as well is the project's ability to assuming liability. Because when you have events like Speaker 3 is describing, you could be sued. And in California, often, if it's associated with a wildfire, and homes are burnt up and damaged, there's liability risk, and what ability does the project sponsor have to take on that risk? So there are a lot of things to consider.

Question 6: First, I agree, I think Order 1000 was a step back from where the Primary Power order was, and one of the things I think that this discussion needs is a little context. Going back to maybe 2004 or 2005, I had projects with people to essentially file complaints that looked like the Primary Power complaint. And they didn't file. And understanding why is important in understanding what's going on now. And most of it comes down to the statement that seems to have gone by very quickly that Speaker 4 made, which was that most of this discussion is related to a rate base opportunity. And the issue here is not competition, but it's the fight to access a noncompetitive situation. OK? It's looking for that assured return. It's looking for the rate base treatment. It is access into a club that carries with it a lot of responsibilities and obligations, no question about it, but for which there are, at least in today's world, some huge relative financial returns, way above the competitive range for most other people.

And one of the parts of the decisions of people about going forward or not with their complaints was the question, how long would this access to the non-competitive club last? In my view of the world, what I wanted to see happen was that we learned something from the PURPA project and process, and that was that the total exclusion of the utilities was a very bad decision. It created an adversarial process that held back merchant development for years. The incorporation of the incumbents in a process that allows for economic competition at the end, which is for the benefit not necessarily of the first movers, but for the consumers, is really what this should be about, and what so far it's not. And the people that didn't go ahead understood that there might be a very quick transition. And I think what we should be talking about is what that transition should look like, because that's where the money is for consumers.

In my view of the world, the way this ought to play out is that this is a transitional step. We reward first movers. They get a piece of the action, but steady state, there is an incumbent set of responsible parties that get something. With PURPA they got nothing, and that was the problem. And I don't know what they get. We can argue about what it is that they get. But then the essence of what competition can bring here is basically bidding out the capital structure. Speaker 3 is absolutely right. Everybody goes to the same set of contracts. She's also right about the importance of expertise and reliability. I would prefer in the general world that PSEG be a responsible party for making sure the lights stay on if I was living in New Jersey. And her company has assets and resources and experience that I don't think most non-incumbents are going to be able to bring to the table immediately. On the other hand, 11 ½, 12 ½, whatever percent returns on equity--there are people out there that can make equity available to these markets much, much cheaper. And if that's what this process is about, we address all the constraints that Speaker 3 is concerned about. But if the end result isn't a business model where the consumer wins—not just where more people get access to the exclusive club--then we've done all of this wrong. And so we know sort of where we are now. How do we get quicker to the place where I have satisfied Speaker 3's concerns--because I understand them, and I think they're reasonable--but I also get the innovation into it? How do we get to the place where we create a venue for the first movers? But the bottom line is how quickly can I get price competition via capital (and I distinguish that from performance here)?

Moderator: Let me ask a question back, because I'm struggling with this idea that some third parties may be able to come in, and through double leverage or cheaper access to capital than the regulated utility be able to build the same project at lower cost. However, if in entering this market they must become a utility with the responsibilities that go along with that, including the restrictions on the capital structure that a utility has access to, isn't that a problem for that idea? And would it be appropriate to have third parties get in with a different capital structure and not have the roles and responsibilities of a utility?

Questioner: Well, first, ignore the double leverage for the moment. You can have my entire pension fund for less than 11 ½% after-tax return on equity. OK? I'll sign up. And I bet everybody in this room would take that for their 401(k)s with a PJM credit or whatever. So there is some fat there that can go away, regardless of pricing. But the fact that there may be abilities to improve capital structure isn't a negative. OK? I mean, if it's there, we should be exploiting it for the right people.

The second thing is (this is what I mean by bidding out the capital but keeping the incumbents to the extent necessary to make things work) that I'm happy for your company, or Speaker 3's company, or if Speaker 4's company makes the transition, for her company to take the lead. I don't know what it is that I need to give to you to do this. This is the tough question. Is it 20%? 5%? 50% of the projects that we're talking about? Somewhere in there, there is a number that will satisfy keeping you as a viable business and maximizing benefits to consumers. But having done that, I'm happy to be in business with you. I'm happy to be a silent, a minority partner. There's lots of pension funds around that will give you all the equity you want, have traditionally on the merchant generation side, have huge sources of cheap capital. And you get to do what you were doing normally.

I think there still needs to be a reservation for pure innovation. I think we have some really neat, nifty new innovators that are coming up with ideas in transmission, and we have to make sure that that doesn't go away. But you having an X% pension fund as part of your equity--and we can fight about what X is…because this isn't, and it shouldn't be, about who gets to be in the club. It should be about how we lower the cost.

Speaker 2: I guess what I'm struggling with, and it's not the first time FERC's been schizophrenic about their policies, but we've had years leading up to this--policies coming out of FERC saying that we're going to incentivize the construction of new transmission, and we're going to do that through the incentive rates that they have put in place for IDC, or that they put in place for Order 679, and in other places. So to your point, and I knew we were going to get there at some point and talk about this, now you're talking about a process to drive those back down. Under what you're talking about, the benefits for consumers is come from bidding in your ROE, to establish what companies are willing to build these projects for. So I guess the question is, on the one hand, you have FERC with their incentive rates over here, and on the other hand you have FERC eliminating the ROFR and putting the competitive process in place. They seem to be counterintuitive.

Questioner: Let me ask you. If somebody came forward and gave your company the opportunity to put in $5 billion in equity (and let's make it PJM for the moment, because I like the Schedule 12 system. It's transparent. Everybody gets it. The financing people all feel very comfortable with it), but you were told you're only going to get 9 ½%, would you take it or not?

Speaker 2: It depends.

Questioner: You would pass?

Speaker 2: No, it depends. It depends on where else I can deploy my capital—if there's somewhere else I could deploy it at a higher rate.

Questioner: OK, and for some portion of that, I believe that there would be a role for you that you guys would like--and you may even be able to lever up the return based on your professional skills, management skills, expertise in the industry to extract rents that other people would not. And that capital will be available to you at those prices or lower. And it will take place.

I disagree with the idea that FERC "candy," as people refer to it, is necessary. It is an outgrowth of limited access to competition in this forum.

Speaker 2: And obviously there's a debate going on about incentives and what those incentives should look like going forward, assuming they should exist at all. But having said that, before 679, people weren't focusing on transmission. I mean, the transmission owners in the Midwest ISO weren't building transmission. Now they're fighting over who gets to build it. So I think you're getting to a place now where I think, like a lot of good government intentions, they've achieved the desired result of the policy they put in place, but now they're counteracting that with a different policy. It's as if they are thinking, "Maybe we went too much this way, so let's put another policy in place over the top of the one that already exists to counteract that." As opposed to going back and addressing the original concern.

So if the intention is truly to address state regulators' concerns about cost, let's address the cost issue. Let's not put in place a new process, a new layer of bureaucracy, to solve a problem that could be addressed much more simply and effectively just by having the hard discussions around this subject.

Questioner: Bidding out equity is not a tough bureaucracy to put in place.

Speaker 2: Well, I think this whole process that's coming about what PJM's going to do, what MISO's going to do, and what not, is going to be a nightmare.

Questioner: I agree with you on that.

Speaker 3: I don't think we need to eliminate the ROFR in order to address what you're proposing. There's nothing stopping a company from doing that today. It's a choice that can be made, and pension funds do actually invest in my company, and in most of the publicly traded companies around here. And they're not shy about telling us what they want us to invest in and what they see as the good investment. I'm not sure why it has to be on a project by project basis, but that's an interesting idea, and I don't think there's anything prohibiting that from happening now. Right now, we get 11.68% on our transmission. That is attractive. In the '80s, a lot of people said, "That's not worth putting my money into." The stock market creates a real opportunity to invest in equity where these pension funds can put their money in, take it out, put it in, take it out, decide Southern Company is the place to put their money, decide New Jersey is the place to put their money… I think that liquidity already exists.

Questioner: Not for projects and not for this kind of return. Those opportunities aren't there. You're talking about pensions funds and others investing in your stock. They don't have the opportunity to invest directly--they don't get a PJM credit that is a Schedule 12 credit of all the member companies for their investment at these kinds of returns on equity. And that's what needs to be introduced.

Speaker 3: Well, I think that can happen today. I don't think FERC would say that it can't be done, or it can be done.

Questioner: Well, it's not being done.

Speaker 3: But it could be done.

Questioner: That's why I'm saying this is an interim step that ought to be seen as the midpoint to getting there. And if we don't have a plan to get there, and all we're doing is creating more incumbents that scoop up some of these opportunities over time, we haven't accomplished anything.

Speaker 4: I would just add to your comments. I agree with a large percentage of your comments. I mean, certainly when LS Power has looked at the issue of new entrants, we've said, we've got to have proposed projects and ideas that have a consumer focus. Otherwise, the policy reasons for the new entrants side of it goes away quickly if it's not consumer focused.
And from LS Power's standpoint, that's part of the reason why, when we filed our incentive rate case at FERC on our PJM projects, we waived most of the incentive rates—partly to communicate that message that at the end of the day, we have to be consumer focused on how we think about this.

And then, as different markets embrace sponsorship, different markets will embrace competition. So the key thing ahead on the markets that embrace competition is, "OK, what's the selection criteria?" If you're going to have a competitive process, then what's the selection criteria? And from an LS Power standpoint, we have no problem if the focus is on what's good for the consumer.

Question 7: I want to preface my question or comment with a couple of observations. First, I think this is a really hard problem. So this is not like we're talking about something that's simple, and it's obvious what to do. Second, I understand the principle that the perfect is the enemy of the good, and so having a perfect system is too great an aspiration. But I want to see how close we can get.

As for Order 1000, I happen to think it's advanced the ball forward. I do think it's a good thing, and I agree with the observations that FERC has now committed itself to certain principles, and it is going to have a very hard time going back on what those are. And as I have told some of the commissioners, I think Order 1000, one of its great features is, it didn't say anything really bad. OK? [LAUGHTER] Which is good. That's something. But the problem, of course, is it also left a lot of these issues completely open. And Speaker 2 talked about how there's a lack of a collective industry vision about how to fill in the details of what we're going to do under this kind of a framework. I think that's correct, but I think it's worse than that. Certainly, we don't have a collective vision across the country. That's certainly true. But I would argue that so far we don't even have a vision in each one of the regions that is internally coherent. OK? And that's the problem that I'm worried about. (I should tell you, also, that FERC's ability to be schizophrenic deserves a great deal of respect. [LAUGHTER] But I'm worried that they can't sustain it forever, and so the whole house of cards comes tumbling down if we don't get this thing to be more internally consistent.)

So let me give you a couple of examples that I was just writing down as we were going along. Speaker 1 described a system in California where generation interconnectors who do what the plan wants get treated differently than generation interconnectors who don't want the plan wants, in terms of the cost allocation. That seems to me like it's going to create a lot of perverse incentives which we all ought to think about.

Part of the cost benefit analysis going forward is analyzing the interaction of transmission with other generation investments and demand side investments, like the gas plant that Speaker 2 talked about, but you don't have authority over those things. How does that fit into this framework? And if they don't actually come forward, what are you going to do? And how do we deal with that kind of a problem?

The whole issue about participant funding, and how does it map in, which we heard questions about here--the merchant model, and how does it fit into this framework, has not really been explicated.

Speaker 2 brought up what I consider one of the fatal flaws of a lot of the current discussion, which is the cost-allocation "bucket brigade." So we've got this bucket and that bucket and that bucket. And then he looks out his window, and there's only one transmission line. And that's a fundamental problem, which is not going to go away, and until we get something that's consistent with the fact that there's one line with many effects, rather than cost buckets that you can then go allocate separately, I don't see how this thing can work.

The cost allocation discussion that we've heard so far has all been about, "Get the money!" Right? That's what we mean by cost allocation. [LAUGHTER] No, no, that's not cost allocation. That's getting the money. [LAUGHTER] But who pays? For the beneficiary pays principle, and how that all fits in, we don't have a coherent story yet that's been worked out. I think New York is pretty close, based on the work of Steve Littlechild in describing what went on in Argentina. But the rest of this conversation is just not facing up to that.

I haven't heard a word about my favorite subject, financial transmission rights, which are supposed to be the benefits that are created, and how those get allocated.

So it seems to me that this just doesn't hang together yet. We don't have a coherent vision, and I don't think FERC has got the ability to be schizophrenic forever. And so eventually this thing is going to unravel if we don't fix it. Or is it possible that we can muddle through, and nobody will notice?

Speaker 1: Well, I'll start with the first point. To focus on your comment about the direction we're going with the interconnection process, I guess I'd view the current system as flawed and as creating perverse incentives, because fundamentally, the way the interconnection process works today is that a generator is pretty much indifferent to where they locate on the system, regardless of whether, if you locate out here, that requires a billion dollar transmission investment to make you deliverable to load, or if you locate over here, you can be deliverable with no investment, because if the rate payer pays for it all, why should they care? So fundamentally, what we're trying to change is to have them care. And to really approach what's needed for transmission investment from the standpoint of asking what make sense holistically for what we're trying to achieve from a planning standpoint. And if you fit within that paradigm, great. You get to avail yourself of the interstate. But if you don't, you're going to have to build your own interstate. So you know, I will collegially push back to you on that point, that I think we're actually creating a better paradigm that is providing proper incentives for generators to think about where they locate. I'll leave it there.

Speaker 2: You know I once worked for a company that had a dress code. And I asked the question one time, "Why would a company that has professional employees need a dress code?" And they said, "Well, one day this one particular employee walked in, and it looked like he had slept in his clothes. So the CEO of the company said, 'We need to have a dress code to establish what criteria people can wear and what they can't wear.'" And my question was, "Well, why didn't you just talk to that one guy that looked like he rolled out of bed and tell him he can't dress like that? As opposed to imposing a dress code across the entire company?" And I think sometimes this debate goes to that very issue, in the sense that we have particular issues with regard to who has access to that noncompetitive party that one of the earlier questioners talked about. Let's solve that problem. I think instead, FERC said, "OK, well, we have this issue, so we're going to come up with a broad policy and apply it across the United States in RTOs and non-RTO areas." We're going to have to put in place processes, compliance filings that are going to essentially cause a lot of us to spend a lot of time on an area that--again, I'm not sure the ultimate benefit to consumers is going to be all that great. So how much money are we actually spending to put this new process in place, to solve a problem that we probably could have solved almost on a case by case basis? So now we're going to essentially open this up to a lot of uncertainty. We're going to have questions around issues like, as these projects are identified by RTOs, who's going to ultimately build them? If Speaker 3 decides she wants to propose a project at PJM, does she get the rights to build that project, just because she was the one waving the flag for that particular project? I just think, again, we've taken the approach of, let's put broad policy in place to solve a problem that probably could have been solved much more easily by addressing that problem individually.

Speaker 3: And the challenge of generation interconnections and transmission, and how this all fits together, isn't addressed at all by this Order. And it is a continuing challenge. Our view is, as I said earlier, that regulated transmission should be the backstop. But it's not. Often it's really driving the market results. Even in PJM, which I think is a very progressive area that tries diligently to do what's right for the market, we have transmission planning that's done far, far in advance and put into the marketplace with as much protection as possible to make sure that there's a really good belief that the transmission's going to be built. But we need better alignment between generation and transmission planning. We haven't tackled that yet. FERC really hasn't even approached the problem. Instead, I'm not sure what problem they were trying to fix. My sense is, probably somewhere in the country there was some legitimate issue. Maybe it's LS Power's projects in the Midwest. [LAUGHTER] I don't know. But I look at PJM, and I just don't see the problem that they're trying to fix. But I do see other big problems that are just being glossed over here.

Speaker 4: I would just comment very quickly on two items. First of all, from LS Power's standpoint, we definitely think there was a problem that FERC was addressing here. And in general, we think the FERC Order 1000 was a very strong step forward. And I think that time will tell in terms of how big of a step or how small of a step, in terms of what FERC came up with. But one thing that is interesting to me as one who is following what's going on in all the regions across the country relative to this compliance process, is that it's very clear to LS that FERC is very serious about this compliance process. And at every regional meeting that's going on all over the country, there are three or four people from FERC that are there at the meeting, or there are even more on the phone. And if you think about the scope of all the regional efforts that are going on across the country, it's very significant. And FERC is dedicating pretty significant staff time and travel time for all these discussions. So it's clear to me that FERC understands what's going on at the regional level. I think they've got some opinions on it. And hopefully the rehearing order will provide a little bit more clarification on a few of these issues.

Question 8: I'd like to pick up on the issue of ROE reform that's been stated several different ways. Speaker 4 raised it. And it came up in a different way in the questions, including being broken down, I think, into two pieces--ROE and capital structure. And what I think people are forgetting is, you're making a filing in front of FERC, and you're telling FERC what your capital structure will be to get your ROR. Is it fair competition to say, "My capital structure is 50/50," and then to go ahead and fund the 50% equity 60% with debt, without having that be obvious? Are you getting a return that you're not really entitled to? Should you at least be required to disclose this to FERC and to the states doing the siting and to the RTOs to see if you're financially viable? It just seems to me that a utility that is highly regulated by the state cannot do that. And so on every project, the utility is going to lose on money. And so should it be disclosed? Should it be cranked into the formula rate? How do you deal with getting fair competition on capital structure?

Speaker 2: I guess to that point, double leveraging's been used in the natural gas pipeline industry for decades. And as far as disclosing whether or not you're using the back leverage, the holding company or not, that is something FERC is very familiar with and very aware of. I don't think there has ever been a situation where when you go in and make that determination as to whether it's going to be 50/50 or 60/40 or what have you, whether or not you're back leveraging. And as far as the issue associated with the risk, if companies are publicly traded, the risks are assessed essentially in our ratings from S&P and Moody's and others. So if we're a risky concern, that's going to be reflected in the rate, essentially, and what our ratings are. So to your point, I'm not sure what issue you're trying to solve. I'm not sure whether it's about LS Power, that's a privately held entity, or whether it's about a publicly held entity. That information is out there.

Questioner: The issue is explicitly telling FERC and the states what your capital structure is, and that, if you're going to compete on ROR, then if the competition is not going to be on the same basis, then at least let the state that is doing the siting and FERC know that it's not on the same basis.

Speaker 2: But does it matter?

Questioner: It matters because I would say it borders on fraud.

Speaker 2: Even though it's been done for years in the industry?

Questioner: Well, you can do a lot of things if you don't tell anybody. If you tell FERC, "I want an ROR based on 50/50, and here's my ROE," and you really don't have 50% equity, shouldn't that at least be disclosed?

Speaker 2: It is disclosed.

Questioner: No, it isn't.

Speaker 2: Yes, it is. It's disclosed in every SEC filing we've ever made.

Questioner: I mean disclosed to FERC as part of the filing, when you're asking for your ROE. We obviously disagree.

Speaker 2: Well, again, I guess the question is, who cares? Or what's the point?

Questioner: Who cares? I would think the state cares.

Speaker 2: Why would they care?

Questioner: Because if you have a lower real cost of financing, then why shouldn't that be passed through to the consumer?

Speaker 3: Again, who ultimately is the jurisdictional rate authority for that? I mean, if you're providing the service, and you're doing it at a particular cost, again, you're making the filing at FERC. You're making a determination as to what your capital structure is and essentially what your approved ROE is.

Question 9: I'm going to direct this at Speaker 1. I have a couple of quick observations and a question about the process that you put up there. As you indicated, California has these goals of 33% renewables by 2020, but what actually will be driving California procurement for the next bazillion years is climate change, because we are supposed to be at 90% of 1990 emissions by 2050. So if you think in power plant years, which are just like dog years, they're plus seven, we're already at 2019. And I think we've done a pretty good job at trying to keep things moving forward. But it's very likely we're going to see additional transmission into areas that have renewables like Nevada and Wyoming, just like we did in the Northwest and the Southwest.

The second point, with respect to the new use of the transmission and putting that cost on the generators, I'll just point out the fact that for the most part, that would be really rational if we had just a pure merchant model in California, which we do not. When you overlay the procurement process in California, which has in it least cost, best fit, one would assume that the utilities are selecting people for contracts that actually fit into a transmission plan somewhere under a least cost, best fit criterion. Apparently if you are doing it post hoc, that means that there's a failure in this process somewhere.

Now, the ISO's done a pretty good job over the years of adding transmission, and it's been mixed between incumbents and new entrants. Southern California Edison did a very good job at building the Tehachapi line, or they are in the process of building it out. San Diego is building Sunrise, again to meet some of the renewable requirements here. We've also had some independent transmission entities, Trans Bay, but perhaps even more importantly, the Path 15, which addresses a longstanding constraint that the incumbents hadn't resolved. And when it became clear that the market was in serious trouble without fixing it, it actually took an independent to fix it, because the California Public Utilities Commission was standing in the way.

So I think the history here is a pretty good lab experiment with respect to looking at all this. And you knew, I think all of those projects that I just described, however, predate the transmission process you put out there. Can you just give us some sense of how many independent projects participated in that process? How many were selected? And any observations you have about it.

Speaker 1: On the new process?

Questioner: Yes.

Speaker 1: You know, when I was preparing my notes, I said, "You know, I ought to get that out up front, because somebody's going to raise it," and I didn't. So here I am. Zero, in terms of new projects. Well, I take that back. There's been one project approved in the 2010/11 plan, but it was a minor reconductoring of a lower voltage facility. So the fact of the matter is, while we have this very elaborate plan for considering non-incumbents in the planning process, when we look comprehensively at what's needed, given what's been approved to date, there just isn't a compelling need at this point. So that's unfortunate for the non-incumbents. But nonetheless, we can't just be identifying needs for purposes of giving people opportunities if the need's not there. So we are where we are on that, and I know it's incredibly disappointing for the non-incumbents who are really looking to California for opportunities.

And on your point about how we're far from done, you mentioned the greenhouse gas regulations that, as people look to how they're going to meet those standards, could be driving new investment, and as you know, we have a governor who's very interested in looking beyond 33% renewables. And we also have uncertainty on what's ultimately going to develop. And we have generator projects that may not get all the permitting and siting. Some of the transmission that goes with it similarly. So I think there are opportunities for change down the road that can lead to opportunities, and we have a structure in place to accommodate it.

To your earlier point about this new change with the interconnection process, where we have generators that are outside of the plan picking up the cost, and you ask why couldn't procurement sort all that out? I think it comes down to the fact that transmission is a long lead time thing, and generation gets built much quicker than transmission. So if we simply let all these projects come in through the queue and identify what's needed to be deliverable, we're going to have way more transmission than is ultimately needed. So we're really recognizing that and trying to say, "OK, what's our best guess from a generation standpoint of what's going to develop? Let's build a plan around that, and let's encourage the procurement and development around that, but not preclude entities that want to build outside of that plan, but they're going to have to do it on their own bill."

Question 10: So this is an interesting topic, and I wanted to ask your opinion about the role of the RTO, and if you're comfortable with the RTO taking an expanding role here, becoming more of an arbiter between winners and losers in this right of first refusal. And the RTOs, I think, have demonstrated a very key role and efficiency and success in that role. But this is expanding it. And I want to ask if you're comfortable with that. And if the RTO really can take its place in a different realm, so to speak. And I speak in particular with some concern about the potential for overbuild. The RTO has a bias, obviously, to having life be a little easier, which means a lot more transmission. If it has to make a tough decision between a number of incumbents and these non-incumbents, well, what about just a few more projects, to make everyone happy? And then, you know, the politics of this go around a little easier. So that's a concern of mine. Are we going to get some overbuild?

Speaker 1: Well, I think it's a great question, and again, our approach is really a top down transmission plan. So we identify what's needed, regardless of who's ultimately going to build it. So on the issue about what do we think is needed, frankly, cost is a significant consideration. And I think on balance, we try to strike a reasonable balance of providing enough headroom for achieving the policy goals we're looking to do, but not overbuilding just in case. So you're never going to please everybody on that equation. But it is something that we're very sensitive to.

In terms of our comfort level of selecting among competing projects, I totally agree with you that this is uncharted territory for us. And while we have, I think, a good set of criteria, when it comes to ultimately applying these criteria, we need to bring in the kinds of expertise we need, particularly in assessing the financial capabilities of the entities to do this. So it's a new role for ISO/RTOs, or at least for this one. And one we're going to have to grow into. And you know, we tried to structure it, as you saw in my diagram, so if the competing projects are going through the same state siting authority, we're punting it to them. Let them figure out who's the best, most viable project. So it's only in the case where they're pursuing alternative siting authorities where we'll step in and try to sort out who goes forward.

Question 11: I'll tell you what keeps me up at night. On the one hand, I do want to encourage innovation in transmission. But on the other hand, I am concerned about the uncertainty created with rate base sponsorship projects and what implications that has for the market overall.

If I look at what our commission has done on the generation side, we've said, "Our state is open to merchant generators coming in and building.

And while we have authority to rate base new generation, that's only a lifeline that we will exercise as a last resort if there's a need, and nothing has been done." You know, if suddenly we have many different companies drawing 50 lines across the state saying, "We may build sponsored projects across your state," that has the potential to create uncertainty that would destroy the business value for new merchant generators coming in. And I want to know, what do I tell them, given the absence of a coherent policy, to figure out when an RTO is going to approve a project, whether it's reliability, economic, or policy based, and particularly given that I think our economic and policy criteria are weak today? What do I say to that generator who might like to solve a problem that I have in an area that's separating from the rest of the transmission grid in my state if I can't tell them that there won't be some transmission project that will come in and take away the value of his investment?

Speaker 2: Just tell them to put their faith in FERC. [LAUGHTER]

I think that's a good point. I think that as FERC gives up on the federal right of first refusal, there are going to be certain authorities that are going to necessarily have to transfer to the RTOs. And whatever process they put in place, their compliance filing is, I think, going to ultimately be tested at FERC. And you're still going to be subject to the 206 process at FERC, in case you have competing projects. And ultimately, if MISO or PJM or California makes a decision that a particular developer doesn't like, it's going to end up at FERC, and it's going to end up back at their doorstep. I think regardless of what process you put in place, because that's the only avenue. The regional authorities don't have the statutory ability to pick winners and losers. I think what they can do is, they can put a process in place where a vast majority of the time they're going to be able to pick it, and it's going to be the right decision going forward. But there are going to be those instances where they don't. So I think you're ultimately going to rely on whatever process they put in place and hope that that process is structured sufficiently that when the decisions are made, they're able to both withstand both a complaint at FERC or other judicial scrutiny.

Speaker 3: And I actually am worried about an overbuild. I am also concerned about the impact on the merchant generation model. Transmission doesn't create power. It just moves it from one place to another. We need to make sure we have enough generation, either on one side or another side of the transmission. But there are fixes, I think. And one of them most fundamental elements of the PJM planning process right now, is that PJM retools these projects, and if new generation comes in, and the transmission is not needed anymore, they get canceled. And you have a lot of transmission owners not very happy about that. But I think that's so fundamental to the transmission planning process. And it's one of the reasons why transmission owners want abandonment authority, and why abandonment authority for these big projects that take multiple years to build is so critical. Because you shouldn't have a model where people are trying to push transmission projects that are just not needed anymore. You really need to take that incentive out of the model. And again, I come back to the fact that the transmission and generation timelines are not aligned perfectly right now.

Session Two.

"Over There": Electricity Market Developments from Europe, Brazil, and China

While HEPG concentrates on North American markets, developments in other parts of the world may well provide lessons and insights from which we can learn. Reviewing the evolution of electricity markets in three very large economies— Western Europe, China, and Brazil — can be instructive. What is the theory and practice of market design? And where is it going? How are concerns about carbon emissions influencing market rules and resource selections? What role are renewables playing and what policies are in place to promote them? How are intermittent resources affecting system operations? How liquid are the trading markets? How open is transmission access? What methods are used in setting transmission prices? How is congestion managed and/or priced? Who does transmission planning, how is it done, and how is it decided? Who will build new lines or enhance existing lines? How much of the market is regulated and how much is competitive? How is market power dealt with in competitive markets? How is demand response handled?

***Moderator*:**
In our discussions, we often get somewhat insular because we talk primarily from the U.S. perspective, or if you want to broaden it, a North American perspective. So we thought it would be useful to take a look at some of the things that are going on in other markets around the world, to get an idea what some of the debates are.

We asked the panelists to do two things in selecting what they're going to talk about. First, to look at the things that they think are the most interesting developments in the markets that they're in, and then second, to look at specific things that they think would be particularly instructive for participants in the U.S. market to think about, relative to what's happening in their countries. So you may see that the panelists touch on somewhat different topics, but those were the criteria we asked them to look at.

We'll start in with the Nordic market first, which is one of the oldest competitive markets. And then we'll move to the U.K. market, and then from there we'll go to Brazil and then cross the world to China and take a look at the different markets.

The panelists, I regret to say, are all economists [LAUGHTER]. So, the one bias they share, despite the fact they come from different cultures, is they come from what anthropologists call the "economics backwater" [LAUGHTER].

Speaker 1.

So, what about the Norwegian and the Nordic electricity market? As you said, it was one of the first that was deregulated in the world, in 1990, 1991. It's a small part of the world. We consume like 400 terawatt hours a year. There's a population of 25 million. Energy is traded on our power exchange, called Nord Pool. The financial market was part of the Nord Pool system previously, but has now been sold and you can see who bought it (NASDAQ). That was in 2010.

The other main characteristic of the Nordic market is that there is some vertical separation of transmission and distribution on the one hand and generation on the other hand. For most companies that is by separation of accounts, but one of the first steps in deregulation was to divide Statkraft, which was the state owned generation and transmission company, into two companies, now called Statkraft, which is the generator, and Statnett, which is the transmission system operator.

So what we say is that we have competitive supply and demand for power. As a household you can choose your energy supplier. And there are no tariffs for moving around, so you can do that however often you like. And a lot of people do, maybe 10% a year, something like that, but there is another factor of this that is maybe more important that I will come back to later.

There are no price caps. That's not totally true because there is a price cap of $2,000 Euros on the Nord Pool Stock Exchange, so it's relatively high, so it's almost never binding. Sometimes it is invoked, but almost never. And not even for households. So the energy price in the Norwegian market is not regulated. So you have to pay whatever it costs.

Transmission and distribution, on the other hand, are regulated. So, that's a very different kind of setup than what you were discussing this morning. And I'll come back later to how we put competition into this part of the system.

I've tried to depict the vertical separation in the electricity market in this chart here. This lower part is the transportation. You have the energy generation in the upper part of the figure. There is third party access--that was one of the first things that was important to implement. And that is implemented by Point Tariffs in the system, so you have a tariff that is connected to your connection point.

Norway has a lot of hydropower and that was partly developed by the energy intensive industries, so they are still an important part of the market. Usually they contract bilaterally with generation if they don't have generation assets on their own. But after the deregulation, you see that the long term contracts have been reduced in volume and also in the duration of the contracts.

If you go to Nord Pool Spot, which is the exchange, they calculate a system price which is the unconstrained price, for every hour of the day. There are also area prices--presently I think there are 10 or 13 areas within the Nordic area. 70 to 80% of all the power is traded through Nord Pool Spot.

And then we have the retailers. As you see here, you have the generating companies, and usually they are selling most of their power through the exchange. Well, you have retailers buying, and there might be some connections between the generation and the retail companies, but these are really separate entities. So this is also part of the unbundling.

They offer three types of contacts. One type is the fixed price contracts, usually for half a year or for one year. So there is a certain kind of volume risk connected to these fixed price contracts, because it's not on a fixed volume. It's on whatever volume you would like to have. The variable price is the default contract. About 40% of the customers have a variable price contract. And then, as I was referring to in the beginning, there is the spot price contract, which is based on the Nord Pool area prices. And almost 60% of Norwegian customers are on this kind of contract. So you have actually the spot price coming all the way through to the final customers. And this change from variable price, which was the default, has been tremendous over the last few years. And that's especially due to some of the drought periods, where you see that the prices are actually varying quite a lot. And a lot of analyses show that going for the spot price, which is an average monthly spot price, is actually the best thing to do. And so, actually people are moving towards it.

And that results in some sort of demand response, even if it's not really rational for consumers. They do actually react to the prices. When they see in the newspapers that the spot prices are increasing, they do react to it.

When it comes to transmission and distribution, we have a TSO (transmission system operator), which is Statnett, so they own the transmission equipment too. Investments are by licenses so they actually have to make an application to the regulator, which is called MBE in our system.

That goes also for generation. You need a license to build a new plant. You have to apply to get a license, and you might also, when it comes to wind power, for instance, or all sorts of power, need to be connected to the system. Transmission and distribution companies have to connect generation to the system. But they can charge an investment contribution, if that new connection leads to a lot of new transmission having to be built. So, especially for the distribution companies, that's part of sort of the decision on how to finance new investments due to, for instance, mostly hydro or wind power, et cetera.

When it comes to the distribution companies, which are the suppliers and the last part of the transmission network, there are about 130 companies and in both these parts here, we have competition introduced via the incentive regulation mechanism, and I will describe that later.

In this part, there is an area concession, so that you don't have to apply for every investment that you do, you just have sort of the right to make the investments within a certain area that you are serving. There are also some obligations, so if I build myself a house somewhere, my distributor has to connect me to the grid.

So for me as a consumer, this vertical separation means that I have one bill for the energy itself and I have another bill for the transportation of the energy. So to a consumer, it looks really separated also. It's not just something that the regulator tells me is going to be separated, it is really two different bills.

Going more closely into Nord Pool Spot, this covers mostly the Nordic markets. We had a period with a German area, but that is now resold via market coupling, and Estonia has also come into the Nord Pool market.

When a person from a Nordic country talks about the "spot market," what he or she means is the day-ahead market. And that is of course then supplemented by balancing and regulation markets, but that gets less attention. It is the day-ahead market that is the market that everyone is aware of.

It is a voluntary pool, except when you want to trade between areas. And there are three kinds of bids. Most of them are hourly bids, which are bids for individual hours. But there are possibilities for doing bulk bids to take into account some of the non-convexities for the thermal plants, et cetera, but overall this is an energy-only market. So there are no uplifts for startup costs and those kinds of things. And there is no capacity market, except for some of the renewables, which I will come back to later.

This is the web page of Nord Pool Spot. You can see the different areas and you can also see the market coupling with the rest of Europe. There is also transmission to Russia, and Russia is also being better integrated into the Nordic system.

Just a few words about the regulated part of the electricity sector. This accounts for approximately, in a moderate price year, 30% of the total cost for the whole electricity sector. The regulation is based on total cost. There was rate of return regulation from 1993, and there has been incentive regulation from 1997. But you also have some minimum guaranteed returns of 2% over a five year period, so some of the pension funds are interested in investing in this industry.

The annual cost includes value of lost load, so that it's a combination of accounting costs and some calculated costs. And the most important of the calculated costs are the value of lost load, where you find the depreciation on the accounts, and then you have the return on capital, which is based on a regulated rate of return. This is the regulator and the book values.

As for the incentive regulation, what's that supposed to introduce here? Well, it's supposed to introduce some kind of capacity-aligned market, where your revenues are independent of your cost, so it's depending on what kind of product you have, the output, the quality of your output, so that the profits of course are depending on the cost. So, if you are very efficient, well, your profits will increase. So, with this system here, if you are efficient, you will have a higher rate of return than the regulated one.

Another issue is that you need to have sufficient revenue here in order to attract not only the financial capital, but also the human capital. And in this industry the recruiting of people is considered to be a very important issue.

Given the very long lifetime of energy assets, time profiles can be important. Presently, the costs and the revenues are based on the accounting values and the yearly depreciations, but you could also think, "Well, what about using replacement values and annuities?"

The regulation model from 2007 is based on this formula. It is based on some fraction of actual cost, this Rho [in the formula] is equal to 0.6 now, so that's the weight of the cost norm. So, for each individual company, a cost norm is calculated. And then it is combined with the actual cost and then a revenue cap is calculated. And this revenue cap is the maximum income revenue that an individual company can have in one specific year, and that is collected through the tariff.

Tariffs are also regulated. A most important thing there is that you're supposed to have some user-dependent amounts or parts of the tariff and then some sort of access part of the tariff. Even if you have a formula, you haven't really decided anything yet. So you have to make a lot of decisions about how you are going to determine C [actual costs] and how are you going to determine the C*, which is the cost norm.

And Norway is a small country, but it's quite diverse. So you have to take into account that some have fjords, some have snow, some have forest, some are in urban areas, so you have to dig everything down in the ground. You have islands.

The last part of this is the renewable resources. The distribution companies see that they have higher costs due to having small scale hydro like this, or wind power integrated into their grids, and that's also part of the calculation of the cost norm.

How well does the market work? Well, you see here, we have a lot of area prices, these are the annual prices. If you look more closely into it, it seems like the prices are increasing. You can't actually say anything about how well it works based on changes in prices.

Well you could say that scarcity is increasing, so it's reasonable that the price should increase. You can also see some of the incidents that we have seen during the last year, that is actually reflected in the prices and it's exactly what you would expect. So, that's a good sign.

When it comes to volume, last year was an all-time high at the Nord Pool Spot, which is this figure, it was 70 to 80% of all power. And this chart shows some figures on the total market, including the financial market, and you see that the amounts that are traded are really considerable compared to the physical power market. The top year was 2002, and that was almost 10 times as much as the actual physical power traded in the market.

These are some figures on the value of lost load. This is the point where this was introduced as a penalty mechanism in deregulation. So there's also been a decrease in the value of lost load. What we also see is that there is a willingness to make investments, and if there is time I will come back to that later.

I think there are some interesting developments right now and some challenges too. The first one is the fact that Europe is integrating a lot. That's not very much discussed anywhere, but in effect now, most of the north-western part of Europe has a common price calculation. So, the prices calculate in the day-ahead market for every hour, are calculated on the same time for all the markets.

There is this tight volume coupling. It means really that there is a company collecting all the bids from all the exchange areas. They do a sort of pre-calculation of prices and quantities. They set the transfer quantities between the areas, and then they send out these volumes transferred between the areas, and a recalculation is made in the local pools. So, convergence of algorithms has been one of the really major issues during the last few years.

A lot of interesting things are going on in the area of congestion management, as well. From November, the Swedes were forced by the European Commission to split Sweden into four areas instead of only one. They are not very happy about that. Not all of them at least, especially in southern Sweden, which has now Danish prices. They are not very happy about that, so they call it an extra tax.

We have some demand response that we have seen during the last three droughts, we could say, both on the industry side and also on the household side. There are going to be advanced metering and control systems from 2017, this is also part of the European regulation.

But there have been some really strange issues here, both on the industry and the household side. My conclusion on this is that it is really important that we have prices that vary according to location and according to time, because if you don't have these price variations, you don't induce agents to do anything to sort of adapt their consumption or their bids.

We had a period in 2009-10 when it was really cold and we had problems with Swedish nuclear power and one of the industry agents that has a lot of production on its own, it's an energy intensive company, they said that well, during the first price spike, they were not in the market at all. When they saw the price they wished they were there. And then on the next spike, they were sort of halfway there, and then on the third one, they were absolutely there. So, you have to have these price variations to have these consumers learning that it actually pays off to take part in this demand response.

When it comes to households, what we saw in this period was also that we had three peaks of the prices and in all the three peaks there was a down regulation after the day ahead. So, you had a lot of, it looked like you had too little power in the day-ahead market, and then when the real-time came, then you had to buy down, so you have to get rid of some of the production.

And two of the explanations were quite interesting when it comes to demand response from the retailers. First of all, they had really bad forecasting models when it was very cold. If you have all your ovens on when you're doing the heating, and then it gets even colder, you don't have more ovens to put on. So the model doesn't really work when you come up with these really cold hours.

Another thing was that when people read in the newspaper that prices are really high, they tend to actually reduce consumption, maybe light the fire instead. And that is also something, if you want to get that into your systems, you have to have retailers that anticipate this behavior, and actually bid it into the system, because if people are reducing their consumption, you have to model it in the demand curve in order for it to have any meaning for prices.

This is a picture on the European integration. This is about, actually, who is going to control the exchanges in Europe.

And that is a problem that I didn't think about before I saw this, this article, which is quite recent, from the major Norwegian newspaper. Because of course, this is something that is given away to someone, to make this business happen, and in my world, which is that of a non-relevant person from academia, I didn't think about this at all, because to me it's kind of obvious, if you have a pool that is going to control or sort of utilize the whole capacity of the system, you have to make that in a coordinated way. So, you can't have sort of competition for a pool. I didn't think about that.

So, this is about a possible agreement between EPEX Spot, which is the German-French pool, and the Nordic pool, to sort of divide the European area between them.

I just want to show you one example from the actual Nord Pool price in 2005. If this is your true network, so I said that area prices is the method of dealing with congestion in the Nordic market. So, if this is your true network, you represent all the nodes and all the lines.

Well, what is really zonal pricing then? Well, it is a sort of aggregation, but what kind of aggregation? What are you aggregating, is it only the prices or is it the network itself too? So, this is the kind of price aggregation, where you keep all the nodes, you keep all the lines and you just require that prices within zones should be uniform.

What is actually done is this. You represent the physical system in a very simplified way. And that means that, for instance, this area here, since this really has three nodes, when you represent it with one node, you know where the bid is located, you don't take into account internal constraints, and what about this link here? It's going to represent two individual links. So how are you going to set the capacity on this one link, to represent the two of them? That's very difficult.

And this is what happens. What you do is that you move internal constraints onto the borderlines. And this pictures the capacities given to the market, in one specific day, so you see a lot of variation within 24 hours and this is not due to maintenance. This is due to internal constraints.

And if you look at the spot price here, for Eastern Denmark, which is where Copenhagen is located, you see it goes to heaven, when the capacity is very low between Sweden and the DK2 electricity region of Denmark, where Copenhagen is. And the Danish system operator was very upset about this and they made a report and they got Nord Pool to recalculate the prices. So, this is the price for this hour at Nord Pool. The capacity is equal to 368, between Sweden and DK2. And the price in Sweden is 336 Norwegian krone and in Denmark it's 14,181, (and you have to divide by six to get the dollar number). So, that's quite considerable. And then, with the recalculation, there is one difference here. And that is the capacity from Sweden to that part of Denmark. That has now been increased to the nominal capacity of 1,300 megawatts.

And what happens? Well, you see that the price in Sweden increases slightly, to 170 krone, and the Danish price is reduced by 13,500, so the Danes are very upset. Also, even at this time, there was this German area, the price here also was reduced from 14,000 to 3,000. So, the Danish system operator just filed a case for the European Commission, and this is the sort of background for the Swedes having to split Sweden into four areas. And that is to avoid having constraints here, on the borderline between Sweden and Denmark.

Finally, investment is a difficult issue. What we see is that there have been different ways of dealing with generation investment, depending on what kinds of challenges you have in different countries. Finland has been investing heavily in nuclear power. That has been helped by long term contracts between generation and industry agents.

In Denmark, you have the highest wind concentration in the world, that has been helped by feed-in tariffs, which, at least in the last period have been a combination of the market price and a feed-in tariff.

Sweden, you have a lot of fuel substitution on the thermal plants. And that's mostly biomass, also connected to forest industry. There have been green certificates since 2003 with prices say like 60%, 70% of the electricity prices. The ambition is to reach 17 terawatt hours in 2016, and I think they are quite well on their way.

Recently in Norway, we've had a lot of new small-scale hydropower. There is some evidence of green option behavior, people are sort of postponing investments, they're waiting for the green certificate market and that came into place in January 2012.

So, there have been quite a lot of new initiatives on the generation side. When it comes to transmission, there are really massive investment needs (and that is also due to these renewable)--a hundred billion krone by 2020, which has a book value today of 60 or 65 billion krone, so that's a lot of money. The main problem here I think is public acceptance. And this is a very beautiful area, if you got to Bergen, you can come here, it's the Hardanger area and there is going to be a power line just across here. And this is sort of a picture from the protests, it says "Hardanger in danger," there are some policemen carrying away a young woman in her national costume. This sign says, "Jens, you are lying," Jens is the Prime Minister. He did not have a good election this year, in this part of the world. And then are some of the paradoxes--this is on the other side of the fjord, this thing over here. That's not a power tower, it's a bridge, you know, that's benefits for the locals, the power lines are not benefits for the locals. That's for the North Sea Petroleum factory and so on.

Question: When you speak of value of lost load, are you talking about curtailment?

Speaker 1: No, I'm thinking about outages. Outages are measured. So, it is curtailment and not …

Question: Involuntary outages?

Speaker 1: Some of them are planned. Others are not. So, it's a combination, but it's mostly things like, say, if you have a power line going down because of a storm or something like that, then every interruption over three minutes is measured.

Speaker 2.
It's quite a pleasure to be back in this group again. I only wish I had more pleasurable news to bring you. But when I talk about electricity market developments in Great Britain, I'm usually going on about how we're at the forefront of the development of the competitive market, and I fear now we're at the forefront of the retreat, [LAUGHTER] as you will see in my slides.

I will be talking about government policy, grandly named Electricity Market Reform, which covers some major issues, and also about regulatory policy. The regulator is allowed to do a few things these days.

The policy of Electricity Market reform is set out in a white paper that was issued last year and has been updated. And it's entitled, "Planning Our Electricity Future." So you can see that the "P word" is back. And by 2030, the government says, we will have flexibility, diversity, security, demand management, competition, least cost transmission--you name it, in 2030, we are going to have it.

Now, this of course is not going to be easy. The government recognizes some important challenges to be met. Security of supply is one challenge. Something like one-fifth of the present generation is expected to be closed in the next 10 years, so obviously that at least will need to be replaced. Decarbonization is a pretty major challenge. We've got a target that 15% of our energy should be renewable by 2020, which means that 30% of the electricity supply has to be renewable, and we are now at 7%. So that's a way to go. Carbon reduction is to be about a third by 2020, 80% by 2050. Demand is increasing. The government is conjecturing we may have a doubling of demand by 2050. Another challenge is rising electricity prices for various reasons. And the investment program is a challenge, both for new generation and the networks--something over a hundred billion pounds estimated to be needed by 2020. So, large tasks.

Now, will the market deliver all this? "No," says the government. The market price is such that renewable technologies are not favored, they're disadvantaged, there are various entry barriers that the government identifies, the carbon price doesn't fully reflect the social costs that are involved in different forms of generation. There isn't enough incentive in the form of the price mechanism, so the very highest price we have seen in the market to date would have to be 10 times higher, it says, to justify some of the needed investments.

So what is the solution in the absence of the ability of the market to solve these problems? The answer is contracts, contracts both for low carbon generation and for various forms of capacity. Now, for low carbon generation, there are going to be long term contracts, feed-in tariffs, and contracts for differences, as I mentioned, with a whole range of technologies--the government envisages that contracts will be signed with wind generators, solar, nuclear. There is a carbon price floor to stimulate investors to invest in the right direction.

Now that is going to top up the European emissions trading scheme. The price of carbon on that market has varied over the last few years, between zero and £20 per ton of CO_2. It's presently standing at about £9 per pound of CO_2. The target for next year is to be £16, by 2020 it's to be £30, and by 2030 it's to be £70--pretty radical change there. And there are emissions performance standards that have been set, such that it should not be economic to building a new coal-fired station without CCS.

That's not all. Various other measures are envisaged. There's something called the Green Deal, which involves various chains of stores being invited to provide energy efficiency investments for customers. They will pay for it over time and the electricity companies administer this scheme.

A new capacity mechanism is to be introduced. And the government says, in parenthesis in effect, "(just in case we need one.) We think we need one, we might not, but we better have one just in case." I don't know if anybody else has been designing a capacity mechanism just in case they might need it. Anyway, that's going to be a major change.

The system operator will have a new task, which is to sign all these contracts and to monitor them, and it will be having to sit down every three years, starting in 2016, with the government, to decide whether things are going well or not, and if not what should be done.

And finally there is to be a more liquid wholesale market. And that is a task that has been handed over to Ofgem, and I'll speak in a moment about what Ofgem's going to do about it.

We are all going to have smart meters--that's all residential customers. That's about 50 million meters, gas and electricity. They are going to be installed in the next five years or so, by 2019. Some people question whether that's a feasible target. There's an interesting question on opt-outs. It seems that you don't have to have one of these fancy meters, if you believe they are unhealthy for you. [LAUGHTER] How many people are going to be allowed to claim that, we don't yet know.

The government had to do a cost benefit analysis of this, as indeed it has to do for everything it does these days. And the cost, it estimates, is about £11 billion. Now that's approximately just over £200 per meter, but the benefit will be just over £300 per meter, mainly from avoiding the need to go out and read meters, but also a little bit from reduced energy, a third from reduced energy consumption, and so there's a net benefit of a £100 per meter over 20 years. Now to my rough calculation, we are talking about customers being £5 per year better off as a result of this rather expensive plan.

OK, what is the government going to be doing in all this? Just in case you've missed the point earlier, the government repeats what its role is. It's going to be responsible for setting out the policy approach and objectives, taking final decisions on key roles and parameters, and setting out and periodically revising its delivery plans. So, basically, it is responsible for everything. The market has a very limited role. It doesn't get much of a mention, and the regulator not much either. So things are changing, as you see.

What is the case for this? Well, the government set up its economic case for this electric market reform. There will, it says, be a slight increase in bills in the short and medium term, relative to its base case. And the base case involves quite a considerable increase in bills anyway. So, under existing policies, it says, there will be an increase in household electricity bills by £200 by 2030, which is from £485 to £682 per average household, so you're talking about a 40% or so increase in bills. With the reform, this £200 increase is going to be limited to £160, so you're saving £40, which the government proudly says is worth 6% of the energy bill. That of course is in 2030. If you take the saving over the period from now until 2030, it's around about 1% to 2%, a little less, but just positive.

But, as you might guess, some are skeptical about this, and there have been various papers written and studies done that cast some doubt on this. For example, this claim that the bill will be 6% lower. This actually is a combination of two things. It's a combination of an increasing price per unit of electricity offset by a reduction in usage of electricity, so it depends pretty critically on assumptions about energy efficiency and lower usage, no doubt stimulated by these smart meters.

One study has calculated, if you look at the increase in price according to the government's calculations, and then you add in the increases in prices to businesses which will be passed on to customers, and you add in the increases in costs which have taken the form of taxes, and add those on, it's equivalent to a 27% increase in price.

And there are, of course, as you can imagine, in the implementation of this, some discrepancies already. For example, I mentioned earlier that the carbon price, the going market price for saving carbon, if you like, is £9 per ton of CO2. The cost of subsidizing offshore wind, which is intended to have the same effect, is about £200 per ton of CO2--so an incredibly costly way of achieving apparently similar ends. This carbon price, it's £9 now, as I said. The target is £16 tomorrow, but it's generally accepted that you're going to need a price of about £25 to stimulate any of these renewable investments, or just nuclear. And the government itself said, "Well, if we didn't have any contracts in place it'd need to be £50 a ton." So very significant changes would be needed to change the investment pattern.

There are, of course, questions about how these contracts are going to work, what they're going to look like, what price they're going to be. Somebody has got to negotiate with the relatively small number of companies interested in building nuclear. They could be expensive contracts. How this capacity mechanism will work, what impact it will have on the rest of the competitive market—there is great uncertainty. Also, customers are beginning to realize that this is costly, prices are already going up, and there is a lot of grumbling. Are they going to stand for that increase in price, particularly since it is likely to hit poor consumers harder than more affluent consumers?

And all these calculations are independent of any developments in the market such as shale gas. They were carried out before shale gas was considered a possibility. It still isn't considered a realistic policy by the government in the U.K. But that of course has a significant effect on the relative cost of that policy. This was a calculation put out last week. If you believe the government's figures, you can argue that its program is £11 billion cheaper than doing nothing. If, on the other hand, you accept the possibility of shale gas coming in, it could be £18 billion dearer. The cost/benefit calculation is very sensitive to that particular development.

Now, turning to regulation. Ofgem has been carrying out its review of network regulation over the last two or three years, and it concludes that the RPI - X (Retail Price Index minus "X") incentive regulation has been a great success. I agree with Ofgem on that. And it says it's brought lower prices, more investment, better service, quality and so on.

Then it asks, is it going to be appropriate for the different conditions that will obtain in the future, when we have low carbon generation, more renewables, new and smarter technologies? Answers Ofgem, "No, it won't do." And of course it faces the question, how are we going to set prices and price controls if we don't know what future investment needs to be, and we don't know what the output needs of the industry will be?

Well the answer is something called RIIO, Revenue Set for Incentives, Innovation and Output, which Ofgem says is, "a new way to regulate energy networks." And this involves the regulators setting outputs after some, "enhanced engagement with customers," then providing incentives for the companies to deliver this in a timely and efficient way, and also incentives for innovation. And if the companies behave, and put forward, "well prepared plans," they will have fast tracked reviews, and they'd be zipped through. But, if they put forward ill prepared plans, it's going to take them a long time.

Now, you may say, "Aha, customers are going to be engaging in this process, is this negotiated settlement?"

"No," says Ofgem, it certainly is not, because we can't leave customers to choose outputs, because present customers don't represent future customers. [LAUGHTER] It has to be us.

Now we have the first example under way at the moment of this new fast track mechanism. Two Scottish transmission companies have been granted fast track status, at least so far, as long as they continue to behave themselves, and two have been told, "No, you're still back on the old slow track." And these companies have put forward eight year business plans--we're now going to have an eight year period instead of five year one--and they have been asked to specify what outputs they think they should meet and what incentives they will have, and some of them say, "We have a reputational incentive here." So you can tell we're going to take that seriously.

And they cover all sorts of things, as I've set out here, and there are penalties involved. They are proposing penalties for late or nondelivery, up to

10% of their revenue. They have asked for a stimulus for small scale innovation, which is to be between a half and three quarters of a percent of their allowed revenues. So we're talking about a few million pounds there. And there's a whole list of various mechanisms for dealing with uncertainty, one of them being a 50% sharing if they underspend or overspend their capex compared to what they said, then there's a sharing of that. And the regulators said basically, "OK."

And let me just look at the customer engagement process, because that's one of the supposedly novel features, and one of the things that enables the regulator to say, "OK this is on the board, this is going the right direction." The process certainly has been fast, though. We're talking about a few months, and the other companies are going to be there for another year or two, I think. These are much more flexible control schemes, they're much more incentive-based than anything we've had before, and I think it's fair to say that the companies are talking more to the customers and about what the customers want.

But if you look a little more closely at what this customer engagement process is, it's mainly a description of how they're going to talk to customers more often and more deeply in the future, rather than having talked to them already. And secondly, as I read it, the nature of this engagement is more along the lines of explaining what we want to do and have you any questions, rather than saying, "Well, what do you want?" and having some kind of negotiation about what people and customers want and what is reasonable to pay.

So, how substantial that process will be I think remains to be seen, and I myself have some question in my mind as to whether Ofgem itself is going to be able to negotiate and manage this relationship as effectively as you get in a negotiated settlement in the U.S.

Liquidity is something I said the government has delegated to Ofgem to sort out. It has a particular reason for that. Ofgem's been grumbling about liquidity in the wholesale market for some time. It doesn't think liquidity is as high, perhaps, as it was, and as high as in some other markets. Now companies, I have to say, on the whole, are not complaining, and maybe because there's more vertical integration there between generation and retail supply, they don't particularly need to trade, so they've not been complaining, but the government now has a particular interest, which is these contracts for differences that it's going to sign with the new generators. It wants a market price against which to sign these.

So, it now has a very clear interest in developing a more liquid market. And Ofgem has suddenly said, "OK, there are six big vertically integrated companies in the U.K., they must all auction 25% of their generation on the market." And the generators themselves are saying, "Well, this doesn't sound like a very good idea, how can we get the regulator out? Maybe if we do it ourselves, then the regulator will go away." So two or three of the companies are trying to encourage the others to start auctioning some of their generation, which they're beginning to do, and they're having some positive results in terms of liquidity, typically for shorter products rather than longer term products.

Some people are critical. They say, "This should have been done five years ago." Others are saying, "Is it really going to make a difference? Is it really critical for new entry?" So, that's something, as it were, under way. Fluid, liquid at the moment, you might say.

Transmission access. We're now re-fighting old battles. The traditional policy has been what they call "invest then connect." In other words, if a generator wants to connect to the transmission system, the transmission company has to build adequate capacity first. When that capacity is in place, then the generator can connect, and not until then. The government has said, "This is not good enough, we want these new generators coming on this system as soon as possible. From now on they must be given a quotation for the maximum length of time it will take for them to get on," which is going to vary by type of generator, and I think maybe by area, but if the transmission system hasn't got its act together by then, the generator comes on the system anyway, and it's up to the transmission operator to manage that system.

The consequence of this, the government says, has been that time taken to get large generation projects on the system has been cut by an average of six years, which sounds quite good, but of course there have been growing constrained-off payments as a result of this, because the capacity hasn't always been there on the transmission system, and the costs are increasing the charges to customers.

There's also an ongoing debate--this has been going since I was regulating, and still hasn't been resolved—about what the transmission charges should look like and whether they should be uniform, postage stamp or not. The Scot generators, the renewable generators up in the north of Scotland and offshore in Scotland, want postage stamp rates because it's otherwise costly to transmit that generation back to the south where the demand is. But Ofgem doesn't like that, and Ofgem's saying, "Maybe we'll stick to locational charges except for wind." So that's where we are at the moment.

In terms of retail competition, my final topic, my own, maybe prejudiced, view is that I think the U.K. retail market is working as well as pretty well anywhere in the world. But Ofgem is concerned that there's not enough switching. When they say, "not enough," it means that the figure of the number of customers changing per year has fallen below 20%. That's one-fifth of domestic residential customers changing every year.

For the average big six company, this means about losing 3,000 customers per day, which means just to stay still you've got to find another 3,000 customers per day. That seems to me pretty aggressive competition, but Ofgem thinks it's too little. It says the problem is that those people who do switch get good prices, but those people who don't switch don't get good prices. They're something like 10% to 15% higher in my calculation. And Ofgem's concerned about that.

And it's says that customers would engage more effectively if it were easier to compare tariffs. It's too difficult to compare tariffs--too many tariffs, too many variations. So they refer to this (and I don't know if you've heard of the nudge philosophy, well here we are, Ofgem has adopted the nudging philosophy) proposal that henceforth, these major retailers would only be able to set one standard tariff for each payment method. Not only will they only be able to set one tariff, but all the companies, all the competitors, are going to have to set exactly the same standing charge, which is levied per month. And Ofgem is going to set that charge. Each year it will announce what that element of the charge is.

Now, a downside of this is that various what seem to me very useful innovations would be banned. So, for example, tariffs that offer zero fixed charges for those that like this, or higher fixed charges for those that want a lower per unit charge. Discounts for purchasing your electricity online, taking your bills online. Discounts for having dual fuel, electricity and gas--all these go. Extra charges for green tariffs--if you want to pay a bit more to go green, nope, standard charges won't be able to do that.

It of course will involve quite considerably higher regulatory charges, both on the part of the companies, the retailers, and the regulators. Customers will have to pay those. And importantly, it seems to me, we're going to have a regulatory element in tariffs once more.

Political influence is inevitable. So, it seems to me this is the most retrograde single step that's happened in the regulatory sector ever, I would say.

OK, to our conclusions, there has been a major policy switch in the U.K, both on the part of the government and on the part of the regulator, from a focus on competitive markets to a focus on central planning. This is an extremely ambitious program, in all respects, but it prompts many questions. Will these plans and mechanisms work? What, if anything, will be left of the competitive market as a result? What, if anything, will be left of independent regulation? Is this a good value policy, as the government claims? Or is it going to be unduly costly? Are customers going to be accepting of the price implications of this, which I'm sure they're not aware of yet? And what about the costs, if fuel prices, fossil prices, don't rise as assumed and it becomes, may appear to be, an un-economic policy? So, my question, I think, is how long is this policy going to last, and how long is it going to be before we see a new government changing the policy? On that cheerful note…

Question: Who is the counter party on these contracts for renewables? Is it the operator, the rec, the government? All three of the above?

Speaker 2: Everybody has been asking that. The answer seems to be, the system operator will be the counter party, and they will then be charged out to all users--all suppliers, I guess.

Question: Your comment about 20% of generating supply anticipated to be retired in 10 years. Is that like a compliance problem, or that's just a guess based on age, or --

Speaker 2: Just age, I think.

Question: On the carbon target, is there a cap and trade system in there or is that an exogenous tax?

Speaker 2: There's still a lot of debate about what way to go. The European Trading System, I think, is basically a tax --

Question: And so that will be a floor for the taxation.

Speaker 2: Yes.

Question: And what is the regulatory entity that drives all this? Where does the authority rest? I don't know the system well--you seem to be referring to several different entities as pushing the buttons to make this happen. Where does the authority reside?

Speaker 2: Well, if you had asked that kind of question 10, 15 years ago, the answer would be that Ofgem, the regulator, would be the only entity that could, in effect, propose to take these powers. But, now, the government, by various acts of Parliament, has taken, or is proposing, to take all these powers.

Question: OK, so these are legislated. That's what I'm --

Speaker 2: Yes, I mean it even got to the stage where, in the last Act, it took power to change the licenses of the companies, because it knew that the regulator wasn't going to make that particular change.

Question: On the retail charges, you indicated that there would be a standard monthly fixed charge. Are there volumetric charges that can be dynamic, or time of use, on top of that, and if not, what's the point of having advanced meters?

Speaker 2: In principle, that is going to be possible in the future. And the regulator is certainly in favor of all that kind of thing. As of today, there are no meters that you could do that with, for residential customers. And they're available for the large customers, and some large customers have more sophisticated tariffs, but for the residential customers, they won't have them for another five, six years. So, that kind of thing will happen in five years' time.

Question: Let me just follow up a little bit on the previous question, because it changed my perception of where you were going. So, the carbon price is an actual price that has to be paid, and not just something that is a proxy in the planning and contracting price?

Speaker 2: Yes.

Speaker 3.
It's very hard for you when you are a foreigner to do any kind of joke, but after the presentation that we just saw, I'm obliged to say that as a disclaimer, I do not represent anything, I will just try to adopt here a positive view on the subject [LAUGHTER].

And you will soon understand the reason of this disclaimer. I was trying to answer the questions that were posed in the outline of the presentation, and so what I am going to do is to talk a little on the background for the Brazilian power system. Then I will mainly focus on the recent developments in terms of transmission--how the system is expanding, auctions that have been run, and how this relates to new concerns of connecting renewables. And then I will make some concluding remarks.

Just as some background information, Brazil has a large-scale power system, with over a hundred gigawatts of installed capacity interconnected by a vast transmission grid that expands throughout the nation. More than 85% of the electricity that is generated is generated from hydro resources. We have what we call "transferring water by wire." Regarding transmission, we have open access, so every power plant has the right to be connected to the system.

Energy is traded in basically two environments in what we call this new model that was launched in 2004. We faced a severe draught in 2001 and an energy crisis, and the answer to these concerns was a new model, and basically we have these two trading environments. One is the regulated one, where energy is procured at auctions that are designed to contract for all the electricity required to meet the estimated demand for the next five years. And the resulting costs are passed through to consumers. This is sort of a modified single-buyer model.

Then we have basically long-term contracting through a series of auctions that are held every year for power plants to be built and to begin operation--five years ahead, three years ahead, there are different contracting opportunities, including maybe opportunities for renewables.

And roughly 30% of the electricity is traded in what we call the free market.

This is the map for the part of the country that is interconnected. We have around 265 agents. The maximum demand as of 2010 is roughly 66 gigawatts. This is a multi-owned system.

Regarding the transmission grid, we have roughly a hundred thousand kilometers of long distance lines, of 230 Kv. We have been experiencing significant increase in the expansion of these transmission lines, as well as in the transformation capacity.

Now we have the "P word" here. How does this system work? We have a planning company (EPE)--this is the company that was created under the new model. We have only one regulator in charge of electricity and it operates at the federal level. Regarding transmission, it has to approve the project according to the technical compliances, and this federal regulator is in charge of running the auctions for the system expansion. We have a national system operator and we have multiple transmission companies.

And so, how does this expansion take place? The planning company identifies the need for the expansion, and then the ministry has to approve, and then the federal regulator runs auctions in the model of competition for the market. These auctions take place basically twice a year. And so agents compete for the right to build, operate and own the new facilities. The winner is the qualified bidder who commits to the lowest annual required revenue for a thirty year concession term.

And so the revenue to be earned by the transmission company is set in these auctions. And then, as a result of these auctions, the winning company signs contracts--a concession contract with the regulator, and then an operation contract with the national operator.

If you are going to talk about pricing and cost allocation in this system, annually the regulator estimates the total cost of the interconnected system, setting transmission rates accordingly. So the total revenue is the sum of the fixed remunerations for all the transmission equipment in a given year, and is collected from generators and load through a fixed access charge that is called a usage charge, but in fact is an access charge.

And since 2007, there is a new ruling that says that new generators, or companies that are going to compete for the right to build power plants, are informed of the expected transmission rates to be applied for the first 10 years of operation. They are trying to avoid volatility.

What is the experience so far with these transmission auctions? We have faced a lot of entry in this market. At first we had something like 10 transmission companies, now we have more than 60 in the market. At first the auctions were able to attract participation from foreign capital, but more recently investors associated with Electrobras (the big holding company in the electricity sector that is state controlled), are being able to win a considerable amount of auctions. This has been taking place mainly after 2008, where foreign investors are facing difficulties.

Environmental licensing is a process that is becoming more complex for these transmission facilities. In the generation auctions, power plants that are going to be auctioned have to have environmental permits in advance, but in transmission, the investors are the ones in charge of getting the licensing. And so, as a result of these problems with environmental processes, we are now facing delays in the delivery of these new facilities. A lot of transmission facilities are being built now in the country because we are in the process of connecting new power plants that are being built in the Amazon basin.

And so, just to take a look on the numbers around the movement that is taking place in these auctions, we have had transmission auctions taking place since 1999, we have a cap value that is estimated by the regulator and then as a result of competition, we face prices or revenue requests that are lower than the caps. And then we have, in this green line, the movement in terms of this lowering, in terms of the caps that we have been experiencing. You see that big spike there is the transmission facility to connect these power plants in the Amazon basin. So they represent a considerable amount of investment.

These numbers relate to the annual revenue that is requested and they are expressed in reals, roughly you could say that one dollar amounts to two reals, it’s 1.7, but just for you to get an idea.

And so we have been seeing expansion in the system. With regard to pricing, we have zonal pricing. We have the country divided into four regions, and congestion surcharges are allocated to all consumers within a given region on a lump sum basis. And for reliability purposes, we have been facing a considerable amount of out of merit order dispatch, with costs borne by consumers.

Recently, there are some challenges related to connecting remotely located renewable power plants. At first we were trying to develop a mechanism that would more closely resemble the open season experience in the natural gas industry. The renewable power plants that were to be connected first were the ones that would generate electricity from biomass, and a competitive procedure would be adopted, but not a centralized procedure like what we have for the regular transmission capacity.

It was not successful, and so there was a recent change in this procedure, and it more closely resembles the ordinary transmission auctions that we have, and these procedures are being used to connect wind power plants, but environmental permits are difficult to get.

And so, just some concluding remarks about what is going on. We have transmission expansion that is taking place as a result of a combination of central planning and market competition. We have all the residual risks allocated to the load. We have had a successful experience in terms of the ability to deliver the system expansion. In the new model there has been relative success in terms of the ability to connect remotely-located renewables, mainly wind power plants. But it's important to mention that we have risk allocated mainly to the load, and we have scarce mechanisms from the demand response perspective.

Question: Is the generation sector regulated or unregulated?

Speaker 3: We have independent power producers.

Question: Are the transmission charges to recover the fixed cost of transmission that you talked about, are they just spread across the entire customer base, or is there some attempt to allocate transmission costs based on beneficiaries?

Speaker 3: No, they are basically split, half goes to the load and half goes to the generators.

Question: Without regard to location?

Speaker 3: Only some location when the plant is about to be installed.

Question: Thank you, that's very wise.

Moderator: Our last speaker, representing just a small little country [LAUGHTER] in Asia that accounts for a substantial amount of the growth of electricity demand in the world is going to talk a bit about developments in the Chinese market and some of the issue that they're facing.

Speaker 4.

It is my great honor to be here to share my personal view on the China side. I think maybe China's electricity industry is more simple than other countries, more simple than UK, maybe more simple than Brazil. And it looks like a one buyer, one seller model. So we have a long way to go. But which way is the best way? Which way is the most appropriate way to go?

So I want to take this opportunity to listen to you, especially since you are the pioneers in power market reform. So I can get answers from your side.

Today I want to focus on three issues. First, I want to introduce the passionate efforts in China in the area of market reform, especially from the mid-1980s on. Second, I want to talk about the current dilemmas that China is faced with. We will talk about the government's position. We will talk about the pricing system. We will talk about the industrial structuring issue. And the last topic I want to discuss is the prospects for the future of China's reform. Who will be responsible for achieving the reform? Who is responsible for the directing the reform, and what should be reformed? And when? Should we reform from now, from tomorrow? Or should we just wait, wait for the US to have a good model to follow? Or wait for the UK have a good model for China to follow?

Comment: How patient are you? [LAUGHTER]

Speaker 4: I don't know how many years we can be patient. I hope the time span is not very long, because we have an ambitious target for electricity market reform. And almost ten years after setting that goal, very little has happened, very little has changed. During this period of time we have conducted some pilot projects. We tried a little in the very specific area in the northeast of China.

On reform timing, I asked Professor Hogan, who told me that you want to do it, you can reform from now. But I'm not quite sure whether from the policy makers' view we have enough strong political will to reform. Because maybe we can have some foreseeable difficulties and maybe some potential problems to cope with. So this is a real problem for us.

The first slide shows a brief introduction about China's electricity industry from the generation side. All the generating power comes through two giant companies. One is State Street and the other is South China Power Grid. In terms of distribution capacity, the State Grid takes around 78 share of the total. And the remaining 23% share is with South China Power. And on the demand side, secondary industry takes the most dominant share, and the other sectors, the service industry, residential, and the agricultural industry, have the remaining market share.

In terms of the market structure it seems more simple, as I mentioned earlier. In China the government plays the dominant role in the electricity industry. The generation companies sell their electricity to the grid companies at the government's regulated rate. And then the grid companies sell the electricity to the users also at the government's regulated tariff. So in this process, government regulation plays a dominant role.

If you want to look at reform in China since the 1980s, I have tried to summarize three phases of the past efforts. From 1985 to 1996 were the primary efforts to start the market reform to open the supply side market to the social investors to deal with the severe power shortage. Before that, the whole national electricity market was strictly command and control. And after that, there were many more independent power plants, the FPPs, participating in the electricity market.

1997 is the first turning point in the history of Chinese electricity, marked by the establishment of the State Power Company. This reform aimed at promoting the separation between the administration and the corporate parts of the industry.

And six provinces and municipalities were involved in a bid-based separation of generation and grid in 1998. This was not substantial bid-based separation, but just functional or simulated separation. Nothing happened in reality. And from the beginning of the new millennium year, the 2000 year, we had full debates on the market oriented reform. Because we had a newly built hydro power plant named Er Tan. From the very beginning of this hydro power plant, it had a huge deficit. So many people argued that we should achieve the market oriented reform to deal with this problem. Overall, this phase lasted for four or five years.

2002 was is the second turning point of the Chinese electricity industry. The State Council issued the historic document, Mandate Number 5. To some extent my personal view is that it is the equivalent guidelines for the future market or entity reform, maybe equivalent to FERC Order 888. And in this Mandate Number 5, the central government showed the ambitious target for the future of market oriented reform by many aspects.

In this mandate, the government mapped out the clear targets of the systematic reform by breaking down the monopoly, introducing competition, optimizing resource allocation, and setting up a healthy power system with a regulated, fairly competing, and open electricity market. That's the target that never happened.

Another part of the third reform phase was restructuring the whole industry. To some extent we restructured the whole industry by splitting the former vertically integrated State Power Company into several pieces. From the grid company we established two grid companies. From the generator part of the company, we established five big generator companies. And we also established four independent ancillary companies. To some extent this is more like a competitive market structure. But the real competition I think is not yet achieved.

To a large extent, China is now midway into market oriented reform. Maybe more accurately it is somewhere in the middle, but at an early stage of market oriented reform. And if we compare to the Mandate Number 5, many field target fulfilled, many more targets are missing, unclear, unfinished.

The finished task of market oriented reform is competitive generators, and seeing many more generators enter the market. This is the only finished task. We have many more unfinished tasks, from redefining the government's position, to the pricing mechanism, to the regional grid companies' functions, to bid-based regional markets, to the regulatory function, to the further separation of transmission and distribution.

So here I tried to summarize the first dilemma for the government. Maybe it is not a problem for the US, or UK or Brazil. It's not so for Norway, but for China it is really problem that, it is the whole industrial reform, or it is a reform of the government. Because if we review past efforts, and we review what we are doing, we can easily find the government, not the market, plays the dominant role in the market oriented reform. The government still controls everything, from market entry to the pricing system. It controls regulation, and controls the wholesale-retail market, even though the government tried to retreat from the coordination between the coal industry and the power industry. They tried to be independent of the coordinator between the coal industry and the power industry. But the coal industry and the power industry, they cannot reach agreement with the coal prices. So the government, how say, are unwilling to be involved in the coordination between the coal industry and the power industry. And also, the central government and local government have different opinions on electricity industry development reforms, and on pricing, many things. So I think there is a game between the central government and the local government.

Look at the future. What will happen? We must reform the unreformed. We must reform the unformed, even though we have a clear target for the future. But we haven't found the appropriate solutions for many things, from *who*--who is responsible for designing, directing the reform, *what* should be reformed and *when* to reform and *where* to reform.

Who. The first question is about who will be responsible for designing and directing the reforms. We have different departments or authorities being involved in the administration and the regulation of the electricity market. We have the National Development and Reform Commission. We have the State Electricity Regulatory Commission. We also have state-owned asset monitoring and the administration commission responsible for regulating or administrating the electricity industries. So it is a hybrid picture of the designers and directors.

So for the future I think we need an independent, empowered, and ever improving government authority with the relevant responsibilities for designing, directing, implementing and revising the reforms. This is a necessary condition of success for reform. Maybe it is not a sufficient condition, but it is a necessary condition.

The second is legislative reform. We don't have a healthy, a sound legal system to empower the regulatory body to direct, to design the whole electricity market. So from the beginning, if you want to we establish a good designer, a good director, we should have the legal institutional change in advance. So in term of the regulatory body I think, we should make the present SERC to be more like FERC, even though it looks like just one letter of difference between SERC and FERC. In reality, it's quite different. SERC cannot play the equivalent functions as FERC. In order to transform the SERC into FERC, we have many things to do. We must have a complete endowment by laws and by relevant decrees to make the SERC responsible for leading the reforms. We need to integrate the scattered functions into one regulatory body to design, to implement, and to direct the whole process of reform. We need to make the regulatory body independent of the administration. Also, we need a dynamic evolution of the regulatory body. We need the regulatory body to have clear boundaries of relevant activities.

So the next question is about what is to be reformed. In my view, we have many things to do, from institutional changes, to market design, to restructuring the whole industry, to providing enough incentives to the investors to deal with the risks and uncertainties or the many, many things related to keep the reforms more secure. And we must deal with the new challenges ahead of us, such like the recovering economy, the smarter electricity, to need conduct innovative projects, things like that.

And among the main future reforms, I think there's a very important task to do, which is that we must make a competitive market. All these competitive markets should be based on some principles, such as multiple buyers and multiple sellers to have an open and a free entry and exit. There should be no abuses of market power. The regulation should be based on having a complete and transparent information system. There should be bid-based, security constrained economic dispatch with nodal prices, which is the fundamental of the electricity market. And the public should be involved in setting the rules, using a process like the Notice of Proposed Rulemaking conducted by the FERC. And we must have a neutral and unbiased judge or referee to be independent of the competitors.

So after that, we must answer the question about when we should trigger the FERC reform, which is related the question of how the reform should be sequenced. Some experts say that the most important thing for China's electricity industry is to reform the pricing system. In order for that to happen, the government would have to lose control over the retail prices. But I think that if you do not have a competitive market, if you don't have a very good market structure, and you just lose the price control, you might get higher and higher prices. So in my personal view, restructuring should be prior to pricing reform. And we must consider moving from the wholesale market to the retail market. Also, we need to establish an independent dispatching center. Currently, the dispatching center is just an internal department within the grid company. And in the future, how can we make the dispatching center independent of the great company? We also need the further separation of transmission and distribution. But when should we make this separation? Now, or tomorrow or some days later? And when should China develop our own RTOs?

The last question about the time sequencing is, when is the best time to reform the market? In China there's a strong opinion that we must wait for the turning point of the supply and demand relationship. For the past many, many years China has faced a severe power shortage. This is a severe problem for the electricity industry. So some experts proposed that further reform should be triggered after the supply side exceeds the demand. Is this a true solution for China? I'm not quite sure. But to some extent, this is true. If you do not have a power surplus, you're always faced with the power deficits, power shortages, and how can you make the competition between the generators, because any generators can sale their electricity to the market because the market is easy in power shortage? But Professor Hogan told me that if you cannot get the prices right, maybe you cannot wait for the time when the supply and the demand relationship will be reversed. If you get the prices right, you can get to the turning point of the supply and demand relationship.

The next question is about where the market should be implemented—as a regional market or a nationwide market. I read a paper on the markets this year. An expert in China suggests that China should have a unified market model. I'm not quite sure this is true. To me, it seems like quite a tough task to form a unified market model, because the different regions have different conditions, different resources, different buyers, different suppliers. How can we form a unified market model? Some people argue the U.S. has many different models, many different RTOs and maybe they are considering to getting together to have a standard market to be only model. So this question is unanswered now. I mentioned earlier that some regions have conducted a trial of a regional power market, but they failed. And this maybe will be a barrier to the further reform. Because many efforts have been tried. And should we try again to repeat the past failure?

The last question is how to reform the governmental functions. At the present time, the NDRC plays a dominant role in the electricity market, not the SERC. How can we transfer the dominant power from NDRC to SERC? It's a problem. And also it is not a problem. If you have a strong political will, you can do this. But where does the political will come from? Maybe from the next generation of leaders, I hope.

Question: I'm curious about the way in which generation sectors competitive. You indicated that you separated into five different companies--and is it that each of the five companies are now bidding for contracts from the government to build the new power plants that are necessary? And I'm curious about whether there is a similar situation in some of the other countries, like Brazil or England. To what extent is the competitive market like a spot market, where your revenues depend on how much you get, or is it IPPs that are competing for longer-term contracts to build generation or that sort of thing?

Speaker 4: We tried to make competition work on the generation side. I mentioned earlier that the biggest five generating companies provide one half of the national capacity. But I don't think there is a true competition among these big five generators. Because under the one buyer, one seller model, there's no bidding competition. So the big five generators, they don't worry about competition, especially in the long lasting power shortage. You needn't worry about the power surplus. However much electricity you can produce, you can get the transmission service from the grid company.

Speaker 1: As far as competition on the generation side, we had a very favorable starting point, I think, with 200 independent power producers in Norway, at least--the number is a little smaller now but they are competing in a pool that covers quite a large part of the energy market.

Question: To Speaker 3, you said they had IPPs, but does that mean IPPs that are competing for contracts from the government for seven years of energy, or is it a generation company that's getting revenues from a bid based spot market, and the revenues are their earnings, and they are volatile?

Speaker 3: These IPPs are competing for contracts. For example, to supply to distribution companies when they are willing to supply for the regulated market. In the free market, you have contracts that have trade freely.

Moderator: As Speaker 3 said earlier, the regulated markets in Brazil are organized. There are auctions at five years ahead, at three years ahead. And anybody can bid. That's the regulated market. And then those contracts are assigned to the distribution companies in proportion to their forecasted demand. In the free market, anything can happen. That's 30% of the market.

General Discussion

***Question 1*:** In 1989 when the first reform took place in the UK, there was all this turmoil and discussion and commotion going on, and out of that popped the pool model that was adopted in Great Britain. It was very innovative. It was cleverly designed. It dealt with many of the hard problems. It didn't deal with everything. It wasn't perfect, but it was awfully good.

And then it went along and some problems developed. And then, I don't remember the exact date, but when the New Energy Trading Arrangement, NETA, came along, it just seemed like people sort of lost their connection with reality. And these papers were being produced by a small coterie of people, and I remember Callum McCarthy was involved, and he came here and tried to explain it in one of our meetings. And it just made no sense whatsoever--I mean this thing about having different buying prices and different selling prices. It didn't address the fundamental problem of the transmission grid and constraints. It just tried to submerge all of that sort of stuff. National Grid will do anything if you give them enough money. So, you know, they aren't a source of intellectual rigor on these matters. And, as I view it, NETA was just a big step backwards in terms of trying to design something that was internally coherent. And it's been going along and going along.

Now you have this process of this white paper, and I saw the white paper, and you described it in your presentation--and what's in the water there? [LAUGHTER] Why is this happening? It just seems to me that it makes no sense whatsoever. There's a whole lot of smart people there. You've got David Newbery and all the people that he works with that came out of that program, and they write these terrific papers and understand it. And you go to conferences, and we have heated discussions about leaves on the trees, but the forest we agree on. And then the forest has nothing to do with what is being proposed by the government. It's like it's in a different country.

Speaker 2: First, on NETA. The origin of that was my proposal. So I take responsibility.

Question: It's your fault! [LAUGHTER]

Speaker 2: It was to me a step in the direction of an even freer market and a less regimented and regulated one. And there were various imperfections, as you know, with the previous pool arrangement. The one thing that I think was not done correctly and was a decision made after I relinquished responsibility, was to have a dual cash-out price, so that people who were short of electricity get charged an enormous amount, and people who have a surplus get paid only a very small amount for it. And that is basically a tax on trading. And the only significant limitation I think of the NETA arrangements, a big criticism has been made, is that there is not enough electricity, and I think that's directly related to this. But otherwise I don't think NETA is a big problem. It may not have brought the advantages that we thought, but on the whole it hasn't been criticized.

I think the real changes started when the Labor government came in and said, "We must have a government policy. We must start making these decisions instead of the regulators." And that has increased. I agree with you that there are good commentators there. The level of discussion and understanding amongst the academic community, the consultants, and in the industry is every bit as high as here, and probably higher than in many parts of this country. But the changes are directly driven by government policy. And someone was asking at the break, "What is driving the present policy?" It's basically taking climate change seriously to the extent of this government saying, "Our policy is to be the greenest of the green. We are going to be right at the forefront of implementing the implications of that." It pulled back a little bit when the large energy users said, "Well, the further you are at the forefront, the more costly it is for us. And we're not going to be able to compete overseas." So the present line is, "We're going to be right behind everybody else. We're going to be there as well but we're not going to be upfront." So the policy was to be very green, and I think someone remarked that you could meet that with a simply a carbon tax or a carbon price and nothing else. But the second stream of thinking was, "We can't be sure. We have to prove that things are going to happen, not just hope that the market works." So hence all the bells and whistles that you see.

And I think the third strand was a personal one. The minister appointed to lead this was from the liberal democratic part of the coalition, not the conservative side. He was on the left of the liberal democrat wing. And he is fervent about climate change. And he's not a much liked minister, but he happens to be a very effective minister. And he succeeded in driving this through. And it remains to be seen what will happen, because he had to resign two weeks ago. He was arrested. [LAUGHTER] Well, I ought to tell this story. He was arrested because it was alleged that he was caught speeding, and he passed the points to his wife. So she took the rap. Of course, nobody would know this except his wife. That was two years ago. A few months ago he left his wife for his mistress. [LAUGHTER] Whereupon the newspapers had some reports about this alleged event. So anyway, we shall see whether the policy continues. But my sense the government is still planning to do it until the bills start coming in.

Question 2: With China, you had mentioned that there was a conflict between coal and energy. And obviously China imports a huge amount of coal, and that's the majority of its electricity production as I understand it. So what's the conflict? And you said something about a marriage of the coal and power sector? I just didn't follow the implications of that.

Speaker 4: You know, China is rich in coal, and we have many independent coal mines. They are independent of the power companies. So in the past they didn't need to sign annual contracts. The government arranged everything. But from the early years of the new century, the government said, "No. We will do nothing in between you two parties," and the government just organized the annual trade exhibition, to let the two parties, the coal companies and the power companies, sit together to sign the annual contracts. But the two parties cannot agree on the coal for power price. The coal mines prefer the higher price, and the power companies argue that "We cannot pass on the price pressure to the end users, because the government controls my price, so I want a lower coal price." So that's a big problem between these two parties.

And for many years in this annual meeting, very few contracts have been signed between these two parties. And after that, the NDRC, they forcefully have been involved in coordinating to make contracts between the two parties. Even though the contracts between these two parties maybe takes up one half of total coal production, it makes sense to have them to provide the resources to the power company. But I don't think the government can easily be independent of this involvement for many years.

Question: so that would mean that there's a chance that the electricity sector may import less coal and consume more locally…

Speaker 4: That's the reason why, in recent years, China has transformed from a net coal exporter to a net coal importer, because if China cannot provide coal for the low price, they can import the coal.

Question: What is the average price of power in each region? Wholesale or retail.

Speaker 3: $60-$70 per megawatt hour. Cost of energy.

Speaker 1: In my slides, you see some of the annual prices. The assumption when you do network regulation is in the same area, but it varies a lot.

Speaker 2: Wholesale price maybe 10 pence per kilowatt-hour

Speaker 4: For China, it is complicated. The retail price in China is classified into several categories. It differs from the residential to industry and from agriculture to the business use. The NDRC sets the benchmark prices for the residential, industrial and commercial users. But basically the residential and agricultural prices are around 7 cents per kwh, and for the industrial manufacturer, maybe 10 cents. The commercial users pay a higher price, around 14 cents per kwh. These are the benchmark prices, but many grid companies don't obey the benchmark. They charge the end users at a higher level than the benchmark. This is a real problem—who can punish them?

Question: My question is on the coal/electricity conflict, too. I assume that there are at least several coal sellers, and at least several buyers of coal for the purpose of electricity production. And yet when you force them into a room, and you put them under a bilateral monopoly structure, you're creating the conflict, it seems to me. I assume it's not perfectly competitive, it's not like there are many buyers and sellers, but there are at least several. But when you force them into a room, and you basically force the buyers to negotiate with the sellers en masse, you're creating a bilateral monopoly negotiation, which is always going to look very rancorous.

Speaker 4: It makes sense but from the power generation side, maybe you can have some solutions. One is they can build their own coal mines or they can buy a coal mine on the market. The second is that they can reduce their generation. Maybe they can have some excuse to do this. Maybe they say, "I need one week or two weeks for the maintenance of the generating units," because the more they generate the electricity, the more they lose their money, because the retail market is controlled by the government.

So I think that this is not the core issue between the coal and the power generating companies. The core issue is the systematic reform of the whole industry. If we cannot find the systematic solution for the whole industry, we just lose control of the price to have a coordination solution for the coal and for the power companies. It is not the best answer to these questions.

Speaker 2: I wanted to respond to the question you posed at the end of your presentation about what should be done, and ask a question. There's a famous Sherlock Holmes episode that people will probably be familiar with, where he said, "The key to this is the dog that barked in the nighttime."

And the inspector says, "But the dog didn't bark in the nighttime."

"Precisely," says Holmes. "Why didn't the dog bark in the nighttime?"

Now, in Britain, everything was driven by privatization. On the one hand, the government had to design a market framework that would be attractive to investors. On the other hand, it had to design a framework that would protect customers from these evil new private investors, and would create competition. And that drove everything. I mean, we thought consciously through all the implications, as far as we could, and tried to design a system that met those two dynamics.

Now the one thing that is completely missing from your presentation that one would expect to be there is any reference to privatization. So my question is, why is there no reference to privatization, when every other country in the world carrying out electricity reform would have at least some element of that? And would that provide any clarifying theme if you asked yourself, what would a private investor need?

Speaker 4: We don't call it privatization, but we call it the state-owned enterprises reforms. Some state-owned companies have been listed on the capital market. They open their market share to public investors. You can buy their shares on the market, if you wish.

I'm not quite sure whether this can be easily totally privatized. Is this the number one question for China? Or a number two, or a number three? If I am a publicly owned company and you are public company, we can find competition between us, even though we are all publicly owned companies. So competition may be more important than the ownership.

Speaker 1: Can I just comment on that? The Norwegian electricity sector was deregulated but not privatized. So it's still very much public ownership in all parts of the industry. But, you know, that's also kind of a cultural thing ,probably. The Norwegian state doesn't need money. And the Swedes sometimes call us the lost Soviet state, so. ..

Question 3: Because of this price squeeze situation in the last few months, several of the large foreign-owned generators that are still operating in the PRC have indicated they will be withdrawing from the market, AES being the most recent one, and one or two others. And there's been very little new announcement of foreign investment in the traditional generating segment. We had this major surge of investment in the late '90s, early 2000s, but in the last several years, because of the price squeeze, virtually no foreign investment has been coming into the generating sector. Is that a concern to the State Council? Or do they feel they can finance internally, without worrying about foreign investment?

Speaker 4: Sorry, I don't know the answers from the top leaders. I just can give you my personal answer, which is that the government welcomes all investors, including private investors, including foreign investors, including state-owned company investors. But the problem is that we must make the competition work in the whole industry. You can regulate the industry, but you cannot strictly control the prices, especially the bidding prices. Otherwise, any other investors who will lose their money, how can they have enough incentive to invest into the markets? So I understand that in the past years, some foreign investor have retreated from the market. But I think this is a temporary phenomenon. Maybe as the developments of the market oriented reform, if the social investors, including the foreign investors, have a good future to make money from the Chinese electricity market, they will enter the market again, because the nature of capital is to earn money.

So for me, the most important thing is to push further the market oriented reform, to make competition work, to show the profitable future for all the investors. So maybe in the next few years when the market reform can have a good start, or substantial improvement, maybe the social investors, including the foreign investors, can come again. We welcome the social investors. We welcome the foreign investors to be competitive in the Chinese power market

Question 4: My question has to do with the number of pricing locations, and I'll focus on Sweden based on the presentation. You know, there used to be one price across Sweden. They went now to four zones. Any time you de-average, of course some are going to be higher; some are going to be lower. So the ones in southern Sweden ended up with a higher price. They were, of course, unhappy. But doesn't that mean, though, that more supply will be built in southern Sweden, which will therefore serve the market? And so in the longer-term, on an average across the whole country of Sweden, prices will go down. Do you agree with that?

Speaker 1: Yes. I agree. When you saw this transition in November, 2011, you immediately saw that the prices in the north of Sweden went down, and also that was transferred to the north of Norway, actually. So you saw these changes exactly as you describe it.

On average, I don't think the price differences are that big. And there is, like I said, a debate in the Swedish newspapers. Some consumers are saying, "We are taxed. This is an extra tax on consumers in the southern part of Sweden." And the TSO (transmission system operator) went out to defend this system. They said that a year ago, when they had problems with the nuclear plants, and they had a lot of water in northern Sweden, the whole of Sweden cleared at a low price. And the effect was that Sweden was supposed to export to Denmark from southern Sweden, where there was no power. And now, when the same thing happens, then you have the high price in southern Sweden. And you actually have imports to Sweden. So it works much better than it used to do. And the big question then is of course, well, how many areas is sufficient? There are a lot of things that you still now do not take into account. So Bill's answer would be, "Go all the way to the nodal pricing." Well, when it's been all this fuss to go from one area to four in Sweden, it might take some time, at least.

Question 5: I'm actually going to ask a non-technical question here of the panel. In particular, this probably applies to Speaker 2 and Speaker 3 more than it does to the others, but it is about the role of governance in electricity markets and competition since we've been involved in this endeavor for now going on over 20 years. And first, you know, in the U.K., as you mentioned, of course, there was the power pool. And then we had the New Electricity Trading Arrangements. But I think one of the untold stories here is the role of governance. Why was it that the pool was deemed such a failure to require this large sea change from pool to NETA? And I think the same goes for the experience that we've seen in New Zealand, and the electricity market in New Zealand back in the early 2000s, where there was effectively no regulator, and then all of a sudden, a regulator had to be created and step in. And in Brazil as well, we had one market designed in Brazil for awhile, and then we've changed to the current design that Speaker 3 described.

I would like to get a sense of your impressions of the role of governance. And I think the Nordic market is very interesting in the sense that you've got one market and five system operators within that market. Whereas here, we have a system operator for each market. And so it's more of a one-to-one translation, and so what are the governance arrangements that need to work and the coordination that needs to work with that? And so if I could just get some reactions to that…

Speaker 2: As to why the pool was inadequate, there are several aspects of that. One is that it was, I thought, a one-sided market. You had generators bidding in, and then basically the National Grid system operator determined the price by making a forecast of demand. There was no demand side and no easy way to introduce the demand side. I was particularly concerned about what is in effect a capacity mechanism in their arrangement which provided a subsidy, if you like, to generation when capacity was tight. That was, in fact, being manipulated. The generators could actually set whatever price they wanted by adjusting the amount of capacity they were declaring as available.

I was also worried at the time that that would be subject to influence by the government or by the regulator. In fact, when I proposed abolishing this and putting forward the ideas that later became NETA, the minister's civil servant came to see me and said, "The minister understands there is a lever he can pull if he needs to. But that lever is going to disappear. The minister wants to know where is the new lever in the new arrangements that he can pull if he needs to." And I said, "Tell the minister, one of the purposes of this change is to take away any lever that he might be tempted to pull." So my aim was to try to make this completely independent of any regulatory or government influence. So in practical terms, higher prices were an issue, but there were other aspects there.

Speaker 3: I'll try to make some reflections that in fact are related to my personal view. I mentioned that we faced in 2001 a crisis, due to a severe drought. And the main critics of the then-current administration were the ones that stepped into the Cabinet in the Lula Administration. And in our case today, our current president is the former Minister of Mines and Energy. And I was talking to someone during the coffee break about how they were very careful even to take the word "market" out of the law. You can do a "find" search, and you'll not find this word. You can go further into this reflection. Speaker 2 was saying that, if you could think of a word or something driving the reforms that took place there, "privatization" would be the key. And these people that are now in the Cabinet, they also were our main critics of privatization. And so at first, the reforms that took place there were more oriented to efficiency. And now you could think that there is more concern about income distribution in the country. And so we are talking about a system and a sector that is very closed. OK? And the consumer is mainly out of this discussion. And so we have a lot of insurance, at the cost of high prices, and sometimes penalizing efficiency.

Moderator: And as an historic footnote, for those of you who were at the HEPG in Philadelphia, in Spring of 2002, the current president of Brazil, who was the Minister of Mines and Energy then, was at HEPG--meaning the only head of state that ever attended HEPG was the minister that she was referring to. But that's historic footnote.

Session Three.
Market Liquidity: Means, Ends and Myths

Electricity market design should improve efficiency and transparency to support both better operation and wide participation. Forward trading can provide better risk management and arbitrage price differences between markets. Deeper markets provide greater liquidity to support low transaction costs and build confidence in the capacity to settle contracts based on market fundamentals. But liquidity is a means not an end. In the United States, organized markets follow the principles of bid-based, security constrained economic dispatch with locational prices. This market design supports open access, non-discrimination, and transparent participation by a wide variety of market participants. In Europe, this model is sometimes criticized as sacrificing beneficial market liquidity that comes from zonal models. But these zonal models are both less transparent and require cross-subsidization which creates its own set of perverse incentives. In addition to the debate about market design, the Volcker rule and other limits on trading in derivatives may have unintended consequences for electricity market trading and liquidity. How does market design interact with trading liquidity? Are nodal models inherently less liquid, or is this a myth? How does trading in electricity markets affect operations and investment? What role does retail access play in creating a demand for forward contracts? Is liquidity providing the benefits we expect? What are the threats on the horizon that could affect electricity trading and risk management? What policies might be implicated or required for broad participation and better performance in electricity markets?

Moderator: I want to welcome you to our session on market liquidity. We have some very important questions to look at here in this session. How does market design interact with trading liquidity? Are nodal markets inherently less liquid, or is that a myth? What's the linkage, and how does trading in electricity markets actually affect operations and investment? What's the role of retail market design and how does that play out in the demand for forward contracts? What are the threats on the horizon—the Volcker rule and banking changes and others that could affect electricity trading and risk management? And from a policy perspective, what does liquidity tell us about policy and what we should be looking at in terms of the structure of markets going forward?

So what do we mean by liquidity? The definition that I like to use is that liquidity represents the reliable ability to convert a market position into a cash position, and thus it becomes the key to being able to hedge various risks for various market participants. There are a number of ways in which we can measure liquidity. We can measure it in terms of the tightness between the bid and the ask in particular markets, or the bid-ask spreads. We can measure it in terms of depth, the volume of transactions necessary to move prices. We can measure it in terms of resiliency, the speed with which prices return to equilibrium following a large trade, or elasticity, in terms of how much the price changes given the volume traded. We also have common measures such as the trading or hedging turnover, involving the amount of hedged activity. And there are other, more sophisticated analytics that can be performed as well, all of which tell us something about the liquidity or the health of the forward markets that we're dealing with.

These markets are important for a variety of reasons. They're important for people who are participating in the markets, to enable them to change and accommodate changes in their underlying risk portfolio and manage those risks. They are potentially important longer term, in terms of being able to spread the risks associated with investment that is required in the industry. And they are also an indicator of what's likely happening in the industry. In fact, one of the ways I first got interested in looking at liquidity indexes was back six or seven years ago when we were trying to figure out whether or not MISO should have a capacity market. And one of the things we thought was, "Well, we don't necessarily have to go to a strong capacity market if we have good forward indicators of liquidity, because they will tell us when we are heading into a shortage situation and when we're not." Well, of course, the market has developed in most of the organized markets in a little different way than that, but we may go back to a situation where we actually have scarcity pricing and price responsive demand at a retail level, and we may come back to seeing indicators of liquidity being important indicators of what the likely future direction of markets will be.

Speaker 1.
This first picture on my title slide, that could have been before we went to dinner last night stepping out of our hotel and looking out at the beautiful sunset here in Santa Monica beach. However, I'm from the East Coast, not the West Coast, so I view that as a sunrise and not a sunset. [LAUGHTER] And I believe that the sun is in fact rising on nodal and zonal contracts. I think it's very early days in terms of where we're at. I think liquidity is rising there, but it is very much in the beginning. And so that will be sort of a metaphor for what I'm going to be speaking about here today.

First of all, let me give you a brief overview about who Nodal Exchange is. All of our contracts are cash-settled, so all financial contracts. We launched in April of 2009. We've got over 70 participants in the market. And what's distinctive about our market is that we have 1,800 different locations where you can trade power across the six organized markets. We also have peak and off-peak power. We have actually various flavors of off-peak, so we have more than 3,600 contracts where you can trade power. That's a very large number, of course, and it's a very granular number. I'll explain later why I think that's very useful.

There are monthly terms that go out as far as 68 months, a little over five years. And because we have so many different granular contracts, rather than screen trading, we actually use an auction based methodology, not unlike what the FTRs do, for the same reason, actually. And so we run an auction every day, and we do all the hubs and zones. We have most of our activity on four days a week, and on Wednesdays we run all the contracts, including all the nodes. We also have an over-the-counter market which is very important. So the auction's been very useful, primarily also to help with price marking. We have to price mark over 70,000 expirees every day, and it's very helpful from that perspective. We get a lot of volume if someone's going to do 100 megawatts over several years, etc., through the over-the-counter brokered channels if you negotiated transactions submitted.

We are central counterparty cleared. All of our contracts are cleared. It's by LCH Clearnet. They're the London clearinghouse, and actually, news as of today is that they're in discussions now for the London Stock Exchange to take 60% ownership. They reached an agreement and hope to close that in the fourth quarter of this year. And then, margining, we used a value-at-risk based approach, because we have so many different locations, that becomes useful in terms of looking at all the offsets that exist between them.

In early 2009, we were still fairly small. Our open interest then has grown through 2010 and 2011, and as of February 17th--so that's just a month and a half into 2012--we have 12% market share of the cleared market. And when I say the cleared market, just to be clear, I'm talking about futures/swaps, whatever you want to call them, the forward contracts in electric power that are cleared. I know that Speaker 3 will be also talking about open interest that includes options, which is about 70% of NYMEX's open interest. But I'm just talking about futures and swaps--forward contracts. But again, we have 12% market share, and as you can see, that's growing very quickly, at least in our minds, and again, it's still on a sunrise kind of perspective.

If we now look at the markets here, in terms of a nodal market design (and this gets into a bit of our discussion yesterday) I think the locational marginal prices and having it at a granular level permits accurate economic information to enable the best decisions in terms of where to add generation, where to add transmission. And so I think that's a very effective element, and it's very valuable, and it's the right way to do it in my mind. Again, one price in the market does not aid in determining where to place the next transmission line or generation facility--I think the United Kingdom is largely a single price. We talked about Sweden's one price going to four. So there's value in actually having the more specific information in terms of making the better decisions, I believe.

When you look at the participants in the North American market that nodally trade, I think it's important to look at the various sources, and there's a variety of them. There's the FTR markets. There's bilateral trades, which are not cleared. There's power purchase agreements, PPAs, which are necessary in order to finance a new generation facility, and that's typically at a nodal level. And there's the cleared trades. And so when you look at the liquidity, I think it's also important to consider the whole broader market and what's happening there, and of course, we have a great deal of liquidity today in the FTR markets, for example, in the PPAs and in the bilateral trades which is a lot of places people need to trade.

Speaking to the market sizes here, the cleared trades were roughly seven billion megawatt hours of volume in 2011. The FTRs have been growing quickly. They're also about seven billion megawatt hours. In the bilateral trades, we don't actually know how big that is yet, but with the Dodd-Frank Act, we'll soon get reported information and have a better sense of the size of that market. This is an estimate based on interviews we've done--we think it's at least five billion megawatt hours, but we'll soon find out over time.

The point here is to look at is that all these elements do feed into liquidity. When you look at the FTR markets, they've been growing very quickly, actually. If you look at the last five years, FTR markets in aggregate have grown 28% a year, on average. Now, of course, I am also adding in there California and ERCOT, which are new, but if you look at just PJM itself, again, you see a similar pattern in terms of what the growth rate is. So the FTR markets, I believe, are robust and doing well and growing. And what we're looking at here, just to be clear, is all of the auction volume done in a calendar year. This includes the monthly auctions, the annual auctions, the long-term auctions, etc., just summed up how much volume went through in the course of a year. And so, again, we believe that these markets are in fact robust and growing, and will add SPP over time, and that will grow, too.

In terms of the Nodal Exchange volume itself, looking at our market, we've done roughly $20 billion of notional value traded since we launched. And if you look at our mix, 60% of our volume has been on hubs, and 40% on zones and nodes. Now, what's also important to realize is that for every zone or nodal transaction we have, people are typically spreading that versus a hub. So actually, the zone and nodal transactions on our market, it's roughly 40% there. The other 40% of the hubs are coming with the spread transactions. So you could argue that 80% of our volume is in fact the more granular locations and not the hubs. And then 20% is then hub to hub like spreads that happen in our market.

In terms of looking at this question about liquidity, this chart shows PJM zonal open interest. And you can see, it's 80 million megawatt hours of open interest, and again, if you think about that, it's really 160, because typically, these zones are all spread to hubs. And when you look at this in terms of the mix, it's 45% Nodal Exchange, 31% NYMEX, 24% ICE. In total, though, this represents 10% of all of the cleared volume on PJM. Again, I'm not counting options, but when you look at all the cleared volume, it's 10% of the total. And oh, by the way, that 10% drags along the other 10% on the hub side, so it's really 20% of the total cleared market in PJM today that is related to doing spreads on a granular basis. And some will say, "Well, that doesn't seem like a very big number right now." OK, three years ago, what was the number? It was zero. Basically, we didn't launch until the first quarter of 2009. It was December of 2008 when NYMEX first opened zonal contracts. There wasn't much volume there at that time. So in three years' time, it's already grown, and it's continuing to grow very rapidly. So this market is growing. It takes times, but it is building, and I'll talk about this more in a moment, I think it's because it's the right way to trade.

You may ask, "Well, what is it in the Midwest ISO? Do you see a similar number?" Well, actually, if you look at all the total cleared volume, 10% of the total volume is, in fact, on the zones, which, by the way, drags along the other 10%, which is the hub, so it's about 20% of the total market. And oh, by the way, Nodal Exchange has got 100% of that open interest.

ISO New England, it's the same story. About 12% of the total volume there is the zones, that's cleared. So I think this is, again, an area where liquidity is growing, and if you started three years ago, and you said, "Liquidity will never come, it'll just be on the hubs, because it just isn't going to happen," and you never offered the contracts, we wouldn't have the liquidity that we do have today, which I think is very beneficial, because it's also the right way to trade power, which I'll talk about in a moment.

So to get into an example of why I think it's the right way to trade power, imagine that somebody's got, say, a nuclear plant in Wisconsin, and they need to hedge this. And so what they're trying to do is lock in a profit here, of say five dollars per megawatt hour. And so they're trying to trade for the year 2010, and they're sitting in early 2009. And so they have different choices as to what they can do to hedge, but if you look at the equation there, if $35 is the price they already have, and they could subtract whatever hedge price they're going to get, and then you have to add back in the LMP of the location that they're actually hedging at, and then subtract the LMP of the node that's actually where they're at, their generation node, that becomes the equation of what they're faced with. Now they could sit there in this example here and trade at Point Beach node in Wisconsin. They could trade at their zone there, the WEC.N Zone, or again in what back then was the Cinergy hub or the PJM Western hub. So they have to make a decision.

And when you look at the prices here (and again, the only data they really have in early 2009 is the data from 2008 and earlier), what you can see is that basis actually varies over time, and this graph is based on an annual average. The variance is even greater if you're looking at it on a monthly basis or anything more disaggregated. And if you then look at what would have happened if they had hedged at some of these various locations, if they'd done it at Point Beach, they would have got exactly what they wanted, that five dollar locked in profit, the $4.4 million would have been perfect for them because there is no basis risk for hedging their actual generation node. Had they done the zone, though, where the basis had in 2008 been $10.56, it was $3.89 actually in 2010, they would have actually lost a million and a half dollars on that hedge, if that's what they had done. They would have actually benefited, done a little bit better, if it was Cinergy hub, and would have actually lost money again if it was PJM Western hub. The point I'm trying to make is that if you're trying to really hedge at your node, and you choose instead to hedge at the hub, because it's more liquid, you're taking on massive basis risk because of a perceived issue with liquidity risk at the node. And that may not be the best tradeoff economically.

So there's this issue that some people will prefer to trade at the hub rather than the node. That's why we see so much volume there, but not trading at the node adds significant basis risk, and again, we believe that markets such as ours are bringing more transparency and greater liquidity to granular contracts, where it was zero three years ago. And today, it's fairly significant, and growing.

How do you then accomplish this? Well, if you want to trade, it's important to use voice brokers, because if you want to do an immediate trade here, they're going to help you find the right party. Also you can use participant negotiations. Participants often just work directly with one another because they know who to work with. Or, in our case, you can participate in our auction. And we have people submit broad slates in our auction every day, but if you want to have a focus on a particular zone, if you want to do that particular Point Beach node, you can do an auction indicator prior to our auction and say, "Hey, I want to do a fair amount of volume, I want to do 100 megawatts on this Point Beach node in this auction, I want to do this time period, and this price, etc., is the range I'm looking for." You can submit to the auction, and then you can create basically a private auction, if you will, right there, to get the liquidity on that particular location. There are many financial players who will trade and give you a very good price on that location. So the fact that a node doesn't trade all the time doesn't necessarily mean that you can't get a good price. And certainly, in the total, be able to lower your overall price risk.

To talk about clearing just briefly, I think that that also helps with liquidity. The main reason is that you're able to trade with a wider set of participants, and, basically, the top 50 FTR traders represent 95% of the total volume, and most of them are not rated investment grade. And there are other benefits in terms of limiting your default risk. Your total transaction cost could be lower--when the Committee of Chief Risk Officers looked at us back in 2006, they had estimated it was about 84 basis points of cost to do that, and so they viewed it as being cheaper to clear than it was to do bilateral trading. And you have a lot of other benefits in terms of netting your positions, because you can net that all against a central counterparty, and also, in this new Dodd-Frank regulatory environment, we can talk about the pros and cons of whether or not it was necessary, but at least with the reporting dimensions and other aspects of it, it certainly takes away some of those regulatory burdens if you are clearing. And it may be mandated for some in the process.

This slide talks in more detail about that first point I was making about clearing, which is, again, that the top 50 FTR participants (in the four Eastern ISOs and California) are 95% of the total volume, and only 44% of them are rated investment grade. Five percent were rated Baa3, which is on the cusp. Seven percent were rated below investment grade, and 44% were not rated. So from a liquidity standpoint, if you've said, "Look, I'm only going to do bilateral trades, I'm not going to clear," then you've potentially eliminated half the market of who you might be able to work with, and therefore, you are taking on more price risk than you would ostensibly if you're clearing, plus all the other advantages of netting and things of that nature. So I think there are benefits to clearing.

The moderator already touched on what the definition of liquidity is. I think this sentence is kind of key. It says liquidity is "the degree to which an asset or security can be bought or sold in the market without affecting the asset's price." So that points to the price risk dimension. Now liquidity is often characterized by a high level of trading activity, but I would suggest that not having a high level of trading activity may not necessarily mean that by definition you can't get a good price at your location. When we go to the granular contracts, we're not going to see the same volume nearly on Point Beach as we are going to see on PJM Western Hub, but that doesn't mean you can't get a very reasonable and sufficiently good price at Point Beach when you want to do the transaction. People need to do this anyway when they have PPA agreements and they are trying to put together a new solar wind project, etc. So being able to address that, I think, is important, and there are mechanisms that we mentioned earlier, such as the auction, etc., which can make it easier to do those transactions.

The other piece is of course the hedge risk. And you need to look at that as well. And that's the adverse price movements in an asset in terms of where its location is, and again, I think it's really important to have a market that is very granular, as we spoke about a bit yesterday. And if it is granular, then you have to be able to hedge at your location. And so, what is then your total price risk? It is not just the hedge risk. It is not just the liquidity risk. It is the total of those two together.

And so this slide here then shows the relationship between the hedge location price risk and the liquidity price risk. If you look at where the nodes are, there is no real hedge risk if what you're trying to hedge to is the nodes. There is no basis risk, if you will. And so it's great from that standpoint. You don't have that price risk. But you are taking on more liquidity price risk. There is some price risk to it, and it may differ based on the location, the timing, what your issues are in trying to get that done. The hubs, of course, if you're trying to hedge to a node, have significant basis risk, but you don't have to worry about the liquidity risk, there's a lot of algorithmic traders and others who are getting their books flat every day, but they put trades into, for example, the screen trading of PJM Western Hub, if that's what you want to do. Then, of course, there are the zones, which are kind of a hybrid and in between, and therefore, you see a lot of activity in the zones, and the zones are I think a very robust market. Where things are naturally migrating is from the hubs to the zones, and I believe over time, we'll see more and more of our nodal transactions, because we are seeing them where people are hedging their exact node and going out five years, etc. On the zones, it's a bit of this bridge, and it allows you to sort of work between the two, and therefore, it becomes a good balance.

So, in summary, I would just say that again, I think that it's still early days in the liquidity. It's growing. And I think that if you say, "Is it a myth that liquidity can't be built on the zones and the nodes?" I would say "Yes, it's absolutely a myth." You can get trading done. If you say that the volume needs to be as high as it is on PJM Western Hub, well, absolutely not. It's not going to be, but that doesn't mean that it's not the best decision in terms of having a granular market in order to allow people to make the best economic decisions, and then have sufficient liquidity that you can actually get very good price deals done at your individual location, so you can effectively manage your business and have it work well.

Question: Would you expand a little bit more on your conclusion regarding credit risk? In netting, I understand, OK, but in an absolute level, I don't understand what you were saying about how if you and I go into a nodal swap at a given location, and the rest of the world doesn't exist, and those are our only positions, it seemed to me that you were suggesting somehow this was reducing credit risk.

Speaker 1: Absolutely. So let me explain. The key thing is that if we do a bilateral trade, and we bump fists and say we're good, then we've got credit risk. If we do a cleared transaction, then we have very minuscule risk, and let me explain. Central counterparty clearing means that actually you're not trading with me. You don't have to worry about my risk. We both submit for clearing. Now our counterparty (in this case, for us, it would be LCH Clearnet) is the buyer to every seller, and the seller to every buyer. And oh, by the way, sitting between you and me and LCH Clearnet, we typically have a bank, and that could be Deutsche Bank, it could be Goldman Sachs, it could be Citibank, Merrill Lynch, etc. And so we've got a bank then that's sitting between us. And so, for you not to get paid by me, first of all, I'd have to go down, I'd have to take down Goldman Sachs or Deutsche Bank or somebody in the process, too, who then have to then hurt LCH Clearnet, etc. So as an example, when Lehman Brothers went down--big bank, big clearing member bank--actually nobody was harmed. LCH Clearnet has margining, both initial margin and variation margin. Variation margin is sort of the movements in the price day to day as you do the curves out in time. And initial margin is to handle several days of price movement if somebody goes down and you need to move that transaction over to another clearinghouse. And so, as a result of that, the market's protected. Since the late 1800s when LCH Clearnet was launched (by the way, they clearly like the London Stock Exchange, etc.) there's never been a counterparty that's not gotten paid, because of the central counterparty clearing. Therefore, while I can't say it's 100% eliminated, it has been effectively limited.

Question: And you're saying the insurance cost of that is low enough.

Speaker 1: Yes. So the margin is like the insurance, and that's a great example, and if you look at the Committee of Chief Risk Officers back in 2006, what they were saying was that if I do a bilateral trade, I'm at risk of the other party's defaulting. And their estimate was that the default risk was equivalent to 84 basis points. Now, of course, what happens is that it's 0000 for 10 years in a row maybe, and then suddenly you get hit with a Lehman Brothers saying that it's a big amount, and oh, by the way, it averages to be 84 bips. And so what ends up happening is that they're saying that you need to be reserving those amounts properly, from an accounting standpoint, based on the risk you're taking if you do the bilateral trades and you choose not to clear. But everybody kind of says like, "Hurricane Katrina's not going to hit New Orleans, it can't be category five, let's build the berm to category three protection." Well, guess what? Your siphoning the money off so you don't build to category five protection means that you pay more in the long run when the hurricane hits. Does Katrina hit New Orleans every day? No. But not having the berm at the right size, not having that insurance, meant that you paid more in the long run. So that's what the benefit is of clearing.

Speaker 2.

It actually took me about 15 minutes to read the question when I got it [LAUGHTER], and then I had to read it about 15 times before I actually understood it. But on about the 15^{th} time that I read it, what I realized was that it wasn't really a question, it was really just an answer. [LAUGHTER] So my job as a student of Bill's back from the Kennedy School was to be an interpreter of the Hoganese that was in there and convert it. And particularly with respect to the first myth there, which is that nodal markets are inherently less liquid, that's probably where I have a fair amount of expertise, and I will focus mostly on that. (With respect to the other issues around the banks, I'm going to defer to Speaker 4, because I actually am not a banker and don't necessarily know that much.) But with respect to the first question, I actually asked this question of a lot of different counterparties in the market, and they sort of all scratched their heads, "What do you mean?" There's just no question, when you look at the trading that takes place in the market, whether you're looking at the number of transactions or price discovery, if you just look at the trading that happens in the southeastern US with trading that happens at PJM West, that nodal markets, the markets of ISOs, are way more liquid. So I'll go into that in the presentation.

Now, of course, as I read the question, a key caveat in there seemed to be the instruction not to just talk about liquidity, but to talk about what we're trying to do in the spot markets. And so I thought I'd start there, just with a reminder on some of the principle reasons that we have spot markets.

And one is to have efficient dispatch. We want the right units, the least-cost units, running to meet the load, and we want the right usage of transmission, the most efficient uses of transmission, and, ideally, a spot market will do that.

But there's another purpose there (and sometimes we focus too much on the first one) and that's to facilitate long term contracting and competitive entry (and exit). And one of the things that spot markets do is they reduce the risk around people making trades. You have an index, it's a reliable index for people to settle transactions against, and ideally, it's sending the right price signals for long run efficiency.

These are really important goals, and at HEPG over the years, I think we must have had about a dozen of these sessions that focus on things like capacity markets, or price responsive demand, or scarcity pricing, or whether we are getting the prices right. And that's really about that issue of whether the competitive markets are doing the right thing, not just in the short term, but also in the long term. And so that really is sort of the lens through which I look at this.

Let me just say one thing as well, because I think ideally we want competitive markets to give us the right answer in the long run in terms of the type of generation, where it gets located, and what transmission gets built. But if I were a regulator, and I had a purely regulated market, and I didn't want to do competition, I'd still want transparent pricing--because when I've got transmission builders out there coming to me, telling me we've got a Third World transmission system, and we've got to invest billions and billions of dollars of ratepayers' money, I'd like to see the prices to kind of know whether that's true. (Just a slight reference to yesterday's sessions.)

With respect to whether LMP market design sacrifices liquidity, the answer is no. And what I put up here is the traded volumes from February from the ICE (IntercontinentalExchange), which is probably the dominant electronic trading platform out there. This shows one group of bilateral markets and one group of LMP markets, and what I took from this, and also from talking to other people in the market, is that clearly, the PJM market is the most liquid market. At the same time, there are some LMP markets that are not necessarily as liquid, and if you look at Mid C, the mid Colombia market, that's actually a bilateral market that's quite liquid. But most of the bilateral markets are not nearly so liquid. So what I took from this is that I don't think it matters so much about retail access, although that might help, but regardless of how the market design works, liquidity seems to be mainly driven by whether you have diverse ownership of generation, diverse ownership of load-serving obligations, and ready access to transmission. If you have those things, you have a very liquid market. And if you don't, you don't have a very liquid market.

So my next example is from Great Britain. And these markets, I think, are prone to having very significant inefficiencies. I just picked the most recent day, and comparing the system sell prices and the system buy prices, the bid/offer spread between those is actually quite wide. And if you want to own a merchant generator or be an undiversified player in the market, whether it's on the load side or the generation side, you really can't play in that kind of market, and I'm almost certain that in Great Britain, just based on looking at this, depending on system conditions, you're almost surely going to have generators that are running that are the wrong generators to be running in the wrong locations, because the companies are trying to dispatch for their own load, and there are other generators that are trades that should be happening that are not happening because the market is designed this way.

Comparing this to PJM, I just brought a slide up, the bal-day market in west hub, which trades hundreds and hundreds of times a day. Every couple minutes, there are transactions there, and I just took a snapshot of one particular day but the west hub market, (this is just bal-day trading), is very liquid, with very low bid offer spreads.

But isn't the nodal market "too complex" for supporting liquidity in long term contracts? I mean look at those prices (at different nodes in the Western Interface on August 9, 2001). They're just random. They're all over the place. They've got $19 at Conemaugh, and right next door, Homer City is at $218. This is an example of a really high-priced day. We had the Western Interface binding--the Western Hub was $312. The Eastern Hub was $636. All the prices are just random, and in fact, there's no simple zonal pattern to the prices. And if I had to guess what the transfer capability was between west to east, and I was a system operator that had to use the zonal market and come up with something, I'd have to guess something that wasn't the right system capability. It would have to be lower. I'd have to be really conservative about that, and I think the speaker yesterday from Norway alluded to that issue around the difficulty of figuring out what the transfer capability is.

But although there's not a simple zone pattern here, these prices are not random. These prices are the marginal cost to meet the next incremental load at that location at that moment, and they're sending the right signals to all the generation. What would be random would be to try to turn those into zones. What are you going to do? Put Homer City and Conemaugh in the same zone, since they are right next door to each other in the west? So what would be random and wrong would be to try to turn this into a bunch of zones in order to simplify it.

This is a map of MISO, and it shows the same thing--very different locational marginal prices. Some locations might be negative, others positive. It looks like there are two pieces of congestion there.

So the point here is that this stuff all looks really complex, but it breaks down so that it's not that complex. And you basically simplify it with traded hubs and zones, augmented by FTR markets. So this map of PJM shows Cal 13 peak prices at West Hub, which are $43, and for everything else I put the prices relative to West Hub, because that's often how things will trade. So if you look at East Hub, it's six dollars over, it's $49 for Cal 13 peak. NI Hub is eight dollars under, so it'd be around $35. And you have different generators and nodes in different locations.

I actually slightly disagree with Speaker 1. I think it's very hard generally to find a market for something like Point Beach, but you'd probably be pretty comfortable finding the zone nearby. But because these prices are so transparent, people will get comfortable with them. So someone will come to the owner of a Point Beach, and he's willing to write you a contract at that location, but he's going to take a little bit of a cut for the bid/offer spread. And so the question here is, how comfortable are you with it? So what happens with the nodal markets is that the nodal markets and the patterns of congestion drive the expectations the market participants have, and that becomes the basis for the pricing and load auctions. It becomes the basis for forward hedging, and it's really transparent. People will get comfortable with it, so you can write the forward contracts around it, or the market participants may be comfortable with it and not worry about the basis risks. So I'll do my hedging at West Hub and not worry about the basis risk. I'll just take that on, or others may want to hedge that basis risk. So you have a choice as a market participant, whether you want to do it or not.

The other piece of design is the FTRs. And this is a slide that shows the revenues from the PJM FTR auction, which you can see has been over a billion dollars every year since 2005. It's a very, very efficient, liquid, competitive market. This shows the number of participants in the last annual auction. We had 185 different market participants in the FTR auction.

Here's a quotation from the answers that were in the question: "Zonal markets are both less transparent and will require cross subsidization which creates its own set of perverse incentives." So here an example from ERCOT, the Texas market. There is a big wind area with a lot of development over the last several years in ERCOT, and they actually set up a separate zone in ERCOT, with a West Zone, and then they have a North Zone and a Houston Zone, and that sort of thing. But because they had these zonal prices prior to implementing LMP, actually the ISO had to do all kinds of curtailments. And even though they would send the lower price signals, the price signals weren't quite right. In theory, the ISO could go in and pick and know exactly which wind plants he's supposed to curtail. But that was way too complex for them, and you get into this game of negotiating what the rules are going to be. So at the beginning of the year, ERCOT would say, "All right, what are the constraints that we can use to trigger the West to East constraint," because they had a list of 10 or 15. But of course, there's a transmission outage in some shoulder month, and the constraint is different. And the ISO wants to use the West to East constraint and the market person says "No, the rules say you can't do that, you have to put me on an out of merit energy and give me a constrained-down payment." And so that's how that would work, and I actually think that this may be similar to the current situation in the Mid-C market right now where there are a lot of curtailments as wind is increasing. Once you did LMP implementation, the prices became the dominant mechanism for managing congestion, and what you also found is that you had very different system conditions, depending on outages, wind patterns, load patterns, and sometimes some of the wind plants would get higher prices versus lower prices, so it's working much better now.

One more example. (I could have come up with tons of these.) When we had our generation expansion boom in the U.S. in 2000, a lot of the generation siting decisions were made without a real sense of having the LMP price signals. So this is example of a combined cycle plant of about a thousand megawatts that got put in western Illinois, and here's an example of prices on a hot day in May of 2001. When that generation came online and increased generation, its prices actually went negative at its location. So it needed to have those LMP signals in order to be in the right location.

I'm going to say just a few quick things on the banks, and then I'll turn it over. I think that there's been a real change in the market. There's clearly been a shift over the last four years with the financial crisis, where there's a tremendous increase in clearing and things like that. So there's no question that that is taking place. And the market is still very liquid. And the banks are still in the market. But I think it's a myth that liquidity from other players or exchange players can replace the banks' role in the power market, in that the banks do something different--they also extend credit when they do trades, and that's embedded in their bid/offer spread.

But I also think we're entering a pretty tricky period here, because it's pretty hard to figure out, from my perspective, what the difference is between "customer business" and proprietary trading. You know, if I match up with Deutsche Bank over the broker market and do a trade, maybe that's a prop trade, but if someone from Deutsche Bank takes me out to Melisse for dinner and we have a really nice wine, maybe that's a customer deal, I don't know. [LAUGHTER] But ultimately, the notion of the banks doing these customer deals is they're doing lots of different deals and they're on either side of the market. And another myth is that power markets are liquid. They're not liquid in the same way that credit default swaps are liquid or equities are liquid or oil or that kind of thing. And there's no way the banks do business like having 10 year tolling deals and things like that without warehousing some of that risk. That's just not happening, and to the extent that what Volcker wants is for them to get out of that business and just lend money, but don't trade, it's going to be quite a transition.

Let me just quickly show these slides of credit default swaps. Prior to 2007, you would see the banks as having this inexhaustible access to credit. You could do long-term trades with them and you wouldn't have much exposure. You can see what happened in the credit crisis, and even right now, I think it's tricky. I think one of the Georgia munis came out for a 10 year tolling deal a couple years ago. I know Morgan Stanley, JP Morgan, maybe Constellation responded. And if I were that muni, I'd be very careful, looking at these, who I transacted that deal with.

So you have other market participants like Constellation. You can see what happened to their CDS rates when they went through their liquidity crisis in 2008.

BP, right? They're very active in this market. What happened there? Everybody remember? Oil spill in the Gulf.

Hedge funds? Well, they're really transparent. We can be comfortable doing a 10 year deal with one of those guys. [LAUGHTER]

Last point. I think regardless of the Volcker rule, you've got to believe that some of these transactions are going to get done to the extent that there's a financial interest to do them, and the incentive is there. There's a profit opportunity. So maybe it's banks, bank subsidiaries, bank affiliates, IPPs, private equity, hedge funds… If the deals are there, you would think that they would get done, but I think the landscape's really changing here and if you have a higher risk profile entity that's looking to do these kind of trades, it can be, "I've got a great idea for a new green thing, but it's generating RECs and environmental credits out in the future, and I've got to build it now." I need a bank to both finance that deal, and what the banks have traditionally done is also given a toll, been the off taker for those things and taken a cut, and I think that those may have a harder time. It's not clear how those are going to evolve. So I think that's a big question mark. We'll see how the rules get written and what actually happens.

Question: On the UK market that you showed there, if I understand correctly, I suspect that's not a single market with a difference between a buy and sell price. What you've got there are the cash out prices.

Speaker 2: Yes, it's a balancing market.

Question: Well, it's not a balancing market. It's called a balancing mechanism, because they are administratively decided upon. There are rules for deciding what the buy price and what the sell price is, based on certain bids and other things. And one of the aims of Ofgem at the time was to have a big spread between those two prices.

Comment: So that you wouldn't use them?

Question (cont.): Yes. To force people, or to encourage people, to be self-balanced. So I don't think it's a fair indication of the zonal market, but I agree with you how awful it is. [LAUGHTER]

Speaker 2: OK.

Question: I'm just wondering, is what you're saying that when you have LMPs, you sort of will have the trading in FTRs on the LMPs, and at the same time, on hubs or zones? Is that what you're saying?

Speaker 2: Yes.

Question (cont.): So this creates hedging possibilities?

Speaker 2: Well, the key thing is you do get very transparent pricing, and so once you get comfortable with it, you can do hedging at the locations. And when you go to a bank to do that kind of hedging, they're going to require some margin for that risk. Now, ideally, the traded zones wind up being zones nearby. So what I think tends to happen is that market participants use the FTR markets for their locational risk, or they'll make an evaluation of at what prices am I willing to hedge?

What happens is that the different zones end up being used as the index everybody trades against. And then if you want to go to a very specific location… (We'll see how well Nodal Exchange does in encouraging people to go to having a really liquid market at all the nodes) I don't think you need to go there. If you really want to go there, and the prices are transparent, you can get a bunch of banks to write you contracts, or counterparties in the market will take that risk for you on a bilateral basis. Or you can get Nodal Exchange to clear it for you. But generally, market participants use the different zones to hedge, depending on the needs of the market.

Question: Empirically, you're looking at Nodal Exchange versus the bilateral basis risk and the premium of a Deutsche Bank. How do you see that now? I mean, you're in the middle of making that decision. Is it a close call from time to time?

Speaker 2: Depends on what kind of margin Deutsche Bank will give me. If Deutsche Bank will let me do a bunch of deals up to, like, $10 million, where they won't margin with me, then I'd much prefer to do it with him than with Nodal Exchange, because the difference between the exchange and a bank is I've got a cash margin with the exchange, and he's going to extend me credit as part of the trade, but I'm going to pay for that. And so right now we do both. We do all of it.

Speaker 3.

To begin with the title of my slides, "The Evolution of the CME Group Electricity Complex," I chose the word "evolution" very carefully, because NYMEX and CME have been engaged in electricity futures research for over 20 years. So we could also call it the "fits and starts" of the electricity complex, because it really has been a set of right turns, blind alleys, wrong turns, and then some more right turns. And I think where we're at right now in terms of the current age of electricity at CME Group is clearly the most successful time period we've ever had, from the standpoint of volume. And the reason for that, largely, is LMP. LMP means that there's an unambiguous price that we can settle against. There are not dueling banjos of prices. There's a single price for day ahead and a single price for real time. That's a very important element in the futures contract environment. There's no contest in PJM, ISO New England, New York, and the other ISOs as to what the right price is for day ahead and real time.

A few words about CME. Today's CME Group includes four regulated exchanges. CME, CBOT, NYMEX, and COMEX, which is a wholly-owned exchange of NYMEX focused on metals contracts. We refer to ourselves as the most diverse exchange in the world from the standpoint of the range of products that we offer, and all of our contracts are Designated Contract Markets at the CFTC. That is the highest level of regulatory coverage that exists at CFTC. Dodd-Frank may very well have changes for all of us, but that is the regulatory landscape at the present time.

Last year we traded 3.4 billion contracts. Globex is our trading engine. As an exchange, we have a wide range of financial safeguards, but we also have ClearPort. ClearPort was developed largely in response to the Enron debacle, and then the other merchant failures that followed Enron. What ClearPort basically provides is a means to take OTC contracts that are bilateral in nature, with the credit risk that Speaker 1 referred to, and to transition those contracts into a regulated futures market position, into a clearing relationship between the exchange clearinghouse and the clearing members. And so basically, the link between the buyer and seller is broken, and the risk exists between the clearing member and the clearinghouse, which we cover on a day to day basis with margin processes that were referred to earlier, and a pay and collect mechanism of variation that takes place every day that we operate.

We have almost 1200 contracts listed for clearing. That's one huge difference compared to where we were 20 years ago. Twenty years ago it was brick and mortar. Twenty years ago, we didn't have technology and we didn't have the potential for a granular level of risk management. So we're very pleased to be where we are right now from the standpoint of technology providing the opportunity to provide a wider range of risk management. The costs were substantially higher years ago in terms of launching in the market. We had to build demand, we had to recruit the members. The submissions took sometimes six months to prepare. Today it's a much faster process. So we can offer more.

These are the contract complex areas that we currently offer. Petroleum, ethanol, emissions through our investment in the Green Exchange, natural gas, of course, power, natural gas liquids, coal, uranium. We launched a financially settled contract on uranium almost five years ago. I was involved in developing that effort, and it was a very interesting and rewarding effort to deal with the uranium marketplace, and definitely it was a positive from the standpoint of our understanding of the related markets.

Moving to our electricity complex, our focus is on risk management price discovery for the US ISO/RTO markets. We do have a few contracts that settle in the Dow Jones electricity indexes, but they are not active, so our activity is directly focused on providing risk management price discovery for the organized wholesale markets. We offer 2.5 and five megawatt contract units focused on day ahead and real time. We also have launched a capacity futures contract, the first capacity futures contract listed anywhere in the world. I'll talk more about that a little bit later in the presentation. All of our contracts settle on ISO prices. We have monthly contracts and we have daily contracts. The monthly contracts follow the same uniform listing of current year plus probably the next five years. We could make that the current year plus 10 or the current year plus 20. There's no regulatory prohibition that would impact the decision a like that but it's really just a function of what the marketplace needs from our standpoint, what requests we get. The daily contracts are listed for the current month plus the next month.

Our 20 year-plus history--back in 1996, we launched our first electricity futures contracts, deliverable at COB (the California Oregon Border) and at the Palo Verde nuclear plant. Those were physically delivery. We didn't have financially settled market possibilities at that time. And so we did what we understood best.

That is, we launched contracts. We physically delivered to COB and Palo Verde. Of the two, the Palo Verde was the more active, but at that time, we didn't have the potential for electronic data. And so because we didn't, we launched in a floor-based environment, with floor traders. That was always a source of difficulty because in the early years, electricity had a reputation, and in many ways it deserved that reputation, of being highly volatile. And it was difficult attract floor members into that trading environment.

Two years later in '98, we launched our first eastern electricity futures contracts, Cinergy & Entergy. Once again, the settlement was physical delivery.
In 2003, we launched our first financially settled electricity contracts based on the Western Hub. Those are the first contracts that we launched based on ISO pricing.

And then by December 2008, our philosophy evolved quite a bit from the standpoint of our contract focus. And instead of only listing the markets that were perceived to be the most active, we opted to take a different approach. We thought about listing a day ahead for some time prior to the decision to go forward. But it became clear that there was a need for risk management in various zones of PJM. And so instead of trying to pick the winners or be subject to the losers, we decided to take a uniform approach and list the primary zones of PJM. Some of these markets weren't quoted at the time we listed them. So the markets in many cases didn't really exist at the time of our launch. Our view was, "Build them and they will come." In many respects, they have come to CME and to the other exchanges that have been referenced today. [LAUGHTER]

I think we're all engaged in serving a need. And that need is directly focused on the underlying underpinnings of PJM and the other ISOs. That is, LMP at the granular level. Nodal specificity would make it difficult to have contracts for each node or FTRs at each point within PJM. But the market doesn't really need that. The market needs distribution of liquidity. And on top of the framework of LMP come the zones. On the top of the zones are the hubs. So our experience has been very, very positive connected with the nodal framework. We launched ISO New England and all of the zones except for Vermont in 2009. We launched capacity futures contracts last year for New York City and the rest of the state. Our open interest reached one billion megawatt hours on October 14th of last year. And our buy-in last year was two billion megawatt hours, which was 62% up compared to the previous year.

Options is a significant part of our overall activity. The Western Hub, in particular, features prominently from the standpoint of our options environment. And then in 2012, the Cinergy hub to Indiana hub MISO transition was quite significant from our standpoint.

We have thousands of contracts. This is the distribution of our contract markets by ISO and by region. We have 14 Canadian contracts. Eighty are ERCOT contracts, and we have the most ERCOT contracts and the least amount of activity in ERCOT. We have contracts in ISO New England, MISO New York ISO, PJM, and Western Power. So in total we have 262 contracts.

This slide shows the distribution of our markets, showing the number of listed contracts in each ISO, and the contract types available. Just running down the list, you can see it's not consistent. There are differences ISO to ISO. The commercial market has its preferences. We haven't really detected much interest in ISO New England in having real time contracts. The same thing for New York. If we felt that there was enough interest, we'd list the contracts. So it's really contingent on what the distribution of commercial activity is that we identify as our part of our contract development process.

This chart shows our 2011 volume. PJM accounted for 91% of our total megawatt hours. ISO New England was 5%. MISO 3%. So primarily, it's a PJM-oriented distribution of activity.

This chart shows the distribution of our open interest, outstanding contracts. PJM's percentage was down to about 70% in early 2010. Currently it's over 90%. Largely, the difference is MISO, and I think the transition from the Cinergy to the Indiana hub was a critical element. What happened there never happened before. That is, a viable, LMP-based hub was transitioned out of business. And there were thousands of contracts out there in our world and in the exchange community and the OTC community that had to be dealt with. So I think the jury is out in terms of how this will shake out from the standpoint of liquidity.

Given the focus of the panel, I also included a segmentation by the zones and the hubs within PJM. The Western Hub is 93% of the volume. The NI Hub is at 3% and the AD Hub, 2.7%. The zones are 1.1% of total megawatt hours. So the hubs, from the standpoint of our activity, are the most key component. But that's not to minimize the zones and the importance of the zones to commercial markets and the participants in these markets.

This slide is the distribution of the non-hub activity for PJM and for ISO New England. We've excluded the hubs, and here you have the zones. You can see that PSEG is our leading zone from the standpoint of the open interest. For ISO New England, Connecticut clearly is the leader, but there is participation in the other zones as well. Our philosophy is to offer risk management in a way that benefits as large a group of participants as possible. So the zones clearly play a part in that.

This slide shows some details on the actual contract language. We have five megawatt contracts, which were introduced in December '08.

This slide is a visible indication of how our markets can benefit the underlying commercial community. What I have in this slide is peak day-ahead settlement prices in the Western Hub versus PSEG. So you can see the differences going forward in time in terms of the value of congestion, the absolute difference, Western Hub against PSEG. PSEG is probably the best measure for the eastern side of PJM. This information didn't exist on a public basis until we listed the markets, and the exchanges have gone a great distance in opening up the markets to price discovery that really was just the province of the broker community and other kinds of sources.

This busy chart shows the Commitment of Trader information to CFTC. Any of you as a follow-up to this discussion can go to the CFTC.gov website and you can click on commitments of traders. What the Commitment of Traders (COT) info provides is a window into commercial and non-commercial use of the underlying recorded markets. So the red is the commercial category. And the contracts are along the bottom in terms of the contract codes. Swap dealers and commercials accounts for the balance of our markets. You just add those two together. With a market like PSEG, it's 100% accounted for by commercials and swap dealers. The green is the non-commercial. At one time the CFTC only identified commercial and non-commercial. They've become more granular in terms of opening up the COT to the other categories of swap dealer and managed money.

I mentioned the capacity futures contract. These are five megawatt month contracts that we launched last year. This is also a benefit of having a Market like the New York Capacity Futures market. Instead of owning one season now, which is the case of New York ISO at the present time, our markets list multiple seasons so we can look out in time and at least get a view as to what an organized group of participants think about the value of capacity going forward into the future. So the farthest out is the Cal 14. We've had requests to broaden that. We're acting on those requests, but this is another example of the information that could be generated by the derivative process and exchanges in the contract development process.

And moving to the next slide, this is showing you how the price of capacity has changed since we launched these contracts. You can see that with the New York City March 2012 contract, we started at $2.00 and we're now at $4.00 per kilowatt month. And with the July 2012 contract, $8.00 to $10.00 so it's been much more substantial in terms of an increase in the March 2012 contract. This information is free of charge on the website.

I also included some information on volatility. That's a topic of frequent interest in the markets. Interestingly, the power volatility has been consistently below volatility in natural gas during this time period. There has been a very tight correlation relationship between natural gas and power. The correlation is over .9, .93 for the entire time period. When you move forward, though, you can see that that relationship is not exactly as stable as it was in the early part of the previous slide. The correlation declined to .83. So it is a developing story in terms of the relationship between natural gas and power.

In sum, this is the most successful time period that we've ever had in the power markets and I think that the move to LMP as a framework for the organized competitive markets has been positive for us and for others in commercial markets providing risk management.

Speaker 4.
Before I start, I do need to make a disclaimer. My comments today are mine and not necessarily the views of my employer. And on the idea of myth, the first myth that I should probably correct is that I'm a banker. Because having spent 30 plus years now in the power industry, the last four of which have been in a bank, I'm very much a power guy masquerading as a banker, rather than a banker masquerading as a power guy. And it's really based on that history and experience that I'm going to speak today. I'm not an academic. This isn't based on a lot of in-depth research. It's really my views, thoughts, and comments based on my experience and history and operating in various capacities over the last 30 years in the industry.

Let me first touch on nodal LMP markets and design. With few reservations, I have been and continue to be an advocate for nodal LMP markets. As an ex-system operator, I believe that nodal LMP markets, properly operated, best match the engineering reality of grid operations, which require incredible real time coordination. Vesting control in an independent systems operator who can coordinate operation of a functioning spot market while managing reliability in an open and non-discriminating manner is critical, I believe, to fair and efficient markets. That said, even this requires a level of simplification. And they aren't perfect, nor do I expect they ever will be. But it does provide proper economic dispatch with minimal socialization of congestion costs and avoids market distortions that could be associated with broad zonal markets.

ERCOT actually was a good example of some very distorted situations where the zonal market modeling didn't reflect the actual transmission constraints, and it was sending the wrong price signal to the wrong generators which exacerbated the problem, which could then only be taken care of by out-of-merit dispatch, which then drove make-whole payments to people that should have been dispatched downward being dispatched up. And so I think that LMP markets are absolutely the way to go.

That said, I think there are critical issues that remain. First, on the topic of scarcity pricing versus capacity markets. There's much debate about and there are different market designs based on whether you have regulatory capacity markets or whether you use scarcity pricing. It really comes down to this. If you look at the operation of the power market and the lack of storage, reliability requires (and I believe will always require) excess supply under even the highest demand period. While we can debate what the proper levels of reserves are, and different markets have different requirements, the result is that even on most peak days, you're really oversupplied from an energy perspective. One thing I think I've learned is that competitive over-supplied markets will collapse to short-run marginal costs. And I believe that this always will leave a revenue gap to earn a return on capital.

That idea may be controversial. I personally believe that without some way of addressing it, effectively, power markets require oversupply, and those prices will always collapse to the short run marginal costs, if you're competitive. And so you need to find some way to solve that revenue gap when it's needed.

So to solve this problem, some markets, as I said, are focused on scarcity pricing with no capacity markets, while others are focused on regulatory capacity markets. Scarcity pricing has additional benefits of driving load response, but it's unlikely to resolve all problems, in my opinion. In fact, there's actually a bit of a negative impact. And that is that scarcity pricing actually increases the operational risk for a generator. If I'm a generator and I have to offer in day ahead, and I get taken day ahead, when my unit trips in real time, I now have to buy back the real time, having been committed at the day ahead price. And so if you have this obligation to offer day ahead and now you're taken on the high days, when the unit trips, it's most likely when the scarcity pricing is going to go in. So now I have a much bigger operational risk. So I may have hedged my commodity risk through a swap against the day ahead market. I'm now committed against the day ahead market, whether I was hedged or not hedged. And now I have this big operational risk. So you have to be careful about that.

So I think capacity markets can assist. And maybe we can get there through scarcity pricing and high enough price caps. But they won't be sufficient to solve all of it. And most importantly, the capital markets are going to require forward contracts.

When we talk about liquidity, I think the really critical thing is forward market liquidity. It's forward market liquidity that's really critical for efficient deployment of capital and development of new products for wholesale and retail customers. Even the most perfect spot market design is not sufficient to drive forward market liquidity. And I personally think we probably get a little too obsessed with the perfect spot market design.

What do we really need to drive forward market liquidity? In the absence of regulated cost recovery, both capital markets and just prudent financial management are going to require some level of forward hedging to ensure debt service. If you look at the Midwest in the late 90's, when we saw prices go to eight or $10,000, and nobody rushed in and created caps and cap prices and said things were out of control, you had a rush of development of IPPs and development of generation. However, what you really saw is that many of those IPPs went bankrupt, including NRG and Calpine and GenOn, or Mirant. Smaller players. To me there are really three key takeaways there. First, I think deregulation works because the poor capital decisions and poor capital management by those generators are not being borne today by rate payers. They were borne by investors. You had a price signal. People responded. Built lots of generation. Didn't do a good job of deploying capital. So I used to think deregulation would drive better capital deployment decisions. I'm actually not convinced of that now. I have seen equally poor capital decisions under a regulated environment with the nuclear build out or what have you as I've seen in an unregulated world. The big difference is the rate payers isn't stuck when people make those poor decisions. The investor is.

The second takeaway is that absent regulated cost recovery, the capital markets are going to require hedging programs to manage commodity risk, and market liquidity is critical to this, and it's forward liquidity that's required, not short-term spot market liquidity.

So what's the downside of nodal markets? The downside to me is that the increased complexity, the lack of common price risks between buyers and sellers, and the lack of forward price signals tend to decrease market liquidity in forward markets, which is critical to the efficient deployment of capital.

After listening to the speakers today, I'm going to revise that comment a little bit. I'm actually not sure, if you look at it overall in totality, that it actually decreases liquidity. I think if you take the whole thing, we have more liquidity. What it really does, and I think a couple of our speakers touched on this, is it actually decreases hedge effectiveness. Because if my price risk is at a node, but the most liquid contract I have (and clearly we saw it in Speaker 3's presentation) is PJM West Hub, then my hedge is ineffective for that. And so what you have is a more complex marketplace with a lot of people having different price risks that can't be managed just through trading hubs. However, trading hubs are needed to aggregate nodal prices and provide common prices for the development of core hedging products. It's through the major hubs that you get the most commonality of price and therefore the greatest number of buyers and sellers, and the most liquidity. It's a key part of helping to manage risk, but not all risk. Zonal basis markets are required to get from, say, West Hub to East Hub. And you get liquidity at the sub-zone level, but you've still got to get what I call the "last mile", and the FTR markets I think are critical to that.

So a generator could manage risk by putting together that liquid hub product first, then moving to a zonal basis product, and then turning finally to a nodal product through an FTR. My concern is whether you get enough liquidity at nodal markets. I think the Nodal Exchange and things like it will be a good addition. But the real core problem is that there are not enough people that have that price risk. And so trying to get many buyers and sellers at an individual price node is problematic.

What this leads to is there's a need for sophisticated market makers to provide liquidity and manage risk for participants who simply want a nodal price hedge. They must be able to understand the complexity of LMP, the inter relationships between changes in fuel markets and power markets, and make use of FTRs and hubs and fuel markets to provide markets for nodal generators and LSEs who just want a simple answer. The key is forward market liquidity.

Now, to get a balanced and more active forward market, I think it's critical to have retail competition. It pushes the price risk into the hands of someone who actually has to manage it, because they now own that price risk. Unfortunately, our path to deregulation actually compromised this a little bit. We focused on deregulating the generation side, and we left load with wireless companies, who for the most part could pass through spot price and really weren't incentivized to manage the risk in forward markets. And so what we ended up with is forward markets that are dominated by sellers and speculators and don't have enough participation by buyers. And so you get this dominated market.

Retail competition has helped that tremendously, and I'll contrast two examples. If you look at ERCOT, or Texas, there's a really vibrant retail market. Texas put together this "Power to Choose.com" website. You can click on your zip code and you can pull up every retail offering that you can sign up for. For my residence in Houston, I have a choice. There are 43 different retail energy providers offering 240 different contract rates, ranging from an average price of six and a half cents a kilowatt hour to 14.2 cents a kilowatt hour, with terms ranging from three months to 60 months. There is a choice between fixed, variable, or index rates. You can index your rate to gas or you can just have a variable rate. You can have a fixed rate. You can choose renewable content ranging anywhere from no renewable content to 100% renewable content. And I can either pay as I go, or I can have prepaid contracts. So the tremendous development of customer choice that you are seeing through the development of competition, is real. And personally, I like that ability. I can be indexed. I can be fixed. I can change it from one time to the next.

By contrast, what's really helped the Northeast is the load auctions. And a big driver of liquidity in the zonal basis markets is around the load auctions. Because all of a sudden you auction off this load into the hands of some entity that has to now that zonal and nodal price risk. And so it's no longer sitting in a wireless company that can pass through spot. Somebody now signed up to take on that risk, and we see a significant increase in liquidity of those zonal basis products around those auctions.

I think both models are viable. Personally I prefer the vibrant retail market. I think it's better for consumers. It provides more customer choice. But auctions are also viable.

I have one final topic to touch on and that's in addition to just market liquidity and we started with this. It's the credit and collateral costs. So not only do you need liquidity in trading hubs and zonal hubs and basis markets and different products, but if you look at the generators, if you look at the retailers, and if they had to do everything cleared to manage credit risk, the collateral costs for those people are tremendous.

And I used to wonder, "What do the banks do in this space? Why are banks in this space?" And the one thing that I have seen is it's the intersection of the capital markets and the commodity markets. So we can go to a generator and say, "Look, we'll take a first lien on your generating assets, and we'll use that to backstop our credit risk associated with your hedge." We call them "right way risk first liens." What we understand and model is that as the commodity prices rise, and I have credit exposure on my commodity hedge if a generator defaults, the value of the lien on my collateral increases. That's not risk free. And we do price that risk in. But we can provide that counter-party with that credit-enhanced product.

Secondly we have seen the development of things like knock-in LC revolvers. So some companies have come and said, "Look, I know if we get a big move up in gas prices, my collateral requirements go up dramatically. I don't want to have to keep a revolver on or keep extra debt on the books to provide me that insurance. I only want that insurance if the commodity event happens." And so they'll come to us say, "Look, we would like an LC facility or a credit facility that knocks in if gas gets beyond a certain level or power gets beyond a certain level." Now, to provide those, you need to be able to access the credit markets and the commodity markets, and you need to be able to understand the intersection between the two, and then there's the gas producer hedging facility, as I mentioned. The development of those advanced products I think has been key to allowing companies to manage their collateral risk.

One of my concerns, and I think it's shared broadly, with the Volcker rule is whether you're going to squeeze people that can provide that out of the marketplace. And I would agree with Speaker 2 on this. It gets hard to distinguish in many places, even in risk management policies within the generators. People would say, “Well, we don’t want speculative risk taking. We don’t want proprietary risk taking.” I’ve yet to be able to get somebody to define it well. We do not have the luxury, and I don’t think we’ll ever have the luxury, of really deep liquid markets at every location, so we can simply lay off every price risk. You have to end up warehousing the fact, we want people to be able to warehouse things. As a portfolio, if I go do nodal prices with a whole bunch of people and aggregate it much more into the equivalent of something that looks like a hub, then I can hedge at the hub and then it actually will become much more effective. But recognize that I still have that risk. And is that proprietary? Is it client-based business? I don’t think you can clearly define it, and I am concerned--not because it will hurt the banks. I think it’s the generators. In fact, I don’t the banks have had much to say about it, because I think the generators and producers are speaking up very loudly about it.

So, finally, concluding remarks. I think that nodal LMP markets are required to manage unavoidable engineering complexities in power systems operations. Significant work remains to complete this effort, including scarcity pricing and capacity markets, addressing monopsony, reducing unnecessary intervention by operators. Robust retail markets are critical to developing sufficient liquidity in forward markets to support efficient capital. Discussion on liquidity must include the development of enhanced products that address the need to manage collateral requirements. You need liquidity in those things as well. And finally, while significant work remains, I think we are seeing real benefits of LMP markets on liquidity and deregulation, and I think if we stay the course, we will see a steady and gradual increase in liquidity. We will see a steady and gradual increase in product development for people. Somebody approached me the other day about developing a product for steel and aluminum manufacturers, where you can give them a power contract that is linked to, say, the price of aluminum. And so if they can index their power costs, which is their main input cost, to the price of aluminum, then it’s a much more effective hedge. To be able to develop a product like that, you need to have a counter-party that can understand both markets and develop a product that can link those two.

I’m concerned about the potential for a move backwards, but I’m optimistic. I think it does work. I think we are seeing it. I think we need to stay the course and keep our back into it and do the hard work to keep it moving forward.

Question: Are the kinds of activities that Speaker 1 and Speaker 3 are doing, with the different credit structure, creating a competitive pressure on you, with respect to what you’re doing differentially as extending credit of the counterparty? Are you seeing a competitive impact from this?

Speaker 4: What we find is actually that those things are good for us. In fact, I think this was one of the myths Speaker 2 talked about as well, about the banks having a bottomless pit of capital. That’s not true. It wasn’t true before, and ’08 proved it. Beyond the Volcker rule, there’s all kinds of pressure for the banks to make sure that they are charging for credit and liquidity risk. When we do that asset backed lien, we’re providing that hedge, and then we’re going and executing on the exchange, to flatten our risk. We’re effectively taking on that liquidity risk. Now what we’re finding is we’re having to quantify that and build that pricing in, so I have to pay internally for the liquidity stress that I put on the bank when I do it. I have to pay for the credit risk I take on that, based on the first lien structure. Where we see competitive pressure is that there are still some entities that are not pricing credit and are not pricing liquidity. And that’s actually the competitive pressure. I don’t think it’s the exchanges. The exchanges actually facilitate trading between counter-parties that do want to take that credit and collateral risk. The real issue is that not everybody prices credit and liquidity into their transaction. So if I have a generator who's saying to me, "Hey, I want to transact on the first lien," but they're comparing it to a cleared market, then, first of all, I have to educate them, "When you go over there, you have to think about your capital costs." Or there may be another large entity that signed up for the first lien and doesn't build in credit costs associated with it. And so then I start to look uncompetitive.

General Discussion.

Question 1: This is a very important topic and I was very interested in this whole discussion. I'm trying to see if a simple-minded story has anything to do with the truth here. [LAUGHTER] And so my simple-minded story is that for all the reasons that Speaker 4 was talking about related to forward markets and hedging, it's quite obvious you're not going to have the same level of volume or the same level of liquidity at every single node.

But that's not the right question. That's not the problem we're trying to solve. If you have these hubs and zones and so forth, you have a lot of things going on, and people are doing whatever. For example, they could be worried about the future of gas prices and how the gas price is going to interact with their contracts, and they decide they want more, or they want less exposure to that. And they buy offsetting positions, and the volume is going up, and they're trading with somebody else and there's a complicated set of relationships--all of those kinds of things that go on in that kind of a marketplace. And that's fine. And if we had a situation where every other node in the system was perfectly correlated with the hub, we would be done. Right? And there would be a basis differential, but it would be a fixed amount. It wouldn't matter. There would be no risk, and everybody would know, and everything would be perfectly correlated. Everything could be going up and down and up and down and up and down.

But it's not perfectly correlated, and you have a basis with the last mile problem, and how do you deal with that last mile problem? Here's the simpleminded part of the story--the last mile problem is not a problem for the same volumes that people are trading on the original hedges. The last mile problem is for when electricity actually gets produced and actually gets consumed. Those are the only people that we are really worried about. And all the other kind of financial packaging, the correlation portfolio analysis, and all this stuff with lots of trading, that can be handled at the hubs. And then the basis risk for the last delivery is handled by the FTRs. And so if you've got FTRs and you've got very liquid hubs and zones, if the FTR is perfectly matched with what we are consuming at the nodes, we'd be done. They are not perfectly matched, so there's a little bit of risk left when you have to deal with that kind of thing. But when you put those two pieces together, you're solving the problem that you're trying to solve, even though the measured volume of contracts at the particular nodes might be relatively small. That's my simple-minded story. Does that have anything to do with the truth?

Speaker 1: My take on it is yes, absolutely. And I'd add another piece in addition, which is that in addition to the FTRs, you can also do the cleared transactions at the node and you can do the bilateral transactions with the banks, and you can do the PPA agreements—or you can take the risk if you want to do that. And so in reality it's better than that. But from my perspective it's about looking at the total risk. I do think that there's still a perception that, "Gee, the liquidity risk must be so severe, I've just got to stick to the hubs." And I think some people are accepting more basis risk than they need to in the sense of just saying, "I'm going to ride that out, because I'm so worried about the liquidity risk." And I say that in part because in our market you can do things like auction indicating. And you can say, "Look, come find me at Point

Beach here. I want to do 50 megawatts for this time period, this amount of volume, whatever, and come to the auction and see what pricing we can get." You can then compare that to your other alternatives. And sort of see how much price risk you are taking.

Typically I'd also like to say that a lot of people take on hedges, and they'll often hold them. So the physical player who's doing the hedging is often going to hold that contract for a while, and doesn't need to keep trading in and out of it necessarily. The financial player may choose to do that. But we find that a lot of our contracts, for example, people do choose to take them on to settlement. We don't have algo traders because we don't have screen-based trading. So you don't have a lot of that volatility that's momentum trading or something of that nature.

Speaker 3: In many ways, the definition of market liquidity is very subjective. It's conditioned on what market you are talking about and what the end user wants to do. Do you want to transact tomorrow? Do you want to transact next month? Are you in a near month? Are you in a far month? Are you 10 years into the natural gas curve? Depending on the answers to those questions, you'll have your definition of liquidity.

Now, we don't find that liquidity in the 262 contracts that we offer is uniform. Of course it's not. We have large scale products like the Western Hub, AEP Dayton, NI Hub. Those markets are consistently active. And then we have the zones, and the activity in the zones varies over time. We've found that the planning year example has a lot to do with distribution of liquidity. If you look at our open interest, which is available on our website, you'll see that there are clear differences when the planning year ends. That's largely because commercials are taking positions based on BGS and other types of auctions to hedge their 24-hour risk in terms of winning the bids and those generation options. That is a clear indication from the standpoint of our markets that we have a high level of commercial use, because obviously we have a direct linkage. What we found is, with the zones, it's activity that does vary. Many participants put their positions on and hold them. They don't trade out of them. Because they have the supply obligation and they're going to keep that position on until you have the final settlement price.

Speaker 2: Well, there's a lot of risk in this business. The main one is the directional risk in power prices, natural gas prices. That last mile is something that can be managed, but usually as an owner, you're kind of comfortable with that, because you chose to own power plants in that location anyway. You've got transparent prices. You've got collateral risks, operational risks, outage risks. There's all kinds of risks--regulatory risks, market rule risks. That little piece of fixing that last mile is low on the list, and you certainly can do it with FTR markets. And if you're really, really worried about it, you can go to a suite of banks and say, "All right, I want you to hedge at my location." And they'll embed that in their bid offers, and you can pay away a little bit to do that. But I don't think the executives at our company spend a lot of time thinking about this particular issue. It's one of the issues that gets sort of managed and it's not a big deal.

Speaker 4: So I guess what I would add to that is that I think it's less than some other risks. But I absolutely think it's important, and it's critical in certain situations. If you take a generator as an example, here's the challenge. If you're a marginal generator, everybody came rushing in to value these things as spread options. When you value a spread option, you can realize that value if you dynamically hedge them over time. If you dynamically hedge, you need to increase your hedge level, and you hedge and unhedge to capture that time value of volatility and the lack of perfect correlation, say, between gas and power markets. And everybody puts this extrinsic value on the option, because they can manage it that way. But if I have a daily spread option and I value it as a daily spread option, but the only thing that I can trade three years out is a one year contract, but I've got deltas changing in July/August but I can only trade a calendar spread? That diminishes it. If I can't trade in and out of that last mile, if I put an average hedge on for the basis—yes, I can ignore it, and I think, to the questioner's point, it's a smaller risk. I agree that it's a smaller risk. But it's not immaterial. One of the guys I worked with once said this about liquidity. "It's like an electric fence. It doesn't hurt, right until you touch it." [LAUGHTER] And when you run out liquidity, and you need to get out of a position, and you can't, then all of a sudden, it becomes really big. And so I would say the last mile problem is a significant problem. But it can be ignored until it's important, and then it becomes material.

Questioner: But can you address a large part of it with the FTRs, or does that not solve the problem?

Speaker 4: The problem with the FTR is I can procure an FTR based on the average (in quantity) hedge requirement for a generator or load. Since the FTR auction is not a daily auction, I can go and procure them a year at a time. At best, I have monthly liquidity in those to rebalance my hedge position. I don't have it on a daily basis. And so the development of a nodal exchange where potentially now you get a bilateral market in an equivalent product that maybe you can trade every day will help. But the constraint is still whether you can get enough counter-parties, buyers and sellers, at those locations.

Speaker 2: One of the nice things about Nodal Exchange is that if Speaker 4 and I decide that we have a transaction that we can do but we want to clear it, we can actually go to something like Nodal Exchange and say to them, "Will you create a contract to clear this for us?" And it will probably get done in couple days. Just because they have a straightforward methodology for dealing with all of the locations.

Speaker 3: We don't have any FTR markets listed at the present time. One key issue for us is how do you margin? In order for us to efficiently margin, we have to be able to price the underlying commodity every day. So typically we do that with the over-the-counter brokers. They give us the deals, and we get the prices. And so we're basically marking thousands of contracts based on those broker marks. So without having a source of information in terms of an instrument like the FTR market, it would be very difficult for us to offer an efficient margining process, as opposed to overmargining, which dramatically increases the cost of capital to compensate for the lack of direct minute to minute, day to day price discovery.

Speaker 1: From our standpoint we do have to price 70,000 expirees daily. And we have the auction to help with that process in terms of being able to do that. And from a margining standpoint, we do use a value at risk-based methodology which accounts for the puts and takes among the varied positions which allows it to be efficient for what we're doing, which is very complex. I mean, we couldn't have launched what we did without having the auction that we have in terms of making that as an alternative. And again, I believe the sun is still rising on this market, etc. As Speaker 4 mentioned, we need to have more and more participants come to party, etc. But I feel that it's growing and expanding, and I look forward to its continued progression over time, to become a tool that helps the marketplace. That's how we were started. It actually came out in discussions in the ISO markets about a need to have a daily auction or something like that, a mechanism to have a secondary market, if you will, for positions that come on for FTRs. And by doing spreads, you're able to do that with the LMP spreads.

Speaker 4: That touches actually on an important point. The price transparency needed to be able to have cleared exchanges or for everybody to do due diligence, whether they're traders or market, is really critical and a big problem in our space. And I'll stress again that this is only me speaking for myself. But if there is one thing I personally believe regulators could do quickly and easily to help with that problem, it would actually be required reporting of all trades, and to have that centralized and recorded so that it would be very transparent. You would have the most amount of price discovery related to what transactions and what prices have happened in the marketplace. So it would facilitate market and clearing exchanges and just good discipline risk management.

Question 2: I want follow up on the "simple" story and try to summarize it very succinctly. LMP, or nodal pricing, is a necessary condition for liquidity, but it is not sufficient. LMPs and FTRs are necessary and sufficient together, because I think the FTRs do deal with the last mile problem. The analogy I would use is if I look at a lot of the exchanges, and I look at the basis swaps between various city gate delivery points in Henry Hub in the natural gas market, I think that having those basis swaps seems to make Henry hub a very liquid trading point.

But the question that I have, and maybe for everybody on the panel but especially for Speaker 3, since we've had these discussions before, is that with the high correlation between gas prices and power prices, does that make gas contracts a viable hedging option for power prices, understanding that correlation and then using the different basis swaps, whether you have FTRs behind it or you have a gas basis swap? That's the first question.

But then there's something that Speaker 4 said in his comments that made me stand up and kind of take note here, about energy markets being oversupplied, by definition. And I think we need to be careful about that, because at least in the PJM market, when you have price transparency and you're able to get resources such as energy efficiency and demand response, that are not dispatchable energy resources necessarily in the energy market, one could imagine a situation where if you have 10% of your capacity in demand response, and you're just meeting your installed reserve margin, the amount of steel in the ground means that you're going to see a lot more cases of higher prices and price volatility in the energy market, because you don't have that depth in the energy market that you may have today. So I think we need to be very careful about making those kinds of statements. And that we will then see changes in the capacity markets and capacity market pricing because of that. So I just I'd like to get the reactions from some on the panel with respect to that and I'll just leave it there.

Speaker 3: Well, I'll lead off, given the reference to natural gas and power. The natural gas and power relationship has been a strong one for many years. And in some markets it's stronger than other markets. As an example, Texas has typically been consistently above .9 from the standpoint of the correlation relationship. Why? Because Texas is very close to gas supply. There is a lot of gas supply inside the state and around the state in the greater Gulf area. We have 80 ERCOT contracts and very little activity. We do have open interest, and the ERCOT contracts do show up once in a while. But generally speaking, it's not significantly active.

Could some of the power hedging be done on the gas side? Well, last year, the Henry Hub contract was up 21% in terms of total MBTU. Basis contracts were down. Henry Hub was up. Henry Hub is a highly liquid market. Thirteen years out, in terms of consecutive months. And the bid-ask spread is narrow. You can get your deals done. So balance off against that liquidity whatever interest you have in transacting on the basis side to perfect your hedge. Well, the oversupply on the gas side has had the effect of collapsing some of those relationships. So basis in the greater Gulf area has become less and less significant. And that has tended to focus attention on the central benchmark. I think there are similar issues and dynamics operating with the Western Hub. So it could very well be that some of the success that we've had in the natural gas volume side is directly related to power hedging, because of that tight fit. But that tight fit doesn't extend to all regions.

Speaker 4: I can touch on both things, actually. And I can speak from first-hand experience on the first question, around using gas. And this is actually an important factor in power liquidity in both ways. First of all, I would say probably the majority, or certainly many, of the large generators, particularly base load generators, use gas as a hedge. I remember when I first went to NRG, they did not have a gas fired generator in the fleet. And in the interview process I was asked, "So what do you think?" And I said, "Well, first of all, you've got to have a view of gas." And they said, "Well, we don't have much exposure to gas." And I said, "Well, you might not burn much gas but you have a lot of exposure to gas." [LAUGHTER] And it was part of my first board presentation to explain the correlations and how long we were in gas. And so given the high correlation, you need to think about that.

Now, the liquidity starts hitting this, because people lean on the gas market for exactly that. Especially when you go out in the term market, if you're talking three, four, or five years out. The bid-ask spread and the liquidity in the gas market is so much better, and your transaction costs are lower. And so we see a lot of people continuing on the power side to use gas as a hedge. If you take a generator like Calpine with 26,000 megs of combined cycle, how many people would think, "Are they long or short gas, effectively?" They have to buy a lot of physical gas. But if you actually look at spark spreads, spark spreads are positively correlated to gas because the market heat rate might be 10 and the unit heat rate 7. They are long 3 MMBTU of gas for every megawatt hour. And so even they're long gas, and they will use gas as a proxy to hedge a spark spread. Or at least we did when I was there. I don't want to speak for what they're doing now. So it's a challenge, because the more that they do that, the more difficult it gets to create power liquidity and tighten bid-ask, because all the power guys are transacting in the gas market.

And so it becomes a self-fulfilling prophecy. If you don't have liquidity in the power market, everybody goes to lean on the gas side because, if the increased bid-ask of transacting in the power market is equivalent to a significant move in the relationship between power and gas, then they'd say, "I'd rather transact in gas and I'll wear that risk, because I'm just paying for it upfront if I transact in power." But if everybody transacted in power, the problem potentially would go away. So we've got a bit of a Catch 22 in how to get past and develop more liquidity to a point where people actually transact in the market they are in now. What will fix that very quickly is if the relationship between gas and power starts to break down, which really goes to tightening reserve margins. Then people will want to transact a lot more in power.

Finally, to your second question about the capacity markets, I absolutely intended that to be a controversial statement. And I absolutely understand that there are theories that demand response can solve that problem and you don't necessarily need capacity markets, but it remains my view that at the end of the day the market needs some form of capacity markets to solve the problem. The other alternative, which I didn't mention, is actually getting to restricting people's ability to actually lean on the spot market and balance their entire generation or load portfolio on the spot market. One of the things we saw in ERCOT, pre LMP, was that there were limits on people's ability to balance and within tolerances, they had to self schedule. And as a generator, we saw loads and utilities coming to pay for the ability to load follow. And so if you have a load following generator versus a base load generator, you could get a premium for that service, which is really important to power markets. But if everybody can just balance with the ISO, there is no incentive for people to pay a premium for the ability to do that load following in a bilateral forward market. I think if you saw that, it potentially could offset the need for capacity markets.

Speaker 2: Just to add a really quick point, I think the whole market is getting more sophisticated over time. So, for example, Speaker 4 goes in and makes presentations and the board says, "Hey, you guys can use gas." The siting decisions around plants are better. When you build plants now, a couple of merchant plants coming on line. I think one is built by Hess. It's serving the New York City load. There's another one with LS Power in New Jersey. So you're seeing merchant plants located in the right locations.

So to the first question, what are you trying to do with this whole thing? Well, when you get the prices right, then the tricky thing about that is it makes them transparent, and then people get upset because they can see the cross-subsidies and things like that. But if you don't make them transparent, then you'll continue to get the wrong long-term efficient decisions around how much transmission to build or what generation to put in and things like that. So I think people are getting more and more sophisticated around dealing with those issues.

Comment: I think the issue with restructuring and deregulation is really getting the prices right and making them transparent. Maybe that's the biggest value that we've seen out of this exercise that we've been undergoing since the mid 90's. And that's what gets us to the better capital allocation, as well as real time spot decisions.

Question 3: This actually goes back to the issue of the last mile. One of the things that I think is important relates to who carries the risk and how you price. On the hubs, the SFT (Simultaneous Feasibility Test) goes to the weakest link. So FTRs at hubs, if everybody did that, it wouldn't work very well, in terms of the intrinsic market of the RTO, not the synthetic market of those guys swapping.

Question from audience: Why is that?

Questioner: Because…What's the lowest voltage of some of the nodes from some of the hub definitions? We have some really weak links…

Comment: But there can be sources and sinks.

Questioner: Exactly. But you're still going to be intrinsic to the market. You're going to be limited in terms of openly doing that. You can't sink them.

Comment: It's just arithmetic. You're just taking the nodes and you're aggregating them in a different way. It doesn't change the simultaneous feasibility test.

Questioner: But it does change the quantity that you can start going from every place to that sink.

Comment: If you take any configuration of FTRs, you can decompose it into, from A to hub, B to hub, etc. So it's the same.

Questioner: No. But then somebody is out holding the A to B. That doesn't close out the last mile. It gives the last mile to somebody else. Externally, the synthetic or the OTC product can do that by marking against it. But internally you're limited in your ability to do that. You have to always have somebody else picking up the residual.

Speaker 4: I mean it seems to me that if the only thing that's available in the FTR market was the intrinsic transmission capacity, then there's a limited market. Right? But because it's simultaneously feasible and because –-

Comment: It's not because of the hubs. it's because of the grid.

Questioner: But if you want to sink at the hubs and everybody trades against that, then the ability to intrinsically do it…

Comment: I could model the system without hubs. And I could model the system with hubs, and I could run an FTR auction and let people buy whatever they want…

Questioner: And it stays exactly the same. That's right. That means that if you want to always structure your basis risk against the hub, there's a limited capability to do it. That's, because otherwise --

Speaker 4: Only if everybody is going the same way.

Questioner: So what happens internally, you'll do the kinds of things that the various traders will do is you'll look for things that are the high DFAX on whatever is a similar kinds of constraint, and you use those as proxies. But it's only through the liquidity that they're talking about that you can actually build the open interest up as high as you want.

Speaker 4: I think if you look at the auctions… you've seen our FTR platform. This is basically what we do. So if you just think about the outcome of that, if everybody was moving to the hub and it was effectively driving congestion in the auction, because we were hitting transmission constraints, it's going to drive up the price of that congestion. And if you have many participants, and sophisticated participants, who are looking at that and are saying, "Now wait a minute. That price now exceeds the risk and there's a good risk reward," they will provide the counterflow, and effectively the auctions will price where people are willing to price that risk.

Questioner: I'm just saying you can't decompose it to this being the last mile. In your conclusion, there is the last mile plus the willingness of somebody else to pick up the counterflow. And they're pricing a product against that as well. If everybody trades against the hub, there still has to be somebody balancing out what is essentially the infeasible difference. If everybody wants to reference --

Speaker 4: But everybody doesn't trade against the hub. DC Energy does a really good job of not trading against the hub, for example.

Questioner: [LAUGHTER] And my point is just that that last mile doesn't sit solely within the FTR. It's going to sit between these mechanisms, where somebody is still holding something unhedged outside of the transmission system. It's still going to be a risk swap between the participants. They can mark against it, but it's not intrinsic to the transmission system.

Comment: I have to think about this. I don't think this is right. I think the hubs don't matter for that purpose.

Questioner: They do if everybody thinks they do. If everybody uses it as their proxy. But it's resolvable by the trading platforms, because essentially they are limited by open interests.

Speaker 4: I think agree with what was said before, which is that there's not enough transfer capability on the grid for everybody to hedge at every location. And that that allows for the OTC trading at those locations that allow you to hedge.

Questioner: I'm agreeing with that conclusion. I'm just making clear that there's something different between what I would call the intrinsic and the synthetic.

Speaker 4: I think it all becomes synthetic. So ultimately, it's going to be limited by the underlying capability of the transmission system, whether you model them as hubs or not. It's going to show up in the price for the FTRs. And whether it's the hub or whether it's just one particular transmission constraint, and there's demand that far exceeds the intrinsic transmission capacity that's built in the FTR market, it's going to drive the price up. And if there are many players looking at the FTR markets, then if that drives the prices in the FTR auction beyond the proper risk-weighted or risk-adjusted price for that, somebody will come in and take that out.

Another little piece I'll add is that if you look at FTRs, there are many be different ways to participate and play in the FTR markets. As an example, you can look at, say, an East Hub to West Hub basis swap. Effectively what you're exposed to is the difference due to congestion and the difference due to losses. If I take the opposite position in the FTR market, my combined position is really just exposure to the losses. And so people will look at the FTR spread between East Hub and West Hub and the swap price for East Hub to West Hub. And if the difference exceeds the risk-adjusted price of losses, they'll take the opposite position. Which is what would happen if you did get this constraint, and it drove the price of a hub up out of whack, somebody would go take up that when it exceeds the risk adjusted price. I don't think that drives a big constraint. We don't see it in the auctions.

Speaker 1: I would just add a final point in terms of flexibility of trading. I had an unusual question at one point. Somebody said, "Don't you have to represent every FTR spread in terms like point A to B and B to C?" I don't. I just have to represent every generation node, every load zone, and every hub in PJM. And people can define any spread or not outright or spread between two locations.

Questioner: Absolutely. You don't have to do that. The SFT is what I'm calling intrinsic.

Speaker 3: Another aspect of the hedging process in the LMP environment, beyond hubs and FTRs and zones, is day ahead versus real time. We regularly see spreads between day ahead and real time. Because market participants do have exposure to that spread. And by offering both, by having real time Western Hub and day ahead Western Hub, we can facilitate that. And a significant part of the activity comes into the exchange.

Question 4: I wanted to ask a question that followed up on the analogy of the rising sun or the setting sun. In the perspective of panelists, where do they see liquidity going in the short term? And what are the major factors? Some of us have obviously debated things like Dodd-Frank. How big an impact will that be? But are we kind of rising now in an environment where liquidity will be blossoming in the nodal environment? Or are we at a steady state, or are we at a problematic setting sun perspective?

Speaker 1: Well, from my perspective, we're certainly in a rising sun environment. I'll just take the cleared markets as an example. If you go back three years, in the cleared markets, it was zero at the zones. Right? And today it's 10% on the zones, which is another 10% on the hubs, so typically spread between the two. About 20% of the total cleared market is in fact the more granular location. I think if you go forward, we'll always see a bit of a combination. So let's say that the zonal trading was 40%. Then you'd have 40% at the hubs, and you're spreading between the two, and that leaves you with 20% sort of an outright. So there does become a 50% sort of maximum that I think we'd likely see in the nodes and zones and the total cleared open interest.

But that said, I think we're also seeing that the market will continue to grow now. If you look at the last three years, actually the total cleared volume slightly declined if you add up NYMEX, ICE, and Nodal Exchange over that time period. However, if you look at the indicators we're at so far in the first quarter and it looks like we're going to see some significant growth here in 2012. Now, we'll see how that it persists, etc. I think as the economy recovers, I'd like to believe we'll see more trading and I think we'll see more happening at the granular level. And again it's people looking at that total price risk. There's a discussion about the last mile and you can let it ride or you can go ahead and hedge that. I think we'll see more people choosing to hedge that. Albeit, I also believe that, of course, in terms of relative liquidity, it will always be hubs first, zones second, and then nodes. But I think the question ultimately is still do you get sufficient price liquidity for your contract? You're not going to have the volume there, but do you have sufficient price liquidity that you're able to get the right total price risk answer as a trader. So I believe it's a rising sun.

Speaker 3: I do share the view that we have reason to be optimistic. We grew 62% last year, in terms of total megawatt hours. And we've added quite a few options. We've added additional zones. We see continued opportunities. However, trying to assess the landscape right now does require an assessment of the regulatory environment. And Dodd-Frank is not done yet. And the swap definitions are not done yet. And that's a key element in regulatory definitions of the various contracts that we all offer. So we can present our views, but we haven't had the CFTC's view of the definition of swap. We don't have the swap repositories in place. There's a lot that still hasn't been done connected with Dodd-Frank.

Shifting to gas, the gas market has turned on its ear from the standpoint of where that market was five years ago. We go back 10 years, there was a view that we had to build LNG facilities, and the US did build fourteen and half BCF of LNG import capacity, and how much are we using? Less than one BCF. Absolutely incredible. So now we're entertaining the export of LNG and, of course, that's going to take a few years before that can become a reality. But it does highlight how the gas industry has changed.

And when the gas industry changes, there are direct, profound implications on the power side. Today if you look at the price of the Henry Hub and you calculate the difference between the Henry Hub and the Chicago City Gate and Henry Hub and SoCal Border and Henry Hub and Transco Zone 6 in the northeast market, you'll see that the differential is below the cost of the transportation. That is, someone is having to swallow that difference between what the pipelines want to charge from the standpoint of their rate structure and what the market is providing as the value between the two points. And that has the potential to significantly affect the power market as well. The fact that you've got, on an optimistic estimate, 500 TCF in the Marcellus, so close to the market--not in the Gulf of Mexico, in Pennsylvania, the Marcellus belt--has had an effect on what the pipelines think about, and on their businesses. It has an effect on the investment decisions that underlie the gas market. And having that amount of supply will have a profound effect on gas fired generation.

Speaker 2. To the extent that the deals are there, and they make sense for people to do, I think they'll find a way to get done. But I do think that with Dodd-Frank, it's not clear what the rules are going to be. And I think as they're writing that rule, they're thinking about some of these issues around what it does to liquidity and what the role of the banks is, which, as I showed in the slides, is changing anyway. It's tricky to know exactly how that's going to go.

I do think with respect to some of the zone liquidity, we've had some important developments, like Nodal Exchange coming along and being able to clear more basis and more locations, rather than just being restricted.

So you get those kind of developments which actually do help. We do probably more of our trading with on ICE with Clearport, but also Nodal Exchange has become very helpful from our standpoint.

Speaker 4: Just a couple of quick comments on where I think liquidity is headed. Overall, I think we have a steady march up, if you consider overall liquidity. But as we touched on, there are significant threats on the horizon. The Volcker rule is the obvious one. The other one that we haven't mentioned, and I think this is a really critical item, is regulatory stability. The most damaging thing in my mind to market liquidity is regulatory instability. And ERCOT right now is having that big debate. The news said the other day that some of the regulators are talking about increasing the price cap from $3000 to $4500, and potentially up to $7000 or $8000. That may be a good development in the long run. In the meantime, immediate reaction is the market went up three times the price of gas. And people can win or lose in that. What I've seen is when you get shocks to the system, where everybody's done their research and they made their assessments, but then there's just this dramatic change to the regulatory construct, that is a very difficult risk to manage. That effectively drives liquidity out of the marketplace.

The final comment I would make on liquidity is, this is where power lags relative to gas markets, metal markets, oils markets. A significant development over the last decade, I would say, is developing each of these things as asset classes on their own. So you'll have pension funds and institutional investors come in and say, "I want exposure to metals. I think that increased demand in China is going to increase demand in metals prices"--or oil or gas. People want to be long and they want to be short, and you'll have a significant number of players. Not actually physical underlying participants, but they will come in and do that. That actually really, really helps on tightening bid-ask, on improving liquidity, particularly in term markets. One of the challenges we have in power is how to develop power as a transparent enough market where you can actually attract financial players, institutional players, hedge funds, various people who will want to have exposure to power prices as part of an overall portfolio. The complexity of nodal markets is probably one of the biggest challenges, because when you try to explain to them how markets work, I think back to the name of Bill Hogan's very first paper on power was, "Why Does This Make My Head Hurt?" [LAUGHTER] And when you start talking to institutional investors about power as an asset class, their heads start to hurt. You really have to have people that really know the detail and are in the markets.

Speaker 2: I just say it's so correlated with gas anyway that I'm not sure that --

Speaker 4: And that relationship I think will tend to break down over time.

Speaker 3: Well, Speaker 4 mentioned ERCOT, and I can testify that having a high price cap is a significant negative from the standpoint of trying to manage your risk. $3,100. That price did occur in the ERCOT market in February '11, shortly after ERCOT went live with its version of Texas nodal. Now if you were sitting in the seat of the risk committee which operates at CME, you might be concerned about the potential for $3,100 per megawatt hour when you're thinking about how to margin the daily contracts. Now trying to handicap how likely it is that the $3,100 will be triggered is an art form. And in the aftermath of $3,100, we understand quite well why it happened. Could it happen again? Well, I can't exclude that possibility, and the problem is that with such a high price cap, that's an outside possibility that has to be covered by the risk management process. And the first rule of the risk committee and exchanges in general is to protect the clearinghouse. Businesses find we want to grow the business but you had to protect the financial integrity of the clearinghouse first, and having a $3,100 cap or a $4,500 cap does present significant challenges from that standpoint in terms of handling the risk at the clearinghouse.

Question 5: My bias is that the zonal products and the nodal products will grow and that lack of liquidity is not an issue really. In fact, if you look outside the power markets and into other traded contracts, you find all sorts of liquidity levels. But they have a useful purpose in the market. If you're buying/selling corporate bonds, they're less liquid than a lot of FTRs. But that doesn't mean we should get rid of them and that they don't serve a purpose.

So my question is, will zonal and nodal contracts grow in volume or not? What other products do you see on the horizon that from the exchange side, Speaker 1 and Speaker 3, you might be offering in the marketplace, or that from the customer side would be useful in terms of trying to create a more functional market from your perspective? I do kind of agree with what you said, Speaker 4, that it is a new kind of asset class. It's really emerging, and while it's complicated and will make your head hurt, fortunately some people's heads here hurt less than mine. I feel comforted by that. And it's a very logical and very transparent--when you look at how sometimes gas prices are set at basis points, that's not so clear to me, in contrast. So at least here, there's a lot of clarity if one digs into the facts behind it. So I see there's a lot of promise. But the question is, what kind of contracts would be useful for you all going forward? There have been new developments even with daily call options as well in the power market. So I know there's a lot of stuff going on. What would you say would be the valuable next things on the horizon?

Speaker 2: Well, I'd love to see markets expand to some other areas. And so if we get an Entergy contract with them entering MISO, or SPP, developing some contracts around there. I think that that's a very positive. There was an interesting discussion yesterday around how to implement Order 1000, and you need to be an ISO to be arbiter of that stuff, so that might push us more towards RTOs anyway. So I would say that pushing for more markets that way would be very helpful in the power market. And just from a historical perspective, the market is so, so, so much more liquid now than it was when I started doing this in 2001. It's partially the electronic trading platforms that have come along, and expanding them to be able to do basis and do much more

Speaker 3: Well, from our standpoint we've done quite a bit on the options front over the last two years. We have pipeline options on the gas side. We have calendar swaps. We have a variety of gas contracts. On the gas side, I do see a tightening relationship potential in the gas market and the power market, so trying to match up the generator's needs on the gas side I think makes a great deal of sense. Especially inside the month. So when you do offer swings, I think we'll be continuing to expand what we're offering intramonth to cover the generator needs very directly. I think on the environmental side, there are clear opportunities across the energy space. California is a good case in point in terms of the start next year of the cap and trade. So energy is increasingly linked in markets in California with environmental requirements, and that presents an opportunity for us as well in terms of environmental products interfacing directly with the energy side.

Speaker 1: I would just say we like to be very flexible and responsive. As so we listen to what people like Speaker 4 and Speaker 2 say in terms of what they want, and then we make that available. When we first launched, we just went out one year. We now go out 68 months. We didn't have any contracts in California ISO or ERCOT. We now offer contracts there. Again, we'll just continue to sort of listen to what people need to do and add the new locations. So, for example, when SPP goes nodal, we'll add those. If Entergy joins MISO, we'll add those. If people want to break up the LMP into its discrete components, we'll do that. So again it's a matter of listening to the marketplace and sensing where that demand is. We've had a lot of discussions about other products, too. Right now we all do monthly terms. Do we go to finer time periods? Do we look at things in terms of RECs or other emissions products, etc? But again, we'll add those if there's a demand there from the marketplace. And our goal obviously is to give flexible cleared products that allow the market participants to do what they need to do. And we'll just be the facilitator enabler of that.

Speaker 3: And that granularity could expand to periods of peak. Right now the definition is 16-hour peak. The potential is there to trade in increments in super peak, and it might be quite useful from the standpoint of a generator's operation to have super peak available.

Speaker 1: That's a great illustration. We used to do peak and off-peak, and within the last several months we've introduced new off-peak contracts that do things that are the weekends, two by 16 or doing seven by eight's, etc., so that people can have the type of off-peak they want. Do we sit there and say, "Ah, the market must have a seven by eight or a two by 16?" No. We listened to people in the marketplace and they said, "Hey, why don't you introduce this contract, because we'd like to trade it?" So we're always keeping our ears open and then being responsive.

Moderator: I would just add that there is some discussion out there, at least in parts of the community, about trying to do retail products that are a combination of a dynamic price and call options for retail customers. And that might lead to new types of option products that might come into the market.

Comment: There's something that we haven't touched on that I think would be very helpful, that the ISOs could do. And that's further development of the FTR market. PJM is again probably the standard. And they have long term auctions. They have planning year, one year out auctions. They also always have a Balance of Planning Year. So every month I can procure for one month, and every month I get an opportunity to trade in or out of that. And to the point about managing the last mile, the more liquidity I have around the ability to adjust my needs, the better. If we look at other ISOs for the most part there are annual auctions that only have at best a monthly reconfiguration. And so I get one shot to do the entire year, and then I can only rebalance my position as I come into the delivery month. And so a balance of planning year type of auction every month instead of just a one month auction I think would be a significant improvement in the ability to manage that risk. And I think it's something that all the ISOs could do. And long term FTR auctions I think is really important to be able to manage that risk further out the curve.

Question 6: Two of the speakers talked about offering contracts in the forward capacity market and our experience has been that the bid-ask spread is really wide. It's extremely difficult to predict prices. We have really smart traders that actually have all the modeling and so forth. And then when we ask them, "Well, what's the 15, 16 planning years going to clear at?" I get this huge wide rage that's basically worthless as far as hedging. There's a lot of issues. Nobody knows how much demand response is going to participate in the market. That's an unknown quantity. The transmission model is sort of like a black box at PJM because it's almost zonal. It's not really the same transmission model they use for LMPs. And then to even further complicate things, we have a very steep demand curve, so small deviations in supply lead to a huge volatility in prices. So specifically for PJM, I'm interested in your comments as to whether there is any liquidity in trading in these forward capacity markets.

Speaker 4: We don't actively participate in capacity markets. There's probably some demand out there and we get requests for it. This is probably where regulatory instability hits us the most. Trying to be a market maker in a market with a very steep demand curve and instability in the rules is probably suicide, quite frankly. And the reason you get big bid-ask spreads is because the risk of trying to be a market maker in that market is very high. So I think you need stability.

Speaker 2: I would take a different tack on this one. I think that the lack of liquidity is driven by the fact that there are no buyers for the capacity. The ISO is going to buy it and procure it for all the load, and that's the bargain that we got into to do this. So if you're a retail provider or you're a utility, you just have risk if you go and decide you're going to procure it. Unless you're speculating and you say, "OK, I think I can buy and I know more what the market is going to clear at," you're going to be able to pass it through to your load. And if you buy it, great, and you get a nice handshake from the ISO, and if you mess it up, your regulator comes back and they ding you if you're a retail guy and you did a bad job buying capacity. And that's why you have these forward capacity markets in the first place in some sense, because you had retail guys who didn't buy capacity. And then they would go and complain to the regulators when the prices went up, because they didn't hedge. You get a lot of market interference. So one of the slides I had up talked about how liquidity is driven by having diverse ownership of the generation and the load, and willingness to buy and so on. And if you had that, there would probably be more transactions here. From the generator's perspective, I think we would like to be able to go out and hedge more. But it's a question of how much we are willing to pay to do that. And if we're not, we're just going to have to take what comes out of the capacity market. All else being equal, we're happier with the capacity market than not having the forward capacity market. Because once those signals come out, they're sort of locked in longer term. So I think it's a hard line to get there to be liquidity given the structure. And I think the structure of it is the right structure, to have a centralized capacity auction where everybody pays. Because otherwise you get the different load serving entities retrading the deal at the end of the day. And this way it just looks transparent and it gets passed through and there's no political fighting about how we're getting the missing money with it.

Speaker 3: In thinking about the capacity market, we saw an opportunity with New York, which presently only has one season out, so we opted to list multiple seasons, and we have had response to that. The rest of the state has just under 400 contracts. Each of those is five megawatt months. It certainly isn't the leading liquidity supplier within our universe of contracts, but it's useful. And parties have positions on all the months that we have listed. In fact, we're going to list additional months because of that level of interest. And having markets like this adds to the underlying market in capacity because you have an additional source of information, additional bid offers, and additional views related to price. And just having the market means that there are more transactors paying attention to it. Brokers pay attention to it. We get quotes from the brokers and it helps develop the subsidiary business as well. So we will continue to provide as much leadership as we can on that front with additional capacity markets.

Speaker: But I think that just proves the point of how the liquidity in the market is a derivative of the regulatory rules and things like that. And so in New York, you might have a rate case that's going out a few years and you've got Western New York Utilities. All right, they know what they have to make and they know where capacity markets. They are now buyers of capacity, and they have a desire to have those markets exist. So then you get a more liquid traded market of contracts. And you can list those forward. And that makes sense. So I think the liquidity is really just a function of what sort of regulatory rules you end up having and then how the market ends up responding to those.

Moderator: I'll just add, from a regulator's perspective, that one of my main criteria about whether or not capacity markets are working is whether there is liquidity in the voluntary forward contract markets. And if there's not, that suggests to me that there's some inherent problem, whether it's the steep demand curve or the lack of visibility into the model. There are things going on there that suggest we have some really fundamental issues with the way we're handling capacity, if no one is willing to voluntarily step up and get a relatively narrow bid-ask spread in the forward market.

I guess the other question that it raises for me (and I raise this from the perspective of someone who sees more than 90% of the actual outages that actually affect customers are in the distribution system and have nothing to do with the amount of resource adequacy that we have) is that I think there's a real question about whether or not our rules on resource adequacy actually reflect what people would be willing to pay if, in fact, we had a voluntary market. And even where there's retail access and even where there are customers who have the ability to go in and set their own capacity requirements, I think we don't see it there, and I think it raises some fundamental questions that we as regulators ought to be looking at, and largely have not looked at well over the last several years.

Question 7: Speaker 3, on your screen 14, where you list money managers and non-reportables, where, if at all, do hedge funds fall into this category of holding positions? And in light of Dodd-Frank and the Volcker rule, what market impact do you see, particularly that regulators should be concerned about in terms of price volatility and the position of utilities?

Speaker 3: Hedge funds would be within the category of managed money.

Questioner: They're the money market?

Speaker 3: Correct. And one of the intentions of the CFTC was to capture that segment in making the Commitment of Traders report more granular.

Now in terms of the impact of Dodd-Frank it's very difficult to call in terms of how that's going to affect the market. We know that regulatory stability is a key to developing liquidity. Shifting a little bit to the point that our moderator just made, if we don't have regulatory stability in the capacity programs, an exchange like CME or others, Nodal included, have a difficult time developing contracts because users when they enter into the deals, expect some sense of permanence. So part of what's necessary from our standpoint is to have that level of certainty so that we don't have to change midstream. So we don't have to make emergency declarations to the CFTC because the timeframe of the capacity auction was changed significantly, and no one notified the exchange, and we didn't identify that. So having a level of stability is a very important element. And right now I can't really say that we have a great deal of regulatory stability.