HARVARD ELECTRICITY POLICY GROUP
EIGHTY-FIRST PLENARY SESSION

The Four Seasons
Palm Beach, FL
THURSDAY AND FRIDAY, DECEMBER 10-11, 2015

Rapporteur's Summary*

Session One.
Transmission Expansion and Cost Allocation: Order 1000 Redux

Transmission expansion and cost allocation protocols present continuing challenges for the evolution of electricity systems. Whether from the Clean Power Plan, direct support for renewables, or the changing patterns of generation and load, a central problem remains to adapt and provide workable rules for transmission expansion, both within and between regions, and the associated cost allocation requirements. Promulgation of Order 1000 in 2011 capped the development of the canonical regulation under FERC that has been subject of important Court challenges and continuing disputes. Everyone recognizes that a viable transmission expansion framework depends on a hybrid design that captures the complex interactions among new sources of supply within organized markets, between regions that reflect different organizations of the electricity system, and that interacts and supports both public policy objectives and the requirements of electricity markets. How is the experience with Order 1000 developing? What is the impact of "roughly commensurate" or "very roughly commensurate" cost allocation rules? What is the state of progress in implementing voluntary interregional expansion protocols to complement those mandatory compliance rules within regions? How are we doing on supporting efficient transmission investment?

Speaker 1.
Good morning, everybody. I am going to talk about transmission planning in NYISO. Basically, what we're trying to do is to mix the reliability planning process and the economic planning process and be, sort of, mixed with the so-called public policy planning process and Order 1000.

In New York we've been very lucky that we have something called a "locational marginal pricing" mechanism, not only for energy but also for capacity. (I leave aside the argument as to whether we should have a capacity market. That's not today's topic.) But we've been very fortunate that over the years, for the history of New York ISO, we have seen a lot of new capacity being added to the system that actually first came up in the planning process. When we have a reliability issue, not necessarily tomorrow, but, say, 5 years or 10 years out,

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

PHONE 617-496-6760 **FAX** 617-495-1635
EMAIL *HEPG@ksg.harvard.edu*
79 John F. Kennedy Street, Box 84
Cambridge, Massachusetts 02138
www.hks.harvard.edu/hepg

we've seen that this market has been very, very responsive.

You see on my slide, the top map shows that 80% of generation has been built in the South/East. That actually has been very, very critical, because that's where most of the load is in New York, and specifically New York City and Long Island. So this has been, I will say, a success story, in that throughout our reliability planning process, it actually favors the market-based solution.

Also, through the reliability planning process, we report future reliability issues. We indicate the locations where the reliability could fall. That also is how we allocate the benefit to the beneficiaries, down to the zones and locations, and so we see generation added to the system where it is critical to meet future reliability needs, and we also see transmission built into New York City, particularly New York City and Long Island, that will typically see resources in the future years maybe run short. That has been a very successful story I would like to share with you.

This has been the outcome of our reliability planning process. Fortunately, we have not had to do beneficiary pays cost allocation because all of those have been the so-called market-based solutions--basically, the risk has been taken by the investors.

Now, mentioned a moment ago that we added an economic planning process on top of reliability planning. The system could be reliable. The system could be very efficient for the near future, but going forward, for the same planning horizon, our planning basically also reflects whether a system has high congestion costs in the system in terms of dollars.

We have seen over years and years that the generation from north and west of New York that is serving southeast New York--New York City, Lower Hudson, and Long Island, those are the loads that don't have enough generation, so the generation has to be provided from the north and the west. It has to flow through the transmission system. So we found that, particularly for the transmission feeding the Lower Hudson, in general, their transmission is heavily congested.

Also, going probably back a couple years ago, we see that some resources in the west of New York and also in the western part of Pennsylvania and part of the PJM have been retiring, so that actually overloaded some of the transmission on the western side of New York. That has been the number three most congested path in New York. Of course, there is a lot of congestion also in New York City, specifically on Long Island, but that congestion does not compare to these three congested areas on the map that I'm showing here.

So what I'm presenting to you is that we've got congestion in the system. Again, before I get to the New York ISO's planning process for trying to address these issues let me review the processes and procedures that we have in place that have been filed with FERC and are in our tariff. I think we have the tools, it's just a matter of how we use the tools effectively to address these various issues and also to address the cost allocation issue, which is really the topic of this panel.

The reliability planning that we have has been in place since 2004, and then we added the economic planning process that is accepted by FERC in 2008, and we have the Order 1000 public policy transmission planning process that was approved by FERC in 2014.

Actually, prior to FERC Order 1000, we were working with our neighbors, PJM and ISO New England, and also with some Canadian provinces, through the Northeast Planning Protocol, on interregional coordination, and then we use that protocol, and it was accepted by FERC a couple of months ago, so we've got these four pieces.

The reliability planning, economic planning, and public policy transmission planning processes actually interact, but they are separate. The interregional planning process has been integrated as part of the regional planning process, it could be integrated into any one of the three.

I mentioned that in the reliability planning process, we have basically two steps. One is to identify the needs, what reliability criteria would be violated, and the year and location, and then find a solution. In New York, we actually treat transmission, generation, and demand response and energy efficiency as equal solutions. In the reliability planning process, we have a preference for the market-based solution if the solution indeed moves at the speed that we really like. So that's the reliability planning process.

In the economic planning process, we follow the same procedure: identify the congestion, and then call for solutions. And in the solution discussions, we allow people to tell us the project, then we evaluate locations. Then in this process we actually use a so-called super-majority vote.

I would like to share Bill's Argentine Model, going back to a presentation he gave in 2007. That has been the model for us in our compliance with both Order 890 and 1000, in terms of the cost allocation principle.

So we have three processes: reliability, economic, and public policy. They all follow the beneficiary pays principles. The public policy process is the place where you address the gap between reliability planning process and economic planning process. That's the place where I think there is argument, because there is some portion of socialization of costs, so later on we'll discuss more details on that.

That's pretty much the planning process. Basically, the state Public Service Commission determines the need, and the New York ISO's planning process addresses the solution. There is a pretty detailed steps to follow.

So far we have a public policy need identified for western New York to build high voltage transmission, and we also, are looking at Central East Transmission upgrades (basically from City of Syracuse to Albany and then from Albany down to Lower Hudson). This is still in the form of proceedings and the PUC needs to address it on the December 17th session. Hopefully a decision will be made there.

New York State has an energy policy that has goals of 40% reduction in CO_2 emissions, and that 50% of the generation has to be renewable (by 2030). And this map shows you where the wind potential is, and the color of the map shows the potential of solar. Going forward, this is the planning we have to deal with.

Interregional primary is, as I mentioned earlier, part of the regional planning process. Each of the interregional planning parties agree to incorporate interregional projects into the regional process, so the cost allocation is primarily on a so-called avoided cost basis. If a project will benefit New York and also will address issues in New England, then that project will be cost allocated by us on that avoided cost basis.

Question: For the reliability piece, it says that you like merchant solutions best, but if there is a transmission owner obligation, you say you allocate costs based on beneficiaries. Can you give us a little more detail on that?

Speaker 1: As I said, New York has 11 load zones. So, when we find there is a reliability issue, as part of the planning process, we have information about which were subject to a violation of the reliability criteria or resource adequacy or transmission security criteria. That is part of the need, and then the cost of the project that is addressing that need will be allocated to the problem area or zones.

Question: I think you said that the different zones may have costs allocated to them. How does that work?

Speaker 1: Those DC transmissions that are built around New York City and Long Island, they are actually merchant. There is no cost allocation for us. It's basically the developers who bear the risk. So, if there's an AC transmission, hypothetically, that gets built, according to this, then if it is intended to address resource adequacy in New York City (New York City is "zone J" in our terminology) then zone J will be 100% allocated that cost. In other words, it has to go with the need that is identified through the first step of the reliability planning process.

Moderator: Does New York City have to agree to pay?

Speaker 1: Well, if it's a reliability issue, right. If the need is identified through the economic planning process, not only does New York City have to agree to pay, but there has to be super majority. This back to Bill Hogan's principle, 30%-30T: At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents. So that's one of the principles, and it was very, very useful. You do not want any economic project to crowd any other potential project, particularly from merchant activities, or, if you will, market activities.

Speaker 2.
Thanks. I was a little bit surprised when Bill invited me to talk this session on Order 1000 because having argued the case for years and years and lost, both at FERC and then the courts, I thought it was sort of a settled question. But I think maybe what's happening is that we get into implementation of Order 1000, and some problems are starting to arise, which are exactly the kind of problems that some of us were concerned about years ago, and maybe it's beginning to be time to rethink what FERC has done with Order 1000.

For those of you who aren't really familiar with Order 1000, it has several components. Transmission planning regions were required to form and sort of self-identify themselves. For the RTOs, that was pretty easy. For the non-RTO areas, they had to decide who they wanted to get in bed with for planning and cost allocation purposes, but that's all been done and taken care of.

Order 1000 defines some principles for some required mechanisms that the planning regions were required to adopt, including intra-regional cost allocation and planning and inter-regional cost allocation and planning coordination. There were rules in the Order for stakeholder participation in all these processes.

Another thing that Order 1000 did was remove the federal right of first refusal, which for the first time basically established competition for construction of certain kinds of new transmission facilities. I was a part of a group that formed during the congressional debate over the cap and trade bill back in 2009, I believe, when there was a legislative proposal for socializing transmission costs across broad regions, and a group of utilities were very concerned about that proposal and formed this Coalition for Fair Transmission Policy, which I was the Executive Director of.

The main arguments that we were making at that time, and are still making to the state, are, first, with respect to transmission planning we felt pretty strongly that, particularly for those areas that still do integrated resource planning at the state level, transmission planning needs to be a bottom-up process based on the needs of local areas, and that the state IRP can't be or shouldn't be preempted by regional planning.

Cost allocation, we believe, must be roughly proportional to real and measurable economic and reliability benefits to customers--and I emphasize the "real and measurable," because that's really part of the problems that have developed. There really has never been a good definition of what "benefits" means, and that has led to a lot of issues and problems. We think the cost for public policy projects should only be allocated to load-serving entities that have to meet the public policy requirements. They should not be broadly allocated beyond that, and we think that FERC can't, under the Federal Power Act, assign cost absent of a customer contractual relationship.

Turning to some of the history behind Order 1000, it was originally issued in July of 2011. There were about 30 parties that requested rehearing at FERC. Most of those parties also appealed the Order to the D.C. Circuit, which denied all those appeals in August of 2014, and now implementation is continuing. I think today all regions have approved compliance plans, although it's taken most of them three or four attempts to get to that point.

Is it working? Some of the stated purposes originally for Order 1000 were to give more clarity and certainly to transmission users by having an ex-ante methodology to allocate costs for new projects. The Commission believed that litigation over cost allocation would be reduced by setting in stone how costs would be allocated before the fact. The guiding principle of Order 1000, that cost allocation must be roughly commensurate with benefits, was extracted directly from a couple of court decisions, *Illinois Commerce Commission v. Ferc*, and I think there was another case involving the Midwest ISO where those words were used.

But, as I mentioned, benefits was never defined in Order 1000 or in the court case, and the result has been a wide variance in compliance plans. We have California, which essentially socialized all transmission costs under the theory that all new transmission enables more renewables and that has benefits to everyone in the state, so everyone should pay for transmission. On the other hand we have PJM, which we'll talk about, which has specific quantitative methods for various types of transmission projects, and you heard about the New York ISO, which also has a slightly different approach as well. So there's a wide range of compliance plans to meet Order 1000, which kind of indicates that it wasn't very clear what FERC was looking for in the first place.

I'm going to talk about a few case studies. At least two of them have gone through the FERC process already, and one is at FERC right now. The first one I wanted to talk about is the MISO MVP projects. Starting back in July 2010, MISO submitted requests for approval of a multi-value project (MVP) chain of projects for Commission approval. The planned cost allocation was to have the costs postage stamped to all load. The idea of "postage stamping" is that everybody picks up a share of the cost of the new transmission project. The idea behind MVP was that, given a basket of projects with multiple benefits, costs would be allocated roughly proportional to benefits over the long term, so even though individual projects may benefit one party or the other, if you look at all the projects in total, there's a rough balance between cost and benefits.

FERC conditionally approved the MVP filing in December of 2010. To qualify for postage stamp pricing, the MVP projects have to satisfy one of three criteria. They either have to be driven by the need to satisfy a documented public policy law or mandate, or they must provide multiple types of economic value across multiple pricing zones, or they must comply with reliability standards and provide economic value across multiple pricing zones. I think what's fairly clear from those definitions is that most projects, or almost all projects across more than one pricing zone, are going to necessarily meet one of those criteria, so you could basically include in those MVP projects just about any multi-pricing zone transmission line. FERC's approval was anchored substantially in broad state and stakeholder support, and it is true that the MVP projects were approved before the MISO compliance filing in Order 1000, but FERC didn't really talk much about the Order 1000 principles in approving the MISO MVP projects.

While there are some problems and have been some problems with the MVP cost allocation method, and it has gone to the courts, unfortunately, the courts have decided against the states on this issue as well. Michigan has one problem. They have an in-state renewable requirement, meaning that any transmission line that's built, say, to North Dakota or South Dakota or Minnesota to serve MISO needs by definition doesn't meet the renewable requirements in Michigan, because that's out-of-state renewables. Now, there are some arguments that Michigan's in-state renewable requirement is unconstitutional, but the fact is that it hasn't been challenged yet. Indiana, which has utilities in MISO, has no renewable requirement at all, so customers in Indiana have to pay to meet the renewable requirements of the other states in MISO. All the other states in MISO have RPS requirements with different targets. The primary purpose of most of the MVP projects that have been proposed are to move renewables, and particularly Midwest wind, to the load centers in the Midwestern area. MISO's filings do not even contain cost or benefit information for the individual projects that were part of the overall basket, either broken out by utilities, pricing zones, or states.
So, for example, Michigan (which was one of the supporters for the Coalition for Fair Transmission Policy) constitutes about 20% of overall MISO load, so they're required to pay 20% of the $16 billion that the MVP projects represented for transmission lines across 13 western states, and most of those projects, which were primarily to deliver renewables, deliver virtually no benefits to Michigan consumers, because Michigan utilities can't count any of those renewables towards their renewable requirement.

The MVP plan also made assumptions about how states will meet their renewable portfolio standards, assuming they were going to be met with midwest wind, and not taking into account the fact that distributed generation is growing in importance. And even if the basket of projects balances costs and benefits over the long term, there's no guarantee or even a likelihood that all these projects are going to get built, as public policy, demand, technology, and economics is going to change over the lifetime of that planning horizon. And as a matter of fact, it's interesting that the first project built for MVP benefited only Michigan. It was a project in

Michigan's thumb, so if that's the only project that gets built, it turns out that Michigan may be the only state that benefits.

I'm going to move to an even, I think, stranger case, and that's the case of the Tehachapi Renewable Transmission Project in Chino Hills, California. Some of you are smiling, so I think some of you have probably heard about this project. The TRTP was a transmission project being built to provide 4,500 megawatts of transfer capability for renewable projects expected to be built in Kern County, California. It was originally estimated as a $3.2 billion project. I'm not sure what the estimate is now. I know there are some folks from SCE who may be able to provide that. The construction was approved by the California PUC before either generation projects or customers for that generation were identified. And the ISO policy, as I mentioned before, is to socialize the cost of transmission to all customers in California, so in this particular case it wasn't even possible to identify beneficiaries or non-beneficiaries before the project was built. But it gets even worse than that in terms of the principle of cost and benefits being roughly proportional. SCE, Southern California Edison, began construction on one segment of the line, segment 8, which was to replace the existing 220 kV line with a double circuit 500 kV line. As the construction of that segment started, Chino Hills, which is a wealthy community (I think it has the fifth or sixth highest per capita income in the state of California), started raising strenuous objections to these tall towers that were being built over a 3.5 mile segment of that line through the city, and they filed a petition with the California PUC. They filed several court challenges to get that segment to be placed underground. SCE originally objected to the petitions, citing the schedule delays and the fact that it would cost in the neighborhood of $400 to $700 million dollars of additional cost to underground that 3.5 mile segment. At the time they estimated that would be about 25 to 33 percent of the total budget for the TRTP line, and they also pointed out, which is true, that undergrounding of the line would have to be paid for by all California ISO rate payers under their tariff. SCE was of course also concerned about precedent—if other cities in California would also decide that they wanted their lines undergrounded because Chino Hills could get theirs done.

On July 11 of 2013, the California PUC issued an order granting the Chino Hills petition to underground that line in a three to two vote, and they also wanted removal of all the existing towers and the new towers that SEC had just built. The PUC came up with an estimate of the cost at $224 million, and they stated that the burden imposed by the overhead lines on the community of Chino Hills was unfair and contrary to community values. PUC stated in that order, "We conclude here, on balance, that fundamental fairness requires that the costs of undergrounding should be spread among all CAISO rate payers, at a minor cost to each, since the complete TRTP will benefit all." Since the whole transmission project benefits everybody in the state, the undergrounding, which was deemed to be a necessary part of that line, also had to be cost socialized. SEC also went to FERC and sought and received approval to recover the stranded cost of those transmission towers that they had already constructed. And, again, the stranded costs are being socialized as well.

Under California ISO's Order 1000 allocation plan, the cost of the undergrounding and stranded cost recovery will be added to the stranded postage stamp rate, but at some point FERC is going to have to evaluate that when SCE seeks recovery of those costs, and it's in California ISO's transmission tariff.

As to the question of whether or not Chino Hills is going to provide a precedent, it's very interesting that within three months of the Chino Hills order, the city of Ontario, located not far away, filed a petition to underground the portion of segment 8 that went through their city, saying that their situation was worse than that of Chino Hills. I just thought this was kind of interesting; "Ontario officials even raised the specter of racism and ethnic prejudice in their effort to convince the [PUC] to order SCE to scrap its current plans… and bury… cable." That's a direct quote out of the local San Bernardino paper. On March 15 of 2004, CPUC denied Ontario's petition on the basis that it would delay the project five years with significantly increased costs to rate payers. Ontario so far has vowed to fight on. I don't know what they've done so far, but, again, eventually I think FERC is going to have to decide this issue, and whether it is fair for all of California customers to pay those costs of undergrounding lines in just one city. That's one of the outcomes that we have under FERC's Order 1000 policy that has never defined benefits and left it really to states and ISOs to do that.

This is the last case study, and then I'll wrap it up. The Artificial Island, for those of you who don't know, is an island in the Delaware River that has two of PSEG's nuclear plants on it. The output from both plants has been limited at certain times because of transmission constraints. PJM recommended a transmission solution and conducted bids on a transmission project. At the same time, there was a parallel case involving a merchant transmission company, Linden VFT, for a Bergen-Linden Corridor project that affected Con Ed in New York. For cost allocation, PJM relied on a specific methodology that they call DFAX, which is essentially a flow-based methodology for part of the facility cost, and part of the facility cost was also postage stamp allocated based on PJM's cost methodology in Order 1000. The application of the methodologies in this case resulted in over 90% of the cost of that project being allocated to Delmarva in both Delaware and Maryland. The application to the Bergen-Linden project resulted in substantial cost allocations to both the Linden VFT project and Con Edison. Numerous parties, including Maryland and Delaware commissions, protested the Artificial Island cost allocation. Linden and Con Ed have protested the Bergen-Linden cost allocation.

Meanwhile, while this was going on, there was also a competitive solicitation for building this project, which was also contentious and resulted in litigation at FERC. PJM, in the FERC case that is examining these cost allocations, recognized that there are valid concerns for Delaware and Maryland and even Con Ed for application of the DFAX methodology to these particular projects. And, just a couple weeks ago, on November 24, FERC found that these proposed cost allocations were not shown to be just and reasonable, and they've now established a technical conference in the complaint proceedings. The findings suggest the cost allocation is not roughly commensurate with benefits, even though the Order 1000 methodology was correctly applied in these cases, and FERC is going to have to decide whether ex-ante cost allocation fits these cases in this particular project. So Order 1000, as far as it's ex-ante cost allocation provisions, will be revisited in these technical conferences.

What are some of the lessons learned? These cases, plus numerous others that I haven't mentioned, suggest that the ex-ante cost allocation methodology doesn't work in every case if the objective is to assign cost responsibility with benefits, even if roughly proportional cost allocation is the goal. And if the objective was to avoid costly and lengthy litigation, I think Order 1000, at least in these cases, has certainly had the opposite result, and has led to perverse results in some instances. I think it's pretty clear.

Some of the other problems with Order 1000 are that the failure to define benefits has led to accepted compliance filings that provide very loose definitions--such as California, at least in my mind, where every transmission project that allows greater penetration of renewables is deemed to provide statewide benefits.

Social benefits such as a cleaner environment, increased jobs, or a pleasing aesthetic, in the case of Chino Hills, or very speculative possible benefits are allowable as a basis for cost allocation.

Conspiracy theorists might even suggest that this was a means to socialize costs but still meet the constraints that the courts have placed on FERC. Unfortunately, I think it's just going to lead to increased litigation as Order 1000 methodologies are applied to specific cases with weird results.

Why should we be concerned about this at all? Socializing transmission costs, I believe, masks true LMP price signals and distorts all of the benefits that are supposedly associated with those price signals. How is somebody going to determine where it's beneficial to build generation if there is socialized transmission being built that can undercut those LMP price signals? The results will be increased investment uncertainty for new generation as the value of reducing congestion can be wiped away by socialized transmission projects. Transmission will be over built relative to alternatives for which costs aren't socialized, and choices between remote renewables, such as wind or large-scale solar and even local distribution, will be skewed towards the former, even though DG may be cost effective in a lot of instances. And, if states believe that cost allocation is unfair, projects simply won't get built because those projects need state approvals, and if states feel that they're being unfairly burdened with the costs of those projects, there's just no way that they're going to approve construction if such approval is necessary.

What should be done? I think it's fair that we should retain the working parts of Order 1000. I think coordinated planning is always good, assuming states' rights are protected. Stakeholder participation in these processes is valuable. I think it's good to involve states and RTOs in decision making, and I think the principles for cost allocation are the right principles, but I think we need to throw out the ex-ante cost allocation methodology in favor of a process which examines individual projects based on principles but doesn't set an a priori methodology for determining how we should allocate costs so that they're roughly proportional to benefits.

Can it be done? The argument that costs and benefits of any given transmission project cannot be fairly estimated is wrong. Every transmission project should be and is evaluated based on impacts to the grid, both positive and negative, and benefits and costs can be roughly derived from these planning studies. Regulators should be aware of any transmission project, I believe, that doesn't carefully evaluate the cost and benefits and decide who benefits. The costs of reliability projects or the reliability portions of multi-value projects should be allocated to the planning regions where reliability is otherwise affected. Costs of economic projects should be allocated to the economic beneficiaries. Costs of public policy projects should be allocated to the states where the state's public policy creates the need for the new transmission or part of the new transmission. And we should always remember that the perfect need not be the enemy of the good. Just because we can't allocate costs perfectly doesn't mean that we shouldn't try to allocate them as well as we possibly can.

Moderator: Thank you. A tour de force, even though I wasn't here for the whole thing. Just add a footnote, it was Judge Posner who declared the Michigan in-state renewable requirement to be unconstitutional in his decision on the MISO case.

Speaker 3.
Thank you for having me, and, Bill, for inviting me. The last time I was at a Harvard Electricity Policy Group was 13 years ago. There, the topic was the merchant generation construct. Its future was really in question in the wake of the California crisis. Energy price caps were the talk of the day, and the money had gone missing, to paraphrase a little bit. The money had gone missing, and we were looking for answers.

Well, that was generation, and today the subject is transmission, which has its own intricacies and complexities. I'm going to have several points that I want to talk about, and the first is that I think that big transmission, which I've arbitrarily defined as more than 250 miles of at least 500 kV, that a lot of it's been proposed over the last 10 years, and I don't think any of it's going to get built, and I don't think it should get built, and those are two different questions. One is positive, one's normative.

In my view, the incremental expansion of the grid that's been well underway, and I think has been particularly successful in the RTOs, is largely the right stuff. I think it's got rational processes and reasonably objective drivers, and I'm going to talk about that. And then I'm going to talk a little bit about the Clean Power Plan, and whether that's a game-changer for the kind of thing we should be doing with transmission going forward.

This slide is a little bit of the documentation of the rise of big transmission with PJM's Project Mountaineer, which you may remember from 10 years ago. That was a hugely ambitious set of plans starting at what would be enormous coal projects in the west around the Amos Substation, none of which ultimately got built (meaning the coal plants. They all have been cancelled).

FERC got on board the big transmission effort in 2008, with the map you can see here. Then, five years ago or six years ago, MISO had a plan for going east with enormous big transmission projects. Five years after that, it said, "Well, maybe we should go west and south with these enormous projects." I'm not sure today what they might be thinking about. We all know about the Clean Line projects going west and east, largely oriented around the wind resources in the middle of the country. There's Atlantic Wind going way east—offshore. I think you all know that project, starting in southeast Virginia and going almost into New York City. Since then that project's been considerably down-sized, but it's still there.

So, after 10 years, no big transmission has been built or has been approved to be built for the future. I don't think it ever made sense, and I think there were six reasons, largely, for this. First, the laws of physics--just the nature of physics is that you move electricity through essentially a form of displacement. You don't physically move electrons at all. Only the energy moves, and that makes electricity fundamentally different from just about any other substance, commodity, or product that you can think of, particularly in terms of how you transport it. Other factors include increased reliability risk. Also, the bigger the lines, the more you have to have larger contingency limits on operations.

There's obviously a huge lumpiness in investment risks associated with these very large multi-billion dollar projects. They're very rigid in source and their sink, particularly when you're talking about DC projects where you have to put huge convertor stations at enormous costs of several hundred million dollars apiece at each end.

By and large, what we have found is that there are superior incremental alternatives that we've actually been building over the last 10 years and expect to build in the future.

I'm going to talk about what I think of is the right stuff, which is the incremental non-big transmission projects. In PJM, tens of billions of dollars of new transmission has already been authorized and built, none of which is for big transmission.

And I'll talk a little bit about how I think the transmission process is becoming more robust, through the pressure and transparency of the RTO stakeholder processes and the increased competition among very sophisticated transmission providers.

My first case study is the PATH project (the Potomac-Appalachian Transmission Highline) versus the Mount Storm to Doubs rebuild project. Now, the PATH project was an enormous project, which you can see here. It was a subset of Project Mountaineer back in 2005 that PJM has outlined. It was going to go from Amos to Kemptown, and it appeared in a succession of PJM annual plans, and it was considered to be absolutely, absolutely necessary. It just had to be built for reliability. Well, several years into this series of plans, Dominion identified an alternative, which was to rebuild an existing line, the Mount Storm to Doubs 500 kV line, which you can see above the proposed path line, and they had different variations on that theme. Well, trying to compress many years into what ultimately happened, ultimately Dominion's alternative at $600 million supplanted the PATH project (which was going to cost $2.1 billion) effectively entirely, and the Dominion alternative, the rebuild, avoided 156 miles of greenfield 765 kV transmission.

So, even though this is a pre Order 1000 story, I think the takeaway from this is that as long as you have sophisticated alternative providers of transmission solutions, you can get to better results. This to me is an extremely dramatic illustration of that, of somebody else stepping up years into the process and saying. "There's a better idea," and it was a better idea.

Let me give you another example of where I think things are working. This is SPP. This is the build out for wind. We all know SPP has enormous wind resources, 60, 90 gigawatts--we don't even know how much. But, over the last few years, SPP has been steadily building out its system in these incremental upgrades that are targeted, and they've interconnected 9,700 megawatts, and I'm sure it's more even as we speak here, and there's no sign that SPP's incremental expansions can't effectively interconnect all the wind resources that can economically come to market in SPP.

Now, I want to talk a little bit about seams, because they've been the source of a lot of FERC angst over the years trying to deal with these issues. This slide bears on the PJM/MISO seams issue—the largest seam in the country by almost any standard. What this shows is that after looking at 39 flow gates between PJM and MISO over a several-year period, what was found was that if you looked at all the congestion between the regions, that the upgrades that were already being planned or were in service as a result of the internal RTO planning process were alleviating three quarters of the interregional congestion. This is very, very important to understand. I was shocked by this--that basically what's going on in terms of what's being built for reliability largely inside the regions is having the secondary benefit effect of relieving the interregional seams congestion.

And so. though it's not to say that seams aren't important, I think there's a real message here, and I guess what happened with SPP and MISO might have been very similar where they looked at 70 potential projects and maybe only three or four still looked promising. Now, the one that apparently should be being built isn't getting built because of whatever issues, and I don't know for sure why, but that's one project--that's really small beer in the grand scheme of things.

Let me just talk about Order 1000 in the PJM context. I'm amazed at the volume and diversity of proposals that have come forward as a result of Order 1000 windows in PJM, and if you go back to the appendix of my slides, there's seven pages of small print of dozens and dozens and dozens and dozens of proposals to address maybe 10 or 12 congestion areas.

Now, these are market efficiency congestion areas that PJM asked for proposals on, and the breadth and scope of these proposals is staggering. What I've put also on this slide here is the amazing range of benefit/cost ratios that you can see if you go over to the column marked "B/C" and they've got a 2014 vintage and 2015 sensitivity, and you'll see that there's a dramatic difference among the benefit cost ratios. So it's PJM's job to sift through this, develop the expertise in evaluating the projects themselves and their costs. We have enormous modeling in PJM for evaluating benefits, which is a huge undertaking it its own right, but it's PJM's job basically to sort through all this.

But what I think is the big takeaway is just how varied the proposals are in terms of scope and the differences in benefits and costs. So to me it begs the question of, given the variety of proposals that Order 1000 is actually eliciting, what were we missing before Order 1000, where the assumption was, "Well, one transmission owner, one solution, that's that, move on, next problem." That's my takeaway. Others may have different takeaways, but that's mine.

As for the Clean Power Plan, I think it's going to be taken in stride--the transmission aspect of it. Brattle did a study, which found that "Transmission planning processes are adequate," and the EPA has discussed this in several places in the final rule. They've got a good case for how this is going to be taken in stride, and I'm going to show you a slide.

This slide is based on the initial proposed rule. Based on that, PJM did a study of the reliability need under CPP, and under a worst case scenario, 32 gigawatts of generation retires in PJM. I don't think anybody thinks that's happening. But, let's assume it did. This is the extent of the upgrades that would be needed for reliability. Now, this might look like a number of projects, but in the grand scheme of PJM transmission planning, this is chump change. This is in the noise in terms of what's going to be done over the next five or ten years anyway in the ordinary course of things.

I didn't think the NERC CPP study that came out earlier this year was authoritative, and I've got some reasons here. I think that when they said that, "Well, we've got a problem for reliability because the new 500 kV line takes 15 years to build," I think that's just answering the wrong question. I don't think we should be building new 500 kV lines of any distance. And then they said, "Well, reconductoring a 100 mile, 230+ kV line can take seven years." Well, the Mount Storm to Doubs rebuild project, that took, soup to nuts, four years, not seven years. Then they talk about changes in power flows, and I certainly agree that these will happen. But they specifically focus on power flow and PJM, and how it may change directions—the power flow may change from easy to west, and that may be a problem. Well, maybe it's a problem, but there's 8,000 megawatts of transfer capability from west to east, and that transfer capability, roughly speaking, is still going to be available if power flow should change from east to west. I just don't get it.

I just had one slide on the difference between efficiency and equity, because sometimes to me this distinction can get confusing when you are talking about cost allocation. Efficiency, in a traditionalist economist view, relates to what is built, and we obviously need to be efficient in what we build for reliability, which is basically an Order 1000 orientation and what I've talked about. We need to be efficient in what we build for market efficiency. And that's critical, because we have three different options. It's not only about what we build within a category called transmission, it's also about what we should build among the choices of transmission, generation and demand response, and among those, only transmission is really centrally planned, at least in most of the RTO contexts, which I think makes the problem really, really difficult, and the fact that there are multiple solutions that are possible even in transmission makes it really, really hard.

As for equity, that's allocating the cost of what's built. Again, we have a problem in that only transmission is really cost allocated, and then assigning the benefits can be very bedeviling.

Conclusions: I have tried to make the case that big transmission hasn't been and shouldn't be built. I think that the past supposed drivers of it haven't materialized, and I think that RTOs, under FERC oversight and prodding (and I use the word prodding carefully because I thought, well, do I mean verbal prodding or cattle prodding, and I think it depends on the FERC order in question) are continuing to improve, with incremental transmission expansions that make sense. Thank you very much.

Question: What about the CREZ? (Competitive Renewable Energy Zone line).

Speaker 3: That's a really good question. The CREZ is 345 kV so it didn't meet the 500 kV standard. The 500 kV and above standard was somewhat arbitrary, and I think that CREZ is an illustration of something that can make sense. It's a grid approach, and it's been built out incrementally. It's targeted. It's AC, it's not DC, so I think it's *sui generis* in my perspective. I don't think it makes a case, though, for the big transmission that I was really talking about.

Speaker 4.

I really just want to hit the key questions that were outlined in the panel description. I'll reference a few of the comments made by my colleagues as I go through, but we can also leave some of the dialogue for the discussion to follow.

So, the first question is, how is Order 1000 developing? I'll hit the major areas, and I'll start with cost allocation since that's gotten the most discussion here. One of the unique aspects of Order 1000 is that FERC did allow cost allocation to vary by region, so I think if you look across the landscape, there are some single state ISOs and RTOs that may look very similar, but for the most part, across the U.S., cost allocation is very tailored to region, and I think that flexibility has allowed those regions to work within their own constituency and come up with a cost allocation methodology that works—it may not always be popular in every single instance, but overall it has worked.

One very interesting aspect of cost allocation is that it has evolved over the years. Many of the cost allocation procedures that have been put in place were actually underway before Order 1000. Order 1000 strongly encouraged some regions that did not have formal processes to implement cost allocation processes, but in many of the ISOs and RTOs--SPP, CAISO, PJM--I think they all recognized that transmission, in its inherent nature, benefits multiple entities, and having a cost allocation mechanism to support that can bring those benefits forward.

I was heavily involved in the Southwest Power Pool (SPP) Priority Project process, which characterizes the incremental projects that were done in the SPP. It's interesting, as that evolved through the pipeline at the SPP through its planning process, the constituency, the SPP staff, and the commissioners that were involved all recognized that cost allocation was a necessary component of those priority projects to be done, and this was well before Order 1000, so that is a case in point.

One of the, I think, unfortunate but necessary aspects of cost allocation is that there will always be an instance where cost allocation, when you put a process in place, will cause limited issues of winners and losers that people may not like, and I think a cost allocation process that can survive for the long term is really to make sure that from a rough justice standpoint, recognizing the long-term nature of transmission investment, that the benefits of that transmission system, when taken together, not on a project-by-project basis, but when taken together, are shared by all, both from a cost standpoint and a benefit standpoint.

I think the regions, as they've implemented the cost allocation process, have done that. The ones that have run into problems from a large-scale process have gone back and reevaluated and recrafted. PJM, for example, currently has an uncontested cost allocation under which they are working.

There are two examples, which were referenced before, which are really effectively generation projects or merchant transmission projects that are causing some concern and discussion, but for the most part, the large portion of transmission projects which have utilized that cost allocation methodology over the years and recently have been supported by the PJM constituency and staff.

When it comes to public policy, another aspect of Order 1000, again, there is a regional public policy process in all the ISOs and RTOs. It seems to be working. Approaches vary. One is spreading "public policy" projects costs across the footprint. That has been done multiple ways, either within a single state ISO like California or through the MISO process, where the MVP process combines reliability, economics, and policy together and says that if it has those three legs and can be demonstrated holistically through a portfolio standpoint to be supported. then those costs can be allocated across the footprint. But there is a mechanism to look and evaluate those policy projects. In other areas, public policy projects are handled through a sponsorship method, where if there is a single state within a ISO/RTO like PJM, for example, a state can choose to sponsor a project to meet its own policy needs, and there is a process to effectuate that. So I would say that in large part, the policy aspect of Order 1000 seems to be working.

Interregional planning, I would say, has made marginal progress. By that, I mean that there has been some additional formality put around the interregional planning process. I think one of the areas that we could all work on as an industry from an interregional planning process perspective is that most of the interregional planning processes that are out there require effectively three cycles of planning. They require a local planning evaluation in one ISO/RTO, another local evaluation in the neighboring ISO/RTO, and many times a third interregional look, and the inherent nature of the elongated process creates two issues: one, it takes a long time, and so sometimes it's more expeditious, when there's a real need in front of customers or from a planning perspective, to choose a non-interregional solution; or, two, whenever you create, effectively, a veto right by one region or another, the bar is raised tremendously high, and so an interregional planning process that could perhaps work more effectively is one that does consider an interregional process from an independent or overall view and then allocates costs for those projects as they're determined from a wider look, as opposed to how each region looks at it, and we think that can help get interregional projects built. There have been the quick-fix solutions that have been looked at by each region, and I think because of having to go through those two planning processes that those have been effectively the only interregional projects. I would call them "interregional projects" because they do address flow gates between regions, but they are not cost allocated projects that have been approved.

The other aspect to consider is competition. Competition is occurring in some differing levels across each regions. It is very slow and evolving. In the MISO process there's about $26 billion of transmission investment. For the first time, in this next cycle, there's potentially around a $60 million project to be competitively bid, and so that gives you a sense of the scale of the amount of competition versus the amount of transmission that has been directly assigned to incumbents. But the processes have been put in place. They've been vetted through the stakeholder process, and they are starting to be used, which is incremental progress there.

I would say that overall Order 1000 has generally been working well. I think it's important that we recognize that Order 1000 did build on many of the things that the ISOs and RTOs are already doing, and really just required that some formality is put around those processes and they be done consistently--not identically, but that they have a consistent requirement for having a process across the nation, and I think it has achieved that goal.

"Is the "roughly commensurate" or "very roughly commensurate" standard working?" is another question posed. My view is that "roughly commensurate" is an absolute requirement for cost allocation to work. If there was a requirement for every single project approved to determine the exact benefits that were associated with that project, number one, it would be very unworkable to do that on a project-by-project basis, and I cannot think of even a way to implement that on a project-by-project view as it goes forward. I think it's important to look at cost allocation on a portfolio view, recognizing we all enjoy the interconnected transmission system, and we may benefit from a transmission system that is a state away. I think many of the projects identified from an interregional view have also supported that a project may be a region away, but we can still benefit. And so that interconnected nature of the AC system does, in my mind, require or necessitate a "roughly commensurate" standard in order to work.

Transmission is a long-term investment. You're talking 30, 40, 50, 70, 80-year assets sometimes, and in order for that system to deliver benefits and be put in place and be approved, I think it needs to be looked at through that lens as we look at cost allocation, and I think the standard has worked fairly well. It has caused instances where there have been complaints or there have been areas of concern. I would say most of those that I can think of were pertaining to generation—effectively, generation projects, not necessarily reliability or load projects or even public policy projects. And so, in those limited instances, that has caused some additional concern as to the applicability of that cost allocation in those specific instances, but for the large part the standard has worked well.

I'll spend a few words on what AEP is doing to promote efficient transmission. I think the industry has worked very well in identifying areas where they can work together to effectively or efficiently deploy transmission investment. One example is the Grid Assurance initiative currently being worked on by AEP and seven other utilities around the U.S. The concept is that instead of each utility purchasing and buying and holding spare transmission equipment in case there would be a catastrophic event, is there a way we can all work together to minimize the level of investment overall that we all would need to bring forward and which would cost our customers, and can we do it together, recognizing that those catastrophic events aren't (hopefully) going to hit every single utility or every single area at the same time. So that is an example of an area where industry is really looking to be more efficient in the way they approach transmission investment.

Our BOLD (Breakthrough Overhead Line Design) transmission initiative at AEP is an another example, where we are looking at how do we effectively utilize, for example, 345 kV corridors that may need more capacity. This may be applicable in urban environments where you say, I can't go 500 kV, I can't go 765 kV, just because it would require additional space, but how do I get more capacity through that area? And so that is an example of an initiative where by using advanced technology you can get more power through a limited corridor without increasing voltage, without having to replace station equipment, but allowing more power to flow.

The industry is looking heavily at rebuilds versus greenfield projects. I think there have been a lot of rebuild projects done as projects are rebuilt for age. We've got a very aged infrastructure out there. As the transmission infrastructure ages, there is a question as to whether the rebuild work that is being done at the time of rebuild can replace a greenfield project, and that's being done a lot, I would say both from an AEP perspective and across the industry, and you've seen the results of that, I think, in the planning process, where there's been quite a few rebuilds out there right now in recognition that greenfield projects are hard.

The counterpoint to that is that I think it's very important that we do not remove big transmission from our toolbox. I think it would be imprudent to say, "We're not even going to look at it." Big transmission is very hard to get done, but it can bring significant benefits.

If you take the average retail rates, for electric consumers across the U.S., and you overlie the areas that had big transmission (which are the 500 kV system in the northwest which effectuated significant hydro build out, the 765 kV system in the AEP area, and interconnected systems)—those areas where planners comprehensively looked at it and said, "We have low cost generation, we have a low cost resource, how do we get the most efficiency out of that?" and you overlay where rates are now decades later on top of those systems, it is amazingly different than areas that do not have that infrastructure.

So I think it's important that we recognize that even though transmission is lumpy, even though transmission can be expensive, it does get utilized, and it has been a very important part of the economic growth of this nation over the decades and continues to be so. And so, while it's equally important not to say, "Every need can be hit with a big solution," it's also important that we don't take big transmission completely out of our toolbox and say we're never going to look at it.

Interestingly enough, again I'll reference the SPP, and its incremental transmission build (that slide that was shown earlier) that transmission plan was a result of a robust analysis of a backbone 765 kV double circuit 345 kV project. I think there was even a 500 kV project looked at for a short time. As the SPP looked at all those solutions, the plan that actually got built and the plan that the SPP actually relies on now was a result of that. In my opinion, that would not have happened if they hadn't looked at a comprehensive big build first and said, "How do we maximize the efficiency of this build out?"

With respect to the MVP project build out in MISO, the same thing applies. DC projects were looked at, smart transmission was one not shown but that was equally looked at, many of the interregional planning processes forced people to work together to say, "If we build things on a larger basis, how can we work together to get the most efficiency?" What actually got built was not the big transmission overlay that you saw on some of the maps, but if you would overlay the MVP portfolio, multi-value project portfolio on top of those maps, you will see that those are the areas that I think saw quite a bit of benefit from actually deployment of efficient transmission investment looking at options all the way from do nothing up to large transmission build, so I do think it's important not to take that out of our toolbox. I'll leave the rest for discussion.

General discussion.

Question 1: Speaker 3 made the point that central planning is hard, and I certainly agree with that. You advocated incremental projects, which I think is very, very coherent, but I think it also implies the need for coherent framework to select the portfolio of projects from among the very large number that you mentioned were being put forward.

When you describe the cost and benefits, they seem to be on a project-by-project basis, which suggests to me they're being evaluated on a project-by-project basis. Speaker 4 touched on the issue of a portfolio, and so my question is, to what extent are we missing a coherent framework to optimize the selection of a portfolio as opposed to throwing potential projects all up on the wall and seeing which ones stick on an individual basis? Perhaps more to the point today, to what extent (because we don't have a coherent framework for selecting or optimizing a portfolio) is the allocation problem that much harder because we don't have a principles-based story for, "This line is the one we really need as opposed to that one," and I think you're the example of the multi-billion dollar 765 kV project that was bested by upgrades as a case in point.

Speaker 3: We have in PJM the category of "multi-driver projects," and at PJM they have criteria for evaluating which project among those competing to provide a solution to a given problem, whether it be reliability or economic market efficiency--they have criteria for that as well. The finer points are still being worked out for the market efficiency category. But as far as reliability goes, we've got a pretty well-defined set of criteria.

Now, not everybody's happy with them, but when you talk about the regional facilities, they tend to be socialized, and the lower voltage facilities tend to be assigned, in the case of reliability on two zones, on the basis of aggregated DFAX, and in the case of a market efficiency project on the basis of net load payment savings. So Speaker 4 talked about rough justice, and they seem pretty rough justice-y to me. Could they be better, more refined?

And also, just getting back to the case of things where there are multiple drivers, there's a procedure being worked at PJM for allocating costs using your reliability or your market efficiency allocators, but dividing up the cost of the project itself among the drivers and then doing the allocations on that basis, and it makes some sense to me.

Speaker 4: I think one of the interesting parts about competition coupled with the current planning process that we need to be careful about is that competition tends to very narrowly focus on a specific issue, and I think even if the ISO/RTO or the planning entity wants to take a portfolio view, you could lose that perspective in a purely cost-driven competitive approach. I could see an unintended consequence happening, where in a specific case, a higher benefit/cost ratio but lower benefit project could be chosen, but if looked at from a larger portfolio view, the project not chosen could be a key portion of a higher benefit project that doesn't move forward just because the focus is so narrow. And so I think it's important, as we enter the competitive environment for transmission, that we keep that in mind and don't let those very case specific, sometimes very small project analyses lose that larger perspective, and I don't have a silver bullet for that. It's something we're thinking about right now. Where could that drive us as we go forward?

Comment: I would just add that it's a little perplexing to me that we're talking about centralized planning for transmission in markets where there is no centralized planning for generation, and how when you're talking about portfolio projects you're talking about a portfolio to meet future load patterns and generation patterns, but we don't know what the generation patterns are going to be because that's competitive, so how can you develop a portfolio project for something that you don't have any control over? I just raise that question.

Speaker 1: Let me help you a little bit if I can. In New York, it doesn't matter what need, if there's a need, you have proposals, whether there's a portfolio of projects, or whether it's a single project. So you select the project based on cost effectiveness. And you could have two different people coming, and one saying the proposed project costs $500 million, another one says it costs a billion dollars. Which one do you choose? We choose none. We come up with our own cost estimate, and our cost benefit is going to be assessed based on our own cost estimate. And then, once the most cost effective project's selected, then the cost allocation will be based on the need, which is identified before this project. It's not project specific. I hope that will address the issue. If you have a portfolio with more projects, they tend to be less cost effective.

Comment: Just a comment. I think Speaker 3's presentation sort of pointed out the problem. Five years ago, everybody wanted to build transmission into PJM from MISO because they had too much coal. Then, all of a sudden, it was, "Go south, young man," then it was, "Go west, young man," because the new gas-fired generators in the Marcellus were going to ship power because of the Clean Power Plan into the Midwest. And so it's very hard to do transmission planning without having some notion of what the generation mix is going to look like, and that makes it a problem. I mean, it's not insurmountable, because you have to guess what the future is going to look like, but that's what planning is all about.

Speaker 4: I think that's one of the real benefits of our integrated AC system. This system has been called by some the largest and most complex machine in the world, and I do believe that. It brings tremendous diversity and resiliency, and so if flows change, etcetera, the AC system can accommodate that very well. If you get into the pipeline sort of model, there are pipelines that are just the wrong way or completely out of the money, and there's not that robust network to rely on. So I think the equivalent to that is the DC equivalent, not that DC should never be considered, but I think one of the things that we need to thing about as we evaluate DC is, how does that remove flexibility, potentially, versus and AC system? An example of the diversity of the AC system, based on my experience in the west, is that California built a large amount of transmission into the CAISO to bring power both from the California-Oregon border, the hydro in the northwest, and from the desert southwest. All of that was south and west, mostly. Now California is in a situation where, on peak. power could be exported, and that same transmission can serve that need because it is an AC system and because it is very, very robust and flexible. So I think that is one example of many of the diversity and flexibility of the use of the AC transmission system.

Question 2: Speaker 2, at the end of your presentation, you mentioned that remote renewables end up being preferred under Order 1000 over distributed generation because the transmission cost gets socialized. My question for the rest of the group is, does that ring true to you, and in general, how has distributed generation fared in these planning processes post Order 1000 with the requirement that non-transmission alternatives be considered? That's question one.

The second question is about state law. To what extent do you find that state laws continue to act as a significant barrier to the competition goals of Order 1000, whether they be state right of first refusal laws or also state laws that limit siting permits or eminent domain authority to incumbent utilities? No one's talked about the role of state law in this process, so I'd be interested in your responses to either or both of those questions.

Comment: I'll be willing to take a shot at some of that. I'm not sure that distributed generation (and I assume by that you mean local wind and solar, essentially, and maybe some dirty backup generators) gets very good treatment, other than some kind of an estimate of net load, which may or may not be a very good estimate. The state laws are very important, and that's one of the reasons why you want to get the cost allocation right, because if you get cost allocation wrong, and the state sees that it's getting allocated costs for projects from which it doesn't benefit, it's very hard to make a case that it should grant eminent domain to build that line, and so that's yet another reason why getting the cost allocation right is very important. Anybody else?

Speaker 3: I agree. For the most part, the increase in distributed generation, at least in PJM, is being dealt with through load projections, which are becoming more sophisticated over time, and I think most people would agree that they are improving.

As for the state question, I think that the state role is a double-edged sword. Certainly a state certification process can act as a veto on projects that are interstate projects that should otherwise be built, by anyone's objective criteria, except for the fact that the beneficiaries of the project are disproportionally not in that state, and that's a problem. The other side of the coin is that sometimes the state, being a more local entity than the feds, is more attuned to citizens' concerns about the impact, particularly of larger projects, particularly of greenfield projects, and by slowing down the process and requiring a more rigorous analysis with more voices, sometimes the results can be better.

I think the PATH Mount Storm to Doubs outcome is an example of that. The Virginia Commission was asked to provide a certificate for the PATH project, and they ultimately said, "Well, we want the Dominion alternative to be considered." Well, word got back, and within a year or two, all of a sudden the more rational project went forward. The same thing happened in Pennsylvania with a project that was built, the Trail project. That project was a very large project. Well, with respect to the sink portion of that project in Pennsylvania, I think it was called the Prexy Facilities, it turned out that that was probably an overly large proposal, that segment of the Trail project, and after the certification process was done, a settlement was developed under which a portion of that project in Pennsylvania was a fraction of what was the original proposal.

Comment: I think it is true that states are probably an impediment to full competition for new transmission, an impediment to getting new transmission built if they feel that lines aren't in the benefit of their in-state customers, but I think maybe it's the better of two evils. I don't think giving the federal government that authority fixes things, and in fact probably makes it worse, because states do have the ability, as Speaker 3 just mentioned, to reroute lines or to take care of customer concerns, whereas FERC is not going to be interested in those local impacts and is not going to be attuned to them. If you look at gas pipeline siting, which is FERC jurisdictional, that hasn't been exactly a pretty process either, so I think these issues are appropriate at the state level, even though that may create some constraints on new transmission.

Speaker 4: To the questioner, there are some states that have put in place above and beyond restrictions on competition, which effectively favor the incumbent utility, either totally or to some extent. I think there is some balance that should be struck between the realities of going through a competitive process in a state--potentially for small projects or very low voltage projects that may not be appropriate. I think there are some laws that may have struck that balance. There are some states which have just wholesale gutted competition under Order 1000. I think those states may be tested with the benefits that they're forgoing by competition. I think if those costs become known, maybe those laws may be reevaluated, but those are the areas I would say are probably causing the most limitations on competition specifically, above and beyond the regional planning referenced earlier.

I would agree that we are getting better at evaluating distributed generation. It might be not perfect, especially across a large footprint like PJM or MISO, its challenging to identify how those interplay with each other, but the technology is helping us get better. Some of the concerns I've heard about not considering distributed generation in wholesale planning processes may push more towards, "Why aren't you carving out distributed generation?" or whether you are sort of assuming future generation that may not occur. I think that one's harder, because I've been in the industry long enough to see energy efficiency used as just a convenient way to say, "Well, maybe this future load, in 5, 10 years won't occur, and we're not going to have a problem," because there was no obvious solution, and I think doing a distributed generation carve out where they may not be distributed generation, I would say, is probably a bridge too far, but I do agree that we have gotten better at considering it, and should get better.

Moderator: Getting government approvals is by no means new. Years ago, when I was in a meeting discussing a transmission project, somebody asked, "How many fire engines?" and I was a little bit perplexed. And then I realized that they measured the difficulty in building transmission and getting the right of way in terms of fire engines, because handing out cash to the local municipal government was not considered very kosher, and so they used to give away fire engines to the local entities in return for the rights of way.

Speaker 1: Let me add something. I meant to say the same thing. As far as the state law and preference, it's not going to change. It's something that the regional planning process has to deal with, and Order 1000 indeed gives you actually perhaps not less but more state room to play. Basically states now can define the public policy that drives the transmission need.

Now, let's back up just one step. Let's look at how the transmission has been built in the past. It's primarily been built by the states, so this is something, again, that the current processes that we have will have to deal with. They will have to recognize what state has to play, and take advantage of what are lessons learned in the past.

To answer your first question about, in New York, actually, it's pretty simple, because from the get-go of the RTO from FERC, we have treated all resources the same, whether it's central generation or transmission. And then, that beneficiary decides to pay. Of course, if we consider generation, if DG cuts the load so therefore the need that you identify in the first step of our process, is gone, addressed by reduction of the load through efficiency, or diesel DG, or solar DG, that's different matter. So as long as you treat them properly, if it's there, it's there. If it's not there, then you address the need with transmission.

And, talking about the question of what the future is, we all can debate. Gas prices could be forever low—but we knew from the last 20, 30 years that the moment it's agreed that gas prices are going to be forever low, next year it's going to be very, very high. So that's actually the beauty of so-called coordination. You've got to study the different scenarios and make sure the stakeholders understand the proper scenario that we'll have to deal with.

The Eastern Interconnection Planning Collaborative (EIPC) was actually funded by DOE a few years ago to do all these studies of different transmission scenarios, and we had like 80 something scenarios, so it's going to be very hard for somebody to say, "I'm going to build mega transmission from west to east and you pay for it," and we'll say, "Have you considered the rest of the 79 scenarios?" It's not an easy question to answer, but if you have certain processes and you allow people to know and understand the underlying assumptions, I think it's probably going to be easier for us to deal with those different arguments.

Question 3: First, I want to say thank you to the panel for excellent presentations, and I want to say a special thanks to Speaker 2 for his observation. I think it's the first time I ever attended a discussion where I thought seriously that I was in the camp of conspiracy theorists. [LAUGHTER]. But I think it's actually not technically a conspiracy if it's actually one person who does it, right? I do subscribe to the theory that there was a very powerful regulator who wanted to say one thing and do another, and that it's embodied in Order 1000 and some other decisions that FERC has produced, and that process produces conversations which I think have, sort of, *non sequiturs* in them, because we're saying one thing and it doesn't follow from what we're doing or the argument.

I'm going to get to a question, but I am going to preface the question by saying, and I think John Moot said it very well in that piece he had in the *Energy Law Journal* recently, which I've quoted, about the importance of markets going forward as we look at the green agenda. When it comes to distributed generation, all these new things on the demand side, new kinds of generation, we don't know what's going to happen. There's a lot of uncertainty, and we need really big changes to take place to meet the challenges that we're thinking about, particularly if we're thinking about the discussions that are going on in Paris and the stuff that's going to come from that, and I think markets are critical to that in order to provide the incentives and the innovation opportunities and experimentation.

If it could be solved by central planning and we knew what to do, then we should do it, but we don't know, so we can't. So I think markets are critical.

In the transmission expansion area, for fundamental reasons that we know about, you can't have complete market-based solutions for transmission, so you have to have a hybrid system that has a mixture. But you can design that hybrid system so that it supports the rest of the market as opposed to working at cross purposes from the rest of the market and creating more problems. And what I'm worried about here is the question about where we're going with transmission.

Now, let me give you examples of two kinds of arguments, which I think are critical to the story. I say in advance that I agree with Speaker 2 about this. One argument is that it will work out in the long run on average. If your behavior wasn't going to be affected by the prices that you faced, we would say, "Well, sometimes you'll be consuming energy when the marginal cost is really high, and sometimes you'll be conserving it when it's really low, and so if we charge you the average cost all the time, on average it will work itself out."

And if behavior couldn't be affected, then it wouldn't be so bad. As a matter of fact, it would be just fine, and rough justice would work, and sometimes you'd be paying too much and sometimes too little, but we all know that the fundamental assumption in the context of the problems we're talking about is that we want behavior to change, and the prices we charge to people, even if they might have rough justice if they didn't affect behavior, do have a big impact on people's behavior, and so the pricing is not just to collect the money in a way that's sort of fair, it's also to provide incentives that are compatible with efficiency.

So I think this whole putting the portfolios together approach, and the thought that it's too much here and too much there but on average it's about right is just illogical given this context of markets and affecting peoples' incentives.

The second area that comes up in this conversation, and I think is really important, is this: the notion that we should do cost benefit analysis for transmission expansion, but we can't identify the beneficiaries and that's too hard in order to assign a cost. (I have a hard time holding these ideas in my head at the same time.) As Speaker 2 said, and I agree, it's inherent in the nature of cost benefit analysis for transmission that you have to identify the beneficiaries. That doesn't mean it's easy. Cost benefit analysis is hard, but you have to do it, and once you've done it you know who the beneficiaries are. That's not a complicated story, and we should go forward with that.

Now, my question is, I think Speaker 3's presentation argument would be, "Eh, not to worry. We're not going to make any big mistakes because we're not going to do anything big, and we're only going to do little incremental things, and even though they might be stupid we're not going to make too many of them because they can't get too far out of whack and transmission isn't all that important in the overall grand scheme of things, and so not to worry. It's going to be a little expensive, but it isn't going to screw up the rest of the system." The other side of the argument that I worry about is the existential question, which is (and let me spin this scenario) we keep trying to do this cost socialization under Order 1000, and finally the distributed generation guys say, "We need cost socialization for that in order to compensate for the transmission story." We need to prevent people from building generation in the bad places because that is not consistent with the transmission cost, so pretty soon all this is just creeping central planning coming back into the whole thing, when we don't know what to do but we're certainly going to do it. And I think that's the existential question about markets.

So that is the problem. I think it's a logical matter. The Order 1000 cost socialization story just makes no sense. It's not based on principles. It's a cost socialization. It's fundamentally incompatible with markets, period. Now, the question is whether that is a big deal. This is an unfolding story but is this something that's existentially going to contribute to the unraveling of markets in general, which are always under pressure, or is it, as Speaker 3 says, a case of, "Not to worry, we're only going to do small increments everywhere anyhow, and when you get too far out of whack, eh, we can live with it. It won't have any fundamental problems?"

Speaker 3: I should say that I'm not suggesting we shouldn't build lots of transmission. My thesis is that we should build lots of transmission and we are building lots of transmission. It's just not the grandiose projects, and I tried to explain why I think those don't necessarily make sense. I do think that the processes we have, in at least the one RTO that I know the most about, PJM, have evolved considerably, and I think they are relatively sophisticated, given the constraints that PJM has to operate under. And I think the point is well taken, for example, about, "Well, we have centrally planned transmission and yet we have competitive generation," and at a certain level, that is a shotgun wedding. But can it be made to approximately work? In PJM, the way that it's been made to approximately work is that the transmission plan is based on a five-year out projection of the topology, but it will include new generation that has cleared in the capacity auctions that it is assumed will be built and integrated into the transmission plan that is five years out. And, in turn, the three-year out transmission plan, which is sort of an interim plan, formed the planning parameters for the capacity auctions that are conducted. So there is an iterative and a relational effect between the two that I think is relatively rational.

And the other thing that can happen is that if a given reliability issue is identified that is ultimately found to be relieved by generation that shows up that was not planned for, that can be dropped from the plan. But so far we've had relatively few instances in which we've had to figure out how to deal with now early stranded costs of any magnitude, except for one well-known example that I won't talk about, but we haven't dealt with much in the way of those. So I certainly don't want to suggest a passive approach to any of this, but I guess I'm more optimistic.

Speaker 2: I think you know my answer, but I think it's a really big deal. I mean, you used to hear, and I think the Honorable Pat Wood used to say this all the time, that transmission is only 5% of the total cost of electricity so why worry about it; worry about the other 95%. Well, even if that were true at one time, it was true based on historical costs and not incremental costs. Just take the Tehachapi line, for example. That's $3.2 billion. You could build half a nuclear plant for that. That's not small potatoes, and when you're talking about large transmission projects, you are talking in the multi billions of dollars. It becomes a big deal. But, even more importantly, I think, is it changes people's thinking. More important than the dollars and cents is the fact that it changes people's thinking that transmission is just sort of a byproduct of everything else we're doing in terms of distributed generation and renewables and wind and everything else, when transmission should be considered as an integral part of the whole picture, and we should be looking at what the costs are overall when we combine what we're doing on transmission with what we're doing on generation to try and get to the lowest cost. We should not just say, "This is the best source of generation, and we're going to build transmission to meet it." But I think we have to go back to some kind of integrated resource planning if we're ever going to do things right. I hate to say that, and I know you don't like to hear that, but I think that's what we're going to need to move forward.

Speaker 4: I guess I would probably be slightly concerned with saying we can't identify beneficiaries. I think there's a spectrum, as you do. One is just having everything you build get pancakes spread across the footprint. I think from a consistency standpoint, that is a way to allocate costs, but I think the dangerous other end of the spectrum is that every single specific projects gets evaluated in terms of the justification for that project on a localized basis, because I think there are many, many variables that over time can swing that all over the place, and if you start that on a project-by-project basis, even a small project basis, I think that becomes untenable very quickly.

And so I do think that Order 1000 is compatible with market structure. The Commission said, "Regions, come up with a cost allocation methodology that's consistent, and we'll leave it to you how to do it," rather than saying, "You have to socialize it," and rather than saying, "You have to do it this way." I mean, SPP looked at highway-byway, they did all kinds of usage analysis, and they said, "This roughly approximates the overall beneficiaries and usage." Were there entities that disagreed? Yes, there were, but even those entities, when pressed, would say, "Let's not just have a cost allocation methodology," which would have taken priority projects in that case completely out of the realm of the planning process.

And so, in PJM, the usage base model, the DFAX model, tries to approximate and use market factors, whether it uses the capacity market to support the projects as they're approved, or it evaluates the usage of those facilities as load uses them. There are some nuances with the generation projects I mentioned, which may cause some concerns, but

I think the overall application of PJM works, and it is compatible. Is it exact? No, it is not, for each project, but it is compatible with the market, and the intent of Order 1000, as I understand it, was to allow for these projects to be evaluated on a multi-beneficiary basis, and if those projects could deliver those benefits, have a cost allocation mechanism that supported it, and I think the intent of that has been achieved, largely.

Can it always be improved? Absolutely, but I think a lot of it has been achieved, coupled with the fact that those ISOs and RTOs in many regions had already started that process, in recognition of that need.

One comment on centralized generation planning. I spent a large part of my career in a multi-state region without an ISO and RTO, with an IRP, and an interesting part about that is that I can't think of centralized generation planning as effectively a way to effectuate transmission. What I mean by that is if you look at IRPs for the WECC area, those IRPs have changed dramatically over the years, but, interestingly enough, there are core aspects of that transmission plan which were immediate, and actually many of them that got built are being used. Even now, they are being used as a bridge to allow for more time to solve the generation needs. Sunrise Powerlink is a perfect example. That line was not built to accommodate the retirement of a major nuclear plant. Today it's being relied on. There's transmission from Idaho down to Salt Lake City, which the IRP would have said was built to carry brown electrons coming from Wyoming down the pipe and into Salt Lake. That's not the case; it's wind, but that transmission is still being used today, and actually could, interestingly enough, be a very core piece of market evolution.

So, I do think it's important we don't say that everything in transmission development should be driven by generation assumptions, because I think that is very different, because those assumptions can move. I do think transmission development should consider many scenarios, which I think many regions do very well today, whether that be looking at many generation assumptions, looking at DG assumptions, looking at the spectrum and coming up with a solution that holds under all those areas.

Speaker 1: To the questioner, I think that we agree with you that the market should not forget market forces. That's what actually drives most of the discussion in our lives, and here as well, and I think the key words are "market compatible transmission."

Frankly, I've been struggling with the market itself. What market? Is a market based on or built upon the maxi transmission, or is the market based on or accommodating or being compatible with evolving transmission? Because we know we have an aging infrastructure issue with transmission. We know we have public policies that are going to require more renewables integration. Transmission as is may not be able to accommodate that. And there are many other things, including DG, as well. So this will change the current status of the transmission infrastructure. So we have to deal with new transmission one way or another.

Now, what is market compatible transmission? I think the way I put it is a transmission project that does not create a shock, like "Wow, there are many megawatts of generation that's built that did not anticipate this transmission. This transmission is going to completely collapse the market." If a transmission that created no shock has been not expected in the marketplace, will this transmission be a market compatible transmission? That's something that either reliability or economics or public policy transmission should consider. I'm just throwing the question back to you. Personally, I would assume that's market compatible transmission, and that's something that we better get it built.

Question 4: I think this last comment was a very good segue into what I am concerned about. Speaker 1 said, "Well, if it's transmission that doesn't create a shock to the system, then maybe that's market compatible," and I guess my question really is, who decides that? Because it seems to me that what Order 1000 attempted to do was to take local planning processes and turn them into regional and interregional processes, and there's a lot of good public policy reasons to suggest that keeping it at the local level was not the most efficient and cost effective approach. But I can't help but suggest that in regions like PJM and MISO, perhaps, and SPP, there is no competitive discussion that goes on over what ought to be built and what the effects of it are and whether they are prudent. Even with reliability upgrades, there could be questions about whether this is the right time and whether we should be concerned about affordability and rate shock, and I wonder what we've lost by turning this into a bureaucratic discussion, and not a discussion about cost, at the end of the day.

Comment: A lot. I mean, you're preaching to the choir with me.

Speaker 1: I would say that now Order 1000 requires transparency, requires data sharing, and also promotes the cost allocation principle that basically cost should be commensurate with the benefit. So if there is a project that has been built for some other reasons and has been characterized with a different benefit for somebody else, that should be allocated. As part of the interregional piece of Order 1000, we agreed that if a project is part of the Order 1000 process, it has to be part of the PJM process and part of MISO's process, and then if we both agree that this a is good project that addresses the need for both regions, then we will agree to a cost allocation. So I'm not sure how to address this pre-Order 1000 issue. I'm not quite sure if it's in front of FERC or in front of the stakeholders. I think that FERC made its determination, but I think there are still some other discussions out there.

Speaker 2: There is another solution to the problem, which we don't talk about anymore because FERC said we couldn't talk about it anymore, but that's participant funding, and I've always said that, yes, beneficiaries should pay, but the beneficiary should also be assured of getting the benefits of the investment they make. So, for example, in your case, if you participant fund a project, which you have in your instance, and somebody else comes along later and creates costs for you, I think you ought to be reimbursed for that. I think that's a cost to the system that ought to be recognized, and I think you should have been granted certain capacity rights or FTRs, to begin with, and if somebody comes along and reduces the value of those FTRs, you ought to be compensated. That would help the problem immensely, but FERC said participant funding can't be used as an Order 1000 cost allocation method, at least for the projects that are built for region-wide cost allocation.

Speaker 4: I think FERC said that it can't be the only solution. I can think of many instances, even in organized markets, where participant funding or sponsorship is still alive and well. It's not the only thing used, but it is —

Speaker 2: But the problem with that, going back to my conspiracy theories, is that you can't go halfway with participant funding. You either go all the way or you don't go, because you can't participant fund some projects and not participant fund others.

Speaker 4: Yes, I guess.

Speaker 2: I think it's the same as saying you can't do some participant funding.

Comment: Can I offer something, just to correct the record? I think that FERC is perfectly happy with participant funding. It's just that it doesn't get you everything you want.

Speaker 3: First of all, when it comes to cost allocation I think we have to recognize that PJM has allocated costs to what must be thousands f upgrades over the last 10 years. I think it's less than 1% that have become controversial, and I am very sympathetic on the ones that have become controversial because it seems as if what we were using for cost allocation may or may not have been appropriate, and that's going to have to be addressed. But let's remember that 99% of these have gone through without opposition.

Questioner: Yes, but just let me say that most of those have gone through because they're zonally allocated.

Speaker 3: That's correct, but I'm just saying there's an acceptance, for example, of that approach for cost allocation for those projects, and there are still hundreds that have been regionally allocated, of which only a handful have become controversial, so if it's not thousands, it's still hundreds that have been allocated to more than one zone, again, without opposition.

Now, in terms of what we decide to build, which is the other question, remember there's efficiency and there's equity, but getting back to the efficiency question, what is your alternative to Order 1000 eliciting many proposals to for a given identified challenge, whether it be a reliability violation or a congestion issue on the energy side? Let's remember, the approach before Order 1000 is the black box. PJM says, "Here's the issue," the transmission owner says, "Here's the solution," end of story. If you think that Order 1000 is problematic in terms of what it is eliciting, do you mean that relative to the alternative of a black box that just pronounces here's the answer? That's it, no transparency, no stakeholder input, done. That's my question.

Comment: I think the issue is just improving the cost allocation process. We very often, sort of, devolve into a Humpty Dumpty world. I've been in meetings where they tried to declare the entire industry a public good, which then gives you, sort of, *carte blanche* to allocate costs any way you want, and then if you can declare it to be a public good and not a private good, then you have basically an argument to be fairly free in what you do--but this stuff isn't a public good. Take, for example, the issue that Speaker 2 brought up about Ontario and Chino Hills. To me the difference between undergrounding and above-ground transmission is not a public good. It's benefiting Chino Hills, and I don't see how that benefits all of California. It's a simple decision, and if you presented that decision to Chino Hills to say, "OK, we'll be glad to underground this if you're willing to pay the incremental cost," my guess is you would've gotten a different decision.

I can remember in my neighborhood after a snow storm, when the trees fell on the overhead distribution lines, everybody came outside because nobody had electricity, and they were going to demand that Pepco underground all the lines, and they were bothering me because they didn't know why they couldn't just order it, and I said, "Are you willing to pay the extra cost for undergrounding?" and they looked at me like I was crazy.

Speaker 4: I do agree that that instance seems separate from the larger question of how to pay for transmission infrastructure. I mean, I think it's dangerous to lump those two issues together. I won't take a position on either way, but I do think they are different. One is, "Here's a base transmission need, here's what the transmission infrastructure looks like," and if there is an above and beyond issue, whether it be undergrounding or some other solution that affects a localized need for a very high cost, I do think it's dangerous, if there is a concern raised on cost allocation of those incremental costs, it's dangerous to say, "Well then we should apply the same concern all the way down." I do think they are two separate and distinct buckets of cost to consider.

Comment: By the way, these aren't simply transmission issues. They happen in generation also, especially with reactive power and contingency generators. For example, the Presque units in the Michigan Peninsula now have a different cost allocation than they did before. But once you face the incremental costs of doing things and you get the cost allocation right, what follows are a series of decisions that essentially are efficiency enhancing, and if you don't get the cost allocation right you don't create the incentives to do whatever is necessary for the next capital investment to make the system more efficient.

I don't know for how long the units in the Michigan Upper Peninsula were functioning under a broad cost allocation, and the units on Cape Cod, the canal units, were functioning on a broad cost allocation for a long time, and people weren't putting on the table the fact that the really efficient answer was to build some more transmission to get rid of some of these contingencies. So the principle goes much further than just transmission.

Question 5: Thanks. I was very sympathetic with Speaker 3's basic rationale. Transmission can mean investing large amounts of money into very long-lived assets in a world that's increasingly very uncertain, and what's the answer? Well, one answer is that you build small incremental stuff so you avoid the big part, or you go to the "no regrets" approach, where you only build the things that kind of make sense under every possible future state of the world.

I am wondering whether there is room under Order 1000 or under existing planning practices for transmission to think of some of these potentially bigger projects as insurance projects. Rather than thinking about only building projects that make sense under all conditions, that would mean thinking about building some of these bigger things to protect against some really, really undesirable outcomes.

I'm not sure, Speaker 3, whether you have a sense that the kind of incremental build out based on things that make sense today, then potentially leads to a transmission system that's actually not capable of doing certain things that may be required if, for example, we find out in 10 or 20 years that we need to ramp up renewables that come from a specific part very dramatically. The two examples I could come up with is the interstate highway system, which is a public infrastructure that was probably partially designed to protect against some risk, being able to move equipment around very efficiently. And the other thing I could come up with is the nuclear industry and social insurance to handle nuclear accident risk. So is this a framework that makes any sense? To articulate the need for a transmission project as an insurance project against some risk does, of course, potentially open the door for building a lot of things with that argument, so I'm not sure I know how to confine that to the interstate highway-type projects.

Speaker 3: Let's see if I can say a couple things about that. First of all, there's no assurance that building a big transmission project actually increases reliability. There are two reasons for that. The first is that your contingency risk becomes much larger because you have a very large project. The biggest threat to transmission is weather, meaning lightning, which is correlated with size of transmission, so these things can go in other directions.

The other problem you have is that a big transmission project could essentially squeeze out the incremental upgrades that would have been done in its stead. Those projects won't be showing up now and won't be done, because the reliability violations that they would otherwise have been done for will now be taken out, potentially, by the big transmission projects.

The other problems that you have are include incredible rigidity. Generally speaking, the very big projects, when it comes to the sources and the sinks, you have incredible rigidity. You can't move them around. The grid is much more flexible. And, as we've talked about, the larger the project, the more regrets you could end up having, because, relative to a network, you're reducing the future adaptability for, say, a given dollar. That's one way that I look at it, anyway.

Speaker 2: I think what you're doing is making the public good argument for transmission, and every time somebody starts comparing transmission to the highway system, I start to think, well, if that's true, if transmission is a public good, why don't we turn it over to the government and let the government build out a transmission system? Of course, the government isn't really good at solving congestion problems, either. If you ever travel on I-95 during rush hour around New York or Washington, you can see that. But I don't think transmission is a public good. I think transmission is something that connects customers with a network, and it's a network idea.

But if it's true that transmission is this public good, or insurance policy, as you call it, why not say the same for generation? I mean, the best insurance policy might be to build a nuclear plant in the middle of the country, or a series of nuclear plants in the middle of the country, which would protect us against any possibility of not having enough power in the future--a great insurance policy. Would you recommend that we do that? Where do we draw the line? I mean, the line has to be drawn somewhere.

Speaker 4: My view is that absolutely we should look at transmission as an insurance policy, and I want to separate that response from, "Let's build the interstate highway system," because I don't think we need to jump to that link to say, should transmission be looked at as an insurance policy and looked at over different scenarios? When I mention least regrets, there are two ways to view least regrets. One is lowest common denominator. That's not what I personally reference. The other is looking at all the scenarios both from a cost standpoint and a potential highest use standpoint. And I think what you've seen out of many ISOs and RTOs--SPP's priority projects, MVP projects in MISO, any of the portfolio view projects--had a very heavy element of that view. And an AC system, I think, absolutely does provide that insurance policy. The Sunrise Powerlink project I mentioned previously is a perfect example of that. There are many others I can name that have been used under those scenarios, even scenarios not even conceived at the time of that transmission investment.

Now, should that go all the way, like when you have a hammer, everything looks like a nail and you should build big transmission on everything? Please don't take that away as my intent either. We should look at solutions, whether they are big projects, however you define big, or incremental projects, or rebuilds of existing assets to a higher capacity. We should look at all of those, but I think we should look at all of those through the risk lens. For example, say you have a transmission asset out there that needs rebuild, and for a very low incremental investment you can get 40% more capacity out of that transmission line. If you didn't have that lens you wouldn't do it, but I think for that small marginal dollar, it is absolutely appropriate to look at that, and not just do it for doing it's sake, but look at it and say, "Is this a very real investment that we should make on behalf of our customers to avoid future projects down the road and get additional capacity?"

And so I am an absolute proponent for looking at potential risk, whether that risk be, where is generation going to end up? Or, where are retirements going to occur? For generation, you should look at the future of load, and whether that will be affected by demand-side management, distributed generation, or other things. Look at that full range of scenarios and plan the transmission system fully with that in mind and make that judgment, and maybe there's one scenario that shows this is needed and the 99 others don't. In that instance you may say, "I'm willing to take that risk," but there are scenarios where maybe the risk is 50/50. There are very concerning scenarios that you want to look at and at least objectively force that analysis as you go forward.

Generation retirements has been mentioned, and I think that's a unique risk right now that we face. We face incremental need for generation. We also face generation retirements. The unique thing about generation retirements is that, many times, you don't find out about that until it happens, and so that is one perfect example where we can look at those potential retirements based on age of generation, where we think those would occur, and make objective decisions about where, if any, transmission investment is needed, because if you wait until it's known, your options are very limited. You certainly won't build big transmission, because you don't have time, and you may be stuck with many incremental higher-cost projects to respond to that, if you don't view the whole portfolio through an insurance view and say, "How do we prepare ourselves for these potential futures, which we know are very real?" We don't know the exact shape of it, but we know the future is real.

Speaker 3: Speaker 4's last point, I think, is one of the many good arguments for a forward capacity market. I just want to note that.

Comment: Can I say that talking about insurance or projects to avoid risk doesn't take the cost allocation issue off the table? It's just an insurance project, and insurance costs need to be allocated to those who benefit from the insurance--so that it's perfectly OK, but it's basically still a cost allocation issue, because I don't need to pay for reliability in New England or New York, but a lot of people would like to declare reliability projects a public good and have me pay for a piece of them.

Speaker 2: Well, and you're also assuming that transmission is the best insurance policy.

Speaker 3: No, I didn't assume that. I said they [LAUGHTER] --

Speaker 2: Speaker 4 seemed to be assuming that. I mean, if I'm a customer, I have choices of insurance. I could pay for transmission, or I could put solar panels on my roof as my insurance policy. You're presupposing that transmission is the right insurance policy, and I think that's the wrong assumption.

Speaker 1: Coming from an engineering background, transmission, to me, is not necessarily an insurance policy. Yes, it does a lot of public good, but it's more the nature of the transmission that you build it (I'm talking AC transmission), but you cannot really control how it is used. I think that's the issue. To me, for the competitive market, you measure the market's success or failure, not by how much insurance there is, or how much prices go up and down. The measure of success is ultimately whether you can induce competitive projects to come to your market, and the cost of that is not really paid by the consumers, such that you have to do cost allocation. I think that's really the measure of success.

I liked the earlier proposal about identifying a market-compatible transmission project as one that does not cause market shock. That kind of project is obvious. Everybody, sort of, benefits, and it makes the market more efficient, and it will enable more investment to come to the marketplace. That's what transmission is supposed to do.

Question 6: How should state regulators think about this problem? Because it seems like several people have identified a real agency issue, and there are two different approaches here. One thought is, "Hey, there's a public policy goal here of building transmission. We need to build transmission." Years ago we talked about the U.S. having a third world transmission grid after the blackout, and we were going to need trillions of dollars of investments. And I know that if I'm a utility executive, I certainly want to do the right thing for my rate payers and the right thing for the system overall, but I sure would like it if that right thing happens to move the needle on my rate base and internal rate of return, and my observation is that the PATH example is not an isolated case. For every Cape Cod situation, there's 10 of those type of PATH situations where there's actually less expensive transmission available. And even in the PJM and these ISO stakeholder processes there's a lot of market participants there who actually have incentives to have more transmission built.

And so my question is really, how should state regulators think about this problem in terms of what their role is in building transmission? Because maybe we were at a level of détente there back in the old system, where you did get a lot of transmission built, but there's a compromise between the two processes. I can tell you, as a market participant, I've seen a massive reduction in the level of congestion on the grid, in part due to changes in the grid, but also due to all the transmission upgrades that have taken place over the last 10 years or so, the Trail project and such. I'm just curious how you guys feel that state regulators should think about this problem.

Speaker 3: Those are a lot of good questions there. State regulators are going to see the larger projects in the state certificate proceedings for approval of the segments of the projects that appear that will be built in their states. You'll also see them, I think, in the context of rate cases for the transmission component of retail rates that remains under their jurisdiction that has not been unbundled. In some states it's been unbundled. I have a concern that even in PJM there are a category of projects, the transmission projects that PJM only reviews for whether it has a negative reliability impact on the grid and does not conduct a process of reviewing to make sure this is the optimal solution, etcetera, etcetera, etcetera. And for those kinds of projects, it may be incumbent upon states who do have authority, whatever authority they do have, to at least be aware that these kinds of projects are occurring, because the magnitude of them has been steadily increasing over time in PJM.

Speaker 4: I think it's important that the transmission companies and the state regulators and the federal regulators all have a constant dialogue. I do think it's important from a transparency standpoint. There are two or three ways to approach transmission. One is to surprise the market, which is not an approach I personally subscribe to. The other is to have an active, ongoing dialogue with customers on, for example, asset rebuilds. We've got an aging infrastructure right now. Some companies have a very large transmission system. You're seeing the realities of that investment happening right now. As companies evaluate rebuild of that system, how are they rebuilding their system to avoid future greenfield projects? How are they rebuilding their system in an efficient manner to deploy capital? I think that is an important thing. Take, for example, a very old substation that has a very old transformer. You could only replace the transformer, take the outages, then come back to replace the breakers, then later come back to replace the control house. There are ways to do this in a more efficient manner. Those will cause, potentially, short-term cost increases, but I think it's important to communicate the overall benefit of the approach to the market, have an ongoing dialogue, and I think that dialogue goes both ways, and I think it's important.

You asked a question about state regulators. I think it's incumbent on the utilities to make sure that the needs are understood, the reasons are understood, and it's important that that dialogue be able to happen both ways, so the realities of the regulatory environment are communicated as well.

Question 7: I'm fascinated to hear Chino Hills discussed in this forum, because the way that that order was written was really designed to describe Chino Hills as a one-off isolated problem and not as a big example. But some of the lessons that I would share, and I'd like to get the panel's reaction on, is that having a good process, is really absolutely critical. With respect to the CPUC's process that happened before that particular Chino Hills decision was adopted, the CPUC did not use to require the resolution of petitions for modification before things were built, and that's still not a statutory requirement, but the CPUC now has a policy that tries to fast-forward steel in the ground petitions for modification, so that you don't end up with this situation where the towers are built and then you're evaluating something. In Chino Hills, there was a very narrow corridor where these very large towers were literally right next to people's backyards, and there were many, many houses within the potential fall zone of the nearly 200-foot towers, and the city of Chino Hills did commit some money and resources to the undergrounding, although not the full cost. So there are a variety of factors, and although the petition for modification regarding Ontario is pending, so I can't go into that, I can say that the decision regarding Ontario did also distinguish Ontario from Chino Hills based on the fact that during the whole process the city of Ontario did not ask for undergrounding, didn't ask for a number of the measures that the city of Chino Hills consistently did.

I think really the question here is, is it the state role to really set up good rules so that you resolve these questions before building and don't end up with stranded assets? And, also, is it really up to the state role to look at the process so that you are able to identify early on whether there are any particular areas where the building plan may pose an undue hardship on a particular community, and how we should take that into account.

Speaker 4: I appreciate you speaking up, because, as I mentioned, I'm certainly not taking a position either way in that specific case, but I do think there is an art to this, because you can certainly see that there are, I'll call them niche, I don't know if that's the right word, compromises you make on a day-to-day basis on any transmission line designed to get a project sited. And then there are policy-level decisions. For example, if there was a state law in a certain state to say, "All transmission needs to be undergrounded," that may open up a wider general policy decision on cost allocation. Those issues have been wrestled with in multi-state RTOs and dealt with through cost allocation or sponsorship of those costs. So there's an art there, and that's why I'm certainly not putting myself in a commissioner's shoes to say for any specific docket what should happen, whereas I do think the process that you outlined to make sure that those issues are vetted up front, and to the extent that can be done in an efficient manner so it doesn't draw out the siting process dramatically, I think, would really help.

Speaker 2: I didn't mean to imply that it was the wrong decision. I think the only point I was really trying to make is that you have a single cost allocation policy in California that may not apply to all cases, and I just think that more flexibility would be helpful.

Comment: I was talking off of Speaker 2's presentation. I wasn't burdened by all the facts that you were. And, to some extent, I would argue, not for federal intervention here, because I don't see an interstate issue, and if that's what California believes is equity, and the equity, sort of, stays in California, I'm not sure there's a federal role, but it seemed to present a really easy example.

Question 8: As I was listening to the discussion, it seemed like there was something implicit that I'd kind of like to make explicit. That is, that the concern around *ex ante* cost allocation is more significant for economic and public policy projects or potentially multi-driver portfolio-based approaches than for reliability projects, and particularly within the RTO context. I'm having a hard time envisioning the process that an RTO could use to plan a reliability project without an *ex ante* cost allocation methodology in place. Prior to Order 1000, and really Order 890 even, all those cost allocation methodologies were in place for reliability projects, I think. Because the RTO, as the transmission operator, identifies a reliability problem that needs a solution. If the RTO doesn't have the ability to act on that solution, and instead it becomes a conversation with the members as to whether or not you move forward, how does the RTO ensure reliability? Yes, a member organization could say, "Well, I'm going to do a demand side program instead, I'm going to do XYZ," but that can still occur within the context of the RTO having the *ex-ante* cost allocation methodology in place for reliability projects. If that's all true, the bulk of the projects in the RTOs are reliability projects, so, what is the concern? Is it a discreet category of projects? Is it that those categories of projects are more significant than we otherwise might think?

Comment: I would argue that there shouldn't be a category called "reliability projects," because they're all economic projects. I mean, the reason why you do reliability is because we've set up a somewhat arbitrary standard, in one way or another, and you can impute the cost of that. And so the reliability project brings the cost back into some range that you consider acceptable, and there certainly are people who benefit and people who don't benefit from the reliability project, so *ex-ante* is fine, but you want to make sure those costs get allocated properly and to the people who benefit from the reliability that project is bringing, and we have all these wonderful calculations, value of lost load, probability of lost load--all you have to do is do the multiplication correctly, and you find out who gets allocated the cost.

Questioner: That takes me to *ex-ante* is expanded to multiple categories instead of eliminated for all categories.

Comment: I wasn't arguing against *ex-ante*. I was arguing against *ex-ante* as a model that would be applied to all projects, which, I think, is kind of where we ended up with Order 1000, and I don't think that's appropriate. But, clearly, particularly for reliability projects, but for any projects, you want to know what you're going to pay before you start the project, so you need to figure that out. You just don't need a single methodology that applies everywhere to do that.

Speaker 3: Could I just make one observation about this? I'm not so sure that we do anything that is explicitly a value of lost load calculation for a reliability-based projects. We have a 1 in 10 standard for resource adequacy, but I don't think we have the equivalent of that on the transmission side. We do transmission upgrades to alleviate reliability standard violations, and the vast bulk of those are driven by N-1 contingency violations, but that's where the analysis stops. There's no further extension of the analysis to see whether we've met any sort of objective value of lost load criteria for virtue of doing something that costs X. Now, maybe we should be doing it, but it would be a complete change in how we decide to do a given reliability project and whether we decide to do a given reliability project. And I think if we did do the 1 in 10 standard analysis, we'd find that we're valuing incremental lost load at hundreds of thousands of dollars a megawatt hour. In other words, it's completely economically insane, which is probably why we don't try to bring it into an economic framework, because we'd never build any of these projects if we actually had to justify…

Speaker 1: Let me just make a clarification. Actually, in New York, our cost allocation starts from resource adequacy standpoint, and if resource adequacy issues are caused by transmission, then the bottled zones would be the beneficiary zones.

Session Two.
Value of Solar: Shining Light on Hidden Values

As we debate the appropriate method of pricing distributed solar generation, regulators are increasingly presented with studies on the Value of Solar which are designed to influence pricing decisions. It is often unclear whether the studies actually advocate using value of solar as a pricing methodology itself, or simply to put net metering in a proper perspective. To date, only Minnesota has adopted Value of Solar, as a means of pricing, but it did so only on a voluntary basis, and no utility has chosen to adopt it. The conclusions of the studies are widely varied. Support of rooftop solar often focuses on the "hidden values" and externality considerations inherent in distributed solar. Critics of net metering focus on pricing anomalies/distortions, economic efficiency, and unintended socio/economic consequences. How relevant are such studies to the task of proper pricing of distributed solar? Is the Value of Solar debate déjà vu for the avoided cost PURPA debates of the 1980's? How should we look at the avoided costs associated with rooftop solar?

Speaker 1.
I think my job here is really to provide a gentle introduction, talk about why there is such wide variation in the value of DSG that people have calculated, and then maybe offer one or two musings that might be more or less controversial that maybe we can pick up on in the discussion stage.

This first slide is meant to be tiny and you're not able to read it, because these are the twenty potential costs and benefits that I found in the30-odd studies of the Value of Solar that I looked at. I've listed them one by one. You're not meant to read them, you can look at them afterwards, and I think you can copy those slides if you want and get all of them.

The first thing that I did when I was looking at these things is I started realizing that what you need to do is to codify these values and put them in an order that makes sense, and the order I came up with was this. So, really there are seven categories of potential costs and benefits associated with DSG. There are utility-related solar costs. You could say any kilowatt hour that isn't bought is a cost to the utility, because they're not receiving the revenue from it, and then there are various incentive programs and system integration costs that you would include as well.

Then you get into what are the potential benefits of solar, and they relate to generation savings, capacity savings, transmission and distribution savings, and then what you might regard as outside the remit of what you might regard as the central stakeholder here, but there are potential environmental benefits, and then there is the one people tend to weave in here occasionally, which is the potential economic development benefits of there being more distributed solar generation on any grid. There's a security benefit at the very bottom, though I decided not to include it here. Here's how I codified those various individual benefits that were in the different studies into those seven categories, and what I want to talk about a little bit is how each of the studies looks at combinations of these seven different categories, and one of the major issues that lead to the diverse valuations associated with each of the different things that are assessed.

Just to illustrate the divergence that you get in terms of the valuations here, here are the results of five studies. So, the first relates to Arizona, the SAIC study, and it gives a value for kilowatt hour of solar in terms of cents at about 8.2 cents, I think. And then the Crossborder energy study for the same service territory is up around 17 or 18 cents, so there's obviously a big divergence in terms of the studies. If you look at the Clean Power Research 2012 study, which is another representative one, it has a huge component associated with energy savings, and I'll make some more comments about that later, so it's out of kilter with the other ones in terms of the potential energy savings.

One of the things that I think leads to there being a divergence in terms of the valuations that people make of DSG is that they're just looking at things from different stakeholders' perspectives. I would argue that at the base, what we should be doing is looking at the thing from a rate payer's perspective. That is, the DSG customers and non-DSG customers associated with any particular area or service territory for a utility, and the relevant costs and benefits that we should include there are the utility DSG costs, the energy generation, and the potential capacity savings in terms of transmission, distribution, and generation, and you shouldn't be including here the potential for there being some environmental benefits, which are more societal in nature. They don't fall directly to a utilities customer, whether they're generating themselves or they're just buying power from the utility. And you shouldn't also be including the economic development benefits. You can consider those separately, but they shouldn't be included in any valuation of solar, because it really isn't about the central core here, which is what the rate payers should be considering as to whether the value of solar is greater than its cost. One of the major issues that you come across when you start looking at these studies is really what people are doing in terms of thinking about the scale of solar penetration. A lot of studies start off with what you might consider to be very low scale penetrations, sort of on the order of less than 1%, sometimes. They examine the benefits and costs of solar for a very small scale addition to the system, and hey, presto, they come up with something which says that the benefits are huge and the costs are tiny, so let's then gross upwards and make the solar penetration 20%. And then everything's great. We've saved a huge amount. Consumers are better off generally.

So one of the things that gives us sometimes erroneous measures of the Value of Solar is to use this very small incremental-type approach and then gross upwards. I would say that's one of the major issues we should be thinking about here in terms of valuations. What you should be doing is taking more of a kind of lumpy approach and saying, "Well, what would a system with very small penetrations, less than 1%, look like, and what would a system with 20% look like?" to figure out what the actual valuation should be.

And so I think this is a sort of fundamental point. If you think about the costs of solar and you just really say that the major costs of solar are the revenues that wouldn't be paid to the central utility, those are measured in average terms, because pricing of power is generally on a volumetric basis, so you might say the average cost of power in Arizona would be, say, 12 cents or something or other. That's really the cost that somebody isn't paying when they self-generate. The benefits, on the other hand, when they're assessed in the studies, they're often done on a marginal basis. What's the marginal benefit of power when you add a 1 kilowatt hour that somebody's generated out there in a distributed form, and when you measure that and it turns out to coincide with peak during the day? In that case, it's got a huge valuation, and then you get this argument that, well, the marginal valuation is, say, 20 cents, and the average cost of provision of power is 12 cents (or something or other), so the argument is then made that it's more beneficial to have DSG on the system, and it justifies having either net metering or a high feed-in tariff on the basis that the benefits are bigger than the costs. That's really the central argument here. So you need to be really careful of those things, this average versus marginal valuations of costs and benefits.

When you look at the studies, a lot of studies use marginal valuations, and that isn't really fair when you start thinking about increasing penetrations, because eventually what will happen with marginal valuations, if you use them and you're being truly fair, when you get to 30% or 40% penetrations, then what happens is that the marginal value of solar pretty much is going to drop down to zero because it doesn't coincide with there being any required generation at that point in time during the cycle of the day.

Turning to lessons for "good" valuations that I would draw on the basis of the studies, the best ones do several things. First, they make the stakeholder perspective clear. Am I talking about the perspective of the rate payer, or am I talking about the perspective of a society as a whole, in which case, with a rate payer perspective, I shouldn't be thinking about environmental or economic development benefits?

Second, you need to ask, am I using an appropriate mix of systems? A lot of studies make an assumption of, well, we've looked at the average system, and the average system is south facing 30 degree fixed in orientation; therefore, I'll assume that all systems will look like that going forward, so they don't have appropriate mixes that match with reality. Obviously, I live in Arizona, I drive around and see people with systems on their roofs, and the amazing thing is the number of systems that aren't south facing, and/or have obvious shade form trees. You could argue that there's misinformation taking place because people, when they buy or lease systems, which is a problem for us, they're not getting information from the people who are leasing them the system about how the system will actually operate. They're getting theoretical system capabilities, not the actual ones based upon the orientation.

Third, you need to make good assumptions about input prices. One of the biggest potential benefits is energy savings, fuel cost savings, and one or two of the studies, I would say, make ridiculous assumptions about natural gas prices going into the future. Nobody knows what gas prices will be going into the future. This morning I was just looking at my investor app, and I looked at natural gas prices, and they vary between $1.9 and $3.9 in the last 52 weeks, so who knows what they'll be in five years' time. The price of oil is less than $40 a barrel. I bet you, if you placed a bet a year ago or two years ago about the price of oil being less than $40 a barrel, you'd had got ridiculous odds, because nobody would have anticipated it would actually take place. We don't know, really, what's going to happen with commodity prices, so it's not a good thing to make assumptions which assume an automatic escalator of, say, 3% or 4% in terms of natural gas prices and that being the thing that gets backed off.

The other lessons are to use robust methods of forecasting that give you a good idea of the potential growth and penetration of DSG. Some studies just assume that there's going to be some ramp up. It's not based upon any real forecasting method which gives you some idea of how things might develop through time. Be very careful about grossing up what are effectively small scale incremental additions to the system and then making valuations using utility marginal costs at that basis, because that gives you an erroneous measure.

I think the other things that these studies need to do more carefully is to measure the transmission and distribution and capacity benefits on a yearly case-by-base benefit, really get down to the planning level and figure out what you can back off so they actually make sense rather than making gross assumptions, in percentage terms, about what you can make out of the system, because often because of the intimate non-dispatchable nature of the solar additions to the system, it's not possible to realize the benefits that are stated in some studies.

And I've got some sympathy with the people who do studies who aren't part of utilities or don't have access to these tools, but nevertheless this is the gold standard, I would say. If you're going to estimate the benefits of reductions in fuel usage, variable O&M and transmission distribution line losses, you should be using an appropriate simulation tool, a planning tool, like ProSym and PROMOD. Now, I know this is a difficulty, because one of the things that I'm working on is that there's an argument taking place in the state of Hawaii at the moment, which I'm involved with, but I'm on the wrong side, from the modeling perspective. I'm on the side that can't afford the PROMOD or ProSym tool, whereas the people on the other side can afford it, so you're sort of a bit lost. You can't really use the toy that you need to be able to come up with a sensible estimate, so I'm aware that this is a problem, but nevertheless, the gold standard in measuring these things is to use something that's sophisticated enough to deal with the vagaries.

I'm an economist by training, and really I'm all about efficiency, and I think what we should be doing is striving to provide the most cost effective energy system that we possibly can, because the end result of that is that it will satisfy all of the different objectives that we have, and I think that our objective here really is to try and reduce emissions and increase the amount of renewables on the system, and that means, sometimes, solar. So, I'm all in favor of that, and I just want there to be the most cost effective way of achieving that, and I think that net metering and feed-in tariffs have some very complex and difficult problems associated with them; their setting and then the control of them.

And I won't go into detail, but I think Germany is a fantastic case study if you actually want to look at the effect of feed-in tariffs and in turn how they've backed out of those things through time.

One of the things that worries me here is that if you look at the numbers I showed you before, you could argue that if the value of a centralized utility is the price at which it delivers its power to its consumers, at, say 10 or 12 cents a kilowatt hour, and the benefit associated with solar that people on the solar side are arguing, distributed solar, is higher than that, logically you get to this reduction to absurdity which says that you shouldn't have any centralized generation, because the benefits are bigger than the costs. We should all have something on our roofs and forget about centralized generation.

In college I did some economic history, and there's a reason why there are utilities and central generation and a regulated set of natural monopolies, and that's because it's the most cost effective, efficient way of providing us with energy, and I'm slightly curious about the way in which non-centralized generation or non-centralized coordination of DSG would be more cost effective than centralized generation would be. If you can convince me of that, you're welcome to. I don't see, at the moment, myself.

I would say this; I believe in free markets. I think that we should have a free market in this and let anybody put anything on their roof that they want to. They can excess generate and offer what they excess generate to the open market. We live in a world now with big data, smart metering, smart grids. We can instantaneously figure out what somebody's generating. If you wanted to, you could create a cooperative of people who have DSG systems and get them to coordinate their activities together and sell power on the open market just like any merchant generator would. I would say that was a more sensible way to deal with this, rather than trying to get into the various complexities associated with net metering or feed-in tariffs. I think that might be the end. Thank you very much.

Speaker 2.

Let's talk about Value of Solar, and remember what we're talking about is a study to calculate the costs and benefits of solar, typically PV, although theoretically it could be something else, and we want to boil it down to a common unit. Pennies is pretty common.

And we need to separate this from the public policy discussion of net metering. The public policy decision is typically done at the state legislative level, and then the commissioners, along with the consumer advocate and other interveners, have to, sort of, figure out rate making within that context, so they're both important questions. But this conversation isn't about whether or not net energy metering is a good idea, it's about how to calculate the Value of Solar so that the public policy folks who think about things like net energy metering have the best information available to make that decision.

And so the details matter, and this may help explain an important reason why we get such varied outcomes in Value of Solar studies. The value of an incremental PV unit depends tremendously on the electric system where that PV unit will be installed. It depends on the market rules, the generating fleet of that system, what fuel is on the margin, the size of that system, and, of course, how much other PV is in that system.

The size of the installation itself matters tremendously. DG systems (which we will call less than a megawatt to allow for small commercial, while residential systems are something on the order of five kilowatts) they avoid costs that a utility-scale system, a 20 megawatt system, simply doesn't avoid. There's a different cost calculation, and we use the different categories to sort of draw that out.

Ownership matters when we talk about cost, because, let's be clear, lost revenue is not a cost. It is not an economic cost. It matters, it very much affects rate making, but when a customer builds PV and puts it on the system, there is no or very little cost to the utility, and lost revenue is not a cost when we talk about good planning.

Finally, we have to think about the perspective, and this was brought up a little bit earlier. The former speaker advocated that Value of Solar studies should be done from the utility perspective and not count all of those social benefits, and that I half agree with. But, if the Value of Solar study is designed to help public policymakers decide what public policy should be, then you bet the social costs matter to those public policymakers--environmental, economic, and otherwise. And so it's really important not to just take the cents per kilowatt hour number and say, "Well, this is the Value of Solar for you because it was the Value of Solar for him." Nonsense. You've got to look at the details and make sure you're not comparing apples to watermelons.

So, yes, there's a long list, and I want to talk about a few of them. Energy, that's the easy one, but let's remember that PV is a little different than most resources, because while it's not dispatchable, it's remarkably predictable and seasonal. And so, when it comes to system losses, we're talking about line losses typically, but system losses also allow for reduced capacity requirements, and the amount of system loss varies tremendously based on the size and location of the PV installation. You don't avoid transmission if you're talking about a 100 megawatt PV project, but you do avoid transmission if you're talking about a 100 kilowatt project, so, again, the details matter. Furthermore, line losses, loosely speaking, are a function of the square of the current on the wire, and so at times of high congestion, avoided line loss value is very, very high. At times of low congestion, it's very, very low, and the temporal nature of human beings and of solar panels are really important in that context in a way they aren't for other resources, typically.

I want to bring up hedge value. It's sort of a funny thing. It's hard to figure out where to put it. I mean two different things. One is the value of hedging against fuel cost. PV doesn't have fuel cost, so from the perspective of the utility, and certainly from the perspective of society, you get a hedge. There's a financial value there. Exactly what that value is--I'll let the folks on Wall Street deal with that. The other hedge is the environmental hedge, specifically the hedge against future environmental regulations. Raise your hand if you think the EPA is never going to promulgate a rule that makes it tougher on emitting resources. Seeing none, I will let us all get to the point that we should acknowledge that as we build more resources that we think folks like EPA are going to be pretty OK with for a long time, we're hedging against future environmental regulations that come with costs. Every time we have to do something else to keep a coal plant running or retire it, every time we have to figure out how to keep our gas plants compliant or not use them in the future, that's a real cost, and so the solar does provide a hedge against that. What's that worth? I don't know, but it's not zero.

"Avoided RPS" is this funny one. Most of the time, solar is installed in a state with net metering, and typically it's manifested in the form of reduced sales, and this matters because the renewable portfolio standard obligation in the 30-odd states that have RPSes are a function of sales. So when a customer puts solar panels on his roof, not only is he generating the RECs that allow for overall RPS compliance, but he's also reducing the total number of RECs the utility is obligated to buy, because he's reducing sales.

And then, there's this other category, other environmental costs, and this is important in places which have monetized internalized environmental costs. I'm talking about both SOx and NOx allowances, which are typically modeled with energy, but also a RGGI state, or California has a carbon price. But that carbon price or that SOx and NOx price may not reflect the full social cost, so we can include the financial costs with the utility and then, sort of, gross up with the social costs if that's the perspective we're looking for.

And there are actual costs to Value of Solar. There's an administrative cost. Heck, we're talking about it, so there's the value of all of our time, and certainly changing the billing to deal with the solar panels, that's an actual cost. Electric meters--maybe that's a cost, maybe it's not. If we're rolling out the electric meters so we can read them from the street, that's probably not associated with solar, but if we need meters that ensure there's no backflow onto the grid for safety, yes, that's a cost associated with solar, and you bet that should be included.

Some of these costs or benefits are costs or benefits depending on the details. So, distribution, capacity, grid support service, economic development…depending on your system, adding more solar may reduce distribution capacity costs in the long run if, say, you have a very low penetration of solar. But if you're Hawaii, adding more distributed solar on the system may actually increase distribution capacity costs. So, there again, the details matter. Where are you and what's your story?

With respect to grid support services, ancillary services, it's probably a small number. It could be positive, it could be negative. Do the math yourself. The same with economic development--will more solar be a net increase or decrease in jobs for the region in which you're focused? It depends on the details.

Some of these costs are utility costs, some are society costs.

And, then there's the cost of the panels themselves. If it's utility solar, then it's a utility cost. If it's residential solar, it's certainly not a utility cost. The utility is not paying a dime for them. They're getting the benefits of that and they're losing revenue, but the cost of the panels is not being borne by the utility. And so, when we look at cost benefit analysis tests, you'll find that residential PV has a benefit cost ratio to the utility of somewhere between 10 to 1 and 30 to 1, because they get all these benefits, but don't have to actually buy anything.

Let's talk about PURPA for a minute. First, on this slide, notice the big red X. Those are things that are benefits and potential benefits of solar that simply are not legally allowed to be included in PURPA analysis. You just can't count them, but you can count them if you're doing a study to figure out policy or rate making for solar. What is included? Well, we always include energy, although not always very well. Typically, energy is modeled as something like 100 megawatt generator operating at exactly the same output, all 8,760 hours a year, and while that make sense for CHP at an industrial site, it doesn't make any sense at all for PV, and the utilities are always very good at including all of their costs in the PURPA hearings. Some manage to include generation capacity. Others manage to keep it out. System losses similarly. Occasionally you'll see hedge value. North Carolina, for example, includes hedge as a benefit under PURPA.

CO2--in states that have an actual CO2 cost, that's going to be included as well. And then, these other things with the line strike, those are typically not included, or in fact would be very difficult to include. There may be exceptions, but generally speaking, PURPA is, sort of, a simpler version of Value of Solar.

The other things I wanted to point out about PURPA is that some states have figured out, Utah is one of them, that you can model your avoided costs for a block of solar separate from a block of anything else. So, in most states, they sort of treat PV as a generic resource, and they do their avoided costs, and they ignore the temporal reality of PV. What Utah did that was clever is two things. The first thing they said is, "Look, let's sort of, theoretically, using ProSym, build 100 megawatts of PV and model avoided costs for a PV system so that when someone wants to build PV we have a better cost." That was really clever. The other thing they said is, "We'll do the math for the first project, and as soon as somebody wants to build a second project, we'll do the math for the second project, assuming the first project gets built," and that allows for the utility to acknowledge and account for the reality that as the system changes, including as the amount of PV in the system changes, the Value of Solar also changes. It's a very reasonable thing, right? That's a little bit about PURPA.

I want to try to answer some questions that were posed. The first is, how relevant are such studies to the task of proper pricing of distributed solar? And the answer is, it depends. I'm a consultant, you're not going to get a straight answer out of me. From a public policy perspective where we willfully impact outcomes, the Value of Solar is important. Understanding the value to society is key to good policy, and I'd add that folks who think that distributed PV is an inefficient societal investment should be advocating for a brutally inclusive Value of Solar study alongside of a Value of Wind study, a Value of Combined Cycle Generation study, and so forth. The problem is not that Value of Solar studies are broad and comprehensive. That's not a bad thing. The problem is that perhaps we're not doing a similar study for other resources to guide public policy. If we're in the world of rate making, we need the Value of Solar study to understand how utility costs are impacted. Driving down costs is a fundamental aspect of planning, and recovery of some costs comes afterward, and so I don't mean to say that we shouldn't worry about the impact on rates, and I don't mean to say that there may or may not be cross subsidization going on, but you don't forego the reduction of cost because there's a change in rate making. Instead, you embrace a reduction of cost going forward because that's good utility planning, and then you figure out how to set rates appropriately.

So, what about PURPA? Is this déjà vu? Yes, somewhat. We talked about it a little bit. The 1978 and 2005 Acts limit which avoided costs show up in PURPA, and nearly 40 years of state by state litigation and tradition further limit PURPA avoided cost categories, and anyone who's done dockets across multiple states in PURPA quickly understands that what makes sense in one state is absolutely off the table in another state, and so forth. So, yes, there are parallels, but I think Value of Solar is quite a bit more complex in a number of ways. It's certainly broader, and it's used for more decision-making processes than a PURPA analysis.

How should we look at the avoided costs associated with rooftop solar? Well, carefully, completely, and within the appropriate context, right?

Again, on policy versus rate making; we need to remember which world we're in and make sure we're looking at the right categories in the Value of Solar study.

I do want to make two points about how to use these studies well. The first is precision and the number zero. Sometimes we have a limited timeframe to get an actual value within a category, typically because there's a docket and we need an answer. Sometimes the error bar associated with the Value of Solar category is really big. Even if the value itself is very small, the errors are very big. Sometimes the value won't manifest itself for many years. It's not going to be a value that shows up today. It's avoided construction costs 10 years or more down the road, and sometimes the cost of the study to calculate the value exceeds the value, right? This really happens. It's happened in communities in my state where they worked really hard at figuring out the cost of something, and they spent more figuring out the cost than the cost. So, in these cases, don't use zero. Uncertainty does not mean the value is zero. That it's hard does not mean the value is zero. If the value really is zero, if zero is your best guess on the cost or benefit, by all means use zero. But if it's just that we don't know what it is—if we know it's positive or negative, but we don't know what it is, zero is inappropriate, because you're asserting that the value is zero when, in fact, you know it's not. So use studies from regions or utilities with similar situations, work with the utilities to come up with the best case, get five ladies and gentlemen in a back room with cigars and hash out a number (which is seemingly what Mississippi recently just did)... But to use zero because we can't figure out what the actual number is, is really inappropriate.

Secondly, on that note, improve precision for next time. If you're in a docket now and, geez, we want to know what the avoided transmission capacity costs are associated with solar, but that's a multi-year study, that's a really complicated thing. We think there's a lot of value there, but we can't get it done in three months, then come up with a non-zero number for now, but, by George, kick off that study. Don't come back two years from now and say, "Oh, yeah, we still haven't done that study. We still don't know. It's still really hard, we still have to argue about whether or not we're going to use zero or some number that we think best represents it."

It's important to push forward on the studies where the value is significant and get better numbers for future Value of Solar analyses, because, as I said initially, the details of the system matter, and the system that you studied won't be the same three years from now as it is today. You're going to have to regenerate the numbers anyway, so go ahead and roll up your sleeves and start doing those studies to get better numbers. Don't just sit back and say "It's hard." I think that's about it. Tell us about Minnesota.

Speaker 3.

In 2013 in Minnesota we passed a pretty significant suite of policies. We call it Policy Innovation. The Solar Energy Standard is one of this suite of policies. It's a separate carve out from our RPS.

Community Solar Gardens are a second element. As of yesterday, Xcel, which is the main carrier of Community Solar Gardens, has announced it's already got in the pipeline just short of a gigawatt of Community Solar Gardens. These are less than 1 megawatt at a time, so do the math, think through what's happening just with Community Solar Gardens.

The Value of Solar Tariff is something we'll get into a great amount of detail about, going forward.

We have a program called Made in Minnesota for solar manufacturers that, as it turns out, attracted three new OEM's to our state.

There were some other modifications as part of the 2013 solar legislation, including to net metering and to PACE financing and Guaranteed Energy Savings as well.

These are the energy bills. MS 216B.164 subsections E and F, was signed into law May 23 of 2013.

I'll go through this relatively briefly, but I think it's important for people to understand that this Value of Solar didn't just drop out of the sky. It was the result of a long road of stakeholder discussions. There was a distributed generation stakeholder set of meetings convened by the Department of Commerce Division of Energy Resources between 2010 and 2011, and the conclusion of that was that net metering could potentially shift costs even if DG was sized to load, and that retail net energy metering was a very rough proxy for solar's value.

As a follow-up, there was a series of stakeholder meetings convened by DER with utilities to discuss buy all/sell all and the Value of Solar best practices that were coming out of, in particular, Austin, Texas. We're going to talk a little bit more about buy all/sell all, but part of our program is not just evaluation of solar, but it's in the context of a dual-meter program, where you're metering both consumption and production, and we get into that.

Minnesota requires the Department of Commerce to develop a methodology to quantify the value components of distributed solar electricity, including (and this is in the statute) the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. Does that sound vaguely familiar in terms of the presentation that Speaker 1 gave earlier? That's because we emulated a lot of the best practices in our own evaluation and analysis of what to do in developing sustainable Value of Solar in Minnesota.

The Value of Solar tariff separates, as I indicated, the customer meters for electricity usage and production. Why is this important? Well, in a net metered situation, you're not paying for the poles and wires as the meter runs backwards. In this scenario, you're able to capture all of those fixed and variable costs on the consumption meter, while the production meter is where you're applying the rate. And, understand, this is, again, not an incentive, this is not a subsidy, this is a tariff that is determined based on the quantifiable, measurable benefits to the utility and rate payers.

The investor-owned utilities may file a VOS, Value of Solar, tariff in lieu of net metering for solar PV that's less than 1 megawatt, and co-ops and munis were exempted. That doesn't mean that they can't do it, it just means that the statute was silent on whether or not they could opt in or not. On January 31, the Department of Commerce submitted a Value of Solar methodology to the Minnesota PUC (it's docket 1465) which it quickly approved. Partly, it approved it because so much preparatory work had been done with so many stakeholders and such a transparent process over such a long period of time, it made absolute sense for the PUC to move forward in its approval. That's the way we do business in Minnesota. We're proud of the fact that we stakeholder to death our discussion, but in the end it produces a really robust product.

The Minnesota VOS methodology is based on the enabling statute, input from four inclusive stakeholder workshops, and extensive written comments from parties, not just in Minnesota, but across the country. People came to Minnesota meeting after meeting after meeting to bring their concerns and their insights into that discussion so that we would have a robust DER generated methodology to present to the PUC. It involves a 25-year fixed rate contract, which is adjusted annually for inflation and specific utility data, and I think this is a pretty significant differentiator. I suspect that Speaker 4 is going to talk a little bit about that.

So, what is it? Here's the preliminary stack of values that was done in 2014 by Xcel Energy. The value was set at 14.5 cents, and it was revised down. I'll get into that in a minute. Calculating the Value of Solar includes eight separate factors, but four account for the lion's share of the value: 25 years of avoided natural gas purchases as well as avoided new peaker power plant purchases, transmission capacity, and CO2 pollution costs. Economic development metrics were excluded.

The value of avoided fuel costs recognizes that utilities cannot buy natural gas on long-term contracts the way they can buy fixed-price solar energy, and it internalizes the risk of fuel variability that utilities have previously passed on to rate payers. The avoided power plant generation capacity value recognizes that sufficient solar capacity allows utilities to defer peak energy investments. Avoided transmission capacity costs rewards solar for onsite production, saving on the cost of infrastructure and energy losses associated with long-term imports.

The environmental value was easily the most controversial. I'll talk a little bit about that. As I indicated, Xcel and the other IOUs were given the option to use the Value of Solar in lieu of net energy metering, and you would think, given their complaints about NEM, that they would have almost immediately jumped to using the Value of Solar, particularly in the context of a consumption and production meter protocol. That didn't happen, and it didn't happen largely because of Xcel's objection to what they claimed was too large an accounting for the avoided environmental impact. I'll talk a little bit more about that, but that was the essential reason, and I'm sure it's one of the burning questions that people in the audience have. If this is such a good deal for utilities, if it's so utility friendly, why hasn't a prime utility in Minnesota signed up?

The preliminary levelized 2014 market value of solar by Xcel Energy was 14.5 cents per kilowatt hour, and it was revised down to 13.6 per kilowatt hour in 2015. If you're interested, you can go and read the dockets. They're extremely extensive and walk through the evaluation from Xcel with its numbers from the Department of Energy Resources with their economists doing a double check, and then the PUC and its staff coming on with their own evaluation. When that value is escalated for inflation, as required by the statute, the 2015 per kilowatt rate is 10.75. So, understand what I'm saying: There's a levelized cost or a levelized Value of Solar that is pegged at 13.6 cents, but when you escalate that at 2.65 (it's a 25-year average of the CPI)... It's lower, we know, than what the typical rate cases have been for Xcel, but it's an acceptable proxy to try to figure out how to escalate with an inflation rate on the levelized cost. This is all based on annually recalculated utility-specific data using a PUC authorized template.

What I want to do right now, too, is do a little bit of deep dive into the Minnesota Value of Solar methodology. It's been out there for two years. This is not the first time that somebody has made a presentation to a group of folks like this about our methodology. It's a 54-page document, and I'll walk you through some of the key content components, because I think they're critical for people to understand. I'm not going to deal with each of these components, although I'd love to drill into them. That's probably a whole other conference.

Page 2 gives you a VOS calculation table. It gives you a pretty good snapshot of what you can expect to see, with actual example calculations, and those calculations are based on the stack of eight gross values that I just talked about. The load match factor for those eight components, that's then multiplied times the load savings factor, and that gives you the levelized cost for each of those eight in the value stack. The fixed assumptions are on page 7. Those give you an idea of things like, what are we using as the term? 25 years. What are the discount rates? What are we using as an inflation rate for escalation?

Another table has the utility-specific data. Each utility is required to enter in its computations for its ELCC (estimated load carrying capability). Essentially what we're doing is matching the fleet to the load. We're trying to discern the impact of peak energy on the capacity calculations, and those are included in those calculations that are submitted publicly, so this is an element of transparency. This isn't in a black box behind a curtain someplace. These are the figures that must be submitted by each utility prior to its doing its calculations.

Then the economic analysis kicks in from pages 21 through 39 for each of the eight components. Then there's an example calculation that gets done with an escalation; it's on page 42.

So, I know that's a lot of stuff to throw at folks, but I don't want to get into a generalized discussion about how you feel about solar. What I'd like for people to be able to do and understand is that we've developed a specific calculation for each of these values in the stack, and matched it to the load for the specific utilities, then done annual recalculations based on their specific data and the methodology.

So Xcel did file for reconsideration of the VOS methodology, based primarily on its opposition to the method for calculating avoided CO2 impacts, and, understand, what the PUC used was the EPA's midrange social cost of carbon. The PUC does require Xcel and other IOUs and a couple of the co-ops that are regulated by the PUC to submit values for carbon and other criteria pollutants when it does its estimates for long-term integrated resource planning.

Here's where I think we emerge. When we started this process, clear back in 2010, we weren't really talking about the new grid. We weren't talking about grid modernization. We weren't talking about grid 2.0, but we sure are now, and what Value of Solar did was provide metrics that have helped frame the value of developing the distribution grid in general. We know it's not complete, but it provides an anchor for how do we begin to look at the value that distributed generation, not just solar, but the complex of what will probably be characterized as micro-grids will provide going forward in the electricity system. So it doesn't evaluate, but should, eventually, the role of storage. It doesn't evaluate, but should take into account, demand response. It doesn't evaluate, but will have to take into account, load reduction from energy efficiency.

What about other technologies? Small wind, CHP, those could be incorporated as well. We're not done, but we feel like it was the initial best starting point that we know of at any place in the country for having this discussion and providing credibility for what we call the emerging distribution grid, grid 2.0.

There are five states including Minnesota that have proceedings underway to essentially remake their states' electricity sectors regulating the utility of the future. "Implications for the Grid Edge," by GTM research, analyzes these proceedings and, in particular, talks about that phenomenon that I just characterized, where we essentially put in motion, with the Value of Solar back in 2013, a basis for evaluating the benefits to the evolving distribution grid.

Could DER modify Minnesota VOS to include locational benefits mapping, such as you see in California or in Manhattan with Con Ed. Metrics for outage mitigation, resilience, etcetera? It's not clear. We may have to go back and change the statute to get that done, but there's a lot of interest.

One of the organizations working quite diligently on this is a group called E21. Many folks are participating in that effort, and that's part of what will inform what kind of statutory adjustments need to be made in order for us to put Value of Solar more squarely in the context of the developing grid. The report is *Minnesota Value of Solar, shining light on hidden values*. We think it's done that. We think it's doing more, that it's setting the stage for grid 2.0. Thanks.

Question: Speaker 3, do you know what the bundled retail rate is in Minnesota in 2015?

Speaker 3: Are you talking about in the Community Solar Gardens docket? I assume that's what you're talking about, because that's related to the Value of Solar, at least it's intertwined in that discussion. Right now, there is residential and small commercial. The applicable retail rate for that, if you include the RECs bump, is 15 cents, and it's 12 cents for non-blended demand charge customers. Now, that's for Community Solar Gardens, but that's the applicable retail rate. I'm assuming that's what you're asking about.

Questioner: Just a regular Xcel customer, what are they paying when they're using electricity?

Speaker 3: The regular retail residential customer is paying, I'm doing the math in my head, a little under 12 cents at this point. For a demand charge customer, it's a little complicated because you also get a demand charge credit. If you put those rates together, that's close to 12 cents as well.

Questioner: My other question is, in Minnesota, do you all refer to this Value of Solar rate as an avoided cost rate?

Speaker 3: It's clearly a computation of avoided cost. Some people have said it's avoided cost on steroids. I don't know if you'd go that far. It's rigorous, but we think the calculations are justified, and that's why I went to some length to point to the calculations in the document, so you don't have to take my word for it, you can go back and look at it, and I'd love to have online discussions with people or other HEPG discussions where we could dive into each of those calculations. Other questions?

Speaker 4.

Actually, I was going to name this the Barbara Streisand panel, because…"Memories." For Alan Schreiber and I, who served through the 1980's (before both of us were born, of course) on the Ohio Commission, a lot of these issues are the issues we argued about 30 years ago. Before I went to law school and got my brain ruined, I was studying to be a historian, and one of the things that's so interesting to me about this particular discussion is that this is essentially the same arguments we had in the 1980s, and one of the preliminary questions I have is, why are we doing this in the time when we have smart technology, much smarter prices, and we have a completely changed environmental context? We have all these things, and yet we're repeating an exercise that didn't turn out so well from the 1980's. And, in fact, what we did ultimately was move more towards markets and market mechanisms, because there were a lot of serious policy mistakes made, well-intentioned, but nonetheless largely premised on subjective views of value as opposed to a more disciplined approach to pricing.

There is also an interesting question here about the use and abuse of monopoly power, and the issue is that many of the solar companies argue that of course utilities want to preserve their monopoly, they don't want the competition, but the flipside of that is that what really is happening (much like you heard in the PURPA debate in the 1980's)is you've got these new entrants into the market not trying to compete, but rather trying to take a piece of that monopoly power to get high above- and out-of-market prices for their product.

So the question of the use and abuse of monopoly power is very much a part of this issue. One of the things that's interesting is that these Value of Solar studies really vary. There are a number of them, and they come to some vastly different conclusions about this. But one of the interesting contrasts is that some of them are used to really try to derive the appropriate price for solar. And there are others, and I would put Minnesota in that category, that are really trying to establish a methodology for evaluating things and recognizing setting a flat price for 25 years may not be the most logical thing to do.

The uses of these studies are really threefold. One is to actually set the price for distributed solar. Another is to establish a methodology. The other, most commonly, is simply to justify the paying of a very high price, e.g. net metering, for distributed solar energy.

What's interesting about this is we have three historically proven and accepted ways of doing pricing. One, of course, is market based. A second, of course, is cost of service; and the third that we've used since PURPA is avoided cost. Ultimately we ended up under PURPA using some sort of market basis or market mechanism for doing avoided cost pricing.

Interestingly, if you use Value of Solar to establish the price (since that's what many of these studies try to do), well, the problem with that is that you end up deviating from that. Although, there is an interesting thing, that some of the studies that really advocated particular prices, the one done in Maine being a notable example of that, one of the things that's interesting is that they don't talk about cost of service discipline until it comes to cost of capital for the investors in solar. Then, all of a sudden, costs become important.

The problem with the Value of Solar studies is that they are inherently subjective. There is no commonly accepted methodology. As both the previous speakers pointed out, this is an incredibly complicated area. It's an area where there are God knows how many variables, and a lot of debate about what you need to consider and what you don't need to consider, and there's an extremely wide variance in conclusions, ranging from what Minnesota does, which is to look at a price but make annual adjustments to reflect what's going on, to the study done in Maine that went through this detailed analysis and suddenly concluded the value of distributed solar was roughly double the retail price of energy in the state, which is a curious conclusion, but that's what they came to.

So there's a wide variance in exactly what these conclusions are. There also tends to be an interestingly narrow focus in the Value of Solar studies. They're technology specific. I mean, if we're going to use value-based pricing, then why don't we do that for every other single resource? Why are we choosing this one to single out? I think we run the risk that, first off, there's no comparison with alternatives for attaining value, a classic example being that there's a wide assortment of literature on the cost of using various methods to reduce carbon emissions, and distributed solar generally ends up at the low end. That is, it's a higher cost way of reducing solar emissions--but nevertheless, we establish the carbon value of distributed solar. What we don't do is ask, what's the opportunity cost for not having chosen a more cost effective methodology, and there's no real assessments of the risks of technology-specific focus rooftop solar.

Someone mentioned the "environmental hedge." It's true that if you're anticipating that carbon is going to be regulated and you want a hedge against that risk, there's a logic to that. The problem is that there's also a huge risk associated with guessing wrong. If you pick a technology that turns out not to be the most cost effective, or one that turns out to stick the state with a lot of costs as it develops its implementation plans, then there's a huge risk associated with that. Generally speaking, in these Value of Solar studies, you don't see the risks as much as you see, reasoning along the lines of, well, it is a legitimate criteria to try to hedge against environmental risk as opposed to looking at exactly what the risks are of the approach you choose to take.

One of the reasons why a lot of these studies (and not all of them--there's the Louisiana study, for example, that goes exactly the opposite direction that basically argues for a relatively lower price for Value of Solar) argue for a higher price is on the basis of externalities But the studies rarely weigh DG against the alternatives for reducing carbon. That is, they don't ask, how cost effective is this as opposed to spending our money on more cost effective ways of doing it? Secondly, you see a subjective choice of externalities. My favorite (again, I turn to Maine) is the example where, not finding sufficient externality value in carbon (which is already regulated, at least to some extent, under RGGI in Maine), they decided, "We'll also turn to go back and revisit 1990 and extract some externality value for sulfur dioxide that's also already regulated. So we can pick and choose externalities to service whatever particular end we want," and it's curious, because each of these studies looks at different kinds of externalities and makes different judgments about them.

It's not exactly science; there's some subjective voice, some subjectivity that goes into that, but it's also fairly clear that whoever is authoring these reports or paying for these reports has some influence in terms of trying to get at least some of them to inflate or deflate the price. And frankly, my point about all this is, this is completely subjective; you could drive up the value of solar, you could drive down the value of solar, but it's easy. This is one of these "garbage in, garbage out" sorts of ways of analyzing.

Secondly, what's clearly overlooked in almost all these studies are the effects of intermittency, and intermittency is not an insignificant issue. One of the previous speakers mentioned that solar is, over time, relatively predictable. That's probably true. What is not predictable is what's going to happen tomorrow at three o'clock, and what is predictable is what's going to happen tomorrow at six o'clock when some states are still in peak and there's not going to be any solar. So you have to factor in intermittency. You have to look at the coincidence of peak and non-peak. You have to look at what's being dispatched and what's being displaced. If you're displacing relatively clean energy, as opposed to coal being displaced, then the externality value is a whole lot less, and you need to look at it. You have to get to a high level of granularity to really determine that.

Now, I don't want to pick on Maine (or maybe I do want to pick on Maine, since they're not here) but I love what they did in their study. They said, "Well, you know, in New England there's really not very much coal. Let's bring in New York, and all of sudden we have more carbon," and so you redefine the market to pick whatever you want, and it's not like there's an accepted discipline imposed on these Value of Solar studies to prevent that kind of subjectivity or manipulating of the data or however, pejoratively or non-pejoratively, you want to put it, and so that's not a minor problem with each of these studies.

Value of solar analysis also typically ignores the social impact. Every study that's been done on this subject, and I know at least of four of them, has indicated that net meter pricing has a regressive social impact. It is, in fact, a wealth transfer from lower-income people to higher-income people. It is, period. And rarely do you find that assessed in these Value of Solar studies, but it is a social cost and it ought to be assessed. Again, it's part of the selectivity of what externalities I choose to pick and don't pick to put into my study.

And "value of solar" analysis also tends to come from e a very myopic point of view. You're starting off with, "What is the value of distributed solar?" and so then we start thinking, for example, "Well, we're going to create jobs. There'll be a lot of green energy jobs." Maybe that's true, maybe that's not true. We certainly have some indication, given than 75% of all the solar panels sold in the United States have produced a lot of jobs in China and relatively few in the United States. But maybe there's some job impact. But also, what's the job impact of picking a higher cost technology over lower cost technologies? That has a job impact as well, and I was thinking, "By God, let's look at employment. Suppose I think we ought not be retiring coal plants because we're putting too many miners out of work. Let's think about that." But, you don't find these balance. It's, sort of, on net; how many jobs will we create as opposed to what's the overall economic development or job impact of having higher than market prices for distributed solar energy?

By the way, I'm not even counting, when I look at the solar panels, issues like Solyndra, which cost the U.S. tax payers a huge amount of money on the false assumption we have a huge market for U.S. produced solar panels, or the amount of money that Bill and I and other tax payers in Massachusetts lost when we spent millions and millions of dollars subsidizing Evergreen Solar, which after two years left the state and moved all its production to China. So some of these job predictions are at best uncertain, and, as I said, they're not balanced off against job costs. Again, using long-term price forecasts for energy, particularly for our fuel prices, is notoriously unreliable. Let me contrast Minnesota and Maine on this. Minnesota explicitly calls for an annual adjustment, and I'm assuming that one of the things they're looking at is the cost of fuel. Maine assumes, what was it, a 3% or 4% increase in natural gas prices every year for 25 years. Now, what is it in history that leads you to think --

Speaker 2: The Maine study used NYMEX futures in the short run and EIA in the long run.

Speaker 4: The point is, we don't know what will happen with these prices. 25-year forecasts, regardless of who they come from, are notoriously inaccurate. In fact, the only thing you know about those 25-year fuel forecasts forecasts is they're wrong. And, as I said, to be fair about it, Minnesota recognized that, and said, rather than relying on these unreliable long-term forecasts, let's do these adjustments on an annual basis to reflect what's actually going on in the marketplace.

Turning to generation capacity considerations (and some of this also relates to transmission capacity that I'll get into in a minute), number one, generally in these studies (and I am generalizing, there may well be exceptions) they fail to fully recognize the intermittency issue. There's a whole debate about how you calculate capacity. There are system planners that will tell you, "Well, you use probability and you come up with certain numbers, and the fact that something isn't going to be available at a particular time, you look at what's the probability of that and you estimate it," but you've got a couple things here, you know. One is, when I was a regulator, if somebody said, "Well, I'm paying somebody a capacity payment, but that somebody is not callable, not dispatchable," why would I impose those costs on rate payers in that kind of circumstance? So, it doesn't reflect intermittency and it doesn't reflect, not only intermittency, but the degree of unpredictability on a real-time basis, even though over the long term, solar is somewhat predictable, but for purposes of capacity I need to know in real time what's available and what's not, and I need to know how coincident is with peak and to what extent it's not. Generally speaking, these generation capacity considerations don't accurately or fully reflect the intermittency.

Secondly, they fail to reflect solar DG's non-coincidence with peak, and fail to recognize the non-callable nature of solar DG. When we evaluate capacity, you can do all kinds of calculations as system planners do, but one of the issues, particularly for regulators but also for policymakers, is, do you really want consumers to pay based on that, or do you want them to pay based on the fact this is callable, that if I have a capacity contract, I'm going to be called on to either produce or to provide energy at whatever the marginal cost is at that given moment in time or whatever my contract price is.

With respect to transmission capacity, you have a lot of the same issues. Keep in mind, by the way, for both generation and capacity, the load serving entity has the obligation to have, either under contract or own or whatever else, to have both the transmission and generation capacity to meet peak demand. There are no contingencies. That's their obligation. Those are the costs they have to incur as a matter of their legal obligation, so those costs are fixed, really, as a matter of law, and even without law it's clearly as a matter of policy. For example, some of the munis don't have those requirements, but as a matter of policy that's what they do.

On capacity payments, if you're not available when you're called upon, that's a problem.

With respect to transmission, it's absolutely true that distributed generation doesn't rely on the transmission system. to deliver energy into the system or obviously to be self-consumed on premise. That's true. But what DG's impact is on the bigger transmission system is another issue. It may well have an impact, positive or negative. That depends on the circumstances, on congestion, but in terms of capacity, there are certain things about capacity that are pretty clear. One is, whenever new capacity is built, there's a lumpiness issue, and whether you're doing it through large scale or (going back to this morning's discussion) smaller scale incremental projects, there's always a lumpiness, because when you make transmission investment, you want to do it keeping in mind that you want to use this for the long term, so you're going to grow into a lot of this. If you do have to get new right of way, right of way is extremely scarce and you want to maximize the use of it, and so the availability of solar, number one, on two things, is important. One is the issue that Speaker 1 talked about, which is exactly what the market penetration is, how significant it is, but the second is whether that's actually going to be available when you need it, and you don't really know that. Any kind of impact on transmission capacity is largely dependent on the specifics and the technology, and you have to look at this on a location-specific basis, and if you don't do that, then it's hard to make a claim that there's a real capacity value, because in general theory, I'm not sure that there is much, but it's possible. You can argue it, but you need to do it at a highly granular basis.

On the distribution issues often in these studies (and again, not always, but often) they ignore the sorts of issues, and by the way, Speaker 2 in his presentation identified some of them, although not all of them, but there are some real costs. I mean, managing bi-directional flow issues, if you get into having to redesign the distribution system, as New York, California, apparently Minnesota, and I don't know who the other two states you were referring to are, but as you look at those, there are costs associated with that restructuring. To what degree they're driven by solar DG, one can argue. They're certainly not entirely driven by that, but the point is there are costs associated in the distribution system with accommodating it, and transaction costs are often ignored. They weren't ignored in the Mississippi study, as Speaker 2 pointed out, but many of these studies do ignore them, and they ignore some of the revenue attrition issues that are associated with net metering.

Speaker 2 was saying, for example, that revenue attrition, or lost revenues, is not a cost; I don't necessarily agree with that. I think it is a cost. It's a cost in the sense that the system is being deprived of revenue that it needs to maintain the level of the system. Or, to put it in other terms, the value of the grid is being severely underestimated in order to advantage something else. The future of solar impacts I think overlooks this. This is an important point. It's a point that was really made in the MIT study, but pricing existing solar arrangements, absent ties to storage, absent ties to things like incentivizing western as opposed to southern exposure to make it more coincident with peak, incentivizing the use of smart invertors…if you simply subsidize or come up with an above market price for the most primitive use of the technology, that does a positive harm to the future of solar. You're not incentivizing increases in productivity. In fact, you incentivizing the opposite.

And what's really interesting is that it often overlooks (and I've never seen this in any study) the fact that the cost of solar panels have declined rapidly in the past few years, that's a good thing, but, as pointed out by the Lawrence Berkeley Lab, just curiously, installation costs have gone up, which says that something strange is going on in the market. In fact, in the United States now, of the major economies in the world, with the exception of France, we have the highest installation costs of solar anywhere in the world. Why? One of the theories is because net metering is set at such an arbitrarily high price that the solar vendors or lessors or whatever they are don't need to compete. They don't need to pass on declining costs to customers. In fact, they pocket those costs or use the money for marketing or whatever the purpose they choose to use it for.

And then there's the impact of cost distortions. What if (and this is not really a "what if;" this has happened in many cases and certainly theoretically it will happen), as solar DG gets more penetration, utilities are going to relook at the fixed/variable ratios in their rates. We've already seen that in Wisconsin. You see that in some other states that are reassessing it. The more you move costs into the fixed category, even though historically in the U.S. we recover relatively few fixed costs from fixed rates, the more the incentive is for utilities to cover themselves by moving more costs into fixed rates, and what's the impact of that on energy efficiency? That's why a couple of the national environmental groups are taking somewhat nuanced positions. They understand that there is a conflict. Arbitrarily high pricing often justified by Value of Solar studies for distributed solar could well have an adverse impact on energy efficiency.

And, by the way, what's interesting is, we don't know what the price signals that come out of Value of Solar studies do to the behavior of the solar host. I've seen anecdotal studies that suggest that actually what happens is that solar hosts tend to drive up the peak. Why? Because solar tends to die at peak. It's curious; as solar hits its peak, or it starts going down from peak, is when we hit peak demand, generally, across the United States, or sometime during that period--but there's no signal to the solar host that says, "Stop. You're no longer getting zero marginal cost energy," and so there is some evidence, and I think this is something that has to be studied empirically, that in fact is driving up the peak, so it raises serious questions about the externality value and the economic value of solar, but you rarely see that acknowledged in any of these Value of Solar studies.

It's also curious, where you have renewable portfolio standards, if you look at the major renewable resources--wind, large scale solar, distributed solar--solar almost always comes out at the bottom in terms of efficiency, in terms of the cost of carbon reduction, and yet we're paying the highest price for the least efficient product. Why? What justifies that? But for the purposes of understanding Value of Solar is, we need to look at this issue and determine how that affects what the Value of Solar is, because if what I'm saying is correct, it detracts from the value of distributed solar, and that needs to be reflected in any analysis of the value.

And, of course, you also then have a reallocation of fixed and demand costs, because you've got a lot of varying interests that have to deal with that.

Let me just skip to the last slide, which is the concluding thoughts, which are really two. One is that Value of Solar studies rarely if ever look at the opportunity costs associated with spending money on solar DG as opposed to using it on something that could reduce emissions more efficiently or be more efficiently priced, or could incentivize solar DG to be more efficient and more productive. And, secondly, if we're going to use Value of Solar to establish prices, then why in the world don't we do that for coal, natural gas, wind, and every other resource? I don't know what the justification is for singling this out and using this technology for a completely different and, frankly, historically foreign to the way that we set prices for energy in the U.S. Thank you.

General Discussion.

Question 1: I very much enjoyed the presentation, and it's making me think, and I think it's very helpful. But, I do have a question. It's the kind of thing that bothers me about the whole methodology, and it's referring to Speaker 3's chart that shows the numbers stacked up, here. I had mine in black and white, so it's a little hard to map, but I think I mapped it correctly, and if I take that chart with the Minnesota Value of Solar calculation, and I take off the distribution and transmission capacity stories and reserve a component and use only the ones on the bottom, which are the things that would be avoided if I built a new natural gas combined cycle plant, and then I add on my estimate of the externality costs, so I get them on an apples to apples basis here, and I use the Energy Information Administration's numbers, which I looked up so I could compare them here…if I could get that bottom stuff for my natural gas combined cycle plant, I would sign this contract in a minute. These numbers of avoided costs are higher than the cost of the natural gas combined cycle plant for the components that are relevant for that. Now, the total is much higher, because it's got all the other stuff that goes on down but I'm not counting that. I'm just throwing that out. On its face, it looks like there's something wrong here.

Speaker 3: Thanks for the question. I think there are a couple of things to say about that. One is that this is a particular component of the market that we're looking at. We're not saying that solar should not compete head to head with natural gas. This doesn't have a bearing on what's going on in Minnesota around that issue right now. You may know, you probably do, that the PUC has authorized, after a pretty extensive competitive acquisition process for peak capacity that came out of Xcel, a solar project to offer that peak capacity. It's 100 megawatts, dispersed over 20 different locations throughout the entire service area for Xcel.

One of the things that I don't want to have happen in this discussion is that we take completely out of context the different market segments that were competing cost effectively with solar in Minnesota, not to mention the other utility scale or the Community Solar Garden elements. This was intended to be a rate that would work within that segment of the market, the less than 1 megawatt segment, and I don't think I even mentioned it, it was sized to load at 120%. I don't know if that answers your question, but we understood that this price wasn't going to work for every component of the market. We understand that there are other segments, and that solar is competing cost effectively in different segments of the market in Minnesota, outside of where the dual meter Value of Solar would apply.

Speaker 2: Can I take a crack, too? Can we go back to the slide with the costs? Your new combined cycle gas plant won't avoid reserve capacity costs. It won't avoid transmission capacity costs either, right?

And avoided distribution capacity and avoided environmental?

Questioner: Yes.

Speaker 2: Oh. I thought I heard you say you left in six. You left in four.

Questioner: The bottom four.

Speaker 2: I see. I understand. I thought I heard you say you left in the bottom six.

Questioner: I'm only looking at the bottom four categories.

Speaker 3: I'm not arguing. I'm just trying to present each of the market segments and what we were trying to do in each of those segments. Honestly, that's one of the reasons I started with the first slide, indicating what we had done in 2013, and I could walk through each of those segments and where we're at at this point in terms of deployed capacity that's coming online or is in the pipeline that is cost effective.

Question 2: Speaker 4, I appreciated the subtlety of your comments. [LAUGHTER].

But, since obviously, and I understand your perspective—obviously, your point is that it all seems very high, but in any event, you would say that in any event it's going to be arbitrary. The question I have then is, OK, if you wanted a more market structure to be available for rooftop solar, what would you recommend? What would that look like? Because right now it's actually very difficult for individual homeowners, and an interesting discussion would be what kind of markets could be developed and aggregated so that you can actually have rooftop solar participate.

Speaker 4: I think there are a number of things you could do. First off, just on the energy level, in organized markets we know what the LMP is, and I think that if solar customers or solar vendors or solar lessors, whoever they happen to be, wanted to aggregate the solar and bring it into the demand response market or somewhere else, that's one way to do it. Simply pay them for the energy they produce at the LMP. That's what its value is at any given moment in time.

The issue about capacity values or long-term value is interesting. First of all, I would argue that that pricing system actually enhances the long-term value, because that's going to incentivize solar vendors and solar lessors and solar hosts to try to capture more of the peak. They don't now. Most of the solar units in the United States have southern exposure. They don't reflect the fact that in most of the United States, peak is moving further and further back in the day, and so what I think we need to do is incentivize them to capture some of the long-term value.

Capacity value is more complicated, because you could run, as system planners do, all kinds of probability analyses of when the capacity is going to be available and when it's not. But, as I said before, as a regulator it troubles me that if something is not callable, why am I calling it capacity? It's not. It's not there; it doesn't deliver. In most cases in the wholesale market, if you don't deliver you pay the incremental cost that results from the non-delivery. So, if you had a system where some of the solar vendors, for example, aggregated load and took on some of those risks, you'd have more effective market.

But, essentially, in my view, most of the solar vendor and lessors are looking for a free lunch. They don't want to take on any risk, but they want to be paid as if they have all these values without taking on any of those risks. I think we need to use market mechanisms that reflect that, and there's no reason why SolarCity and SunEdison and these guys can't aggregate. They could do that; they just choose not to.

Question 3: I just wanted to follow up on Speaker 4's last point about the opportunity cost of investing in the least efficient resources, which is the end result of what we're doing with these Value of Solar studies. Opportunity cost is an abstract economic term, but let's put it in real terms related to what we're talking about. My friend here has said to me, correctly, that when we look at our environment policy on climate change, we're buying insurance against a potentially very bad result, but we only have so much money to spend on this insurance, and we're already finding out that being able to spend the money we're willing to spend to get the reductions we need to get is a very difficult proposition.

So the opportunity cost that Speaker 4 is talking about here is the opportunity cost of efficiently reducing our carbon output in a way that will maximize the investment that society is willing to make to buy this insurance. And so what these Value of Solar studies are doing are not just abstractly economically incorrect. If Speaker 4 is right, and he is, we're doing something very dangerous, and we're undermining our own effort to reduce our carbon output and the whole reason why we're making these investments in renewables. I just wanted to put, at least, my color on the phrase, "opportunity cost."

Speaker 4: Let me put this in a slightly different context, because Speaker 2 and I, during the break, were wasting what should have been our free time by arguing about this.

One of the interesting things is that the hedge argument, at least conceptually, makes sense. The problem is that when we hedge, somebody is assuming the risk. With solar, to the extent to which this constitutes a hedge against environmental risk or fuel risk or whatever, we're socializing that risk. I think if the investors in solar or the vendors of solar want to do that, great, do it. Don't ask everybody else to pay for it. I mean, hedges are, sort of, uniquely private things. I don't know if they have any system benefits (but they may, to individuals), but if they do, then factor that into your business cost.

If it's a utility doing the hedging, which has captive customers, they are still subject to prudence risk. Regulators are still supposed to replicate what would happen in a competitive market if there were a competitive market, but the solar vendors don't have any of that, and I think they need to act like any other business. But if we pay for "hedging" as a "value" of solar, basically, we're automatically socializing some of these risks. We're establishing some value through Value of Solar studies, and then we socialize the risk. That's a huge leap that I don't think we ought to be making.

Speaker 2: I think that we need to be careful not to blame the ruler for the value judgment on length. Value of Solar studies just tell us the Value of Solar. The questioner's point is, "Hey, look, the value of energy efficiency is higher than solar, so maybe we should spend more money on energy efficiency and less on solar," and I tend to think, in general, that he's right. We've seen these carbon abatement curves that look at a whole variety of different ways to spend money (either positively or negatively spend money in the case of energy efficiency) and emit less carbon. And it's everything from electrifying vehicles to changing our light bulbs to installing solar panels and a thousand other things, and if we were being efficient in terms of how much carbon we can cut for the money, we'd start way over at the energy efficiency side and look up at the bulbs in this room and say, "Geez, we're doing it wrong," and we'd probably never get to PV before we've already solved our 2050 targets.

You're absolutely right, but the problem isn't the measuring tape. The problem is not the Value of Solar study. The problem you have is with the decisions that policymakers have made, and the solution is not to give them less good information, the solution should be to give them more good information. So, rather than say that the problem is the Value of Solar study, I think the problem is that we're not giving enough other studies of high quality.

Questioner: No, you're giving them distorted information. That's the problem. You're claiming that solar has a particular value that other sources of generation also have, but attributing these values, for economic and rate making purposes, solely to solar.

Speaker 2: That's not true.

Questioner: But that's what's going on.

Speaker 2: The Value of Solar does not say that wind does not have this value too, or that some value in the Value of Solar studies applies only to solar. It doesn't say that at all.

Questioner: Hold on. You may be talking about a different Value of Solar study than I am.

Speaker 2: I've read dozens of them.

Questioner: I'm talking about the ones that are used to justify net metering, and that's the issue here.

Speaker 2: But net metering is not a Value of Solar study. They're two different things. One's a policy decision about how to get solar installed. The other is figuring out the cost of that policy, and if your problem is with the policy, hey, I'm right there with you. But then, don't complain about the study that figures out the cost. Complain about the policy.

Questioner: No, I'm complaining about the use of the study, not the fact that you do a study. Studies are great. Information is great, but that's not how they're being used. That's not how it was used in Minnesota or in Maine. So that's the problem. What we're really doing is moving a huge amount of capital away from central station generation, including wind and solar and others, and moving that capital over to distributed generation, when it's extremely inefficient to do that. That's what's going on right now, and if you go talk to the Wall Street people, they say that's a tide coming; you can't stop it. And, unless we get our arms around the economics of this, we're just allocating our scarce capital, which we're trying to use to reduce carbon, in the wrong way and making it harder for us to meet our targets. That's what's happening. It's not the fact that you do the study; it's what the study is used for.

Question 4: This is a question that tries to, sort of, go away from the pros of cons of how you calculate the Value of Solar, but I think the Value of Solar study components that you discuss obviously suggest that it's very far from being a precise science.

So, in some sense the Value of Solar studies are then used to set (I think in Minnesota's case), essentially, the equivalent of a feed-in tariff.

Basically, this is the price at which you will be compensated, which has some relation to the calculated or estimated Value of Solar, or the analysis might perhaps justify the continuation of net metering with all the associated discussions. That strikes me at being treacherous, because of the uncertainties all around the valuation methodologies, and also seems to be missing the point that we generally don't price things according to their value. I think that if markets are somewhat competitive, you don't get the full value. The price gets competed down to cost, and that's my transition.

Germany didn't try to calculate the Value of Solar. It said, "Here is the technology, we think it's going to be important, it's in an infancy stage. We need to create a mechanism that encourage decreases in cost." Prices that are based on Value of Solar risk, I think, then compensating a certain resource independent of how the costs evolve over time, so there is a serious risk of creating a similar backlash to the backlash that Spain experienced, where you just have a decoupling of the compensation from the evaluation of the underlying cost, especially if these programs are successful and costs continue to decrease.

I'm trying to figure out whether there's a way for us to get away from this discussion of what is the Value of Solar and here at the 14 different components, and move to this other program, where we just recognize solar will likely be a piece of the solution, and we should do things that help us bring down the cost of solar. In Germany, utility scale solar cost is similar to the U.S.--a buck 60, a buck 50 a watt, installed. The residential costs of PV installed in Germany is $2 a watt, so, at that cost differential, then we can have a real serious debate about whether it makes sense to install a lot more residential PV. If the cost difference is $1.50 to $5 or $4, then it's a lot harder to do that, so unless we're successful in driving costs down, we're having a real problem, and I wonder whether, ultimately, the policies have to focus on that cost.

Speaker 4: Actually, listening to you, I'd say we almost ought to rephrase this. Instead of studying the Value of Solar as it exists, what we ought to be doing is studying, how do we extract the full Value of Solar? We don't do that. That's not what these studies do. They, in fact, justify, as I was saying earlier, a very primitive use of solar technology that, according to the MIT study, and I agree with this, really stop the progress, or at least halt the progress or are a barrier to the progress, of the use of solar energy. So, when you talk about getting the prices down and making it more efficient, that's what we ought to be looking at, not about how do we subsidize it at a very primitive level.

Speaker 3: I think you made a really good point about this being a piece of the answer, and I think I made that pretty clear a couple of times, both in my presentation and since then, and you brought his up as well, Speaker 2, that we're putting together a bundle of clean energy modalities that are going to drive the distribution grid to development, but it's going to be because it's cost effective, not because it's just being driven by solar. And when we began this process of calculating the Value of Solar, the deal was that we were not setting a price based on what we think is necessary to incentivize the growth of solar in Minnesota. We were developing a methodology to determine its value, so it was based on coming into this without having a bias towards a particular outcome, a particular result.

I think more needs to be done in order to, as I indicated, bundle energy efficiency and demand response. There's a decline in the cost of energy storage. It's still more expensive than if you were to do a value of energy storage that stood by itself. It would be pretty costly, but if you bundle storage with solar, with demand response, with energy efficiency, and then you start to calculate some of the other issues that are driving the development of distributed generation, such as security, such as resilience, such as outage mitigation--those haven't been taken into account, largely, and certainly are not in our calculations of the Value of Solar--but you put all of those things together, and then you begin to look at, like I said, a bundle of modalities that are going to successfully drive the cost, as a bundle, significantly lower than where we're at with the Value of Solar as it stands by itself at this point.

To the previous questioner's point, no, we shouldn't be just isolating one of the clean energy components in this process, because it may not, as it stands by itself, be cost effective, but that certainly was our approach as we went into this. We weren't looking for an incentive or a subsidy to reach a certain price point. We were trying to back into this from a different place.

Speaker 4: But actually, when you read the studies, I think your study is a bit of an outlier. I agree with what you said, but your study is a bit of an outlier, because the others don't do what you're saying.

Speaker 3: They take a feed-in tariff approach, essentially, which is, OK, what's it going to take to make solar succeed and give it that bump, and our approach was, no, we are not going to go into this with the assumption that it has to be incentivized. If it does, it's based on a transparent foundation. So this is what we think the value is to the utility, and if it doesn't make the market work, then another discussion we would have to have is about, what is the gap if there is a gap that has to be filled.

Speaker 1: To try and answer these questions, I think that a way out of this whole problem with Value of Solar debates is to actually have a market system. The allocatively efficient judgment of whether a market is working effectively or not is that the price equals the marginal cost, so if we have a process of competition that actually drives prices down to marginal costs, full encumbered marginal costs, that's good.

What I think the answer to this question is is to create a market where we have carbon taxes, and we add those on to the costs associated with producing power in different ways, and then let individual organizations and individual consumers make choices about which particular method they are going to use in order to power their devices in their house or whatever. Adam Smith, let's go all the way back there--he's pretty much about right about this. What we're doing is we're creating a set of administered prices, and the effect of that is we're transferring risk away from the consumers, the end generators, back to everybody else who has to pay for the system, and that's our problem here, because we're basically guaranteeing a price to people, and we don't even know what the price should be, and it takes all the risk away from buying a system or leasing a system, because you've got an administered price, and you know that people are going to make a particular level of return, and if you go to the German example, the original feed-in tariffs, I think people, if you asked them on an individual basis in Germany, it was basically a financial investment that was a no-lose proposition, a complete no-brainer. They were offering 90 cents, and sometimes more, for a kilowatt hour, or whatever, and for somebody to put something on your roof. I mean, you'd be an idiot to say, "No, I don't want this."

Speaker 2: So there's competition in panel manufacturers, inverters, and in nearly all places where solar is being installed, amongst the installers. We should see costs going down because there's competition, but the other half of that is, if the price that we're paying isn't going down, then we're overpaying, right? It's not that cost isn't going down. It is, as a whole. Installation costs haven't been going down in some places recently. There's a variety of different possible reasons for that, but the issue is, well, are we paying more than we have to to get the solar, and so a number of places have taken different cracks at this. Connecticut does something really interesting with what they call ZREC's, and the way they do it is that they have utilities (one is roughly four times larger than the other), and they said, "Utility A, you're going to spend this many dollars per year for the next 10 years on solar, and you're going to have a reverse auction for industrial and commercial solar, and they're going to bid down the price, and you're going to have a certain number of dollars you're going to spend on it, and whatever that clearing price is, we'll up it by a small percentage, and we'll pay that to residential. Next year you have another auction, a new auction, and that price is lower or higher, probably lower," and this allowed them to tailor the subsidy, and it is a subsidy, to something close to the least price they can get, and NYSERDA does this with their development of renewables as well. So there's lot of different ways you can do it, but that's different than the previous questioner's point.

The current questioner's point is, well, if we're going to subsidize solar, couldn't we at least pay the least amount we need to get the solar? And, gee, we should and we don't. You're absolutely right. Keep in mind that there's some real elegance to net energy metering, and if we move to --

Speaker 4: To net energy metering or net retail metering? I mean, people get those confused. Texas does net energy metering. Most of the country does retail net metering.

Speaker 2: So let's talk about retail metering. We can talk about market-based approaches all the time, but if your meter doesn't capture interval data, then we can't apply that, and if you have a smart meter because the utility convinced the Commission that it was a good idea, and they'd save a lot of money in reading the meter, and the utility isn't capturing that interval data even though they have a smart meter because their retail rates are volumetric by month, then we're missing the opportunity for regulators, utilities, and customers to have the information that they would need to make a rational decision about something like LMP.

We don't allow customers today to even have the information, in most cases, to move to rate structures similar to those being advocated on that side of the table, and until we do, then it's really hard to move to rates like that. So, if you're in a utility region that has smart meters and can capture interval data, even if it's not necessary to capture it for the rate structure the customer is on right now, utilities should be capturing that data and sharing it with the customer so that the customer then can't turn around when we propose something other than net metering and say, "How the hell am I supposed to know if this is a good investment for me when the utility won't even tell me what hours of the day I'm using electricity or not? How could I possibly know?"

Speaker 4: That's a terrific point, but I wish you would have been with me last Monday in Oklahoma when the very same people arguing for net metering argued against AMI, because, "That's a complete waste of money." The fact is, much of the solar industry is opposed to that, because they don't want those signals to be there, and you hit the reason on the head, because then the reason for the subsidy largely goes away. You can only argue for retail net metering if you've got a really primitive metering and billing system.

Speaker 2: Let me turn that around. If you have primitive metering, it's really hard to do anything other than retail net metering, and places that do have AMI, they're the very ones that need to…If we're going to get away from net metering to something else that provides a different, perhaps better, pricing signal, we've got to give utilities, commissioners, and customers the ability to make good decisions. That means we have to start capturing the data before we propose some time-based metering, because you can't make good decision in an economic environment without quality information, right?

Speaker 4: You're 100% right. The problem I'm talking about is that the same people that are selling solar or want solar are completely opposed to that. They don't want smart meters.

Speaker 2: But there's nothing that stops any of the utilities that exist now with AMI from collecting the data.

Speaker 4: They collect the data, that's true.

Speaker 2: But they're not. They're not collecting it.

Speaker 4: I'm not sure that's true, but collecting the data and using it in billing are two different things.

Speaker 2: We can't do the second until we can do the first.

Speaker 3: I'd like to caution against generalizations. The Minnesota Solar Energy Industry Association (MNSEIA), I will just tell you, is very active in the discussions around grid modernization, and not just about that, but about how to reform the Integrated Resource Plan, and how to develop performance metrics that are not in place at this point. We're going considerably beyond just modernizing, doing AMI. There's considerable discussion by all the utilities, at least in Minnesota, and that includes co-ops and munis, about what they need to do to facilitate the development of the distribution grid. Now, solar is a part of that discussion, but we're not the only people that are driving that interest, and the technology that's necessary to make that possible and to create those assets. We have foundational expenses or capital expenses that are going to have to be put in place to support that, and they're going to have to be approved by the PUC. It's part of the reason that Xcel, for example, as we speak, is going after a 5% rate increase in 2016 and a 4.5% rate increase in 2017. Now, I'm not trying to elevate them as being heroes in this discussion, because that's going to have a significant impact on a lot of rate payers that aren't immediately going to get the benefit of some of the technology that they're planning to install to help service their customers and the customer choices that are emerging among their rate base. But there's a lot of motion in this area, and I think it's important. Yes, I hear that from some of my colleagues in other parts of the country around solar, but it's certainly not our position as MNSEIA that we're trying to push back on that technology because we'd like to protect what in our view has been not that successful a mechanism for promoting distributed generation--net metering.

Question 5: Speaker 4, I wanted to ask you a question just because you had been a regulator, I know, a long time ago. I was talking with another former regulator, and what seems to us a little bit unusual in this conversation is that it, sort of, assumes that we would ever have perfect information as regulators. When I think about the decisions that I've had to make in the last couple of years, whether it's on rate cases or mergers or AMI recovery, there are a lot of estimates, there's a lot of prediction, there are a lot of competing witnesses who come in with different studies.

It sounds like from your critique that you're focusing on the fact that we don't have an exact science on some of these measures. As I've been following Value of Solar proceedings, what seems really interesting to me is that it was a response to criticisms, that net metering was just too simple and didn't take into account the costs on the network from net metering and from solar, and so here was an effort that said, "OK, well, let's separate this out. Let's make the beneficiaries of this actually have to pay for the impact that they have on the network by separating this, and they pay for the electricity that they use off the network, and then they'll get paid, and we just have to value what that is." And, honestly, this shouldn't be a really difficult thing for regulators to do, because we do this all the time. We're always asked to make judgments about what something is worth, whether a rate increase is appropriate, and to weigh job benefits, economic development benefits... It's not always just an energy factor or a pure economic factor that comes before us.

So I just wanted to throw that back. I'm just trying to get a sense of why this Value of Solar elicits such a strong response about why it's out of the realm of what regulators do, when it seems to me, from my experience, that what regulators do is they take a lot of information, often competing information, and then they have to use their best judgment to figure out how to take that into account and come up with a decision that weighs a lot of factors, and in our statute there are environmental considerations, there are consumer considerations, and there are efficiency considerations, and we have things such as a renewable portfolio standard, so we have, in our case, a policy that's supposed to encourage this. So if you take all of that together, I'm just not so sure that the job of the regulator is to be as precise as it seems that this discussion is implying today.

Speaker 4: There are, sort of, two levels of answer. One relates to my own personal frustration. This debate is exactly the debate we had 30 years ago, and we screwed it up. We screwed it up, and what we ended up doing was moving towards market mechanisms. I mean, states on the east coast and the west coast determined avoided costs that were much higher than market. Alan Schreiber and I, in Ohio, probably made the opposite mistake. We made it much lower. But nobody got it right, and we were constantly searching around in the dark, and then ultimately we all decided to move, as a policy, towards market-based approaches, and once you did that some of the stuff began to smooth out because the incentives were better aligned.

And so the issue isn't so much whether the regulators get enough information. It's what regulators' bottom line is, and what they do is where there are markets you want to let them flourish and enable them, and where there aren't, you want to replicate what the results would have been had you had a viably competitive market.

The problem with Value of Solar studies is, first off, they give you whatever information the authors chose to use. I haven't seen a single study where the analysis is complete. Part of it is because they aren't paid enough to do complete analysis, and gather complete data, and part of it is because some of the authors of these studies have an agenda. The agenda may be to kill solar; it may be to promote solar, but they have an agenda and that drives things. So I don't think you can rely on subjective studies. You can make whatever values you want come out.

Is solar a good thing? Yes, solar is a good thing. Is distributed solar a good thing? Yes. What we want to do is we want that product to be sustainable over the long term, and we don't want to throw cash at inefficient use of that resource, and the question is, how do we develop the mechanisms for trying to do that? As I said, the Minnesota study comes as close as any of these (I don't think comes close enough) to at least trying to point in that direction, because it doesn't try to dictate a number. Most of the studies do the exact opposite. The Maine study is the worst, of the ones I've read, because it just comes up with this number. How do you come up with the value of solar being equal to just about double the retail price? I mean, there's no logic to that.

Speaker 3: But what is interesting to me about this approach (and I haven't looked at the Maine study) is that it at least does break out the different components and then give regulators the opportunity to decide--do I want to include this or not? For instance, if you take the issue of transmission that we talked about earlier today, it's possible that smart investments in solar in the right location could actually have some benefit. And the same for distribution upgrades that we're all facing right now. Now, it's going to take judgment to figure out whether this benefit is going to be in the near term or whether it is going to be in the long term, and I think that if you're the regulator you're going to look through all that.

Speaker 4: Nobody disputes that. That's absolutely correct. The question is, at what cost, and how do we get as close to the optimum as we can? That's the question. It's not, "We want solar, therefore we'll pay whatever price." Nobody wants to do that. (I shouldn't say "nobody," there are people who want to do that, but I can't imagine many regulators want to do that.) So, the question is, how do you put in place a system that does two things: one, it prices the resource appropriately; and two, perhaps most importantly for long-term Value of Solar, is it provides incentives for solar to do the kinds of things Speaker 3 was talking about — tie it to storage, tie it to wind, tie it to energy efficiency incentives for smart inverters which have other values beyond the solar? Create incentives. These Value of Solar studies, for the most part, don't even discuss that. They literally don't discuss it. So, to my view, this information, if it's of value, it's like a fractional value of what you really need to have to understand it to try to get the right policy.

Speaker 3: You're suggesting there should be a separate subsidy source to capture all of those possible opportunities?

Speaker 4: I'd like to get rid of the subsidies. Look, what's interesting and I think we all agree, is that the cost of solar panels has declined rapidly. I don't think there's any dispute about that. That's a great thing. Let's make sure that value gets passed onto customers. We have in place in 44 states in this country a system that makes sure that value gets captured by somebody other than the consumer. Why? Do you see any of the Value of Solar studies addressing that question? No.

Speaker 3: Well, ours does, and you've mentioned this --

Speaker 4: OK, I will agree. Minnesota has the best…

Speaker 3: …I mean, it is absolutely clear to everybody that went through our process and to the PUC that the cost of solar panels and installation is coming down. We know the cost of financing is coming down. We know that there are other variables in this that are going to change. As far as coincidence with peak, we have utilities in Minnesota that are winter peaking. Go do a Value of Solar for them, and it's not going to look like what we laid out for Xcel. We're willing to accept that there are going to be some differences in even in the same state based on the load profile that is generated and used with our methodology.

So I think, again, it doesn't benefit the discussion to have glib generalities. We're trying to make these adjustments to develop greater cost effectiveness, and it's not just about the reduction in cost for panels and financing, but there are going to be other variables that, as I indicated, are going to shift from year to year, given the specifics of each of the utilities that are involved. So, again, trying to be as specific as we can and make market adjustments going forward, I think, is a good model.

And I would like to ask this group, going forward, to actually pay attention and give some precise feedback. That's kind of what I was asking for earlier, when I walked through page by page by page, the way we did, our calculations. This wasn't just, "Oh, well, let's just throw some figures out there and nobody's ever going to look at it." We fully expected to have some really robust and vigorous debate with a number of parties, which we have, but I think it does no service to the discussion to not get into some of the specifics and break them out, because that was part of our approach.

So, ok, when we get to this stack, each of those components we ought to be able to justify. If we think there's this kind of coincidence with peak for Xcel, what is that number? What does the ELCC really look like? What does the peak load reduction really look like? Those formulas are there. It is not speculation. We just didn't say, "OK, well, let's throw a number out there and see what people think about it." So I'd encourage people in this meeting, if you haven't already looked up our report as a result of what I laid out before, to do that, and get in touch with me, and I'd love to have an ongoing discussion, because it is only after having that kind of vetting process that we will get to the kind of value that we really need to have for solar.

Speaker 4: You can do all kinds of subjective studies, and some of them are far better than others, but ultimately what you want to develop is a mechanism that makes solar viable on its own without subsidies, and in such a way that whatever the benefits of declining costs are, they get passed on to the consumer, and make it fit in the marketplace. It's about developing a mechanism, not saying, "What's the external hedge value and let's put a price on that." That's an arbitrary way of doing things that, frankly, no matter what you do is going to be wrong. You could be too high, you could be too low, but one thing you know for sure is, you're going to be wrong.

Question 6: Where there is an organized market and you can look at the LMPs, even at a particular pricing node, and you can load weight them by what's generated for each hour at that node, so you know exactly the energy value, and then you could add a capacity component which basically gives, say, the market clearing price of capacity times an adjustment to reflect the intermittency (there's some good work at PJM on this—what is called the effective load carrying capability. You basically give the capacity value about a 45% haircut to create the solar capacity value), and you can add these numbers, and then you can add a transmission avoided cost, but if you added those numbers up in PJM, you'd be adding $38 and $6 and $7 for those three buckets, prospectively, and then you'd be at $51 a megawatt hour, which is about five cents. In the organized markets, would that be a fair way of evaluating the value of distributed solar (plus the environmental attributes, let's put that in another category)? But, just in terms of the non-environmental aspect, is that a fair way of looking at it?

Speaker 3: I think that you're articulating some of the components, not all, that we incorporated in our stack of values. So, again, I agree. Computing the ELCC is one of the computations that's critical, and I'm glad that you included the environmental elements. I just have to say that MnSEIA, our organization, and pretty much, I would say, a majority of commenters going before our PUC, lost the discussion about the economic Value of Solar. I mentioned that in my slide, but we didn't get everything we wanted, and going forward we'll have some more of those discussions, and there will be some other things that get included, and there are going to be some adjustments to some of the elements that you're talking about, on a year-to-year basis. I don't know if that answers your question from our standpoint.

Speaker 2: For me, I think it's important to make sure we're clear about whose value we're talking about, right? So, if we're talking about a citizen who lives in the neighborhood where the PV is installed, then we can look at the full societal value, including non-energy benefits, externalities, and so forth. If we're talking about the utility value, well, we don't include a number of those things. If we're talking about what's the price we should pay to the customer, then the Value of Solar sort of gives us an upper bound. We shouldn't pay more than the Value of Solar. We might well pay less.

My personal opinion on what we should be paying customers for solar is this: To the extent that the electricity generated on the roof is powering devices in my home right now, concurrently, that's energy efficiency. The utility has no business being involved in that at all. As an American, I'm entitled to generate my own anything and use it within my property, and it's not anybody else's business, so in a sense that's retail rate, because just like when I install an efficient light bulb, I'm avoiding paying retail rate for those megawatts, for that energy I'm not consuming.

For the energy that I export onto the grid, well, then all of this long list of costs is Value of Solar. Again, that's the upper bound, but we don't have to choose that number. At a minimum, sure, LMP plus generating capacity is probably the minimum. Anything below that, sort of, seems patently unfair. But what Mississippi did recently is they said, maybe we should be paying something like LMP or system lambda, because they're not always in RTOs, plus an adder of, I don't remember what the number was, three cents, and that three cents captures, sort of, a list of these items, and we're not going to drill down very carefully, and that's like a reasonable price, and next year maybe it's two and a half cents.

So I think that Value of Solar should be seen as the cap. We shouldn't pay more than that unless, from a public policy perspective, we just really, really want solar even though, as the earlier questioner pointed out, it's not a savvy investment as a carbon-cutting scheme. But the Value of Solar guides us on, what's the most we should pay, and for the energy that is exported onto the grid, we may well choose to pay less than that full value, in the same sense that, in any transaction between two independent parties, there's a producer surplus and a consumer surplus, and if it lands anywhere in between, that's a reasonable market clearing price.

Speaker 4: Let me respond to a couple of points. The LMP, I complete agree with. The problem with capacity, whether it's transmission or distribution, is, how do you want to define capacity? If you define it as some sort of probability thing, which is what I think your numbers were coming from, you can do that. I have to say, as a regulator, as I said earlier, I wouldn't probably pass those costs on to the rest of the customers, simply because it's not callable. If it's not callable, in my view, I don't care what the probability is that it will be there when I need it, it has much less value than it does if it was really there, and cutting a fraction of it…I mean, you can play games with the numbers, but I think it has minimal value on the capacity level. And, quite frankly, it could have more value, and Speaker 3 gave examples where it was tied to other things, and I think the solar business needs to be put to the challenge of trying to add to that value. Giving them capacity for something that's not callable actually takes away their incentive to do that.

In regard to what Speaker 2 just said, I don't see quite the same distinction he does between whether you're self-generating or exporting. I mean, there are slightly different issues, but the problem is that the system--the distribution system, the transmission system, the generation--has to be there for peak. That's what it's planned for. It's the legal obligation of the load serving entity to provide all that, so if that's the case, then that doesn't change by whether the solar panel is working or not working. If the solar panel is working it's great, but if it's not working, that doesn't change the utility's obligation. The idea that somehow you're absolved from paying your share of the costs of the system, where those costs are fixed and they're essentially required by law, but I can avoid them by putting a solar panel on and passing them on to you who doesn't have a solar panel--there's something wrong with that system.

Speaker 2: But how is that any different than if I install energy efficiency?

Speaker 4: It's very different. For one thing, I can plan for it. I know what you're doing. I can see, long term, exactly what's going on. With the solar, you could be gone, who knows when you're going to available…

Speaker 2: I'm planning on the sun coming up tomorrow. I don't know about you.

Speaker 4: You can plan it, but you don't know if that's going to happen.

Speaker 2: No, the sun is going to come up tomorrow. It may be cloudy, but if it's cloudy we're not going to be in a peak day anyway, so this idea that you can't plan for it is a little bit much.

Speaker 4: No, but the point is the system has fixed costs that are incurred to serve you no matter what the circumstances are. It doesn't matter whether you're producing or you're not. It's a completely independent variable, those costs, and if those costs are fixed no matter what happens, and they're mandated to be incurred, the argument for avoiding them I think, is extraordinarily weak. Now, if you're not using the system because you're using less energy, you could still end up paying the fixed cost, but it depends on how you allocate fixed and variable charges. What happens with the solar is you're really creating incentives for utilities to move much more towards fixed charges than the kind of fixed variable…

Speaker 2: I think they have those incentives regardless of solar, and ultimately that's up to the regulators to push back on.

Speaker 4: Well, of course it's up to the regulators, and if you run into the situation where you've got capital-deprived distribution companies where it becomes a problem, the regulators are going to have to respond to that in one fashion or another. So I think that really needs to be thought through. The fixed-variable issue is very much tied to how we price solar, and I don't think you can avoid it.

Speaker 2: Well, I guess I would just respond by saying that we're seeing fixed-variable rate making issues all over the country, and it doesn't seem to be particularly well correlated with the amount of solar penetration in a state. I think that they're both happening; it's not clear to me that the threat of solar penetration is driving that rate making request from utilities, rather than the reality that load is flat even if solar isn't growing, and --

Speaker 4: I think you're confusing two different things. It's the degree of solar penetration and the fear of where it's going, watching states like Arizona, where you've got these pitched battles going on on this, and just talking to regulators in other states they're seeing what's going on. And, frankly, the chair of the Arizona commission is very outspoken. Get this right before you have a lot of penetration, because it's going to be damn difficult to fix it later. So I don't agree with you. I think it's anticipation, and frankly I hope the penetration goes up. That would be a good thing, but what we need to do is be ahead of it in terms of our rate making and our pricing.

Question 7: So, my question follows on a point that Speaker 4 raised in his presentation. It strikes me that one of the biggest changes since the PURPA days relates to this--are we really using our computing capacity, our communications capacity, to actually harness the value that we have identified in solar? Smart inverters are one way of doing it. Can we make things more dispatchable? Should we pay a different rate if things were more dispatchable? So I think that that's really an important question, as we look to the question, how do we get to a point where we're actually harnessing energy values and any capacity value? Should we be looking at this more holistically?

And then, the follow-on to that is that, of course, is that for solar or any other energy, it's all part of a bigger ecosystem which includes the tariff structure. In California, there's the idea of a matinee pricing tariff, which is, in the same way that theaters have lower prices during the middle of the day to bring people to the seats, we still are, for the most part, for commercial, industrial, agricultural entities, pricing things so that the highest prices are charged between noon and six. Now, this made sense during the Mad Men era, but we've know that for a long time demand has really been declining between noon and four. The peak is really between four and six, so one of our concerns is that it could create crazy incentives to actually have commercial and industrial customers do things after six, when prices are low, in order to maximize their individual value. We've also seen several instances in which CAISO has actually asked utility scale solar to turn off or turn down, because there wasn't enough demand on the grid, and so we're looking at, how can we really align demand as well as figuring out how do we better harness the supply? So I was wondering if any of the panelists had any comments on those points?

Speaker 3: Well, I'll take a relatively easy question. Maybe people would disagree with me about this answer, but I think the smart phone app development right now that's already underway for customers to control their appliances--essentially an onboard energy management system--I think that has some implications in terms of how utilities are looking at AMI and other bidirectional feedback mechanisms. There's some fear about, if we do AMI, is this another stranded asset within two years or three years, because the IT, the application for controlling this, is already out of our hands, or at least that data is already in the hands of customers? I'm not sure. It makes the discussion more complicated, but I think it's a good discussion to have, and I'm glad that folks at your level are asking those questions. I think sometimes we have this fixation with technology, as if we're saying, "oh yeah, let's just do AMI, let's do all this other stuff and it's going to work," and we're not actually looking at the market and seeing how it's preparing to replace or do some of those functions without having to make those kinds of costly installations, so it gets put on the individual customer.

Speaker 2: I think it's really important to separate commercial and industrial customers from residential customers when we talk about things like time of use or more complicated pricing structures. I'll give an example. I won't name the university, but at a research university in the Boston Metro area, the finance folks, not the energy folks, but the finance folks, noticed that the electric bill of the university in the last three, four, five years had gone up substantially year after year, and what they figured out—incorrectly, as you guys will quickly understand, was, "It's these kids with their laptops and their cell phone chargers that are driving up the price of electricity at our university by like 30%, so we've got to crack down on that." They're residential customers from an electricity perspective, because they have that level of sophistication. What they didn't understand was that the university had built an enormous number of new chem labs for biomedical research, for general chemistry, and those fume hoods were putting just millions of cubic feet of 65 degree air out the window and, of course, replacing it with air that needed to be chilled or heated. It was the chem labs that were driving the electricity consumption, not the cell phones. And so, we can ask residential customers to change their behavior based on price signals, but we have to remember that customers don't really understand the difference in electric draw between their electric oven and their television, and if they don't understand the different usage of their appliances, how can we possibly expect them to change their behavior rationally and reasonably in a way that gets us closer to efficient usage? Instead, what we're going to get is people doing really silly things and grumbling about their power company all the time, and that's not really a good outcome for anything.

Speaker 4: Right now, there are so many things you can do on an automated basis.

And, one of the things that, I guess, is frustrating to me is that you have the solar vendors who have an interface with customers that are using it in, frankly, primitive ways. They're not bundling these guys. They're not working in energy efficiency, which would increase the value of the solar panel. They're not doing any of those things. So, I think --

Speaker 2: Those products are largely independent of each other, right? The value of EE is irrespective of whether or not there is PV on the roof, or battery storage.

Speaker 4: Well, I mean, the problem is they don't have incentives to do that.

Speaker 2: So, you're arguing that we should pay the solar developers even more money?

Speaker 3: Wait, wait, wait. I mean, when you bundle energy efficiency, demand response, with solar, you immediately shrink the payback for solar. It's the same phenomenon as doing energy efficiency retrofits in buildings where you come in and you do the low-hanging fruit, or you do the short-term payback, but you don't do the HVAC system, and then you have to come in later and say, "OK, well, yeah, I guess we better now try to figure out a way to, in order to reduce carbon emissions, dig deeper into the retrofits," but there's an internal cost effect that I think operates there that does actually incentivize installers to look at energy efficiency.

Speaker 4: But that's the point. I think that siloing of solar is not a good thing. I think what it ends up doing is it drives up the prices –

Speaker 3: Well, I agree with that, but I don't think it's happening.

Speaker 4: -- it increases their profits at social cost.

Speaker 3: I agree that it could happen, but that's not the experience that we're having with our installers and developers in Minnesota.

Question 8: I just wanted to make three quick observations. I think for a price to be a value, you've got to have a willing buyer, and in the case of Minnesota, we don't have willing buyers at the Value of Solar that's been calculated. One question is, what would a rational buyer be willing to pay, given other alternatives, for that energy source, and that might be another way of looking at it.

My second observation is that the avoided environmental cost assumes, really, in my mind, that nothing else is happening to improve environmental outcomes with other forms of generation, which isn't the case.

And my final observation is that I like to think about it in terms of like a Rubik's cube example, and I could go buy a Rubik's cube at Barnes and Noble and pay $25. That's the price I'm willing to pay and they're willing to sell it for, and I leave the store with the Rubik's cube and $25 less in my pocket and everyone is happy. But if I were to step back and calculate the *value* of a Rubik's cube, I might think about avoided alternative toy cost for my child--like I don't have to buy them Monopoly or Connect Four--and might come up with something similar to the $25, but then I might think to myself, "Well, hey, isn't there an educational value that I can also ascribe to this toy for my child? What's the educational value for my child of having a Rubik's cube?" and I might say that that's another $20, so now I'm up at $45, never mind that I was willing to pay $25 and someone's willing to sell it to me for $25, so I think that's one of the problems with some of the values that we place on solar.

Speaker 2: The Value of Solar study says that this is the most you should pay, and in your case, with the Rubik's cube, it sounds like the most you should pay is $45. If you can get it for $25 you absolutely should, and my opinion is the same with solar. It sort of tells us, given our values, whether they're utility or societal, we're going to put in the numbers and we're going to say, this is what we value this resource at, and that tells us the most we should be willing to pay for it, but it doesn't say that's what we have to pay for it. If we can procure it for less, there's no reason why we shouldn't.

Speaker 1: There are two sides to the market there. Barnes and Noble have got to be willing to sell you the thing for $25, so they're happy with the $25 and no Rubik's cube, and you're happy with your Rubik's cube and no $25. So you're valuing the Rubik's cube implicitly as worth more than $25, so both sides to the thing have got to be happy.

The problem with the imposition of a price for a value of solar and telling people that's what you must buy it for off somebody who's excess generating is that you don't have a free market anymore. You're forcing people to buy something which they might not ordinarily buy because there's a cheaper alternative for them. That's my problem with this and why I don't understand why we can't just go to the free market plus carbon pricing.

Question 9: I just wanted to get back to something, and I think Speaker 2 and Speaker 4 both mentioned which, is that with Value of Solar, are we also saying that we should do value of all resources--value of nuclear, value of the grid, value of central station solar, value of wind? And, if so, then what do we do with all this information? You're talking about a huge undertaking. Why do we do just Value of Solar?

Speaker 1: I think one of the interesting thought experiments here that we might all engage in is, if you started with a blank sheet of paper and said, how would you design a power generation transmission distribution system which relied on whatever generating assets that you wanted to, from ground zero, what would it look like? How much distributed solar would be in it? How much centrally generated coal, gas, whatever? And you would design it if you could so that it was the most cost effective, taking into account the environmental costs and also the financial costs, and I suspect there wouldn't be an awful lot of distributed solar in there.

Question 10: Picking up on a point that Speaker 2 made about how we don't want to pay more than we have to for solar, I think a lot of people are uncomfortable because these Value of Solar studies create such a high price that people then use in these net metering applications. And so my question is, if (as I think the data suggests, but rather than argue about facts, just assume that the data tells us this) it's about 50% less expensive to build solar at a utility scale farm than it is to build it in a distributed case, then by providing this very high price signal to encourage rooftop solar, aren't we incurring an enormous cost, this opportunity cost, by not having those resources devoted to utility-scale solar so we can get all the benefits of solar at a fraction of the cost?

Speaker 2: The answer is generally yes, to the extent that we're talking about the cost that society as a whole bears. So the panel gets installed. Somebody paid for it. Could we have done something else that had a lower cost? A great place to see this is in the NYSERDA RPS compliance reports over the last five, six years, and year on year they do some auctions, they buy some wind and a couple of other things, and you can see what their effective dollars per megawatt hour price is to procure these renewables. And then, the Governor of New York said, "We're going to give solar a shot in the arm. We're going to procure a whole bunch of solar. We're not going to change, by and large, how much money NYSERDA spends to procure resources. We're going to change what they buy." And, as everyone here would expect, they procured substantially fewer megawatt hours for the same amount of dollars when they started buying solar instead of wind and a few occasional opportunistic resources. No question. From a society perspective, rooftop PV is expensive relative to other non-emitting renewable resources. That's true.

If we look at utility cost, remember the utility is not paying for the PV, so when we're thinking about how to handle utilities, that's a different matter, because the utility isn't spending any money to procure the PV. The cost for the utility, not the revenue requirements, but the forward-going costs to meet its load obligation goes down when customers pay for PV out of their own pocket and install it on the roof. So, from a society perspective, yes, I agree, it's not the most efficient public policy to reduce emissions, whether you care about carbon or anything else. But, if you're looking at forward-going utility cost, it is a bit clever. And so, again, the Value of Solar study gives us a handle on that, but it doesn't tell us what we ought do.

Speaker 4: To change this question just slightly, let's assume it's utility scale but not utility owned, so it's somebody else's capital; it's not the utility's capital, then ask the same question.

Speaker 2: Well, but the utility is still writing a check once a month to the generator to buy the electricity in a PPA. Right, so the utility doesn't pay a fixed cost upfront, they pay the cost every month, but they're still writing a check. It's still a cost on their books.

Speaker 4: They're doing that in two ways to the solar PV vendor. One is the lost fixed cost, and the other is they're writing a check for the excess energy.

Speaker 2: A few states have utilities write checks for excess energy, but in fact many don't, and the percentage of and the amount of dollars that they are actually writing checks for is remarkably low, because most customers are pretty good about not overbuilding their system, because most states have rules that make it less attractive to do so. And, in terms of cost, again, the utility loses revenue and we still have to make sure we're recovering costs, but the utility doesn't spend any money, or very, very little money associated with billing, when a customer installs PV. The utility is not writing the check.

Comment: Speaker 2, you're suggesting that it's better to have cost shifted to other customers than to have utilities have to spend less money.

Speaker 2: If the Value of Solar exceeds retail rates, the cost is not being shifted to other customers, and I'm not suggesting what's better or worse. I'm not arguing what we should do.

Session Three.
Clean Power Plan: Critical State Implementation Decisions

As states develop their implementation plans and various affected parties formulate their positions on how those plans should be designed, a dominant issue is whether the plan should be mass based or rate based. On the one hand, a mass based approach could allow for compliance efforts to be carried out across a wide geographic area, which would lower overall costs. Rate based approaches, on the other hand, allow for more explicit resource decisions, and may better protect, if not enhance, the value of assets controlled by existing clean energy suppliers. Players in the REC and SREC markets are likely to be quite cautious in trying to determine which option is most favorable to their portfolio and to the long run impact on renewable credit markets. Demand side management and efficiency advocates may see advantages in a local rate based approach with better control as a tool for compliance. Would a rate based approach allow too much discretion that would turn compliance plans into a Christmas tree for various special interests? Would a mass based approach compromise local or state by state control and be insensitive to local impacts? How should states, in developing their SIPs, analyze the question of mass based or rate based approaches to compliance? What is the chance that different regulatory choices would result in a balkanized grid with unintended consequences for electricity markets and environmental protection?

Moderator: Good Morning, everyone. We have a really important session this about the Clean Power Plant. I think as most of you know, this is also the day that the Paris talks ended, or the day after. One of my colleagues was actually in Paris and texted me a picture this morning where she spoke on a panel at Paris. So this is clearly an issue where it's involving people across the world, down to state regulators and utilities and interest groups across the country.

So what we're going to do today is actually we're not going to debate whether the Clean Power Plan is legal or not. I think we did that about a year ago. We're not going to look into the politics of this, but we're going to actually get down into some of the more detailed issues about how this is actually going to work, and the issues that states are facing in determining that, over the course of the next nine months. I think September 2016 is the first deadline where states are supposed to either identify how they're going to approach this or seek additional time.

And there are a lot of different issues at play, but one of them has to do with a choice between a mass based or a rate based plan, and it's interesting. I have a senior in high school who's taking calculus right now and doing derivatives to figure out rates and all of that. We're not going to have any equations today. So that's the good news. In fact, I don't think any of our panelists even have any slides for you. But we are going to try to get into a detailed discussion, to really grapple with what this means to pick the different approaches that are before us.

Speaker 1.
It's great to be back with you. I'm going to try to do a couple of things. I'm going to try to, first of all, explain what my organization is doing, because that will give you some background for some of the comments that I make and how we come to some of the understanding we do about what the state of play is for the states as they work on the Clean Power Plan.

I was also asked to explain some of the basics of the Clean Power Plan. For those of you who have delved into it, you can take any of a hundred or a thousand different issues and spend 10 minutes or 10 hours on any of them, so we're going to try and do in just a few minutes some of the basics of the plan, but in doing that, in talking about some of the basics, also try to weave in some of the issues that are really important that shape our thinking, and then we can start thinking about what the market implications are for those and what states are looking at as they move forward, and hopefully that will lead into the next three speakers that you're going to hear from this morning.

So first, a little bit about my organization. We're not an advocacy organization. What we do is convene folks to try to help them either understand an issue or try to figure out what the best way is for them to move forward. We work a lot in the area of the Clean Power Plan, and so we've got three different groups that we help to facilitate. One is a stakeholder group in the Midwest called the Midwest Power Sector Collaborative. It really brings together generators, mostly coal fired generators, as well as state officials, environmental NGOs, munis, and co-ops. We try to get everybody in the room. It's a group of about 40 people, and that group has been working for over four years trying to figure out, first, when we knew there were going to be some carbon regulations coming, what those might look like and how folks in the Midwest might respond to them, and what might be a Midwest kind of approach to a rule, and then, as the proposed rule came out, and then now the final rule, I have been analyzing them, making comments on them, and some of the comments of that group and one of the groups I'll talk about not only ended up in the final rule but actually were credited by people at EPA for being in the final rule, and it really plays on our discussion today.

And then we have two groups of states that we help to convene. In the MISO footprint, a group where state officials of both the environmental agency and the public utility commission from each of the states in the MISO footprint have been invited. This group has been going for over a year and a half. Very good participation from those states. And the idea there is to help to both educate and talk about what the proposed rule is, was at the time, make comments on it, which this group did, and then also continue, now, with the final rule, and try to work toward what compliance options might be.

And then recently, within the last six months, we started working with a group of state officials in the PJM footprint as well. A similar kind of principle to the group in the MISO footprint, Again, environmental and energy regulators from those states. Not other outside folks in those meetings, unless the state officials want them to come in and talk about a particular issue, and so we've had people from the RTOs come in and talk about issues in both of these groups. We call these "no regrets" processes, because, again, like today, we're not arguing about whether the rule should be in place or not or whether it's constitutional or not. We don't talk about any of that. We just talk about, if states have to comply with the Clean Power Plan, what are their options, and what are the compliance options for each state? How is that going to work out for them? And, again, they operate under Chatham House or we like to call them Vegas Rules, so what gets said in the meeting stays in the meeting, because I think there's a real value in states not only getting an understanding of what the process is and what the rule says but also being able to talk to other states about it and see what their neighbors are going to do.

With the mid-Continent states, we partner with the Bipartisan Policy Center, and with the PJM states group, we partner with the Nicholas Institute group at Duke University. Each of them is doing modeling for the respective groups. States are going to want to rely on a lot of modeling. Not a lot of states right now have the money to be able to do that.

We heard yesterday about the $30,000 to million dollar options of trying to do lots of modeling and sensitivity runs. A lot of states don't have those kinds of dollars right now. And so at least there's some directional help from the modeling that's out there. We caution people to look at lots of different models, because models all have different assumptions. They all have different inputs. The models themselves are different and sort out different things differently. And so states should get the most information they can about that.

One of the big changes between the proposed and the final rule involves trading. If you remember, in the proposed rule, the only way that states could work together on a multistate basis, or that utilities or generators could work across state lines, was if state A and state B decided to get together and do a rate based plan and blend their rates. Now, I'm an optimistic guy. I have to be. I'm a Cubs fan. But within the meetings, the thought process was that that's just not going to happen politically. If you're a state with a lower rate, how do you merge your rate with a state with a higher rate and then explain that to everyone, even though there may be models and charts that show you that that's a long-term good solution? We just didn't think that was going to happen.

And so a lot of the comments that arose as part of discussions in both the Midwest Power Sector Collaborative and the MISO states group was that there's got to be a way for states to keep their individual targets and still allow for some kind of a trading program. And it wasn't just us that was saying that. That was coming out of other groups around the country as well, and they all had different names for it. You heard, "common elements," or "trading ready, or my personal favorite, "the minimum capability requirements," which sounds like something out of a dating website. But the idea is still the same. There's a minimum level of common features in these plans, and then the affected entities within those states can trade outside, and some of the issues of reliability and cost can be helped by trading.

So states now are working toward the first deadline, which is September of next year. At that time, states will either have to submit a final plan or ask for a two year extension to take them to September of 2018. I suspect that the vast majority of states will ask for an extension. There's no real downside to them doing that, in most states. To file for the extension is really a fairly low bar. You don't have to declare, at this point, whether you're going to be a rate based state or a mass based state. You just have to say what you're thinking about, what you're working on, and what your process is to try to get you to where you need to go.

There are states that have said that "While we're going to ask for the extension, we aren't going to declare which direction we're going," because they have either a legislative or a regulatory process where they're going to need those two years to try to get that done. Some legislatures only meet every other year. There's at least one state that we're working with that has a regulatory process that will take them up to two years just to do the regs through their Commission and through their state environmental agency.

So those kind of considerations are out there and then we'll get the final plans in 2018. But we will know something, because states, if they ask for an extension by 2017, then have to tell EPA what they're thinking about in terms of rate or mass based plans. So, where we talk about rate versus mass and what states are going to do, it's really pretty early to talk about those issues right now. Although you are starting to see companies talk about whether they favor rate or mass, and then, if you just follow the trade press on this, you're starting to see states that are individually coming out and saying what their preference is, although most will couch that in terms like, "We have a lot of work left to do. We have a lot of people left to talk to. We've got outreach to do. We've got modeling to do. But at this point, we may be leaning rate or mass."

There's a thought out there that most states will go towards mass based. There are a couple of reasons for that. One is that air regulators, for the most part, are the folks that are writing these plans, as we heard yesterday. Air regulators are used to mass based programs. That's what they work with. Companies, affected entities, are used to mass based programs. They have worked with trading in acid rain and other criteria pollutants for a number of years. It's a process people are familiar with. But that doesn't mean that that works best in every state.

So what we're going to do now is just go through a little bit about mass based and rate based approaches, and I'll try to stay out of the deep weeds as much as I possibly can.

So how mass based trading works, just at a real basic level, is states are given a target that they have to hit that's translated into the amount of tons of CO2 that can be emitted in their state during any particular compliance period, and then for each of those tons that can be emitted in order to meet their targets there's an allowance that's given to that state. So a state has essentially a bucket of allowances that they can then allot how they choose to different affected entities, and I'll get into that a little bit more, because it's not just as easy as saying, "Well, we'll just divvy them out. We'll split them up by the companies that are out there." There are a lot of different options there, and they have some impact on things that we're all going to talk about in terms of what makes the most sense for markets and for the companies as well.

So at the end of a particular compliance period, company X will come back to the state, and they will have a calculation of all of the tons of CO2 that they emitted, and they are expected, for each of those tons, to give the state an allowance that shows that they, A, were given one, or they purchased an allowance that will meet the amount of tons that they emitted. It's a very simple kind of process from that standpoint. The accounting of it is a pretty easy process to do. The emissions are already measured and already reported to EPA and to the state environmental regulators. So not a real difficult process from that standpoint.

For the air regulators' purpose and for our purposes today, just in terms of a basic discussion, they don't really care where those allowances came from. And EPA doesn't really care where those allowances came from. And if you allow trading in your state--and take a hypothetical state that will allow trading and has a mass based program, and assume there are other states out there that have trading allowed in a mass based program--a generator in one state could trade with a generator in another state, and as long as that was recorded and met all the basic requirements for recording that allowance, it really doesn't matter to the state that's receiving that if it came from your state or from a state half a country away. So all of the talk about whether states are going to work on multistate programs, and whether it makes sense to do something on a whole footprint, it's a little less important under the final rule than it was under the proposed, rule because generators have a lot more options in terms of where they can trade from.

Now, in terms of the allowance distribution, this is an interesting issue, because states have a lot of options here, as I mentioned. They can auction the allowances. This is the done in the RGGI states and has been done in the RGGI states. So a company would need to try to figure out how many allowances they're going to need, make that decision, and try to buy allowances through the auction process. The states can give allowances out based on historical emissions or based on some other formula that they want to come up with. The EPA basically says to states, "If you're coming up with your own state plan, and you do a mass based program, you can divvy out the allowances any way you want to."

Now, what that also does is it creates some pressure in states, because when you say that you can divvy out this allowance that has a monetary value, there's a trough that forms with a line that forms in right in front of it, and lots of people will then come to you and say, "Well, you need to recognize us for the good work that we do here," whether they're a renewable energy source, or whether they're a renewable efficiency source. We heard discussion about nuclear plants and their impact on the market and low carbon emissions there. There are a lot of issues that are tied up in that, and so states are going to be facing that, and already are having discussions where people are coming and talking about that if they look like they're going to be on a mass based program.

The other kind of basic option that they can do is what they call set asides, where they say, "All right, we like renewable energy programs, for example, so we're going to set aside X number of allowances for that. We're going to start this program and you can all come and compete for those allowances, and if we don't get enough competition for those allowances, we'll just roll them back and give them back out to the affected entities," but it's a way to try to distribute these without just directly giving it to non-emitting sources or to different kinds of emitting sources.

You can have a program out there where we allow people to compete for the allowances.

So, allowance allocation for people that are considering mass based programs is probably one of the two biggest issues that they're facing right now (and the other one I'll get to in a little bit).

Rate based trading is different, and it's more complicated than the mass based trading. So, in rate based trading, in each of the affected units, each of the generators who are emitting carbon have to meet a certain rate, and that rate ratchets down during the course of the compliance periods between 2022 and 2030. And so, for example, gas has a different rate than coal has, but each of the units is going to have to meet their particular rate target. And so people will look at it and think about the difference between rate and mass and the impact that they might have. If you're an all coal state and you're using a mass based approach and you retire a coal plant, there's now a lot of allowances that are out there that you have given out that they now can use to sell or do something else with in the marketplace. If you're in the same situation with all coal with roughly the same efficiency and you're a rate based state and a coal plant closes, it really doesn't change your rate at all for your state. And so states are looking at all of those options and seeing what might work better for them.

So at the end of the compliance period, the affected entity, the coal plant or the gas plant, will have to come back and go to the compliance option and the state and say, "Our plant now meets the rate," but they're not going to meet the rate, because the way that the rates are set up right now, very few gas plants right now (and none by the time you get to the end of the compliance period) and no coal plants now meet the rates that are out there. And so they're going to need something else to offset and try to bring that rate down. And what they do to bring that rate down is use what are called emission rate credits, or ERCs (another one of these great acronyms).

And you guys are familiar with RECs. An ERC is kind of similar, except we're now talking about a voluntary program. We're talking about something that's a credit for some non-greenhouse gas emitting function. Renewable energy and energy efficiency are the two big buckets there. And so what will have to be done is that the state will have to set up an ERCs desk, or an emission rates credit desk, and a process for people to come in and say, "My program deserves to get X number of these credits," and if they're granted, then those are credits that are also marketable as well. There are also credits that can be generated by the plants, as well. As I said, some gas plants now will be ahead of the mark. They can generate some credits that can be traded in the marketplace as well. And then there's yet another bucket of credits that are out there that are called "gas shift ERCs." I'm not going to get into the formula for it, because I would lose everybody and you'd go running into the ocean whether it's raining or not. But that's another bucket of credits that are out there.

The ERC process is not something that's been done before, so it is something where people are going to have to look at is and say, "All right, does this make sense?" With renewable energy, it's pretty straightforward, because you put out X amount of renewable energy in your plant, and that's already measured. Those are things that we already look at. It's a little less straightforward with energy efficiency--and we all love energy efficiency, but we all have our own ways of counting it and measuring it and verifying it, and there are going to be, I would predict, some challenges to energy efficiency emission rate credits as they start coming through the marketplace. It's *caveat emptor*. So if you're the generator and you bring in an energy efficiency emission rate credit and it's later found, either by the state that you're bringing it to or by some kind of legal action (which can happen with these) that it's not valid, it's on you.

And so what you may end up seeing in a market situation is different kinds of ERCs, the same way, if you're familiar with offset program, there are different kinds of offsets. There's kind of like the gold standard offsets, and then the ones that are a little sketchier out there, if you're buying them in the marketplace. You may end up seeing kind of a good or bad situation as well. So just another thing to think about with rate based approaches.

New nuclear power now is going to be credited under the final rule, though it wasn't under the proposed rule, so there are a lot of states in the Southeast that have new nuclear plants that are scheduled to come online and, as they do that, they will generate a lot of emission reduction credits.

The one thing that states are thinking about right now, and what's important to them is that it's important to know what everybody else is thinking about and what everybody else is doing, and that's why these groups that we talked about are so important, because if I go rate based and I'm the only state, not only around me, but if there are only a few other states in the country that are doing rate based, and the only reason all of us are doing rate based is because we think we're going to be long in these emission rate credits, who can I going to sell them to, and what's the value of that emissions rate credit going to be? And so those are things that states are also thinking about now as they work through this process.

There's one more issue that is really important, because on the mass based side it's something that states are thinking about, and that's an issue called leakage. Now there's nothing like just coming off a nice breakfast and having some talk to you about something called leakage, so we'll try to make this as gentle as we can. But with respect to leakage, the way that we've all thought about it, either from an air regulator side or from a PUC side, is that we've created some law on our side that's going to force generation to go into another state. That's kind of traditionally how we thought about a leakage. This is different. What leakage means as it is talked about here in the EPA rule is that we've got something in our plan that's going to cause new generation to come online at the expense of old generation and strand assets out there that are going to have to be paid for by rate payers and create an unfair market advantage for new gas coming online, for example.

And so the states that are choosing mass based programs have to think about this issue, because they have to do one of three things. They either have to bring new sources into their program (EPA is not mandating that you do that. They're just saying that if have a mass based program, you can bring new sources into your program. Then that takes care of the leakage issue as far as EPA is concerned.) The second way that you can handle leakage is by doing some set asides for renewable energy and essentially for existing gas, and there's a formula set up for states to do that. And the third way is that you can show EPA that there's another set aside formula that you have that will take care of that. Or you can try to convince EPA that leakage isn't an issue in your state. I'm not quite sure how you would do that. I haven't seen anything yet that would demonstrate how they are suggesting that you'd do that, and states are kind of working through this issue, because if you bring these sources in, you get a few more allowances that are given to you, and states are trying to weigh whether or not that's enough to justify bringing those new sources in. So that's an issue that states are thinking about too as they go through this rate versus mass discussion.

So hopefully that teed up enough issues. I'm looking forward to the rest of the discussion.

Question: Are there specific states, based on their generation, that would much more clearly benefit from a rate based approach?

Speaker 1: Yes. And I think the other folks will talk about this as well. Like I say, if you think you're going to be long on emission rate credits, because maybe you're got a relatively new set of gas plants, so they're more efficient. Then you are going to generate a lot of ERCs early on in that process. If you've got new nuclear coming online, that's another way that may be very good for generating ERCs. Or you may just have a lot of plants that they look at individually, and you're not worried as much about trading. You just think, "This is the easiest way for us to get to it in our own state, and we're not thinking about all the other states out there and a trading program. We're not as much worried about that."

So maybe the Southeastern states, the South Carolinas and the Georgias and Tennessees that have not only new nukes that have been contemplated but are actually in the queue to come online, they may not care. They may think that they're good enough to be able to justify that with themselves. So then they're not as worried about being on kind of a rate island there where there aren't any folks to trade with. The question for that becomes if you are thinking about it over the next 10 or 15 years, does that still play out as you get out past 2030, because the rule doesn't end then? You have to keep doing compliance every two years after that. So the question would become whether they're looking at that long term. But, yes, there are states, whether or not they go that way, where just on their face that seems to make some sense for them.

Speaker 2.
Thank you very much. I don't have a lot of answers today. I have lots questions. Speaker 1, I think, set it up nicely. There are lots of balls in the air at the moment, and what I will try to do in the next few minutes is give you my perspective on what it's like in the trenches right now with Virginia in the development process of the Clean Power Plan, and while details of each state are different in some respects, I think Virginia's experience, what we're going through, is generally representative of most states that are seriously tackling the Clean Power Plan.

So let me start off with a few impressions of Virginia's thoughts about EPA's final Clean Power Plan. Our governor was very pleased. Governor McAuliffe went from being a skeptic of the proposed rule to a supporter of the final Clean Power Plan. Virginia will be submitting a plan, and as Speaker 1 said, we will likely be one of the states asking for a two-year extension, but we reserve the right to submit early, and in Virginia there are many reasons we might want to submit early--by '17 rather than '18.

We think the final rule is much fairer than the proposal was, in so far that all states are subject to the same limits on coal and natural gas combined cycle gas units. Don't let that blended rate that EPA sets forth fool you. Really that's just a pro rate of the standards for coal and natural gas, but each state is really subject to the same rates.

We also thin--and this is important--that the final rule is much more legally sustainable than was the proposal.

The bottom line in Virginia is that everything is still on the table. Nothing has been decided and no substantive decisions have been made with respect to any aspect of the Clean Power Plan. Our decisions will be informed in some measure, in large measure, probably, by our ongoing stakeholder process, which is well underway. Just about every state is going through a rather elaborate public process with respect to Clean Power Plan development, and Virginia is no exception. We've just completed a 60-day public comment period; although it's a formal period, we're still taking comments when people send them in. We've completed six listening sessions held throughout the state. We have reached out to vulnerable environmental justice communities, which in Virginia include our coal communities in the Southwest part of the state. We continue to have one on one meetings with stakeholders. Basically, any legitimate stakeholder who calls me up will get a meeting with me and my staff, and we find those very informative. There's a lot of stuff that can be done in these one-on-one meetings, lots of frank discussions that sometimes can't take place over in large meetings.

But we have also commenced a facilitated stakeholder process that has 14 participants representing a variety of interests, ranging from our investor owned utilities, such as Dominion resources and AMP, to our co-ops, such as Old Dominion Cooperative. We also have affected single asset entities at the table, like Tenasca. The Natural Resources Defense Council is at table. So are energy efficiency, renewable energy interests and coal interests, and the Virginia Manufacturers Association, and we also have representatives from the environmental justice community at the table also.

The first meeting of this stakeholder group was held last month, and there will be four more meetings and the next meeting will be held next Tuesday, which should be very interesting. The meetings will address major issues, starting big, and then getting into more detail. Sort of like peeling back the skins of an onion.

The group will discuss basic issues first, such as, should Virginia adopt a state measures approach or a emissions standards approach?

If we choose an emissions standards approach, that's when we get into the rate versus mass question. Should we have a rate versus mass program?

If we go with rate, how do we address evaluation, measurement, and verification issues? All those issues may sound relatively easy in theory, but they're incredibly difficult for an agency to administer, especially an agency like DEQ in Virginia, where Virginia does not have a strong existing infrastructure for energy efficiency or renewables or for RECs. We have a voluntary REC program, and it's not something that we deal with.

If we go with a mass program, do we include new sources? I haven't heard that raised yet, but that's a big issue for our utilities and the NGOs. Do we auction or allocate our allowances? That's an issue Speaker 1 mentioned. If we allocate allowances, how should we do so? And if we do allocate, what type of set asides do we create, if any? How do we deal with the leakage issue which Speaker 1 mentioned?

And, finally, should Virginia just adopt one of EPA's proposed two model rules? One is for a rate-based program; one is for a mass-based program, and they are both presumptively approvable by EPA. It could cut back on a lot of red tape if we like the details of those model rules.

Our stakeholder meetings are professionally facilitated and open to the public, and we expect the press to be at our meeting next week, for better or for worse. The group will attempt to reach consensus, but the proceeding is still valuable even if we don't reach consensus, because we'll learn all the participants' positions--fire tested, so to speak, in the crucible of a debate with those of opposing positions, and I'll get into why that's going to be important in a second when I talk about rate versus mass in particular.

But even if we do reach consensus, I just want to make clear that this is not a negotiated rule-making. The Governor will reserve his prerogative to perhaps go against consensus if he feels that's necessary. There might be some points of consensus. It might be impossible to do within the timeframe necessary. I mean, we don't know. We'll just have to see. But it's not a negotiation process. It's for the information for the Governor. He will make the final call at the end of the day.

Factors that Virginia will be considering when developing our Clean Power Plan--none of these factors I'm going to list to you should surprise you and I think they're ones basically all states are grappling with. First of all, we want a plan that meets federal requirements. There's no sense drafting a plan that EPA isn't going to approve. We're got to look at the environmental benefits. It sounds like a no-brainer, but you have to put it on the list. Some people get wrapped up in cost. It's not just cost for us. It's also environmental benefits as well. We have to make sure that our plan complies with the compliance deadlines that EPA has set forth. We will be looking, obviously, at cost effectiveness, whatever that means. We'll be looking at electric grid impacts, impacts to low income and vulnerable communities. We'll also be looking at reliability and asset impacts. That's something that EPA requires states to look at as we develop our plan. We will be looking at the need for legislative or regulatory action in our state, and, as Speaker 1 mentioned, various things take various amounts of time. We want to make sure we can get something done on our deadlines. We look to legal vulnerability. We don't want to propose something that is illegal or that will likely get thrown out by the courts. We will be looking at state and regional interactions. It's just sort of a smart way of saying we're going to be looking at interstate trading options, and I'll get into more of that in a second. And, finally what will be important to me if not everyone else, is plan administration and implementation considerations, because we've got to have something we can implement.

I'm going to turn to a few of Virginia's likely compliance pathways. As I said, everything is still on the table. No decisions have been made. Especially with the respect to rate versus mass, which is one of the primary things to consider. Personally a mass based program would be much easier to administer—as Speaker 1 mentioned, we've used that with the acid rain program. We know how administer such a program. We also wouldn't have to deal with some of the measurement and verification problems that come with the rate program.

However, despite those factors, Virginia will be looking extremely closely at a rate based program as well, and let me explain why. Our stakeholders in Virginia are now solidifying their positions on rate versus mass and making them public. Our major utility, Dominion Resources, came out last month in favor of a dual source rate program based on its expectation of high growth. It believes its growth numbers are anemic for what we're going to experience in Virginia. They also favor a rate program because of the availability of something Speaker 1 mentioned, these gas shift ERCs. Dominion has two very large, very efficient existing natural gas combined cycle units that have not come online. Don't ask me why EPA did that, but there's a belief that those will be ERC cows. They'll just be generating ERCs, a lot of them, and we haven't done the math on it yet. And, finally, Dominion has a very large nuclear plant that's on their drawing board. It's not nearly as far along as Vogel or the plants in South Carolina or in Tennessee, but it is something that, according to the IRP, they would like to have online by 2028, although that it has a long way to go. It hasn't been approved by our state corporation commission yet, or anything like that but they want to keep that viable.

On the other hand, our environmental NGOs, the Natural Resources Defense Council, the Southern Environmental Law Center, and I think some industrial interests, favor mass based program with new source components in order to cap emissions. It's a much more certain program, and I know, in particular, that NRDC feels very strongly about this. So does the SELC. So we have those interests to contend with.

And, finally, just to fill out the playing field, our environmental justice representatives oppose any type of trading at all, because they're fearful of the creation of emission hot spots. So that's an issue we're going to have to deal with as we go forward.

Turning to some major issues the state will be dealing with, many of them Speaker 1 or I already mentioned. If we do a rate based program, how do we deal with the evaluation, measurement, and verification issues? For a mass based program, do we include new sources? If we do include new sources, do we use EPA's new source component? Do we attempt to justify some other method, which EPA will allow us to do? How would we address EPA's leakage issue? Do we just take EPA's model rule, which might be the easiest? We'll have to look at that. Should we auction or allocate allowances? If we auction, we probably need to get legislation from our General Assembly, which will be very tricky for us. On the other hand, if we allocate allowances, on what basis do we do so? Based on generation, or based on load serving entities in order to mitigate the cost of their customers? That's something that our munis and co-ops would definitely like, and our investor owned utilities aren't quite so hot on that. And what, if any, set aside should we create to foster renewable energy and energy efficiency and the like? Those are things I'll be looking at carefully.

We'll also be looking at interstate trading options. Presently we're involved in three groups of states looking at the feasibility of interstate trading. We're working with states in the southeast, with the Nicholas Institute. We're working with PJM states. And we're also involved in discussions with the Northeast states and some other states. That's not quite as active as the other two groups, but it's certainly there, and it's comprised mostly of RGGI states, I would think, and California. RGGI is certainly something that we will be considering, but with the auction issue it might make it difficult for us, because would have to auction our allowances to join it. These discussions on interstate trading have been going on for a while but they're still in the fact gathering stage.

There's a lot of game theory here. States would like to know what other states are doing, but at the end we're going to be all the victims of timing, I think.

We face some big challenges in Virginia developing the Clean Power Plan. While our Governor likes the Clean Power Plan, our General Assembly is not nearly as supportive. In fact, our General Assembly session starts in January, and House Bill number two (it's a bill from the Republican leadership) would limit the Governor's CPP authority and require General Assembly approval of any rule. We also have legislation that's been introduced that would require the state to join RGGI. I don't think that has a chance to pass, but you never know. So we have legislation all over the board, and it will be an interesting session.

The other big question we have which is, I think, one that pertains to a lot of people in this room, is, how do we devise a least cost plan? Least cost to whom? I think it would be impossible to come up with a plan that's least cost to everybody.

And, finally, and this is what scares me, we may just not have enough time to develop or consider sufficiently good data on which to base a plan. (And this is something that someone mentioned yesterday.) Regulators always get imperfect data, so we'll do the best we can.

In conclusion, we have a lot of issues to work through. I'll use a cliché here, that we don't want the perfect to be the enemy of the good. Nobody's going to get everything they want in our final plan. It's just not going to work that way. Also, so much is going to change between now and the next 15 years. At the end of the day, we want to develop a plan that's not going to chain us to 2010 solutions. We want one that's going to be flexible enough to deal with the world as it will be in 2030. But I think we want to develop a flexible plan. We don't want to be tied to solutions. Thank you.

Question: You mentioned two ends of a spectrum. One is auctioning off allowances. The other is giving them to the utilities, and perhaps to some EE participants, or something like that. Are there sort of out of the box other ways that the state could distribute allowances that in Virginia's case don't require the legislature's approval but aren't simply giving them utilities or auctioning them off to the highest bidder?

Speaker 2: Well, I mentioned that one allocation would be to distribute them to load serving entities. One question that we really haven't addressed yet is the extent of the authority of the Governor and the state Air Pollution Control Board in Virginia to act without legislative approval, and we don't have all those questions ironed out. The state air pollution control over Virginia is very plenary. It's very broad. And we have done trading programs in the past. So we suspect the Board has the existing authority to promulgate mass based trading programs. We've done different allocation schemes in the past as well. When you get past allocation schemes that involve generators directly, you move into more of a gray area as to what the authority of the Board is. And those are questions we haven't all sorted out. Those are some things we hope to deal with and have the parties address in our stakeholder process.

Your question gets into the whole question of set asides as well. We've done set asides before, but once you start moving away from the control of units for pollution purposes, when you get into other, say, social issues, it gets a lot grayer as to what our state air pollution authority may be.

Speaker 3.

Good morning, everyone. The theme of my talk today is, this doesn't have to be complicated. I knew I needed to overtly state the theme. otherwise you would never get it. So. this doesn't have to be complicated. My company is a utility owned by the customers that we serve. We serve Minnesota and part of North Dakota. Minnesota is very progressive and active on carbon regulation and utility regulation to really reduce CO2 and add renewables. So that's a lot of what governs our load. North Dakota is very business focused. They're concerned about cost. They place a high value on their energy industry and the jobs of that industry and the economic benefits that arise from that. And they're interested in self-determination and not necessarily having determination from Washington, D.C. and what they should do for environmental outcomes.

So, there are different political situations over the two states, and the thing is, we have great relationships in both states, and maybe you wouldn't think that would be possible, but we actually do. We have investments in economic development in North Dakota that have created really good relationships and a win-win outcome for us.

I'd say, as a company, we are agnostic on fuel source. We don't care what fuel we use to serve our members 50 years from now. But we are zealots when it comes to cost. We do care very deeply about what the cost is of providing reliable service to the membership. We have long supported, going back several years, a market-based approach to reducing carbon dioxide in the nation's coal fleets, and we've been working, even back at that time, with the Brattle Group on a market based approach to curb CO2 emissions, and the reason we support a market based approach is that it's organized. It's the most cost effective way to handle this, and it allows specialization. For a state like North Dakota, if you're going to specialize in coal energy production, the only way to get there is to trade and to participate in the market. So we see that benefit. In Minnesota, they're active on legislating and regulating CO2 and renewables and energy efficiency, as I mentioned.

And the Clean Power Plan, we think, brings sort of a sense of calm to the country that, "Hey, this is going to be regulated," and it maybe reduces the sense of hysteria in some of the states, where states felt like, in the absence of any federal action, they've got to be more aggressive. Now we've got an organized plan and framework for dealing with CO2. So if there's a benefit to us, it's that in Minnesota, the sense would be, "The federal government's got this. We are reducing CO2 emissions. We don't have to go after the utility to increase their costs with other mandates."

North Dakota is litigating on this, but they're active in developing a state implementation plan (SIP). So they're engaged. And I think North Dakota sees the SIP as an opportunity to formulate a plan that allows North Dakota to continue to specialize in coal fired energy production. So trading, we expect, we will be a part of that SIP. Now, North Dakota is going to work on developing that plan with an eye toward preserving its industry and its competitiveness, and we're engaged in that. They will choose the path, whether it's rate based, mass based, state measured, whatever it is, with our input being part of it, and we expect to support whatever path that takes.

However, today, from my perspective, I'll just give you where I sit on the issue of rate-based and mass-based approaches. It's really difficult to understand how the math will work for rate based outcomes in North Dakota. North Dakota is 4,000 megawatts of coal. In order to cover all of that with enough ERCs to emit at the current levels from those coal plants, you are talking about 6,000 megawatts of new wind in the state. Just massive amounts of new wind. And what's the impact of that on the dispatch of the existing coal fleet? You might have totally reduced the need for some of those ERCs, because you'd have to shut down some of the coal fleet if you added that much wind. So I'm not sure that that is the best approach and the best math.

If you look at our load curve, we have a lot of energy when it's windy in our part of the country and, yes, we plan to add more wind, like 600 or 700 more megawatts, to meet Minnesota's renewable energy standard. But the time when the energy is the cheapest to us is when it's windy. There's lots of energy available in the market when it's windy in northern MISO, and we expect that to continue to be the case. So we don't need 6,000 megawatts of new wind. So the math just, it doesn't work.

And not only that. If you're going to rely on neighboring states to give you some ERCs so you don't have to add 6,000 megawatts of wind, I don't think we're going to choose a rate based plan to make that happen. And if they do choose a rate based plan, I think it's likely that a lot of those states are choosing it because they're generating ERCs for their own purposes within their state, not for the purpose of exporting ERCs. And so it's a whole different picture than the allowances, which I expect are going to be much more freely traded across state lines than any ERCs would be. So it's hard to see how a rate based plan would go.

Now, we don't have a point of view that North Dakota and Minnesota need to choose the same approach--rate based, mass based, or state measures. They don't have to be the same. But we don't like a state measures approach for Minnesota, and the reason why I say that is we don't have emissions sources in Minnesota. We are concerned that if they pass a state measures approach, that has kind of a blanket application to all load in the state, with cost being given to all load in the state. Well, that's kind of a reaching through to the coal plants in North Dakota. We don't think that's fair or appropriate. That's one thing we'd be concerned about in Minnesota.

But other than that, we really don't care whether the states choose the same method, which might surprise a lot of people. But we do prefer that, within MISO, that there's a lot of commonality. MISO has done a lot of studies on the benefit of multistate trading and multistate approaches. If all the states, for example, in MISO choose an allowance-based approach, you're going to have a lot of liquidity in allowances, and not only that, transparency in the price and competition. Everything, we think, is going to work better, to the extent that you can get a lot of states choosing the same method and having allowances trading across state lines and having some commonality in MISO. You really are getting at what we've been advocating a few years ago with Brattle.

Now, looking at the goals for North Dakota and Minnesota and the requirements of the Clean Power Plan, under a rate based standard North Dakota has to reduce CO2 emissions by 45%, but they end up with a goal of 1305 pounds of CO2 per megawatt hour. That's the highest that the math will allow us, because they don't have a combined cycle unit today in North Dakota. So 1305. Minnesota has a standard of a 40% reduction under a rate based approach. 1213 pounds of CO2 per megawatt hour is the standard. So, significant reductions for both states when you look at rate based.

But what about mass based? I think that's more likely. The standard is a 37% reduction, mass based, for North Dakota. So, a little less stringent. You've got to get down to 21 billion tons of CO2 emissions from 33 million. Minnesota, though, has a 25% reduction under mass based. So, again, less stringent than the rate based approach. They're dropping from 28 million down to 23 million.

It's really interesting for us to see that at the end of this standard in 2030, Minnesota might be a bigger emitter of CO2 than North Dakota, and we wouldn't have expected that to take place if it was just up to the states. Our priority on the SIP, then, is that we want to see state implementation plans, not a federal plan. There are things we don't like about the federal plan, and I'll mention just a couple of those today.

And that state implementation plan not only should be developed, it's got to be a plan that can be improved. So you got to deal with things like leakage, or you won't have the SIP be approved. We have to pick the right path to minimize cost impacts, and trading is a huge part of that. The only way for North Dakota to continue to specialize and to keep its industry intact is to trade. And under a mass based plan, leakage is a complication, but we think there are ways to deal with that.

One thing we really don't understand about the federal plan is that the federal plan talks about how there's an incentive that they're concerned about that would dispatch new natural gas combined cycle over existing natural gas combined cycle, because existing plants are part of the cap and have allowances and such. So they talk about giving some of the allocations of allowances to the existing natural gas combined cycle units, and I don't understand how that helps the leakage issue, because you still have the opportunity cost. Even if you have the allowances as an existing natural gas combined cycle unit, you have the opportunity cost of being able to sell those allowances into the market if you choose not to run. So you're going to add those to your offer price as a power plant, and it will make you less competitive against new natural gas combined cycle. So maybe somebody in the audience can help explain how that helps. I don't think it does, sitting here today.

The mass plus new source complement is kind of attractive because it is clear, and we don't have to do set asides. North Dakota can give all of its allocation of allowances to existing coal plants to preserve the fleet as best it can under that plan. So from that perspective, it's attractive, but they didn't give you much room in there. I mean, it's like 3% of your allowances get added to the mix if you go with existing plus new source complements. So there's not much of a sweetener there.

A few notes on trading. Again, we've have long supported trading. We want to see an embedded CO2 price signal in the already developed energy markets. We'll have a hedge on that, because we're going to get 55% of our allowances or more to the coal plants in North Dakota, so that there's going to be a hedge. But we do think it's the best approach to minimizing cost and reliability impacts in MISO. Under mass based trading states can allocate or auction allowances. We favor allocation. We think that's smart. We think there are plenty of incentive for renewables to develop without getting direct allocation of allowances in North Dakota, and the same for combined cycle. As long as we can address leakage, it really shouldn't be an issue.

But when you look at the offers that we will do for power plants into this market, we start with our variable costs and our variable costs might be a variable O&M charge. Say $5 a megawatt hour. There's variable fuel cost, which might be $18 a megawatt hour. So we're offering our plants in at something like $23 a megawatt hour. Wind is getting offered in at zero or negative, depending on the PTC status. So wind is going to always run, as long as a transmission grid can get it to the market. It will be curtailed if the transmission grid can't. Wind is always going to run first, but we're at $23 per mWh. Now, if you add some CO2 value to that, either an opportunity cost value or a real cost of allowances, that could be $12 a megawatt hour, so now you're looking at an offer price of $35 instead of $23. So that's where you're going to see a shift in the dispatch of the market. Some gas units will come into play, depending on the CO2 price and what happens to the offer prices.

The concern, though, is, will we know what the CO2 price is. We will know it's $12? And when the market starts, there's a huge leap in the first three years in terms of reduction of CO2 emissions, and people are going to be sort of hoarding allowances and preciously guarding them. Will we even know what the price is on the first day of this market? I think that's a difficult question. So we should support a transparent, liquid exchange for CO2 allowances across the country.

One kind of final point, and then I'll draw my conclusion, is that when you look at a mass goal for the state of North Dakota, I mentioned that they emit 33 million tons of CO2 a year, and they've got to get down to 22 million tons of CO2. It's a 12 million ton reduction. Now that feels like a huge leap for North Dakota, and we know it's daunting and it's going to change the industry in North Dakota. But when you think about how many allowances are allocated nationally and how many might be available, this is going to be a huge market. I look at the numbers. For example, the state of Texas. They're going to have something like 180 plus million tons of allowances available, allocated to the state of Texas. And they've got to reduce, too. But 180 million tons. That compares to North Dakota's 12 million tons of allowances that they need to be a net buyer of if they're going to keep the industry intact as it is today. That's just Texas. I think there's going to be a pretty active market. And Texas has lots of opportunities for gas and renewables. So I think there will be a pretty active market and a lot of opportunities for a state like North Dakota to specialize.

So, just in conclusion in terms of what we support and where we are at, we're going to support whatever North Dakota comes up with for its SIP, but you can kind of see where I'm thinking that the rate based approach is a really steep hill to climb. Mass based looks good, especially when you look at how many allowances might be available from other states. But we support a robust supply of allowances. We don't want states to hoard them. We want them to freely trade. If Minnesota or other states exceeds their goal, they should monetize the value of that by trading allowances across state lines. So we push for free trading, trading ready plans, and full allocation of CO2 allowances to coal plants in North Dakota. We do support others' decisions that lead to surplus allowances in their states. That's how this plan is supposed to work. It's trading ready for a reason. And that's why EPA chose this. It helps reduce the cost of it. We do support an exchange for allowances for price transparency and liquidity, and we do acknowledge that trading might be the only way for North Dakota to specialize in coal based energy production and have it be cost effective. Thank you.

Question: Both in Texas, where I come from, and North Dakota, we're living in this parallel universe where they don't think coal is going to change, but I've heard a lot of discussion of conversions and combined cycle repowerings. Is anybody in North Dakota thinking about that as a way to take the industry forward, or is it all driven by coal?

Speaker 3: When I think about repowerings in North Dakota, for us it wouldn't actually be a repowering. It would be a retirement of the coal asset and then a replacement with a new combined cycle unit, because the efficiencies of that are much better than if we actually repower the existing plant. It's going to depend on how this market develops. I think the attitude of the players in North Dakota right now is to develop the SIP, let the market unfold, and if it's going to involve trading, then prices will determine decisions on asset disposition.

One thing we're concerned about is the federal plan. If you retire a coal plant, then three years after you retire it, you no longer get any of the allowances. Well, that's not a very good incentive to shut down a coal plant, and we should be encouraging people to look at retirement if it makes sense, and that's not a way to do it. So we don't think North Dakota's SIP will look like that. And that's another concern about the federal plan.

Question: In thinking about North Dakota and keeping the coal plants alive, which everybody wants, might you comment on where you think those coal plants fit in the kind of supply stack relative to other coal plants in MISO footprint?

Speaker 3: That's a great question. One advantage of the North Dakota facilities that we operate is really low variable cost. And they might have more staying power in a market that is kind of sorting out who's going to be most competitive and who's going to survive in an era of carbon trading and carbon prices. So it might be an advantage to have really low variable cost, and one of the reasons for that is we've got mine mouth plants. So by having mine mouth plants, for example, Coal Creek Station, half of our coal costs is actually a fixed cost. So when you look at our offer price, we have a life of plant coal contract with the neighboring mine. Our offer price is based on the variable cost component of the coal, not the fixed. Whereas for most power plants that we've been involved in elsewhere or aware of elsewhere, you've got the transportation of coal and the contract cost of coal, which tend to all be variable. So, in the stack, we think it looks pretty good, as long as we can avoid congestion, and I think it will show some staying power.

Speaker 4.
Great to be with you all. Just in terms of where wind energy is right now, let me give a little bit of background. The growth has been very strong. As most of you know, it's been also been unsteady, partly because of the PTC (production tax credit) being on again, off again. We could actually get a more stable PTC, possibly phased out over time, but we're kind of looking at the 2020s being really driven by carbon, and wind being, we hope and expect, cost competitive in that environment in the next decade.

With our cost down by two-thirds in the last six years, and with, I think, reliability really proven, when you have some states like Iowa at nearly 30% of their electricity from wind, even if you don't know anything about the grid (which, of course, everybody here does) most lay people can say, "OK, well, there's a way to operate grids reliably with a lot of variable resources on them."

We agree generally with EIA's analysis that finds that wind energy will be the majority of cost effective compliance with the Clean Power Plan, and that's not just because wind is zero carbon and low cost, but also because of the geography. You look at the upper Midwest. You think about North Dakota and a lot of other states through the whole central region where a lot of the carbon emissions are and through into the sort of the middle Atlantic, wind energy is well-positioned geographically to provide a solution as states and utilities work on their carbon targets.

We'll need to have a lot of transmission, so I really regret missing yesterday's panel, but we have strong opinions on Order 1000 and all of that. I think the nation has built a lot of transmission successfully--what MISO and SPP did, and ERCOT with CREZ showed the pathway for that.

Almost all the wind I've talked about or will talk about is utility scale. There's really not that much distributed, so the net metering debates are really not a wind issue. We're talking mostly about utility scale technology.

So moving to the Clean Power Plan and climate policy and rate versus mass and all of that, one theme to start out with is having a workable program that will be sustained in the long run is very important. We do believe that wind will be a major part of, if not the majority of, the compliance options, and so what we really need is a market to work and to sustain itself. And so when you think that way, you think about, "Well, are there risks to the overall program? Is there something about the integrity to the overall program that is in some danger or jeopardy such that the whole program could cave in on itself and crater or cause significant uncertainty with the carbon prices and thereby hinder investment?" Our member companies and our Board of Directors include a lot of European energy companies who are looking for simple, clear and transparent, solid, robust market signals to invest in this country when they're considering US versus other country investment. So anything that endangers the overall program is a hindrance to clean energy investment.

I think of a couple of things that have actually been mentioned here in terms of the potential threats that we need to think about from a public policy perspective on how do we make sure this program works for proponents of Clean Power Plan like us. We strongly support the program, and definitely think EPA was right to let states decide. That's just the reality of how this needed to be done. We don't have to go back into Standard Market Design, though I love to debate that, too. But when you have state choices, you rely on state choices. You could certainly wind up with incompatible or somewhat inefficient approaches, relative to a national plan, but the idea is, all right, well, let's make it work--given that framework, let's make it work as well as we can.

The biggest threat we see is the leakage issue, which Speaker 1 and I think the other panelists talked about. So I wouldn't assume that mass based is efficient. Economists love carbon prices. They work well. They are tradeable. Cap and trade is great. That's not what's actually on the table in the regulations. There is a significant leakage in the rules, where new gas is effectively exempt. Now, there are some proposed ways to fix it with the renewable set aside, which is intended to sort of tilt the balance to renewables relative to new gas. We appreciate the attempt, but the amount of the set aside isn't really that much, since everything post 2012 through the rest of this decade already erodes and eats into that 5% set aside. Moreover, that doesn't do anything about, I think, what a lot of the folks here would think about, which is new gas in terms of old gas. The inefficient post investment signals and operational dispatch signals between new gas and old gas are very problematic, inefficient and distortionary, so there's a big leakage problem that needs to be addressed, whatever you're perspective, renewable or otherwise, and that is yet to be resolved. States basically have been told, "Figure out a way to address it and show us that it works," but I think, as Speaker 2 pointed out, that's not a simple exercise, and there are significant interests at stake in some of these states on that question.

And it's not just a problem, but it's a self-perpetuating problem, such that the more that problem is exploited, the more the incentive to exploit it more increases, and it could sort of crater the program. So, again, if you're goal is the long-term integrity of the program, that's not workable. You could end up with higher costs. You could wind up with a zero carbon price, and you could wind up with higher emissions, and I don't think anybody thinks EPA is going to kind of sit back in the long run and say, "OK, that's a fine outcome."

So that would need to be fixed. EPA certainly could come back and fix it, either through 111(b) on the new generation, with new gas regulations, or back in 111(d), but it's not a pathway for regulatory certainty if we just say, "OK, well, if it happens, we can fix it later." So that's one threat.

The other is trading barriers and distortion. So, again, recognizing that the only way to really make this work was to let states decide, and that when states decide, they may choose very different pathways, still, for a lot of folks in this room who've thought a lot about how you make regional power markets work, you certainly can wind up with inefficient and fluky outcomes if you look at regional dispatch and power markets. It can happen in a variety of ways under either mass or rate, but the risks there are probably greater on the rate side, when you have different types of rate systems, and for states to trade with each other, they really have to have confidence in what the other one is doing and, of course, EPA has to allow for that trading, so they have to be compatible. The conversation here on either side of me about sort of an ERC production state and a potential ERC buying state is interesting. They don't seem all that interested in working together on that. So that may be telling.

And then a third sort of general threat about the program is just the politics. There are in both mass and rate approaches significant opportunities for state political fighting. In the mass based approach, it's mostly over the permit allocation, as well as how do you fix leakage. In the rate based approach, there's just the overall design and what counts as an ERC, and the "good" or "bad" ERCs. (Thanks, Speaker 1, for that term. That's good.) And people may think of renewable energy having political power, but if you think we go into Virginia and have the weight of Dominion, or we go into North Dakota and have the weight the utilities have…there are a lot of interests that are very powerful in these states, and again from my perspective, looking nationally at how do we get a workable system, if somebody offered me right now, if a whole bunch of states just said, "Join RGGI right now," I might take it. I mean, you have new gas. You have leakage taken care of in RGGI, and you have the permits auctioned, and I'm sure there's some politics that go around with that, and a lot of folks in the Northeast did spend a lot of time in a lot of RGGI meetings, so even that ain't easy, but that would seem to minimize a lot of the risks to the program.

And I'll finish just the last couple of minutes on a couple of other considerations on rate and mass that I might not have mentioned. So, overall I would say mass is generally probably easier to trade and know what you're buying and selling, as I think Speaker 3 articulated quite well. Mass also has, I think, 10 states already doing it, so it's kind of understood, at least, and there's evidence you can look to and see how it works. The measurement is clear, as Speaker 1 and Speaker 2 both said. I mean, you're monitoring emissions that you're already monitoring. You don't have to set up separate tracking for other resources that the environmental regulators have not done before. So those are all definitely benefits.

And then, if I think about investors from the US and abroad looking at the US market again, there is probably a better chance of long term stability if you have a stable national carbon price, just because of the liquidity and trading that comes with that.

On the risks, though, I get back to this on the downside on mass. The leakage problem has to be fixed. So I would take probably a good rate system over a mass system with the leakage problem. But that's really the main downside. Also, the allocation can lead to problems. You look at what happened in Europe. I think over-allocation of permits led to problems there.

You could sort of fix some of these problem. You can certainly fix the leakage problem through the allocation, and Speaker 1 mentioned an idea of sort of a market based allocation, something sort of competitive. Or states give allocations to every generator or supplier that is basically cleaner than some target level, and whoever does that gets it, and you've fixed the leakage problem. That's one solution. I'm sure there are others.

And then just in my last minute, some considerations on rate-based approaches. There is some clarity with ERCs being pretty much the same as RECs, so I think there is a whole market certainly in our industry and investors in our industry have comfort with how RECs work, and that would be pretty easily transferred over to ERCs. And in a way you're just carving out a small part of the power sector to kind of say, all right, let's track this and allow trading of this rather than the entire system. So that could certainly work for some states. There's clearly an incentive for low and zero carbon resources under that system. There's the advantage of avoiding the allowance allocation fights. And then the other benefit is just that these states are all extremely different politically, resource-wise, and in every other way, and they may want to choose a rate-based approach for very good state-based reasons.

The downside with a rate approach I think has been mentioned. What if the supply states all go with ERCs, but they have no buyers? That's kind of a Pyrrhic victory. I mean, assuming a bunch of states will go mass, then a downside with a bunch of states going rate is that you get a mix of apples and oranges in the same market, and the dispatch and potential investment signals that could result from that. And another downside of a rate approach is that it's not obvious how to merge the systems. How state A and state B, even though they both say they're taking a rate approach, necessarily merge their systems so they are trading compatible is not clear. So it's potentially a less liquid and stable transparent market to the world, if you get that mix or if you get a lot of rate states. So why don't I leave it there.

General Discussion.

Moderator: I didn't really hear very much mentioned of the RTOs or the role they may play. There was some mention by Speaker 1, but I just want to ask all the panelists where they see PJM and MISO and California ISO and New York ISO, where they're all going to participate in this? Are they going to be critical parties, and how are they participating in all these discussions that are going on across the regions?

Speaker 1: Yes. I think they are critical parties and have been very helpful in terms of doing their own modeling work. And we like the fact that in the groups that we're working with, we have both MISO and PJM, because it gives us a couple different sets of models that we can start to work with.

MISO, PJM, and SPP, they've all been saying roughly the same things. It goes back to something that I think Speaker 3 said. We think a lot about and how difficult it can be to administer lots of different programs, and so what the RTOs and ISOs have been saying is, "Let's try to get the greatest degree of uniformity within the footprint of the RTO that we can," and that makes sense, but we also understand that they deal already with states that have lots of differences. There are states that have RPSes and EEPs, states that have different fuel mixes. Their fleets are different. All of that figures into the prices that folks bid into the market, and the RTOs are dealing with that already.

The scope of this is potentially much larger, but they've been very good in terms of weighing in. They're not saying what people should do, but they have been good about saying that states can use them as a resource, and to let them help states understand what the best way is to go for them.

Speaker 2: I'll just add that they certainly are a good resource. They certainly are an interesting party. As Speaker 1 said, PJM is careful; they don't want to tell states what to do. For years they have just dealt with a hodge podge of states. They have got RGGI states. They have got states like Virginia. They have got Midwest states. They have got states who have been doing a whole bunch of things. So I think they're just sort of going with the flow and serving as a resource at the moment.

Speaker 4: If we go down the line, I would add to that that the long term transmission planning is a critical role, and from my discussions with some of the RTO leaders, they know enough now to do some very good transmission planning, if you're going to do it sort of like it was done recently, in terms of scenarios. There could be a bunch of rate based and mass based scenarios. There are different resources. When you put those scenarios in and see if a basket of transmission lines pop out as robust and cost effective under any of those scenarios, then the no regrets policy would be to proceed with those lines now, and we're going to need those lines by 2025 when the targets start to get tight. So most RTOs, I think, are in a position to start now with that. So I think that's a critical role, and we've been speaking with FERC recently and RTOs recently about that.

Speaker 3: I think RTOs can help show the benefit of trading across state lines. That's a key role in their modeling. We've benefitted to the tune of billions of dollars in the MISO market through regional trading of electricity. It's not much of a stretch to add a carbon price to this whole mix and have that be a variable cost that plants consider when making their offers into the market, and we can get a lot of value from using the MISO market and other RTOs around the country for this, as well as what has been there for today, which is a dispatch based upon the lowest cost solution to meet the reliability needs of the grid.

Question 2: There was a lot of talk about the politics at different levels and also the allocation if you choose a mass based approach as being something that's going to be challenging. I'd appreciate people's comments on the challenge of allocating the credits under the mass-based approach, and whether that leads to either the regulators or even the incumbent utilities leaning towards a rate-based just to avoid the politics and uncertainty around a rate-based approach.

Speaker 3: I think a lot of it's going to be driven by the economically optimal solution for the state, and I think the math just doesn't work well enough on rate-based approaches to allow that to overcome the issue that you describe. The cost of adding that much wind in North Dakota and the impact on the existing coal fleet would be tremendously harmful to that industry, and would have a lot of costs associated with it.

So when I think about allocation, we'll have the option of allocating based upon load or allocating based upon generation, and the generation allocation can be either based upon historical emissions or it can be based upon historical megawatt hours, historical capacity. I think the utilities and the power plant owners will argue over some of those things amongst themselves, and the state will have to choose. That's probably where we won't be able to find an area of compromise in North Dakota. But I don't expect that North Dakota will allocate based upon load. For our case, that would really jeopardize our power plants in North Dakota, because we don't have load there. And they pride themselves on being a net exporter of energy. So it probably just depends on each state's situation.

Speaker 4: I'll just add one further complication that I didn't raise before about the allocation, which is that there's no economic justification to allocating to existing generators. In fact, I don't know, if you interviewed economists, whether they would say there's any justification for any allocation scheme on terms of efficiency. It's all just transferring rent, which makes the political problem especially difficult.

Speaker 3: I differ with that. When we think about the allocation of a constrained outcome here, what we've done is we've created scarcity that doesn't exist today. We've limited the amount of coal output that can be put on the grid and limited, thus, the amount of CO_2 emissions from the coal, and we're doing it in a way that we're getting a 45% reduction in North Dakota. Giving the remaining 55% emission allocations to those coal plants makes eminent sense to preserve the industry, the competitiveness and the rate affordability of what we're trying to do here. So I differ with that. Plus, the fact that there are allowances creates an opportunity cost and a cost of CO2 allowances that is a windfall for the wind industry. So I differ on that point.

Speaker 2: I'll just add that, yes, that was a point brought up by our major utility. With a rate-based system, they don't have to worry about allocation schemes and not getting all the allowances based on generation.

Speaker 1: And I think, just as everybody has said, they're going to look at the whole picture, evaluating it not just on that basis, but on everything else that's tied into it and what makes the most economic sense for them, and on whether they get a sense that there's going to be a lot or very little of it, and I think things like that also figure into it.

Question 3: The question I have came up from your presentation, Speaker 1. I get the idea of allowances with a mass-based structure, and when you go to the rate-based structure and you talked about the requirements on each and individual plant, I got that. But then there are these ERCs, and it suddenly occurred to me to wonder if this is a distinction without a difference. At the end of the day, does a rate-based approach also become a mass based system? Because if even the plants can't meet the requirements, but the state can get credits and be able to cause, I suppose, some additional construction of more efficient plants that will use those credits or generate them, then at the end of the day, isn't that just a mass based system by another name? Maybe I'm missing something, but I wasn't sure that there was really that much of a distinction here, if you had those credits also in the rate based structure.

Speaker 1: Well, I would agree with that in that they are both systems that are set up to allow monetization of something to reduce carbon. But they're very different in the way that they do it, and the difference is in a lot of the details of how it gets done. With the allowances, there's a set amount. You know what those are when you go into it, and so for the companies that are looking at it, and the analysis that Speaker 3 did of how North Dakota might look at that, for example, it's pretty clear. You know what the allowances are that are out there in the country. You know what they're going to be in your particular state.

Nobody knows for sure how many ERCs are going to be out there. You can make some guesses from renewable energy projects. You can kind of project what those might likely be. Energy efficiency is really a crapshoot. We really don't know. No matter how much people like energy efficiency, nobody is sure how many energy efficiency ERCs there are going to be, or how that system is going to work, and so it's very difficult… and I've heard utilities actually say, "I like the idea of having the allowances in my hand or knowing how many are out there, and I can kind of project based on that who needs them and who's got them to sell. I can kind of figure out what that price is going to be." Because you haven't done anything like the emission rate credit system before, it's a little bit more difficult to tell you what that's going to be.

Questioner: Fair enough. There's an uncertainty factor. But if people get through that, at the end of the day, isn't there really an escape hatch so that effectively it moves from a rate to closer to a mass approach? In other words, you're saying that you're generating these credits and allowing a broader mix to meet certain obligations. It just seems to me it may be not quite as big a difference as we thought.

Speaker 3: I would add that I think EPA intended that there be an equivalency--that the outcome of either approach would lead to equivalent CO2 emissions, and maybe that really gets at the heart of your question. We're going to get to the same result with either method, according to the EPA.

Speaker 2: Let me just add that in theory that sounds right, but in practice a mass based system involves a hard cap. And under a rate based system, CO2 emissions can go up, and the numbers I've seen do, especially the ones that I've seen from our utilities. Under a rate based system they will go up. Emissions of CO2 will go up. And that's what scares the NGOs. That's why NRDC and EDF favor a mass based cap. That doesn't allow for that type of increase in emissions.

Question 4: Let's put the rate based discussion aside, because that's the whole bunch of things which I don't like thinking about. I'm afraid we may go that way. But let's look at the mass based issues,

I'm worried about Speaker 4's comment, because I find it very troubling in dealing with the leakage problem. So if we go to the new source complement, which I think is a good idea, and I understand that one. And I think that will work fine and that would be terrific.

The other approach to leakage, where you have this set aside mechanism, there's a problem. And let me be more specific about what the problem is. EPA makes assumptions about the future cost of renewables. The assumptions in the Clean Power Plan are, shall we say, aggressive. But they're irrelevant in setting the standard now, because it's moot. They set those standards. It makes a difference to the total cost benefit analysis that you do, but that doesn't change what you do. So that's behind us.

When you get to the mass based system with the renewable set aside to deal with the leakage problem, EPA has a problem, in that they now have to drink their own Kool-Aid. OK. So they have to take the very aggressive assumptions about the cost of renewables, which means that the cost of renewables are very slightly above the cost of new natural gas. So, therefore, the amount of a set aside premium that you have to give to the renewables so that they are more competitive with new natural gas so you don't have the leakage incentive is very small. And that's an internally consistent calculation, given their assumptions about renewables. But if the renewable costs turn out to be closer to what the Energy Information Administration says, then this approach is not going to put a dent in the leakage problem at all, and we're going to have a very big incentive to leak, and this is going to unravel, and then we'll get into the situation where people are saying, "You can't trust those bastards."

So the first thing they'll do after it starts to unravel and they don't get the outcome that they want is they're going to change all the rules. And so now you have this huge mess and uncertainty coming down the line. It will take five years for that to start to show up, but in five years you could have the whole thing go asunder.

When I first read about all of this, I tried to not think about the set aside thing because I thought it was such a bad idea. Now that I understand the numbers better I'm even more worried about it, because I think the uncertainty problems and all the things that Speaker 4 was talking about are actually much more severe for this mass based system with the renewable set aside, whereas if we go with the mass based with new source complement, this is all behind us and we just have to go forward, and everything will be just fine.

So what's wrong with this argument about drinking your own Kool-Aid and getting yourself in trouble here?

Speaker 4: You're very right, in my view.

Speaker 1: Well, there are two issues here when people talk about leakage. And you're not doing it, but a lot of folks out there are kind of conflating the issues. They're looking at the leakage issue, and thinking, "Well, this is a problem, in that we won't be able to comply with the rule." They'll be able to comply with the rule just by doing what EPA said that they have to do in the rule, and so states that are looking at that can kind of put that one aside for now.

The question is whether the leakage problem is real, like you're saying. There's actually disagreement out there. I've heard from lots of people thinking that the price incentive for new renewables is still not going to be good enough to force lots of new generation out there. I know you would agree with that concern, based on what you just said. The question then becomes, is there a way for them to fix it now before getting down the road and having to redo all the rules because they didn't get the environmental benefit that they wanted? I think there may be some ways to do that. They're taking comments on the model rules now and on the federal plan, and they may be able to do some additional things to make the adjustments that they need to address it, if it is, in fact, an issue going forward. I don't know whether they'll do that or not, but I think they're aware of the issue that's been raised by you and by Speaker 4, too. So whether they do something with that or not I don't know.

Speaker 3: I think the best outcome for organized market is to have a carbon price that is applied to all carbon. States can do that if they choose the new source complement route. We'll see how many do it. I'm not a fan of the set asides. I think that wind is going to get an LMP lift anyway because of the carbon price being in the market. So that's going to have plenty of incentive, and I'm not really a fan of new combined cycle units not paying a carbon price while all the existing plants have to pay a carbon price. So we'll see how that plays out and what states actually choose, but I think there will be some interest in that new source complement idea among states, because then they don't have the risk of later regulation if it doesn't work.

Speaker 2: I'll just make an observation. It's a little out of my field, but when I hear the questioner and Speaker 4 worry deeply about the effects of this leakage I get very frustrated, because it's a problem totally of EPA's own making. It's the very first time EPA has set standards for new sources that are less stringent than standards for existing sources, and it was technically unnecessary. In my view all EPA has to do was harmonize the two standards. There's no reason EPA couldn't have set its 111(b) standards for new sources at a level equivalent to existing standards, because our state of the art natural gas combined cycle units are not emitting somewhere close to the 770 tons per mWh in 111(b) and it struck me as a giveaway that the standard is so high for new sources. And it's something that in my view could be easily rectified by just harmonizing the two standards, and that, I think, is very technically possible.

Speaker 1: I think what's interesting, too, is that most of the states that are looking at rate as opposed to mass, one of the reasons that they're doing that is not necessarily because of the leakage issue. It's because they think they're going to be a much higher growth state than the amount of growth that's built in to the mass based conversion. I mean, they think they're going to be a really high growth state. Everybody thinks they're going to be a high growth state, or wants to be, and nobody's going to get out there and say, "Yes, we don't plan on growing at all over the next 20 years." So it just politically doesn't work real well. And so I'm betting against my governor. So then people look at the issue and they say, "Well, gee, I don't know if I've got enough headroom." They're not focusing as much on the leakage issue. They're focusing on the growth issue in terms of the rate versus mass.

Question 5: I started trying to think through the rate versus mass issue for an ISO that covers multiple states. And I don't think the logic that you all are using to go with a rate approach gets you out of the problems that you get if you have security constrained, economic dispatch. In other words, I think you're going to see your problems manifest a different way, and you're going to have to have come up with some kind of administrative solution in the end.

Speaker 3: This is interesting. I actually had some conversation with Brattle about this, too. When you think about states that are in an ISO, and one's on an ERC approach, rate based, and one's on a mass based approach, they both have variable costs that they're going to have to incur to run their coal plants. And if it's a mass based state, they'll either have the opportunity cost of what they could sell their allowances for if they weren't running or the cost of purchasing allowances if they're short. That's their variable cost. The state that's on ERCs, they'll have the variable cost of the incremental ERC that they have to acquire to run their plant. Now, if it's wind that they invested in, maybe they don't have a variable cost component of that, because they own them. But still, they'll have an opportunity cost of being able to sell the ERC to somebody else. So in either case, both states have a variable cost, and shouldn't they just offer based upon their variable cost? There doesn't need to be a true up by the ISO. I think variable costs are knowable by each state, and they'll include them, and the power plants will include these costs in their offers. It will self-adjust.

Speaker 4: I'll just say it's a great question, and think people should be white-boarding how this dispatch with a bunch of examples, like we used to do in the LMP days, in terms of, what are the outcomes if state X does this and state Y does that? I'd love to see the answer.

Question 6: Great panel. I really appreciate the different perspectives. My question has to do with the CEIP (Clean Energy Incentive Program). I didn't hear any explicit reference to that, and that may be because all of you are reluctant to look at not just the opportunities but the challenges. I guess I'd like to hear panelists' perception of challenges and opportunities, and to the extent that you think there are ways to overcome some of the challenges. What form do you see that process taking?

Speaker 2: Well, why don't I start off, as a state regulator? I didn't mention in my presentation, but it is something we'll be thinking about as we go forward. Clearly there will be interests involved in sorting it out. Obviously it's a way to mitigate some costs for our low income communities. I think the program can get a lot of bang for the buck by weatherizing and having EE projects in low income communities.

On the other hand, for EE and RE projects, it seems to be that it shoehorns them into a certain period of time, a certain period of compliance, and is that delaying projects that otherwise would have come online earlier, or is it rushing to market projects that might not be ready in time? To what extent is it sort of messing with the market? I do know that the double allowances that they get…it doesn't decrease the stringency of the program because those allowances just come out. Those ERCs or allowances just come out from later years. So it doesn't affect the overall stringency of the program. It just seems to shoehorn projects into a timeframe that has some uncertainty, because you can't have a project that's in operation before the state submits a plan, and in our case we don't know when we're going to submit a plan. So it increases uncertainty. I do know that our EE and RE people support it, but I don't know if it's a case of support just because they want the flexibility, or if it will actually incentivize projects. But that's something we'll be working through.

Speaker 4: We think the Clean Energy Incentive Program is important. The whole program got delayed between the proposed and the final by a couple of years, based on overwhelming utility pushback on the timelines, which is somewhat frustrating, because in our case we think we're ready to go now and the tax credit could be gone tomorrow, for all we know. And so we could have five years of zero incentive while their carbon is completely unregulated. So the Clean Energy Incentive Program helps a little to mitigate that.

I think we're not hearing about it a lot because it's not the front and center determinant of what the rate versus mass choice. There are some sort of bigger picture questions and CEIP isn't really driving some of those bigger decisions.

Speaker 1: I think it's helpful. I mean, it's certainly something that states can do, and it's another 300 million credits nationwide but given the numbers that Speaker 3 gave during his presentation, that's not a huge amount of credits that's out there.

There's also the issue that states will have to match those, and so when we get back into that whole allowance allocation and set aside issue, that factors into that as well. I think most states, because in 2016 they have to say whether or not they want to opt into the CEIP, I think states will say yes. It's not binding, so they can choose to opt out later if they want to. If they see that they don't have the kind of projects developed that will do that.

I think it's helpful but I just don't know that it's the kind of the main driver yet, and Speaker 4 is right. One of the issues that came up was that people said, "Well, we want to develop a project, but if we get the maximum credit for it starting when the compliance period starts, why don't we just wait to do that then? That makes more sense economically." And so this was a way for EPA, I think, to try to address that concern out there.

The question is whether it's enough to really make it work. There are some concerns that we've heard in discussions that we've had about what it means to be low income. Whether or not states have an appetite for it could well hinge on whether they allow things like a hospital in a low income community that does some really good energy efficiency things. Can that qualify? If so, that's a lot better than a program like a LIHEAP (Low Income Home Energy Assistance Program) where the state would have to go through and individually qualify low income residents for it. And we don't know what that's going to look like in final. So there's still a lot of those issues out there. But I think, obviously, it's another way for states to try to get some credit for RE and EE to going on.

Speaker 2: Let me just follow that with two observations. One of them is that it's another set aside, and discussing how efficacious they are in the first place. The other things is that we might need legislative approval to do the EE program, which would make it more problematic, and we don't know the answer to that yet.

Question 7: Yeah. The comments today have all touched on how critical trading is in the different approaches that people take, and there have been points made about how we may have ERCs that have different qualities. They're not really exactly the same thing, and they're going to be commodities denominated in kilowatt hours, whereas with the mass approach we've got trading in commodities that are dollars per ton. So people have pointed out that there are measurement and verification issues that are going to be important in the ERCs, and so forth. Are any of the state implementation plans concerned with who and where the trading is actually going to happen? Because a lot of the existing trading schemes won't fit the bill right now. And who's going to regulate this? And do you see any possibilities that states are going to want to confine the trading to just intra-state?

Speaker 3: I think that's a very interesting question particularly when you look at rate based plans. I think states will naturally have some incentive. I mean, when the plan just came out and we were just learning the mechanics of it, before we actually ran the numbers, it was sort of attractive to think about the idea of doing an intra-state plan in North Dakota. You could make the approach rate based, and just add enough wind that you meet your own needs with ERCs. You'll bolster economic activity in the state by constructing all this wind, and you get the ERCs within the state to keep the coal plants alive and healthy. The problem is that the math didn't work.

But I think that that is the incentive that states will look at. Those that look at rate based plans will see it as a way to promote economic investment in their state for new resources that produce ERCs, whatever those resources might be--renewables or some form of a natural gas or something highly efficient. So that incentive is going to be there. And they may make ERCs trading ready, but I think that states will naturally want to see investment within their state rather than in somebody else's state to produce the ERCs.

The nice thing about the allowances is that you don't have to really worry about that. You're more going to go with the purchases of allowances and if you can't buy them cheap enough, you'll somehow back down your plant. And that's another problem with the rate based plan that we haven't touched on. Just intuitively, what's a fast way to reduce CO2 emissions? Don't run your coal plant for a weekend or for the month of April. And under a rate based plan you get no benefit from that. It only benefits you under mass based. So those are some thoughts.

Speaker 4: It's as if FERC had said in power markets, "OK, states, trading's good but you have to choose Euros or dollars or bit coin and each of you decide separately which one you're going to use."

Comment: That would be easier. [LAUGHTER]

Speaker 4: Yes. There's an exchange rate that's known, in that case.

Speaker 2: I'll just add that from our perspective the whole valuation measurement and verification issue with ERCs (and that gets to the good quality ERCs versus bad quality ERCs) is a real problem for us. I guess it's more in the EE side than the RE side. With EE, it's tough to verify.

What would make it easier for us and would make the rate approach more attractive would be something where you could have a system where the ERCs are as bulletproof as SO2 or NOX allowances are now. And I've heard some interesting proposals from energy efficiency people that want to, say, create national registries for ERCs, and the national registry would sort of serve the purpose of what the Clean Air Markets Division does on the SO2 side for the CO2 side for mass based program. If there's a third party with EPA approval that sort of is able to vet the ERC and sort of give a piece of paper that said, yes, this is a good ERC and it's EPA approved already, then that makes things a whole lot easier.

With respect to the question of how many states are going to do rate versus mass, I think any state with a new nuclear unit is probably going to go rate. There might be three or four, maybe five states that eventually go rate, and Speaker 1 was talking about how, if the states with a lot of ERCs are going to go rate, then the ERCs are going to be not worth a heck of a lot with just trading amongst ourselves. I don't necessarily see that as a bad problem. It may help our single asset facilities, our one-offs, because the cheaper ERCs are for them the easier it is for them to stay in the marketplace. So cheap ERCs--I don't see that, necessarily, as a bad outcome here, especially if that's what in the best interest of our state.

Speaker 1: Just on the mechanical side of it, in a mass based system, EPA has said that they would set up the accounting mechanism or states could set up their own. You could do it on your own or go together with a group of states. But I think people would say it's worked well in the other criteria pollutant trading programs that have gone on, and people are used to that, and that's kind of an easy thing.

It gets a little murkier--it's not impossible but it is more difficult--because on the ERC side you do have to set up a couple of steps to do this, and for the sake of not driving everybody completely nuts, I didn't go through this when I was going through the description, but there are a couple of things that have to be done that states aren't used to doing, or certainly aren't used to doing it in this way and for this purpose.

When you start off thinking about it, the states that have energy efficiency programs (and I come from the state where we have a pretty robust one and it was administered by the Commission and they had their own way of measuring and saying whether something was cost recovery eligible) systems are different among states in terms of not only what they count, but how they measure it, and what the purposes of it are. There are very few states that have done this with the whole eye toward having their energy efficiency programs measure greenhouse gas reductions.

And so it's just a different thing for states to have to do, and the two step process is, first, to set up the idea of having a qualifying project. So you want to know, if you're thinking putting a lot of money into an RE project, is it the kind of project I'm going to be able to get ERCs from when I've completed it? And so there's an initial qualifying step for these ERCs, and then there's a final step to come back for that and actually have the ERCs awarded. Both those steps are going to be the state's responsibility to set up or do it in conjunction with other states, and then that last decision, on the ERC actually being awarded, is a state action, and so that is something that is actionable, and EPA has said that you have to set up a method for appealing those decisions as well, because you might imagine there will be times where, whether it's an environmental NGO or another company, a competitor who says, "Well, I don't think company X ought to get credit for all of those renewable energy ERCs or energy efficiency

ERCs, and so we're going to challenge it." And so there is litigation that comes from this as well, and that's where you get to that idea of how good the ERC may be in setting up separate markets for it.

So it's not impossible. It's just something that's very different, and I don't know of any states right now are working with that kind of bandwidth. Maybe California has that kind of program set up. So it's not impossible. It's just a lot more to do.

Speaker 2: I'll just follow up. Yes, it would be a big deal to get that together. Some states have more robust EE/RE programs. Illinois, I guess, or Massachusetts. California. But Speaker 1 is saying that even Illinois doesn't seem to have a sufficient infrastructure to deal with it.

And I'll give you the challenges. Take my Attorney General's office. I have two-thirds of an FTE that does air work at the Virginia Attorney General's office. If, indeed, they have to defend ERCs (and I've heard from California that there are lawsuits over RECs and offsets all the time in California)…people are going to be suing all the time. As I said before, it'd be great to have a system where ERCs are as bullet proof as SO2 and NOX allowances. But I think we're a long way from that world.

Question 8: I've been thinking a lot about renewable portfolio standards lately, and I'm thinking about a horrible problem for dyslexic folks, RECs and ERCs and how they relate to each other in practical situations. For example, in some states, my reading of the enabling legislation is that the REC is all environmental attributes. Other states say, no. The REC is just the REC and other environmental attributes that are sort of invented by legislators and bureaucrats.

If you're a wind farm developer and you build to wind farm, you will generate ERCs, presumably, if your state goes that way, but you already have a PPA where you're selling the RECs, and perhaps also the energy and capacity and perhaps not, to some other party, and it's a contract that is probably a trade secret and nobody else gets to read. So how do we figure out where the ERCs go and where the RECs go, and are they stapled together? Is it actually the same in practice, the same certificate? How do we sort out this mess of RECs and ERCs?

Speaker 2: I'll start off from the regulator's position. I've had this discussion with folks on my staff. I'm not sure I care. ERC is the currency of compliance with the Clean Power Plan. That's if we go down a rate based path.

Questioner: With due respect ,though, your state has a renewable portfolio goal, not a standard.

Speaker 2: Right, right. It's a totally voluntary.

Speaker 3: I don't think it's going to matter in the mandatory realm. I think where it really matters is in the voluntary realm. That is, if you have a wind farm and you're gleaning ERCs from it and using those ERCs to comply with the Clean Power Plan, but you also have RECs from it that you're selling in a voluntary market to somebody who wants to certify or offset their load as green, then you have an issue. Are you misrepresenting something to that customer, in that you've already used the environmental attributes for Clean Power Plan compliance? But I think in the mandatory realm, for state RES and ERC compliance, I think the states will figure out in their SIPs whether or not you can count it for both the REC for the RES and the ERC, and I think most states will allow it to be counted for both. But I do believe they'll include that in the SIP, and we'll know it, but it will be complicated in the voluntary market.

Speaker 4: OK. I agree that it does vary by region. A lot of the RPSes are in states that are sort of well beyond Clean Power Plan targets are not so concerned about them, but outside of the RPS states is where a lot of the Clean Power Plan action is, so there's not a total geographic overlap, and I would say, yes, it's an issue between certain companies and project owners. There could be winners and losers, depending on how contracts are deemed to qualify or not qualify. So it's a good time to be an energy transaction lawyer.

Speaker 1: I see the biggest impact, potentially, in the REC market itself, just for those reasons. Some states wouldn't allow you to claim all the environmental attributes, and if you're peeling part of that off for the ERC, they wouldn't allow it, although I agree that most states will amend that to allow that to happen.

But there are two separate things. Speaker 2 is exactly right. I see the biggest change, probably, in the REC market itself. The other interesting thing is, I've actually heard states opine about, "Well, why do we need our RPS anymore?" If you go to a mass based system that's going to help RE in the marketplace in terms of the bid stacks, because now you've got a carbon price added that will help non GHG emitting things. I don't necessarily agree with that position personally, but I think you may see that argument play out in a couple of states as well, and maybe the states where they've already been arguing about that is where you're really see that start to happen. But I think they can coexist.

Question 9: What is your view as to how hydro is going to be treated and whether or not it's going to be considered renewable in the renewable portfolio standards or in the set aside or however renewables are treated? Because right now there's a variation between states and between jurisdictions as to how that works.

Speaker 3: In Minnesota, large hydro is carbon free and non-renewable. So you don't get renewable energy standard compliance from hydro, but you also don't have any carbon issues associated with it. So you get sort of a half benefit. We buy hydro from Canada as part of our portfolio. We also have some of our member cooperatives that get a Western Area Power Administration hydro allocation from the Missouri River.

Questioner: When you say you get a half benefit, the state gets a half benefit, but what does the hydro owner get?

Speaker 3: Well, here's the half benefit I'm talking about. You don't get renewable energy credits that you can use against the renewable energy standard or sell into a voluntary market. So you don't get the benefit of that. But you are carbon free, as a hydro source. So when you're supplying energy to an ISO that includes a carbon limited component or a carbon price component, you're supplying into a market that is going to have a somewhat higher price driven by that carbon price. So that's why I mean half benefit.

Question 10: On the rate versus mass approach, in terms of the allocation story, I think it's important to think about the rate based approach actually being a form of allocation. It's just as if a decision is made that the generator's got a certain amount of allowances, essentially, based on their rate target. So, both of these systems, through a process, allocate value to various entities.

And a related second comment is that having thought about is a little bit, but not all the way through, I am not entirely sure whether Speaker

2's rationale for going rate based is right. Because in those states there will be allowances allocated, and so it's not entirely clear that just because you generate ERCs you're better off, because there is also value coming your way through the allowance allocation under a mass based system. So those are the comments.

And then I'm curious about these energy efficiency ERCs, and whether there isn't an additional problem that goes beyond the traditional problems of say offsets and stuff like that. If I read this right, then actually the carbon reductions that are associated with an energy efficiency measure are actually based on a uniform assumption about the generation mix, as opposed to a, say, state or measure specific or region specific mix, which means that even if the kilowatt hours saved are verified and good, the amount of carbon reduction associated with any given energy efficiency ERC is going to be wrong, with 100% certainty. And so if this is all symmetric --

Comment: The same problem comes up with renewables. I think it's a serious problem and it's the same issue.

Questioner: Right. So the question is, is this a symmetric issue, where as we discussed yesterday, it's going to wash out, on average, or is it going to be biased in a way that either strengthens the standard in the end or weakens the standard?

Speaker 1: As I looked at this and tried to think about it as an administrator, and having the different hats that I wore, I saw, from a practical standpoint, administration of energy efficiency ERCs as the most difficult thing I could think of to try to administer in this, not just because of all the extra steps that people had to do, but because of the likelihood of challenges for that.

In our state, for example, we thought we had a pretty robust program. We had a cost benefit analysis and measurement. But suppose the challenge to the measurement is that you should only give X number of years of credit for that particular expenditure on energy efficiency or that particular program? You're going to end up litigating a lot of things like that, and it just becomes really, really difficult to try to think about, unless people just decide to give a pass to all those credits, which I can't imagine happening if California's experiences with other instruments is any indication.

So I see that you're right, in terms of the fact that there's kind of an assumption that it's OK that it's going to be wrong, because we're also not differentiating between when the energy efficiency happens and what the pull is in terms of fuel sources at the particular time. So, are we doing it at night when we're heavy on wind, or are we doing it in the daytime when we're heavy on coal in the Midwest, for the most part?

It's kind of a difficult area and it's interesting that in the federal plan there are no EE ERCs, and all that tells me is that EPA hasn't figured out a way to do this either that makes any sense. So I think that's fairly telling, as well. I just think it's going to be an issue for states that adopt a rate approach.

Speaker 2: Let me just respond to a couple of your points, and I guess I haven't been clear enough. Certainly Dominion Resources is sold on a rate based plan. The Commonwealth of Virginia is not yet sold on it. We've got a lot of stuff to work through—basically, the issues you just raised. There are lots of countervailing arguments, and we're taking it all under consideration.

On the allocation issue, I think that, yes, a rate based plan is an allocation plan. The generator gets the ERCs. I don't have any control over that. The generator gets them. Under a mass based plan, our state Air Pollution Control Board can allocate allowances as it deems fit or as the legislator deems fit. So, yes, the rate based approach is equivalent to an allocation decision that goes to the generators.

Speaker 1: Just to follow up on this, I also think about it in a deregulated state. So in Illinois we are administering the EE programs through the distribution utilities. That's not the generators. That's not the people whose ultimate outcome for this program is contingent on these EE programs generating ERCs that are available to be helpful to them. And they may, in fact, be competitors in that state and in other states, and so you also create some potential issues with people who are not necessarily on the same page being forced into some kind of marriage of ERC creation here that I'm not sure is necessarily always going to work in every case. Maybe that's over thinking it and creating more problems with it.

On the rate versus mass thing, I hear about that in terms of people looking at it in terms of their individual states and saying things like, "We think we can do better under rate based and not looking beyond our borders," and not thinking of it as you were in terms of, "I could have this other commodity that could be marketable for me." They're looking at it based on, "We think this is something that could be just helpful to us, not looking beyond our borders."

There's an interesting thing with that, and a lot of it hinges around these new nukes. But I was at a public meeting in DC earlier this week, and somebody from a company who has nukes and somebody from the Nuclear Energy Institute both said, "Yeah, we kind of like the mass based. It just makes more sense." And I'm thinking, this is interesting, because you've got companies in the southeast that are putting a lot of money into…it wasn't Dominion.

Speaker 2: Existing nukes don't benefit from a rate program at all.

Speaker 1: Well, no. But even the Nuclear Energy Institute guy--you would think he would have at least hedged and said, "But there's some benefit to new nukes from rate based," and he really didn't, which was a little bit surprising.

Question 11: Do any of you see the Clean Power Plan as having an effect in terms of encouraging utilities who are not already in RTOs to join RTOs, or for new RTOs to form? I think there was some discussion about, "Well, maybe there'll be some additional states that will join RGGI," but is one impact of the Clean Power Plan that RTO footprints expand, or we get some additional RTOs? Is that a conversation that you're hearing in states or among utilities at all?

Speaker 3: I haven't heard that conversation. But it is interesting to note that we feel there are a lot of benefits of having an organized market across multiple states. That's only going to grow when you're adding carbon as another component to the trading environment that we're already needing to have across states. So I suspect that they'll start with bilateral trading, but the value proposition for ISOs is only going to get greater as we trade carbon.

Speaker 4: I totally agree with that. I have not heard this as a near term conversation, but over the long term, to the extent wind is a significant component of the solution, I think that will lead to greater regional trading and transmission and RTO expansion, because the best low cost resources tend to be remote, and the wind patterns are not always correlated so you get geographic diversity through regional markets in trading. So I think that ,and, in fact, I think that's a big part of why we've had the steps towards regional trading in the west, with energy and balancing markets, and now the ISO potentially enlarging.

Speaker 1: I haven't, I've heard it raised as a thought, just like you raised it here, but I haven't heard states actively talking about it. I have heard some states that are in RTOs saying they're glad they are. I've heard that comment from a couple of states, just because of some of the issues that we've talked about here. But I haven't heard it in terms of new RTOs—not from states, anyway.

Question 12: I want to follow-up on one of the points made in Question 10, because I didn't hear the answer which I think addressed the problem I would worry about. This is a rate based question, so I have to talk about rate based mechanisms. But if you go to rate based mechanisms, the standards were all based on the fiction that renewables substitute for CO2, one for one, and we know that's not true. And there have been a lot of simulations and papers that have been out there. There was a Berkeley paper. The title was "Location, Location, Location," which is to say, it depends on where it is and when it's happening what actually is going to happen in terms of carbon reductions.

I don't see why the wind guys don't come up and say, "My wind over here saves a lot more CO2 than solar over there or efficiency over here, so I should get a 50% bump in the amount of credits that I get from my wind facility because I'm going to locate it in a place which is really going to help with carbon, and you're putting your thing in some place where it's actually going to hurt," and blah, blah, blah. Why isn't that food fight just waiting for us down the road here, as we go rate based?

Speaker 4: If one were to go in a rate based direction, I think there should be, obviously, good modeling rather than bad modeling of what the actual carbon impact is. And I think the geography and the way the power system is dispatched show that wind energy displaces a lot of carbon. And I think most modeling has shown that and would show that. So we would support good modeling of impacts of renewables, and we would have views on that. We're not going to go and criticize other technologies, necessarily, especially when most of our members build the other resources as well.

Speaker 3: I would say that because that matter is already decided, it doesn't matter if it's right or not in some sense.

Speaker 2: I'll just add that the administrative complexity sort of stands in the way. I mean, we just don't want the perfect to be the enemy of the good. We want to do a good plan. We know it's not going to be perfect. But whatever plan we come up with, and a lot of states come up with, will probably shock and disgust many economists. It will not be the most efficient thing we could do. We're just going to try to do the best we can. And you may be absolutely right, but the way we're going, we're going to get something done in a year, and we're going to fly with what we got.

Question 13*:* What's interesting to me is that there really was very little mention if any of the reliability concerns that were so strongly voiced during the promulgation of this rule, and how there needed to be input by FERC and state regulatory commissions and NERC, and that somehow once this rule started taking hold that there were going to be real reliability challenges. So I just wanted to hear, from all of your perspectives, now that you're actually working through it, what is it that you're hearing on that, and is there a greater comfort level that through this processes we're not going to face those kind of reliability concerns that folks had talked about?

Speaker 3: On the issue of reliability, it's a significant concern to us. The reliability safety valve, as we see it offers very little value, and it's not likely to be utilized or helpful. We think the real reliability safety valve is the fact that peaking plants are not covered by the rule. So existing peaking plants--we can rely on those. If all else fails, we can run those and not run afoul of carbon limitations and have our own penalty built in, because those are low efficiency. It will be high cost during that time period, so we'll have an incentive to not do that for very long, but nonetheless we have the reliability capability of that. So I think that was an important move by the EPA to preserve reliability, whether they intended or not to exempt peaking plants, that's the real safety bell as far as I'm concerned.

By way of final comment, you asked about the difference between cooperatives and investor owned utilities on Clean Power Plan issues. I think it's more about the generation fleet of the utility rather than its corporate structure in terms of driving its point of view on carbon regulation. But I do think that the one difference you probably see is that investor owned utilities are concerned about preserving rate base and rate based opportunities for return on investment to shareholders, and are looking for new opportunities to deploy capital as a response to the plan. Whereas cooperatives were more concerned about just preserving the competitiveness of our rate. We serve low density areas. A lot of times we serve areas with people of less means than investor owned utilities, lower income areas, and we're just very concerned about the cost of the program and want to have reliability, and we want to be able to compete with the other utilities. Thank you.

Speaker 4: On reliability, yes, we're hearing a lot less about it. I think the attention we were hearing a year or two ago was largely politically driven. It was, at that time, the leading strategy of the opponents of carbon action and the Clean Power Plan to raise that issue. I think they tried and essentially failed. They did not find any good demonstration that it would harm reliability, and the rule became final, and I think a lot of utilities said, "OK, look at the final rule. We can live with it. We can make it work. Let's focus on compliance." And so some of the energy and passion around getting Congress to help and drag FERC and NERC into it waned somewhat.

So now I think people are a little more, in my view, rational, looking at, "All right, how do we do this," and there's not any kind of reason to believe reliability will be harmed, but obviously under any system we can screw things up if we try. So we do need to worry about it as paramount to making any power industry policy work.

And then my just general comment, to restate what I've said is, plug the leaks. Let's look for efficient and workable systems here, because in the long run what we need is something that's workable and predictable relying on trading and transparent prices, and so focus on things that could endanger the long term integrity of the overall program, and to me that's leakage, and figuring out some solution to that in the near term is the big public policy challenge.

Speaker 2: On reliability, I guess with the final rule we don't think overall that's probably going to be a big problem in Virginia. We've had discussions with PJM on that, and they're pretty optimistic that it's not going to present a problem overall. We do have one single asset facility, co-facility, that is certainly going to argue reliability. We're going to have to work through that one as we go forward, but we see it as really as an isolated thing in our neck of the woods.

And just my final comments. I'm glad to be here. I like to be in rooms of people a lot smarter than me, so hopefully I can take some nuggets back to Virginia as we develop our plan. Thank you.

Speaker 1: On the reliability issue, a lot of the discussion that I've heard, and a big difference between the proposed rule and the final rule, only has to do with the trading options that are out there. And a lot of people have seen that, and are saying in a lot of public forums that trading makes it more of a cost issue than a reliability issue, because if Speaker 3 is right in terms of the amount of allowances that are out there in a mass based system, you probably know you can run if you can find the allowances out there. It becomes more of a cost issue at that point.

The one last thing that I would say is that it's actually kind of a good thing. It's an interesting thing, but the narrative on trading is very different now than that it was six months ago, let alone a year or two years ago now. There was a meeting I was at where people were still in, "We don't like cap and trade at all, and we don't like because it looks like Waxman-Markey" and going through all of that. I was at one meeting (not with any of the states that we're working with) where a couple of guys from the PUC were there, and when it was brought up that there'd been trading going on for decades with other criteria pollutants, and that in fact the state that these two guys came from had been engaged in it for years and it hadn't been a problem, one guy looked at the other guy and said, "We're doing that? Well, that's cap and trade. We don't like cap and trade. Do we?" And the other guy said, "No, we don't." Everybody else laughed. These guys didn't get the irony of it.

But all of that seems to have gone away a little bit, and a lot of that's driven, I think in a very positive way, by the RTOs. It's driven by the generators who are saying, "Look, trading makes all the sense in the world," and I think that the best explanation of that I got was from somebody in a very red state who said, "Look, if the trading works out the way that it does, and it makes these numbers look this much better, I'll figure out what to call it. Don't worry about that. We'll make it work somehow. We'll figure it out."

One of the things, though, (not to leave on a down note or to make your head explode before you leave) is that as you start engage with states and talk to them about it, there's kind of an interesting little kind of subplot to trading. And that's the states that say, "Well, we like trading but we don't necessarily want to trade with *them*" because of various reasons. Sometimes it's just, "We just don't like those guys. We're mad at them for whatever reason." But not necessarily that. It's more, "Well, they gave their allowances away rather than auction them, so we're not going to trade with them," or, "They don't cover new sources and we want to, so we're not going to trade with those states." I think that part of the dialogue needs to play out, because I think almost everybody would agree that the broader the market that's out there, and the more trading partners that are out there, the better off we are for cost, for reliability, for seams issues, all of those things. And so those are a couple of themes to start thinking about and listen for as you're interacting with individual states.