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Rapporteur's Summary*

Session One.

Transmission Cost Allocation Roughly Commensurate with Benefits: Now What?

Order 1000 sets out principles for designing transmission cost allocation protocols. The most important is that beneficiaries pay, and those who do not receive benefits do not. This high level principle is appealing for obvious reasons of equity, and for equally important reasons of economic efficiency in providing incentives that complement other features of electricity market design. However, with an echo of Order 888 that defined high level principles for transmission open access, the details are to follow. Kicking the can down the road, transmission planners have been charged to take up the task of filling in the blanks. The Order provides extensive discussion of the comments from stakeholders, and rules out some interpretations. Arguably, Order 1000 has mandated nothing that is fundamentally problematic, nor ruled out a practical solution that conforms to the high level principles. This is good, but it also means that the hard work is far from over. How do we define and measure benefits? How do we aggregate the reliability, economic, public policy, and any other benefits provided by transmission investments? What models and tools in place could be used today, or would need to be developed? How do we define and determine the distribution of those benefits? What procedures should be applied to deal with uncertainty and flexibility? How commensurate is roughly enough? How has Order 1000 changed the landscape? Where are the different regions and stakeholders in the process of specifying the answers? And what might be the answers?

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

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Speaker 1:

I want to start out by the normal caveat that I'm here speaking for myself and not for any of my clients. And I also wanted to say that I'm not convinced nor do I believe that Order 1000 was really necessary, and I think that there were a lot of entities that had concerns with Order 1000. There were about 60 requests for rehearing filed, I understand, but we've been asked to sort of assume that Order 1000 was going to go into effect and wouldn't be stopped either by rehearing or by the courts, so I'm going to talk about how we implement Order 1000 assuming that it does move ahead as we go forward.

But the problem is, how should we do planning under Order 1000? How we should do cost allocation? Can benefits be measured and how? Is there a free-rider problem that needs to be solved, as Order 1000 suggested? And, finally, how does Order 1000 help, if it does?

First of all I think Order 1000 is deficient in several respects. Really all of the difficult questions in both transmission planning and in cost allocation have been left to compliance filings. There's very little guidance in the Order itself about how regions are to do things. It just leaves it to regions to grapple over for the next year or 14 months and then file something and FERC will tell you whether or not it's efficient.

There have been some clues perhaps as to what FERC's thinking is in transmission cost allocation--both the MISO MVP (multi-value purpose) project filing and the SPP (Southwest Power Pool) Highway/Byway approach have been approved by FERC, although they're both up for rehearing and FERC has not issued rehearing orders on those. But I think we can probably say that they're indicative of what FERC is thinking in terms of implementing Order 1000.

Some of the key questions are whether or not Order 1000 requires significant changes to traditional planning methods; how to ensure that cost allocation provides efficient and equitable results; and how to move from the theory of planning and cost allocation to actual practice.

To begin with some of the new requirements of Order 1000: first of all, regions must self-identify themselves--the only requirement in Order 1000 is that there be at least more than one public utility transmission provider involved that's a regulated FERC entity. That regional entity has to establish a transmission planning process and has to develop regional transmission plans. Inter-regional planning coordination is required. Public policy requirements must be considered by the regional entities. Regions must have an ex-ante cost allocation method to apply to projects that are included in what FERC refers to as "regional plans for purposes of cost allocation." And neighboring regions must have cost allocation methods for projects crossing boundaries.

With respect to transmission planning first, generally RTO's already have transmission planning processes in place and I believe at least FERC is looking to those processes as being the planning process. Outside of the RTO's there are Order 890 regions and processes that have been set up, and while FERC never specifies this in Order 1000, it's likely that these same Order 890 regions will be used for Order 1000 purposes.

Traditionally, utilities have always had to take into account public policy requirements in their generation and thus transmission planning. If you think back to the Fuel Use Act, which said that utilities could no longer burn gas in their plants, that required major changes to way utilities planned generation and thus transmission planning. So in that sense I don't think the consideration of public policy requirements and planning is anything really new. It may be new in an RTO context, but certainly not new in the traditional utility context.

There may be a problem that exists where load serving entities that have the responsibility to meet public policy requirements no longer have an integrated resource planning process--and those are particularly the retail access states within RTOs and those are the ones that may be affected most by Order 1000. Those areas face a dilemma--should RTOs do integrated resource planning on behalf of those load serving entities, deciding how best to meet reliability, economic and public policy needs in the region, or should load serving entities with the responsibility to meet the public policy requirements, under the supervision of state regulators, decide how to best meet those requirements? That problem becomes clearest in view when states pass RPS requirements that have in-state requirements. For example, Michigan has an RPS that requires all of the renewable resources to be developed within-state. How does that get factored into a regional planning process? My answer is that it ought to be the states and the utilities who are deciding how to meet the requirements and the RTOs should take those as input, or the Regional Planning Process should take those as input in developing regional transmission plans. This is known throughout the industry as a “bottom-up planning process,” which we view as an absolute necessity.

We requested that FERC specify in Order 1000 that bottom up planning should be required, but so far FERC has refused to take our advice. RTOs and other regional planning entities should serve a role certainly to ensure that reliability requirements are satisfied within their areas, and I think generally meeting reliability standards is a public good, and for purposes of cost allocation any area that would otherwise violate reliability standards would have to upgrade their transmission system, and all customers within that area should pay for those transmission upgrades for reliability. But for economic opportunities and transmission needed or desired to help meet public policy requirements, those should be inputs to the regional planning process from load serving entities or generators who wish to help a load serving entity meet a public policy requirement.

Bottom up planning will also help identify the entities that will benefits from investments, thus making the cost allocation process clearer. Regional planning entities will still have the opportunity to examine alternatives, look at cost saving opportunities for consolidation of multiple needs, and ensure that reliability requirements are satisfied.

Projects don’t need to be placed in separate buckets of reliability, economic or public policy. Cost allocation may be different among those objectives, however, based on the type of benefit that’s accrued to the customer.

Overall, in summary, we don’t think that Order 1000 requires major changes in the transmission planning processes already used. It does require that public policy requirements be taken into account, but we think that through the bottom-up planning process, economic needs, reliability requirements, and public policy requirements of each of the utilities within a regional planning process can best be satisfied.

With respect to cost allocation, Order 1000 of course requires that costs must be allocated roughly commensurate with benefits, which I think just about everyone agrees with, and that’s what the courts said in the Illinois case.

That really means two things. First, that benefits must be defined somehow and secondly, that they must be forecast or quantified in a reasonable manner. And they have to be done *ex ante* rather than *ex post*.

Defining benefits properly in our mind is the key to ensuring both market efficiency and customer equity. The Commission in Order 1000 has declined to state what benefits may be considered by regions, and again we think that’s a deficiency and leads to some possible bad results if regions don’t properly define or limit what can be considered as benefits.

I think some broad principles are important for the definition of benefits and how they’re allocated. First, where transmission is needed to meet reliability requirements, as I said, all entities within the planning area needing those upgrades should contribute their fair share. But transmission that provides either economic benefits or that is needed to meet public policy requirements of certain entities, should be paid for by those entities in proportion to their benefits relative to the overall benefits. There really is no difference between an economic benefit to customers and a public policy requirement from a cost allocation standpoint--presumably the public policy requirement was imposed or established because legislature believes that there is either a direct economic benefit or an economic externality benefit to customers from imposing that requirement. And if nothing else, utilities would otherwise have to pay a penalty if that requirement isn’t satisfied, which really leads to a dollar amount of the value of meeting public policy requirements. In other words it really is an economic benefit. It’s not the job of the regional planning entity, the RTOs, or even the FERC to decide what externality should be considered “benefits” in the planning process. We leave those kinds of decisions to legislatures, both Congress and state legislatures, to determine whether or not the burning of coal results in externalities which should be priced, or why they’re not. The creation of jobs provides benefits that should be considered. We should not place RTOs or FERC in the job of legislating policy. Thus regions cannot and should not, in our view, include environmental externalities as benefits for purposes of cost allocation unless those externality considerations result from existing public requirements. But by the same token, we think considering social benefits of investments is a slippery slope and beyond the authority of regional planning entities. Considering social benefits without also considering potential social costs is especially problematic. And finally, while it's probably true that new transmission provides reliability benefits to someone somewhere and sometime in the future, the real consideration should be whether that incremental reliability benefit was wanted or needed by the customer. If you have 99.99% reliability, do you really want to pay for 99.999% reliability, and what value is that to the customer? Also, with respect to reliability, the reliability standards in criteria already take into account the economic impact to customers of alternative levels of reliability. So to the extent a reliability standard has been set, it's been set based on finding the maximum amount of reliability to the customer at the lowest possible cost. Adding additional reliability to that customer is almost by definition not of real economic value. If more reliability is beneficial to the customer, it should be incorporated into the reliability standard and not be assumed to be a benefit to the customer by the regional planning entity. And thus customers should not have to pay for reliability benefits they don't need.

There's a temporal dimension to considering reliability benefits, and cost allocation benefits as well. Because Order 1000 requires an *ex-ante* method of cost allocation, allocation therefore has to be based on forecasted benefits. Utilities have considerable experience in forecasting, and they design planning horizons based on what they believe can be forecasted accurately, and we think that those same time horizons ought to be used for considering benefits within the context of Order 1000. Anything else would be pure speculation.

Also, we think that only transmission projects within the same time period and within the same area can or should be considered together in a portfolio. Most planned transmission lines, as it turns out, don't get built ultimately, and thus relying on a portfolio project to balance benefits across a region is extremely risky because you may get that first line built that benefits a certain set of customers and never get that second line built. It's not clear whether the Federal Power Act "just and reasonable" requirement can be applied to a cluster of proposed projects. And that was another issue that was brought up in rehearing.

I know I'm running out of time here, so I'm going to go quickly. Measuring benefits, Speaker 2 is going to talk about this in greater detail, but suffice it to say I think that utilities have a lot of experience, and they conduct cost benefit studies of investments—both generation and transmission--all the time. In fact those are usually required in order to get regulatory approvals for any investment by the utility. Utilities also regularly conduct transmission planning studies and other forecast studies of the power system and the dynamics of the power system and those can certainly be used to help understand what the impacts of new lines will be in the context of Order 1000.

To summarize on cost allocation, I think cost allocation should be commensurate with reliability and economic benefits, as Order 1000 suggests, but consideration of reliability benefits has to be limited to those needed for the planning area to maintain compliance with reliability standards. Consideration of public policy benefits should be based only on existing federal and state statutory or regulatory requirements and should exclude external or societal benefits not already reflected in regulation. And consideration of economic reliability or public policy benefit should be limited to the region's typical planning horizon.

With respect to the free rider problem that FERC focuses on in Order 1000 as a basis for changing the whole traditional methods of cost allocation--I don't think it's really a problem at all. First of all, the fact that a free rider problem might exist doesn't seem to be a reason to me to socialize costs to those who don't otherwise benefit from a transmission line. But if there is the possibility that some potential users of the transmission are holding back and waiting for somebody else to build it, there are other ways to deal with that, including changing the rates under section 205 of the Federal Power Act, or possibly building lines through merchant means or "open seasons," where all potential uses of line get a chance. And there are other ways of dealing with it--the entity that invests in transmission should get the physical or financial rights to the line and should be able to charge for subsequent use of that line. The Federal Power Act, as I said, provides an avenue to change rates. You could also have a mechanism built into the tariff to allow for a regular review of rates so that rates can be changed if additional users come on who need those particular upgrades.

The road ahead: FERC Order 1000 certainly does not provide clarity and does allow the opportunity for regions to get it right, but also provides the opportunity for regions to get it terribly wrong. We need to keep the objectives of transmission planning and cost allocation the forefront, ensure reliability and efficient markets for generation while providing electricity to end-use customers at the lowest reasonable cost.

What happens if we get it wrong? First of all, we'll disadvantage local renewable generation relative to remote resources because someone else is paying for transmission for the remote resources. Customers may pay for transmission for which benefits are speculative at best. Locational marginal pricing won't provide the right price signals anymore for buyers and sellers, because congestion costs will be subsidized by those who aren't benefiting from the line. And stranded transmission investment could result, as there's no incentive to ensure that the transmission investment we're making is really needed.

Getting it right primarily means ensuring that transmission planning is bottom up based on the expressed needs of load-serving entities; and defining and measuring benefits correctly so that all users of the transmission system face the right price signals, generation is located in the right places, and all transmission users are treated equitably.

Where are we now? There are over 60 rehearing petitions at the FERC. Ultimately there's no doubt that the courts will review Order 1000. I am sure that there are numerous entities that will go to court if FERC does not change its stance on rehearing. Nevertheless, regional planning and regional coordination, done correctly, is a good thing. I think that Order 1000 holds promise to have the right result, but the compliance filings ultimately will tell the tale. Thanks.

Speaker 2.

I'm going to try to complement some of the things that Speaker 1 has already said. The context and background here is that I see transmission cost allocation as a critical part of electricity market design, and it interacts strongly with the rest of the market design in ways that Speaker 1 has already mentioned.

I cited on this slide something recent, which is the President's plans and comments on the Smart Grid, listing what the pillars are. And if you look at the pillars for what President Obama recently described as the objective of his plans for developing the Smart Grid, at least three of the four imply a need for better cost allocations, pricing structures, and market signals. So if you look at the rest of the market design we've already adopted in the organized markets, if you think about the green agenda, if you think about the Smart Grid—if you think about any of these things, they're all entangled with each other and incentives really matter and the cost allocation rules are a critical part of that process.

In the case of transmission expansion, I'm focusing on the mandatory cost allocation framework, which requires a hybrid system that is compatible with the larger market design. Now, I'm going to be talking about that in my few minutes here. I want to just emphasize that there is also the separate question entirely about cases in which people--in loose terminology, merchant investments or other things like that, where participation is voluntary--in other words, cases where people step in and say, "I want to build this and I want to pay for it." So that's OK and for the most part as long as they aren't going to do harm, as long as it's not manipulative, and as long as all the other things that we would normally worry about…

But what I'm concerned about and what I believe Order 1000 is focused on is mandatory cost allocation, where fundamentally what you're doing is using the regulatory power of the government in order to make people pay for something that they say they don't want to pay for. And so that's the framework and the context. If it weren't for that, this would all be easy, and so that's what we're actually talking about. And I'm working with it and recommending that we think about this in relation to the general framework of cost benefit analysis.

I'm going to assume the cost benefit analysis framework as a given for this (we could have a conversation later about whether this is a valid assumption) but I am going to assume that in making decisions going forward about investments in transmission, we're going to do a cost benefit analysis, and as a general rule we would decide not to build transmission expansions where the benefits are not greater than the costs. As a matter of fact, FERC even set a threshold level that you can't require more than a certain ratio, but certainly the threshold that they set was greater than one. So that seems to be an assumption that I'm making.

What I'm going to be arguing is that cost benefit analysis is difficult and challenging but old news. Right? This is something that we know about, we do already, and we've been doing it for a long time. If we weren't doing it, and we were walking in saying, "Geez, we have to do cost benefit analysis," this would be a different talk and there would be a lot of other things about what we would do and so forth, but I'm taking it as given that we're doing that, OK?

And the essence of the argument that I'm making is that, given that we're doing it, we're already producing the information that we need in order to do cost allocation. So in the context of doing cost benefit analysis, doing the cost allocation according to benefits is not trivial, but it's not as difficult as it might seem on first blush. And the gold standard are things like net benefits being greater than the total cost or that sharing is commensurable with the benefits and it's compatible with the larger design.

A critical part of this is the *ex-ante* estimation and allocation, and I won't elaborate on what Speaker 1 already said. I'm going to focus on a term which I use here, "social welfare." I think that is consistent with what Speaker 1 is talking about. I don't mean what I think he meant by "social benefit"--jobs and all the other kinds of things associated. I'm talking about quantifiable effects that we can internalize in a cost benefit analysis. And the critical part about it is that we have to deal with uncertainty because it's *ex-ante* and there's a lot of things that could happen.

And so although I won't keep saying it over and over again, what I'm talking about is an expected present value view of what's going on in terms of costs and benefits averaged across uncertainty in various ways. And that's a challenging thing to do but I think it's something that we do do and have to do. It involves, inherently, approximation of benefits. This is not a counsel of perfection.

I'm going to talk a little bit about reliability, economic and public policy and how to deal with that; and I agree mostly with what Speaker 1 has already said.

An important idea is that of "benefits estimates commensurable across categories for projects." This gets back to the question that Speaker 1 mentioned about buckets. Often when people talk about this problem of the cost of transmission expansion and cost allocation, they talk about reliability lines and economic lines and public policy lines and blue lines and yellow--I don't know, different kinds of lines. And the point here is that there's only lines, right? That is, transmission lines and investments and all the things that go with them, transformers and everything else. And they have an effect which affects reliability and economics and public policy and all these other kinds of things. And so the way to think about the problem, I believe, in the cost benefit framework and going forward, is to think about a given project and all of its potential benefits and we need to make the estimates commensurable across the categories. So we can't have apples and oranges added to pears and come up with fruit when we're doing the cost allocation. We have to get them into some common unit of measure, and I don't think that's that difficult but I do think it's an important distinction to make for what we often say.

As an existence test for the argument that we already do cost benefit analysis so we know how to do it, I've borrowed this graph from the Midwest ISO and the *Regional Generation Outlet Study*. The graph is a little hard to read, so let me just tell you what it says. This is looking forward for transmission expansion projects across a wide region in the Midwest, and it takes as given the state requirements—so RPS--and they have to make some decisions about what's in the RPS and how much of it has to be in-state and how much of it has to be out of state and maybe there are arguments about this and judgments, and you have to do that. But what they do not do is say, "and therefore we're going to tell you which generation is going to be built and then we're going to decide on the transmission." They view this as a simultaneous problem. So there are lots of ways to meet the collection of RPS standards and on the left they say, “Let’s rely on local generation and not do very much transmission expansion;” and on the right in this graph it’s regional generation with lots more transmission expansion; and in the middle there’s a mix of a little more and a little less here, and part of the cost is the new investment in generation and part of the cost is the new investment in transmission, and they plot out all these different points and then somebody drew this curve through here, with sophisticated econometric analysis of the eyeball and to make a conceptual point.

And the conceptual point, I think, is extremely important and correct--so in doing this analysis and planning, you want to consider the trade-offs in investments in different generations and load characteristics in different transmission configurations. It’s not very interesting to make all those decisions and then say, “What transmission do you need?” That’s a much simpler and less compelling problem.

And then secondly, that there’s going to be a place where the cost in the aggregate are going to be the lowest, or the benefits are going to be the greatest and that’s what we should be looking at and choosing going forward; particularly if we’re in the context of doing mandatory cost allocation. And one of the things which I disagree with on the bottom-up argument is that I do not think it is sustainable to have a situation where we say, “We have a bottom-up plan, it is not cost effective, there are better solutions that are much more cost effective, but this is the bottom up plan, this is what we want to do-- now FERC use your mandatory cost allocation framework in order to make the RTOs make the people pay for the things that they don’t want.” I just don’t think that’s going to survive. And so I think what you end up with is doing what the Midwest ISO analysts did here--picking something where the costs are low and then you say, this is the best combination and that’s how we can justify it. I think that’s critical about the whole process going forward.

I’m not going to have time here, and I’m not going to attempt to repeat the conversations we’ve had in the past on this subject. This graphic is from a talk I gave about a year ago about transmission costs and benefits, and what the picture does is it tries to parse all the things that are happening in a conceptually straightforward way with demand for imports and supply of exports, and you have multiple regions, but it generalizes to the kind of case of the real models that we actually look at.

And the point of the picture is that a lot of what is happening in transmission expansion is interesting and problematic because we think that these investments are lumpy and they’re going to come in large sizes and going to have a material effect on prices in the marketplace going forward. (If that were not the case, we’d be in the merchant category story and everybody can pay for it themselves and we’d be happy. And so we don’t need to do that.) And because of that, a lot of what’s going on here is transfer of costs and benefits between various groups, but not expansion of net benefits. And in the picture, for the expansion of transmission capacity represented by going from the black line to the red line, the net benefits are the little areas F, G and H. But there’s a lot of movement of money around from various sources and it’s very important to be thinking about the right things in terms of the welfare analysis. And the right things are to focus on the net benefits, which are F, G and H. And I don’t have time to go through that whole slide, but it’s in that paper that I distributed earlier, and we talked about before. And the point of this page is mostly saying we have a lot of work ahead of us, [LAUGHTER] because I’m just quoting here on this slide from the PJM planning process Manual 14B--well let’s take 70% of F, G and H and 30% of B, you know? And then we’re going to call that the benefit, and add it up and call that a good thing, and so while it might be a good thing for someone in New Jersey that the prices are going down, we certainly don’t want to confuse that with the real net benefits that are actually coming into the system. And there are a lot of reasons, as I’ve argued before, that it’s going to be very hard to base cost allocation on those kinds of changes in market prices. What we should be focusing on is areas F, G and H.

I’ve also quoted, from the Midwest ISO Transmission Expansion Plan, where they were ambivalent on this matter--they’d have a similar kind of rule, but then I quoted from another part of the related study which says. “We don’t actually use it, so that we’re not confused,” but now what I understand from a conversation this morning is that they’ve actually filed to drop the rule that they’re not using to make the decisions and so forth and actually to recognize what they are doing--so good for you. I'll take credit for that. [LAUGHTER]

So the next issue is this question of allocating the distribution of benefits and it simply summarizes the rules that came from paper I had before. The idea was to think of the locations--this is not completely allocating all the way down to individual persons, but it is allocating to locations and types--so loads at locations and generators at locations. And under the assumption that the FTRs (financial transmission rights) that are going to be assigned to somebody are assigned to the loads in this case, it develops a set of rules which have properties that I think are quite robust. They're not the only answer, but they are quite robust, and I don't want to repeat this because we did talk about this before.

I do want to illustrate something that Speaker 1 said about dealing with things like reliability benefits. I certainly agree with him that when we expand, and we produce reliability benefits, that everybody should pay their fair share. But the question is what's their fair share? And what I'm arguing here is that if you unpack most of these reliability calculations, and I took pictures from the PJM method, what they do is they different kinds of target areas or target zones and then they have analysis of transmission capacity coming in to the target zone and then under the assumptions about the zonal interface, they do the loss of load probability calculation inside the zone. And the violation of the reliability standard is that inside the zone, we're not going to be able to meet the loss of load probability calculation. Not outside the zone--inside the zone. And so if you think about that, you say, "OK well those are the people that are benefitting and one way to meet the problem is not to build the transmission expansion, but to build more generation inside the zone," which is going to be presumably more expensive than expanding the transmission. And so if you look at the picture, it just says--this is an extreme case and we might want to argue about this one way or another--but it says before there's an LLP standard, if we don't expand the grid inside the zone, and after there's one inside the zone about how much local generation we need, and the capacity cost of constructing the local generation that we save is the benefit that comes from the transmission. This is a straightforward thing to measure and it does not mean it's socialized across the whole area. As a matter of fact it's saved in the zone. And so we know exactly what the location is.

I introduced the value of lost load just to raise the other way of thinking about the problem, which is, "Well we'll build until we hit the value of lost load criteria and then we won't build anymore," that's the red area. So you'd save that much, but either way the blue or the blue plus the red area in the picture is a straightforward measure of the difference in costs associated with meeting the standard. It is not an evaluation of the standard. So it doesn't tell you whether the loss of load probability number makes any sense or not. It just says if that's the standard and these are the two ways of meeting it, here's how much you save--that's the benefit of transmission.

And I note that this is not, for example, the same as the PJM DFAX calculation measure, which is going to multiply all kinds of people and everybody outside the zone is going to end up with all kinds of benefits [attributed to them]--it's not connected to the argument. The argument is that if we didn't built this transmission or this generation we would have to curtail inside this zone, not everywhere. And so the benefits go to the people inside this zone. And that's the locational answer. So I think that's the way to think about reliability.

The same thing is true for the RPS standards, and again I repeat the picture for the Midwest. And Speaker 1 already said it, and I agree with him--so you say we take the RPS (if we have cap and trade, we get a price, it's all straightforward, we know what to do)--if we have an RPS standard, we take the standard as given and we do what they did in the Midwest.

This says that the transmission benefits are the cost savings versus alternative ways of meeting the standard. It is not an evaluation of the standard. It doesn't tell whether the RPS standard is a good idea, twice too big, twice too small and so forth, and most of the criticism here that I've heard about these ideas is criticizing the RPS standard, or saying that we're saying that we're going to make somebody else pay for New Jersey's RPS standard or whatever. No, that's not what is being proposed, you just look at the change in the cost of meeting the standards that are there and it falls to the people who benefit from meeting it, and if New Jersey wants to have a very strict RPS standard and we don't build the transmission, they'll have to build a lot of expensive stuff in New Jersey. So the transmission saves New Jersey, so the benefits go to New Jersey, so the costs go to New Jersey. That's the logic.

And then finally, just summing up, there are a lot of things that remain to be done that raise difficult questions: "*Defining the horizon of the analysis*," we've heard about. "*Representing uncertainty"*--we've heard about the problem of how do you exactly represent the uncertainty of the analysis. There were other things in the paper that I showed before that come out of the Midwest studies where they are explicit about this, they have scenarios and probabilities and all this stuff that you need to do. "*Choosing the counterfactual"*--this is a little bit more complicated in the context of dynamics going forward and thinking about, "What about the transmission that would have been built and would not have been built?" and so forth, and we can have a discussion about that. "*Harmonizing the investment decisions"*--the RTO or the regional planner should be analyzing generation that they forecast and expect would be built under different transmission scenarios. They may be able to mandate the transmission, but they can't mandate the generation. So it's not the same thing as integrated regional planning--it's a similar kind of analysis, but it's not the same thing. And then finally, "*Eliciting support of the beneficiaries"*--I continue to be a fan of the New York approach in principle, not all the details but most of them, where basically after we get all finished calculating these beneficiaries and we come up with this calculation that allocates the cost to them, we say, "Do you want it?" and if you get a supermajority that is in favor of it--you don't need everybody, so that you don't have holdouts and free rider problems--but if you can't get a significant fraction of the beneficiaries to agree that this is a good idea and to agree to the cost allocation to them, maybe you're wrong and now the question is how should we think about this problem going forward. I think the New York approach is an appropriate one.

And then I put my usual protection in "*Other*." So other problems that we're going to hear about today that I'm going to put in the list? Thank you.

Speaker 3:

While I, also, am speaking for myself and these ideas are my own, I'm going to admit to a bias, and it's probably different from Speaker 1's. A large part of my practice is representing developers of transmission lines. Big ones both on the merchant model and a cost to service model and I would be lying if I didn't admit that I bring that bias to my discussion of this issue.

I'm a lawyer. I start with the law, and in this case the general rule is established by the ICC v. FERC case that our moderator is bragging about, and that establishes the rule that costs need to be allocated in a way that at least roughly gives heed to the benefits of a project and allocates cost in a rough manner based on those benefits. The prior FERC rule, admittedly used primarily for single system projects, was that all network facilities on an integrated system project benefit everyone. So we rolled them in, and a large part of what the ICC case was about was whether that same longstanding FERC rule should be applied for interregional projects throughout PJM and across PJM and Miso, and the courts said no. And I think that the dissent was correct, frankly.

One of the interesting things about that case is that the court's reasoning was based on their perception that there was an asymmetry between western and eastern PJM, and that people in Illinois and surrounding states were going to pay for transmission that was being built in the east and to benefit folks in the east. The project that Judge Posner talked about was the Mountaineer Project, which morphed into the Path Project and which is now on hold indefinitely. But meanwhile we're moving forward with a bunch of lines that are being built in the Midwest to take care of reliability problems and integrate renewable generation in the Midwest, and we're seeing several billion dollars of new investment being proposed there. And so I think what's going to end up happening is you're going to have people in the east arguing the position the people in the west argued in ICC (the Illinois Commerce Commission v. FERC case) and vice versa. And what that says to me is we need to be careful when we try and do ex-ante analysis of who's going to benefit from what and what the best rule is. Things change very quickly and I'll get into that some more. And for Illinois, I think you may find out in five or ten years that you would have been better off with the original roving rule that this case overrules.

Comment: No Way. [LAUGHTER]

Speaker 3: Time will tell.

A couple of points: the court was really not very specific about what it was actually requiring, but one thing that is clear to me is that they are not requiring a detailed cost benefit analysis. Posner understood that that could not be done, and that FERC was not just blowing smoke when they came to the court and said, “We don’t want to stop this whole thing in its tracks trying to quantify something that’s unquantifiable. We’re looking for rough justice. All we’re saying is don’t come to us and say that because you’re part of an integrated network everybody benefits the same and so every kilowatt hour of load gets paid the same amount.” So what the court’s really requiring is some weighing of benefits in a rough way with an understanding that this probably can’t be done in any precise manner.

And I think also as a lawyer we need to go back to the Supreme Court’s Colorado Interstate Gas Decision. These two quotes from that decision have been repeated in probably dozens of FERC and Court of Appeals cases. The point is that this is a matter of judgment. It’s not a matter of mathematics. It can’t be done precisely, and when we’re allocating fixed costs of a system where we have common uses by different classes of customers, we are trying to achieve basic fairness. That’s what we’re after here, not mathematical precision, and I don’t read anything in ICC v. FERC that’s different from that.

I have some fundamental problems with ex-ante comparisons of costs and benefits, and I’m going to stop here and make a couple of points in response to Speaker 2. Speaker 2’s assumption is that we do cost benefit analysis for our transmission projects. We don’t. In fact I think that the MISO multi value analysis is probably the first time that someone’s tried to do a broad-based cost benefit analysis for new transmission. ISO New England has approved 500 transmission projects since its regional transmission plan went into effect. They’ve not done a single cost benefit analysis. I don’t think any of the RTOs are doing them. And I would further point out that although MISO is doing cost benefit analysis for their multi value portfolio, the costs under the existing MISO rule will be socialized throughout all of MISO, which is the rule that the court rejected, and unfortunately MISO is going to have to revisit that rule in the next year and decide how they’re going to allocate the costs, which I think is going to create a lot of controversy that will probably get in the way of those projects ever being built, even though MISO has done the cost benefit analysis up front. I think that if MISO tried to use that cost benefit analysis to allocate costs, which they are not, I think we’d have a real mess on our hands and I suspect a lot or maybe all of those projects would never get built.

Which gets to I think my fundamental point and that is that we’re supposed to be building a competitive market, and in a competitive market people go out and they look at what’s available to them and then they make decisions. So rather than doing the analysis ex-ante, I view transmission as an enabler. I think we ought to be building a robust transmission system so that people in New Jersey can go out and buy ten cent wind power from the Midwest, rather than 25 cent offshore wind power--and those cost comparisons are real. That comes out of the EIA’s analysis.

So I think it’s almost wrong-headed to do an ex-ante analysis, because the whole point is to create a system that will allow the marketplace to work, and the decisions about who’s going to benefit from those lines, to a significant extent, will be made by people in the marketplace after the transmission’s built. And I think a related point is that if we do an ex-ante analysis for cross allocation purposes, we’ll be wrong, because the system will change, our public policy on what we ought to build will change, the economics of different power supply sources will change, and the topography of the transmission system will change. And so five or ten years after you’ve built the line, the costs and benefits that you thought you had quantified appropriately are going to be completely off base.

I also have a problem, because when we talk about building transmission for public policy projects, we’re not doing anything on an economic basis in the first place. We’re trying to take into account externalities, and those externalities are a cost to everyone in society. So if I build a transmission grid in order to enable the integration of additional renewables, it’s because society will benefit from using less fossil fuel and more wind. Now, some of us agree with that, some of us don't, but the basic point is we're not doing it so that any particular load can take advantage of a resource. We're doing it because society is better off. And in that case I have a lot of trouble with the notion that we're going to try and identify localized beneficiaries.

I would also point out that while Speaker 2 is correct that there's a lot of economic work that's been done trying to create an economic cost associated with reliability, that has nothing to do with our transmission reliability standards. Those are rules that are established not always based on loss of load probability. And there are rules you comply with whether it's cost effective to comply or not, and so the notion of a cost benefit analysis in connection with a reliability project is something that just makes me a little bit uncomfortable. It's not what's going on. You either comply, or you're going to have the FERC enforcement division crawling across your company, and that's not a lot of fun. Believe me, I've represented people who've had that happen to them.

I think one thing that perhaps may make it easier to do a cost benefit analysis, and one thing that we need to think about, is that there is at least the beginning of a movement away from looking at individual projects and doing transmission planning on a portfolio basis. And if I'm not mistaken, that is one of the fundamental changes that California put in place with their new regional planning process. Rather than look at individual projects, they're going to try and take a forward look at what California is going to be relying on from a generation standpoint, and build an overall transmission system. So doing a cost benefit analysis for individual projects doesn't make a lot of sense. You're building a portfolio for the whole state, and I think that's what MISO is doing for its multi-valued projects. It's looking at MISO as a whole, and so the whole notion of doing a cost allocation based on line-specific beneficiaries, which is what the Illinois court was talking about, gets a little problematic.

And I'm also concerned that when we do a cost benefit analysis we forget the fact that the benefits of an individual line depend in large part on the line's interaction with the existing network. You look at what you're going to build based on how it changes the flows on the network and relieving congestion, and yet the existing network is paid for in a different way. So we're proposing to impose a specific system of identifying costs and beneficiaries on top of an existing system which is largely being paid for either on a socialized basis or on a postage stamp basis by systems that doesn't reflect any of these cost causation factors.

My next problem with the whole cost allocation debate is that I don't think most debates about cost allocation are really about cost allocation. And I think Speaker 1's presentation illustrates that. We have very broad disagreements in this country about energy policy. Should we have renewables at all? If we do, should they be local renewables, even if they're more expensive? I mean, to me, anyone that would consider building 25 cent per kilowatt hour offshore wind rather than relying on 10 cent per kilowatt hour on-shore wind, something's going on here that has nothing to do with economics. And this is a serious problem, and it makes the whole notion of doing cost benefit analysis problematic for me. What we really have are a lot of parochial interests. We have some states or regions which don't think we ought to have a regional transmission grid. They believe that electricity is a state or a local business, and for some states, that may be right. It may be more efficient to plan on a local basis, but FERC says we now have a regional and interregional--we have a national electric system, and FERC is trying to promote a build-out of that national system so that we look at things on a nationwide basis or regional basis at least. And those are two very different public policy visions.

And that's what's behind the cost allocation debate, not really questions about who's really benefitting from the next line. And so I think Judge Cudahy was correct in his dissent, when he said that he's concerned that the court's rule could stand in the way of getting transmission built. I think he didn't point out, and might have, that not everybody even shares that goal, and even where they share that goal, there may be parochial reasons why people would oppose and want to create rules that make it hard to build individual lines. So I'm not arguing that identifying beneficiaries in advance is difficult, it is difficult; I agree with Speaker 2 that it's very hard. I'm questioning whether it's the right thing to do, and I don't think it is.

And my second point is that I don't think the law requires us to do a detailed cost benefit analysis. I think we ought not to walk into something that is not a legal requirement when it threatens to bog down a national program for expanding the transmission grid.

So where would I go? I would start with socialization, and I would be looking at either an individual line or a portfolio of lines, and I would create weighting factors to try to determine, based on changes in congestion, the location of reliability problems, changes in ATC (available transfer capability), whether allowing bypasses in an area…and I would create weighting factors. I would start with socialization; I would try and weight it so that we are at least in a rough way aligning benefits and costs, recognizing that we don't really know what the long term benefits and costs are. So what I'm really suggesting is a practical solution to something, rough justice, in order to get us past a decision that I consider somewhat unfortunate.

To go back, my view is that doing something like this would satisfy the ICC v. FERC standard. I don't think we have to do more than this. I think we can do it as well as we possibly can, but let's not stop the entire process in its tracks in order to get it done. But if this is not sufficient, step two of my proposal would be to make these default allocations, and if a particular utility, group of utilities, or states believe that the result of this allocation is to unfairly burden them with costs, let them present a study to FERC. FERC can send them down for some litigation over the issue, and let's have a fair and open forum for these people to claim the allocation is wrong. I would require two things. Someone who is complaining about this would have to come forward with a detailed study showing what the correct allocation should be, so that there is something to look at, and we don't get complaints filed by people who just want to get a process started and stand in the way of lines being built. And the second part of my rule is that one of the things that would be analyzed is whether this person is playing sauce for the goose not gravy for the gander. If you want to propose a cost allocation let's see how that allocation works for the lines on your system that are being paid for and are being spread, so that we don't get a situation where people are game playing and trying to take advantage of the FERC 206 process. This, together with my rule one, will clearly satisfy the court. There is a mechanism available for anyone to go after costs and benefits. The project in the meanwhile can go forward, which, as I think you've noticed, is what I'm trying to do. And I think it gets us to rough justice and something that will allow Order 1000 to be implemented effectively. Thank you.

Speaker 4:

It's a pleasure batting cleanup on this panel, because you will, I think, be in store for something a little different than what you've heard so far. I guess what I'd like to caveat, aside from the usual all errors are mine et cetera, I'd like to caveat the presentation by saying that the emphasis I'll have here is in practice what we're doing on the ground as opposed to I think the higher level, more theoretical conceptions that we've heard here before.

So with having said that, let me move on. Actually, before I move on, just an observation. I was at a meeting last week where FERC Commissioner Lafleur spoke, and Commissioner Lafleur noted that in her first year on the Commission she'd be traveling across the country, and the common theme that she heard in every region she visited (and frankly my region is no exception)--the common theme there is that "We're unique, we're different." And she laughed at that, and I had to laugh at that as well, because back when I started working on these issues as a baby lawyer 20 plus years ago, that was the mantra, and frankly it remains the mantra today in the Pacific Northwest. It's refreshing to hear that we're not as unique as we think we are, however.

Now that said, the relationship of that idea here for practice on the ground is this: Order 1000 is, if nothing, evidencing the flexibility that's required for a whole lot of regions, all of whom think they're unique relative to one another. And that flexibility is something that, at least in my part of the world, we applaud. As a practical matter, one of the things I want to emphasize today is that RTOs aren't the only entities that are charged with integrated regional transmission planning processes. Nor are RTOs the only entities, obviously, with obligations to meet public policy requirements. Now in our case, under the ColumbiaGrid umbrella, you can see all 11 of the participants in our sub regional planning program listed here. It's a range from the federal power marketing entity of Bonneville Power Administration to rural hydro generation public utility districts to very urban municipalities to investor owned utilities, as well as a merchant transmission provider, Tonbridge.

The nature of planning--and this is planning that came about as a result in no small part of Order 890 and which preceded the issuance of Order 1000--in our region is independent. It's conducted under the umbrella of ColumbiaGrid for the parties on the previous slide through an independent staff who then work collaboratively with participants, both those who have signed up on the planning agreement, as well as other interested parties who aren't yet signatories to that agreement. In that open stakeholder process, the products are several. One is the biennial transmission expansion plan. The other is a series of studies that feed into the biennial transmission expansion plan. These studies relate to area-specific issues. For example, in the Puget Sound area, the parties to a Puget Sound area study just recently reached agreement for cost allocation for how certain enhancements to that area will be made.

As described in the final bullet, independence is key to the process here. As to cost allocation in particular, the point to make here is that the recommendations are made within study groups. Those study groups are collaborative, not just as amongst the participating utilities, but also with our staff facilitating and making recommendations. Parties are encouraged to reach their own conclusions as to cost allocation, because in the absence of their agreement, the independent board decides. And in the absence of their acceptance of the independent board's decision, the ultimate backstop there is FERC.

Now I want to say something here about the council of perfection that Speaker 2 mentioned. That would not be this independent board. We aren't perfect. Nor are we going to claim mathematical perfection. Rather, the agreement that sets this process up, the Planning and Expansion Functional Agreement, is the product of collaborative negotiation and compromising parties who looked at Order 890 and recognized the need at that time to change how they were moving forward on these within the region issues.

Now on this graphic, the areas shown in red are those facilities currently owned by parties participating in the ColumbiaGrid planning and expansion functional agreement. The blue lines are other western U.S. and Canadian grid level transmission. This is the product of the ColumbiaGrid planning team's annual assessment, and you can find it at the web page. Similarly for the biennial plans that the assessment is comprised of.

I mentioned briefly before the overarching nature of cost allocation under this particular contract. The Planning and Expansion Functional Agreement is binding as to those 11 parties that have signed it. And they agreed to identify within our region particular projects based on the function of that project. And the function of the project there really defines how cost allocation will occur. So, for example, on a single system project, obviously you don't have the same cost allocation difficulties that you would if it were a project that was constructed in order to satisfy existing obligations or if it were a capacity increase project.

And so what we've tried to describe here is the role that an independent transmission organization such as ColumbiaGrid can play through staff working with parties to develop their own acceptable means of cost allocation. In the absence of agreement, then how do you move the ball forward? And, again, the product here is something for which frankly a lot of stretching was done, whether it was on the part of Bonneville Power Administration, the jurisdictional entities Puget Sound Energy and Avista, or frankly the non-jurisdictional entities, whether it's Snohomish PUD or Tacoma-Grant PUD. Arriving at a common contract amongst these entities for how to move forward is the product of a lot of work over time.

As to each of five different kinds of projects (existing obligation projects, requested service projects, capacity increase projects, expanded scope projects, and single system projects), there is a specific path through which transmission planning and the resulting allocations of cost would be handled.

These 11 parties who have joined have all agreed to a certain framework. In the event that the parties working through the ColumbiaGrid study teams arrive at recommendations, the study teams are comprised of anybody who wants to come. Whether it's the participating utility, the project sponsor, public interest parties, all have a role in this open and transparent process. Where the study team that's comprised of these different folks has a recommendation as to an existing obligation project or a requested service project, there isn't a cost allocation issue, because the parties are in a position to work together and decide for themselves how to deal with that.

I contrast that with staff recommended requested service projects. In cases where the parties have been unable to agree on a particular requested service project, the ColumbiaGrid independent staff can bring that project forward and recommend to the Board how costs are to be allocated. And the Board in its own discretion may choose to accept that or take a different route, again with FERC as the backstop there.

The overarching benefits of this kind of approach? Well, it's collaborative. It's coordinated and it isn't a top down mandate. We like to think it's fairly transparent, and that's a function of the independence. As a practical matter, the wind penetration in our region is scattered throughout Washington. It's diffuse; however, a huge amount of it is within the footprint of those parties who are participating in this planning and expansion functional agreement under ColumbiaGrid. As a result, it appears to us that those renewables are finding greater access to market.

I want to switch gears for this last part of the conversation here. What I've spoken of so far is a more narrow part of Order 1000, namely what FERC describes as "within region." In our part of the world it's the sub regional planning. So interregional planning is another matter. It's obvious that we aren't operating in the same handshake bilateral agreement, nor isolated the way that we have perhaps been in the past. Incidents in, say, Arizona have dramatic effects elsewhere within the Interconnection.

However, in the Northwest we've gone about solving those issues a little bit differently than perhaps other parts of the country. I'd suggest to you that the continuum here has been--well, we're not an RTO in the northwest or in the whole of the west for a region, and it's in no small part through the diversity of load serving entities, the diversity of transmission owners and the like. The current context is out of the Federal Power Act. There are eight sub-regional planning groups, one of which is ColumbiaGrid. This map shows what we look like. Under Order 1000, the various sub regional planning groups are really looking to respond to the Commission not only as to their individual sub-regional planning area, but also WECC (Western Electricity Coordinating Council)-wide, because the western interconnect is part of that interregional response that Order 1000 calls for.

So to that end I'll talk a little bit about WECC, and then we'll wrap it up. There are two primary thrusts there that seem to be responsive to the direction that the Commission is taking us with Order 1000. Through the sub-regional planning coordination group, more formalized coordination processes are being developed between these various sub-regional planning groups. The second thrust here is the RTEP project, the Regional Transmission Expansion Planning Project. Out of that project, and actually probably as we speak, the WECC board is meeting and taking up their first 10 year regional transmission plan. And that plan is expected to be forwarded to the Department of Energy later in the month upon its (one assumes) acceptance by the WECC board this week. The 10 year plan accomplishes a fair chunk of where the Commission seems to be going with Order 1000, but--and here's the big "but"--what it doesn't do is specific cost allocation for projects. Nor, frankly, would one expect that it would if you take as an article of faith the ability of the sub regions to continue doing the work that they're doing.

In addition to the 10 year study that is coming out of WECC, there's a 20 year study that is expected in 2013. So efforts are being made to move forward. This map shows the projects and the primary interconnections that are being undertaken in the northwestern portion of the 10 year plan.

I wanted to begin the comments by emphasizing that the flexibility in Order 1000 is something that we appreciate and are working with in the Northwest. Part of the difficulty in addressing some of these issues is that we have compliance filings coming up, including compliance filings on behalf of participating jurisdictional entities. I hope that I've been specific enough to at least whet your appetite for life in a non-RTO region. If the climate and the geography weren't enough, trust me, this part of it is good.

General Discussion:

Question: Speaker 3, I'm going to ask you a question. You start with what the courts say, and I do agree that we've had too much here of these administrative orders that don't seem to comply with the court directives.

But one thing that I was concerned about, is that this tends to ignore what I call the “bucket issue” from Order 1000, which very clearly says you can have a different cost allocation for reliability. You can have a different cost allocation for economics. You can have a different cost allocation for a public policy.

So while I agree with your comment that there may be EHV (extra high voltage) lines built in the western side of PJM, they may end up with a completely different cost allocation through the PJM process. And in fact the current status is that PJM is going to say they are unique and they will not have a generalized ex ante cost allocation.

So the first question is: doesn't that create somewhat of a problem for the balancing issue? And then maybe the bigger question-- and I want to tie in what Speaker 1 said about how reliability upgrades should be with all entities within the “planning area,” (which is a term you didn’t define)--isn't the real problem we're facing large RTOs over many sub-regions? Should we be looking more at that, rather trying to get it precise over such a large area? Should we be looking at homogenous sub-regions, rather than defining the “region” as an RTO? I leave that for Speaker 1 or anybody else also.

Speaker 3: Yes and I think that's what I'm getting at, is the idea of defining sub-regions and weighting cost allocations to sub-regions based on benefits. So the answer is yes. And I agree with you, we don't know what the cost allocation is going to be going forward in PJM. We're going to have a fun year working it out and everybody's on exactly the same page. So yes, I agree with you.

Speaker 1: I agree with that also, and I used the lower cased P on purpose, because I think I wanted to leave the flexibility to have sub-zones within these larger RTOs. I think that just makes an awful lot of sense, because there are localized reliability projects that have localized benefits that shouldn't be spread across the wide RTO. But then there are also projects that may have RTO-wide effects that should be spread across the whole RTO.

Question: Speaker 3, you raised some good points in your presentation. particularly about RPS standards and the consideration not being based on economics. I think in certain cases the externalities aren't always environmental, either.

Speaker 2 had a good slide with the RGOS (Regional Generation Outlet Study) issue-- if the states were developing RPS standards sort of with the economics and the engineering in mind and found that sweet spot, I think there's be a lot less contention than what you have. But my concern, and the issues that I've had in terms of transmission cost allocation, is that unfortunately, I think what's happening is completely unrelated to the economics and the engineering of the system. And what we end up with are sub-optimal builds based upon reliability portfolio standards that I think realistically a lot of the states are just going to object to.

And considering that our state requirements in Illinois are that we view these within the context of the people within the state of Illinois, I don't see any way around the issue of eventually ending up in courts trying to solve these particular problems. I'd love to see the RPS standards and the public policy with regard to environmental being done openly and with a regional basis and with the economics and the engineering of the system being part of the issue, but I just don't see it.

And your comments about the offshore wind builds is a classic example. And Illinois has until this year an in-state requirement that forced a lot of uneconomic build in class three wind when we have class five right next door. Those types of things I think are wrong, but here we are. We're building and making investments on these bases and so what's the solution?

Speaker 3: I think first of all the idea that we have state by state renewable portfolio standards to solve a worldwide environmental issue makes no sense. So that's number one.

Number two, you've reinforced the point I made about states acting parochially. I mean, it's one thing to increase the cost of electricity to account for an environmental externality. Then on top of that, for some local reason, a good one, you want to create jobs in the state, and you want to show that Illinois is green. So that increases the cost some more. And you know the old rock song, "What's Love Got to Do with It?" I ask, "What's economics got to do with this?" And I'm trying to say, "OK, given where we are, which is a basically dysfunctional system from an economic standpoint, let's try and run through it all and come up with something that works and get a transmission system built out."

It ain't perfect. It tries to move in the direction of what's right and what the court requires. But there are some people who don't want to build the transmission system out. Who don't think it's a good idea. And they may be right.

So we end up in the courts. There are some problems that are not fixable if we don't have a national energy policy.

Comment: You know, whether we like it or not, we have a system in this country that consists of a federal government and 50 individual states plus the District of Columbia. We don't have regional governments. And you can call it parochial interests, but if you want, but states do have economic interests.

In most cases if the state has an RPS requirements it's for that key word that we all talk about today, "jobs," and economic development. And should states not have the right to do that within their states? Should states not have any rights to decide how state-mandated legislative RPS policies are satisfied? Or should we give that to a regional entity that has no accountability back to the state? Its only accountability might be to FERC in some sense.

That's really what's under debate here. And I really thing that until we change our system of governance, where we give all the authority either the federal government or all of it to the states, we have to live within what we have, and that may lead to uneconomic decisions sometimes. But we have uneconomic decisions because of our political system all the time in all walks of life, not just electricity.

Comment: I have to respond to that. There are some things states can do and some things states can't do. I hope we've gotten to the point where we all agree that states can't say that African Americans can't sit at the lunch counter.

The issue is, where do states' rights ends? When does the national interest prevail over states' rights? And my view is that when it comes to electricity, we just haven't reached the point yet where we have a consensus on which way we want to go. And we have actors acting in their own interest who push this in one direction or another.

And I just think this is going to be contentious until we decide which side of that line we're on in terms of whether we're going to have a national electric system or we're going to have a state electric system. I think just saying it is a state right or a state interest is wrong. That's the open question.

Question: If I can follow up, is it going to be a commerce clause issue? I mean, are we going to get to the point where we're going to say you can't mandate these types of things if they're going to have systemic effects on a regional basis?

Comment: In Massachusetts, they had a requirement for in-state renewable resources. Trans-Canada came down and said, "Do you want to litigate the commerce clause issues over this or do you want to reach an accommodation?" And they reached an accommodation. But the commerce clause issues are significant, and one wonders how that will all play out going forward.

Speaker 2: I think I'd try to make a slightly different argument about this, and I think it's an extremely important point.

Everything that you said about the RPS standards and in-state requirements and so forth would be a problem from the point of view of economics and whether or not this makes sense and all that kind of stuff, even if they paid for everything themselves. Right?

I'm not trying to set up a market design system which prevents people from shooting themselves in the foot, OK? That's too high a standard. [LAUGHTER]

What I'm worried about is a situation where they want to shoot somebody else in the foot. And that's where we come to using the FERC mandatory cost allocation authority to make other people pay for their dumb decisions. Or good decisions, whichever way they may be. So that's the point about the beneficiary pays cost allocation.

If people want to have RPS standards that they think make sense and you don't, there's another venue for having that conversation. But we shouldn't have a cost allocation procedure which subsidizes that process. We should avoid that as much as possible.

We should be having a beneficiary pays allocation so that they pay for the cost of the things that they're causing to have happen and the cost that they're saving by having this investment. And other people get some benefits and they pay for it, too, and so on.

And I think that's a critical difference. If they want to go forward with something that doesn't come out of the least cost regional plan, because it would benefit them with more jobs, we should have a separate discussion about whether or not they should be allowed to do that, there are a whole bunch of other issues that come up, but they should have to pay for it. I'm just saying is it shouldn't be part of this cost allocation program. And that's why I said in the beginning of my remarks that I'm setting aside all those things where they voluntarily want to pay for it.

Now there are issues where you have to worry about that, because of the major impacts it could have on the market and prices and all of those transfers and that picture from my slides. So this is where the analogy comes in to the problems in the RPM market in New Jersey, and PJM, and the minimum offer price rule, which I've been involved in along with lots of other people—cases where the benefits that people are trying to capture are intentionally designed to change the prices, and they are causing these big swings, and it doesn't actually add to the economic benefit of the system.

That's a problem, and FERC ought to worry about that. That's a different problem. But if they want to pay for it and they want to go forward, we should at least not have a situation where the costs are then socialized. And that's the distinction that I'm trying to make here.

Question: I have a question for Speaker 3. Even though I wasn't around for the Supreme Court's Colorado Interstate decision, this was a very popular decision to quote in the '80s and early '90s.

That was when the FERC policy on gas was rolled in or postalizing rates. In the '90s FERC switched to incremental cost pricing for expansions, which could be classified as participant funding, I think, or maybe voluntary beneficiaries pay. So this was used to justify FERC's rolled in policy. So we've changed that policy, so what's its relevance today?

Speaker 3: Well, first of all, it's still relevant because it's still a law. But putting that aside, I think your analogy to the gas industry makes my point.

I think the decision was made that the natural gas pipeline industry is a national industry. FERC was given the authority to site the lines and to allocate the costs on a national basis, without parochial state interests guiding this decision.

We haven't gotten there yet in electricity, and FERC is trying to push this without that decision being made. And I'm saying if FERC wants to make this successful, we've got to do some things to move it along.

I'm not against incremental pricing. We're not just rolling in the costs of these existing lines, we are pricing them separately. The ICC (Illinois Commerce Commission) case made the separation between the existing grid and the new grid. The question is how to come up with something that works, that gets by the interests that are standing in the way of building out the transmission grid?

Comment: But FERC changed its policy. This was done to justify rolled in pricing and FERC has since changed its policy to incremental pricing and beneficiaries pay and participant funding.

Speaker 3: FERC changed its policy on the gas side. It didn't change its policy on the electric side. And since I litigated Western Mass Electric, where FERC came in to support that policy, I know that quite well.

It's ICC v. FERC which is forcing you to move away from that policy on the electric side. So you haven't changed it.

Comment: But we have. [LAUGHTER] I mean, our policy in gas rate design is now participant funding.

Speaker 3: I understand that, but that's not your policy on the electric side, which is what we're talking about. And there are reasons for that difference.

Comment: But this was a decision on a gas pipeline.

Speaker 3: I understand that and it's been quoted hundreds of time on the electric side.

Comment: I know. It was a favorite of some of our lawyers.

Speaker 2: I have a question for Speaker 3, which is I'm going to pose in the most unfair manner that I can think of.

What I heard Speaker 3 say is that we don't do cost benefit analysis, we can't do cost benefit analysis, and we shouldn't do cost benefit analysis. And I was very clear at the beginning that I was premising everything on the claim that we are doing cost benefit analysis, and we should do it, and so forth, and we can do it. So we seem to disagree.

The question then is, what is the alternative? And then Speaker 3 talks about the cost of power here, the cost of power there, and so forth. So maybe the alternative is informal cost benefit analysis as opposed to formal cost benefit analysis. Or maybe it's undocumented cost benefit analysis. Or maybe it's flipping a coin and trying to decide what's going where.

What is the mechanism by which we make these decisions, if we're not using cost benefit analysis as the guiding framework?

Speaker 3: Your questions require thought, as always. First of all, I think I was right. We don't do formal cost benefit analysis for most transmission line expansions. My point was not that we shouldn't do cost benefit analysis, it's that I think if we try and do cost benefit analysis on a line by line basis, and use it for cost allocation purposes, we'll reach the wrong answer and we'll stop the entire process in its tracks.

So I think rough justice is the right way to go. And beyond that I don't know what to say. I'm certainly not against cost benefit analysis. I don’t think it necessarily applies well to a public policy project or to a reliability project which is being built to meet an ex ante standard, and which itself is not based on cost benefit analysis.

Speaker 2: I'm not suggesting that we should evaluate the reliability standard. I'm suggesting we should evaluate the alternative ways of meeting it and then pick the one that's cheapest. And the benefit is the savings that you get from using the transmission.

Speaker 3: I certainly didn't mean to suggest that we shouldn't choose the lowest cost transmission solution, or choose something other than a transmission solution if there's a lower cost generation solution. If I was interpreted to say that, that's not what I meant. But now, say you've done that. You've decided you're going to build line A. I'm worried about allocating the costs, and I'm not sure that the analysis you did to find the lowest cost transmission solution is going to tell you how to allocate those costs. It's just going to open up a controversy if you try to use it to allocate the costs. They're not the same thing.

Speaker 2: Just for the record, we maybe should move on, but I think this is part of the problem. It's inherent in the cost benefit analysis of transmission that you're looking at different effects on different locations and different groups. That's what it's all about. If it wasn't true we wouldn't need it, because we already have a copperplate system, and we'd be all fine. So the cost benefit analysis inherently identifies that information. That's a necessary part of it.

Comment: Let's take a couple of examples. MISO is about to approve a portfolio of multi-value projects, based on a cost benefit analysis. The existing cost allocation rule says that because these are multi-value projects and they're EHV, we're going to spread the cost throughout MISO.

The FERC rule says that even if a significant part of the benefits are shown to be in PJM, we won't let PJM pay for any of them unless PJM volunteers, which they will never do.

What exactly is it that you think ought to be done in that circumstance? How should we be allocating the costs of this portfolio of multi-value projects in a way that will get us to a solution?

Speaker 2: Well, this raises the regional versus inter-regional question, and I wasn't addressing that. I think that's a mistake. OK? So if we want to talk about that distinction, in this case I would charge it to PJM.

I mean, in principle, the answer is you charge it to PJM, and you charge it to the beneficiaries in MISO. You don't charge it to the people who are losing in MISO. You don't charge it to the people who are losing in PJM. You don't charge it to the people in California, because they're not gaining anything. You probably don't charge very much to Florida because the impacts aren't very large, and so on.

So there's a whole bunch of things like that. I'm not embracing the dichotomy between regional and inter-regional, and I didn't intend to say that. And I certainly didn't say that.

So if that's the problem, that's a problem for the way Order 1000 is constructed, so we should expand its scope, not contract it.

Question: Delaware was among the states that spoke with FERC prior to Order 1000 because we had the problem of getting no response to public policy interests that we had.

So after Order 1000 came out, PJM interpreted that to say, "OK, we'll do the study and determine who's a beneficiary," and we'll look and see how this plays out.

The result of that was, they can identify who benefits, but it's up to Delaware, or whatever state has made this request, to sell the deal to the states that do benefit. (And this is only with respect to the renewable categories.) And that's like a snowball's chance in hell, frankly.

I don't see the other states jumping on board, even though they're benefiting, when they have no obligation to pay. So the practical matter is that public policy will ultimately be interpreted as, "If you want it, you pay for the whole boat load." I think it's totally impractical to believe that states that benefit will step up and say, "OK, I'll share the load because you want a certain thing." So as far as I'm concerned, we don't really have an answer.

Speaker: Well, I think Delaware ought to pay for the line and then preclude any of those other states from ever using it.

Question: If only I had the means to do that. Be assured, if I had mechanisms…

Speaker: I was just kidding.

Question: I know.

Speaker: I mean, that is a problem, but I know that PJM and the other RTOs have regional state committees, and I think that those are the sorts of issues that ought to be worked out through the regional state committee.

It may be a question of whether or not the other states believe there's a benefit. And if they don't, then there's a disagreement on the fact. If the other states see the benefit and still aren't willing to pay for it, then I just don't know what you do about that. But you have that problem today. Order 1000 doesn't change any of that.

Question: That’s my point. Order 1000 on its face appears to be helpful. But it's not going to change a lot of things.

Speaker 3: I think that a regional cost allocation mechanism should be in place which recognizes that the primary benefit is in Delaware, and so you'll pay for most of it, but that also recognizes that there are benefits elsewhere, and so we don't just socialize the cost, but we also don't spend two years trying to very precisely quantify who the beneficiaries are.

We can see where the congestion relief is. We can see where the reliability problem is. We can see where the ACC increases are. And therefore we can in a rough and fair way, come up with an allocation that makes sense. And we ought to do that.

Whether we get there as a result of Order 1000, I don't know.

Question: Actually I have kind of a statement, and then the question I actually had, because I need to say something about the 25 cents versus 10 cents. It's been mentioned too many times.

It's not just New Jersey. I mean, all the northeast governors basically from Maine down want to do offshore wind. And I continually say, you can't do offshore wind unless a governor wants it. All the governors want it.

And it is economics and it is jobs. But I think that they understand that it's more than that. If you build a transmission line from the Midwest to the East, that thing is going to be there for a long time. But, to be practical and looking at it as a citizen of the world and not of this country, carbon regulation will happen. It will have to happen, because if you notice all the weather events around the world, climate change is happening now. So I think the rest of the world is going to force this country to get our act together at some point in time.

So if you build transmission lines now to transport really coal electricity, not just wind electricity, to the East Coast, those things aren't going to be very useful in 10, 20 years when a lot of those coal plants will be shut down. You also have the siting issues. A lot of states really don't want lines going through their back yard. It's a little bit different than gas, although gas explodes, which is not a good thing either. And there are a lot of other issues, having done a lot of hearings on transmission, that people don't like about it. So I don't really think the two of them are completely comparable, gas and electricity.

So I think for the governors, it isn't just the jobs, the short term considerations. It's also the practical reality that those midwest to east transmission lines will likely not be useful--although they could be useful in going in the other direction. Because with the wind off the coast, those prices will change. It's right where the load is. From Boston down to DC, that's where a lot of the population base is. So it makes sense to put the load and the transmission where they are.

Now for my question, which is on a completely different topic. Speaker 1 was talking about integrated resource planning. And there's an issue with restructured states, and there are a lot of people in those restructured states.

I've been saying for about 10 years now that I agree that the lowest cost solution to the load problem is what we should get, and clearly transmission is not necessarily that. Generation may be if it's located in the congested areas and not in the western part of PJM, where we still pay RPM.

But demand response and energy efficiency standards, building code standards, those types of things that Europe has done but we have not, certainly will help lower the need for electricity. And there are other alternatives.

Unfortunately in restructured states, I think very few if any of us have any authority over siting generation. Certainly PJM and the RTOs don't. The planning process is going on with PJM now. They try to deal with that somewhat and they've made some around the edges changes, but clearly speaking, that's a huge problem. Integrated resource planning is not happening, and the problem is if it's done within this large RTO, the members' committees make the recommendations to that governance structure, and their financial interests are what really seem to typically win the day.

And FERC unfortunately sometimes goes with the side of the states, who care about the customers and rate payers, over the members, but not always.

So what do you guys suggest in restructured states that we can do for these planning purposes that include more than transmission? And actually even more than generation, but includes generation as well as demand response, etc.?

Speaker: I'll take a crack at that. I think New Jersey is already doing some of those things. You have an RPS in New Jersey. You have a solar carve out, which of course is going to require local solar to be developed.

And I agree with you. I don't think RTOs are the place to do integrated resource planning. And in fact RTOs were originally designed to create markets so we would get away from integrated resource planning. But I don't think the states are powerless to affect energy policy within their states, and I think states can and will continue to do that.

And I think, as I said in my remarks, it's up to the RTO to take into account state desires for local renewables or solar or offshore wind, not the other way around. The RTO should not be telling the states how to meet their renewable portfolio requirements.

I want to add one thing also to your discussion about offshore wind. Putting aside the whole Solyndra debacle, distributed solar PV is becoming cheaper and cheaper every year relative to wind. And the focus of transmission for years has been on importing wind from the upper Midwest to the Midwest and East Coast.

I think we need to be a little bit concerned about those investments becoming stranded if in fact solar PV becomes cheap enough as a competitive alternative locally. We won't need that wind in the upper Midwest, and we'll have transmission built that shouldn't have been built if we were looking at all the local economic alternatives.

Speaker 3: First of all, I agree with you on the solar photovoltaic. I mean it's a very good point and I don't know the answer. But Speaker 2, I have a question for you in light of that comment.

I mean what you heard was that the governors on the East Coast, for their own very good reasons would prefer to rely on 25 cent per kilowatt hour offshore wind rather than pay for transmission, 2 or 3 cents to get 10 cent Midwest wind to their loads.

They have the right to do that under our system of government. I'm not going to tell them they're wrong, but how do you do a cost benefit analysis of that to determine what the best solutions are? Whether you should spend--the Atlantic Wind Project is what? A five or six billion dollar project? And I don't know how you address that issue economically?

Speaker 2: I think it's completely straightforward. So you say I want to have offshore wind. You have to delineate the alternatives that are available. That's unavoidable. You have to estimate the costs of the alternatives that are available.

You then have to choose the combination of things that look the most appropriate that are the least cost way to meet that requirement and still have the same proportion of offshore wind. And then you have to allocate the costs. I don't see why this is hard.

Now it might be that you have an objection to offshore wind. That's a different question. But if you take as given that the governor says, "I want offshore wind," then there are some different configurations and there are other ways of doing it. I mean, there's a least cost way to do it.

It's not going to be perfect. The delineation of the alternatives, the configuration of the finite number of scenarios that you look at… All those kinds of things that you saw in the Midwest RGOS study are going to be realities for a long time. We don't have the tools to do anything much more sophisticated than that. But that's all right. That's what we have to do. That's what we've got.

Now inherent in that calculation is the beneficiaries who'll fall out of that calculation in just the way it happens in the Delaware story, with the PJM doing that calculation. And if New Jersey wants to pay for the whole thing, and we make sure it doesn't do harm to the grid, then that's OK.

And if they want to make Pennsylvania pay for part it, then they have to go through this calculation and show that this is the least cost way of doing it, subject to the fact that we're taking offshore wind.

Now it might have been a lot cheaper to take the electricity from the Midwest and then have a lot more benefits for Pennsylvania and a lot more cost allocated to Pennsylvania, but they chose not to do that because they wanted offshore wind. Most of the cost is going to fall on New Jersey. That's OK.

I'm not in favor, I'm not endorsing or imposing offshore wind one way or the other. That's a separate conversation about that.

Speaker 3: Your point is well taken. I think what you're saying is that in those circumstances, states along the East Coast should pay for the transmission. They want the offshore wind, they pay for their own transmission. But that's not what they're going to be arguing, I can assure you. They want to spread the cost throughout PJM.

Speaker 2: I didn't say they should pay for the transmission. I said they should get allocated the cost of the transmission to the extent that they're getting the benefits. And if there are benefits for Pennsylvania as well, and this is the last cost way to meet these various things given that wind configuration…

What I don't see is how the New Jersey decision, that they want to have offshore wind, raises the cost for Pennsylvania. That's what I don't see. But I think it's implicit in your argument.

Speaker 3: Because if Pennsylvania has a different view and they would prefer to buy the 10 cent wind, you can't the bulk transmission built for both. And you end up in a Mexican standoff.

I mean we really have a basic situation here where we're either going to spend multiple billions of dollars on offshore wind or the other. And the two are at odds with each other. And both of them are going to try and move as many costs to the other region as they possibly can. That's the way the system works.

Moderator: And I think that's what we have here. A standoff between you and Speaker 2.

Comment: That's precisely the point I was trying to make, though. The one that Speaker 3 has just addressed.

Question: I'm not quite clear on the benefit calculation in the scenario we just described.

We've got a decision to do offshore wind now. So there's going to have be some transmission investment associated with it. In other words, our allocation doesn't have to do with the offshore wind, that's generation, it has to do with the transmission associated with bringing that power in. I think I heard Speaker 2 say the benefit is basically looking at that least cost transmission solution compared to alternatives that we might otherwise be doing.

If that's the case, if we're going to determine the benefit that way and do the allocation of cost based on that calculation of benefit, then how do we get the right counter-factual for what would have been the alternative solution? And isn't that counter-factual potentially somewhat arbitrary and very critical to determining who pays based on the benefits? Or am I misunderstanding something?

Speaker 2: I've been asked this question before. It wasn't offshore New Jersey, however. It was offshore Cape Cod. And the answer that I gave I'll repeat here, which I still think is approximately the right answer, but I said approximately because I haven't really thought it through.

So what's the alternative? Well, we can build the wind and never use it. Right? So if you insist that you want offshore wind in Nantucket or offshore New Jersey, you can build the wind towers and not generate any wind.

Now the transmission comes in in order to actually generate the wind. Then the benefits go to the wind. So the cost should be allocated to the wind towers.

Question: Maybe that's the right alternative and the right counter-factual, I guess. But my point is it's not obvious that that is the alternative that one should be using to determine the benefits.

Speaker 3: The alternative is to build the windmills in New Hampshire and western Maine, where the wind is 11 cents, and build a transmission line down to eastern Massachusetts and you meet your RPS at about 13 cents a kilowatt hour instead of the 25 from Cape Wind.

That's the point I'm saying. That's the debate you have to have. What are the benefits of Cape Wind and that leads to two different transmission solutions.

Question: That's a different question though, because that's clearly not the right counter-factual, because then there would be dis-benefits of doing the project that we're looking at and the scenario you described.

In which case we'd be allocating the dis-benefits. I don’t think that's what we're trying to do here. In other words, we've made a decision to do the offshore wind and now we've got to figure out who pays what for the transmission associated with it.

You've just said maybe we shouldn't be doing offshore wind. We should be doing something else, but I agree with Speaker 2 that that may be an important question, but it's a different one.

Speaker 2: OK. But also if you take that view, the one I described and you allocate the cost to the wind and New Jersey's going to pay for the wind and they're going to pay for the transmission, the other option will now become more attractive, and the whole point.

So if they want to go ahead and do it, let them go ahead and do it. But if they now start considering some of these alternatives and joint benefits and so on, they might decide they don’t want to do it.

And I'm not here in this context arguing what their decision should be. I'm just saying that we should assign the cost to go along with that decision in a way that doesn't transfer those costs to other people.

Now it's a little more complicated and I have to think more about what Speaker 3 about jointness and interaction between things, and foregone opportunities--there's a lot of that out there already and we don’t worry about that.

It's not my obligation to stop consuming electricity so it makes it cheaper for Speaker 3, you know? So I don't count the transfers for him. So we have to think about that carefully. But I still stand by my approximately right answer for the wind.

Speaker 3: This whole conversation to me indicates why I think top down planning will never work in this context as long as we have states making the decisions about how their load serving entities shall meet public policy requirement, and I think Speaker 2 is exactly right, if New Jersey decides for whatever reasons they have that the 35 cents or whatever it costs for offshore wind is what they want to take advantage of, even if PJM has a cheaper solution, then New Jersey ought to have the right to do what they want to as long as they pay the incremental costs of doing that and not impose those extra costs unless there are indicated benefits to others.

Question: Thanks. My question kind of goes back to one of the first questions that was posed earlier, and I make this question knowing that I might make some of Speaker 3’s point and/or drive him to drink.

In a non-RTO regime, isn't it possible that under Order 1000 you might get unintended consequences? So we were talking about moving RTOs into sub-regions. Couldn't you see an RTO region where the state might decide that the region is itself?

This would have two unintended consequences. One, for my home state, Arizona, it would probably get rid of the coolest acronym in all of electricity. It would get rid of SWAT.

And Arizona would begin planning for itself, as opposed to working with New Mexico and the other sub-regions. Especially in the situation where we have to ask our local regulators for that cost allocation. And I'm doing so knowing that half of the state isn't going to pay.

And by that I mean that if public power and the co-ops don't participate, now I'm going to be asking my state regulators to pay for benefits for another state, and I'm only to be using half of the population in my particular state to do that.

Isn't there a possibility that the state regulators might focus in and say, “No, we're going to focus in on Arizona, and as long as those people are paying, those are the folks that we will go ahead and allocate those costs?” And anti-trust issue aside, isn't it safer for me to go to my local regulators and say, “Yeah, these are good things for Arizona?”

Speaker: But say Arizona wants to build a solar generation to export to California.

Question: But California doesn't want to buy it.

Speaker: Well. [LAUGHTER] Sure. I think we just heard that New Jersey should make its own decisions based on what's best for New Jersey. And Arizona wants to make the best decisions for what's best for Arizona. And we can do that across the country, and there's no reason to have Order 1000, right? Because regional planning no longer makes sense?

I mean, the fundamental question is whether we have a more efficient electric system that's planned on a regional and inter-regional basis to try and achieve the most efficient overall system, or whether we ought to have one that's dominated by decisions made at the state level. And until we decide that, we're going to sit here and debate this.

Question: But does the order solve the problem because I think I can be compliant and actually shrink my planning region.

Speaker: No, I think as Speaker 1 has correctly pointed out, FERC has tried to decide the issue and say we want to have a regional and inter-regional grid and we want to try to a limited extent move the states aside without saying that's what we're doing. I mean that's really what Order 1000's all about, is moving us towards a national electric system.

Speaker 4: If I may chime in, I think there are alternative views on that matter. In the flexibility that Order 1000 sets out, it doesn't require either an interconnection-wide coordination process, nor does it require a state by state interconnection coordination process.

Rather what it looks for are pairs of regions without precluding the larger regional definition to coordinate and through coordination undertake cost allocation. And that's the kind of flexibility that I was referring to earlier. It doesn't appear to at least this observer that that's a mandate.

Question: I'm not sure I have a question but I've got a couple facts I might throw on the table. If you all think it's fun to talk about this, you ought to try to do it. [LAUGHTER]

There's a couple of things that are important. When we think about the transmission build out, and we are about to propose $5.2 billion worth of investment in the MISO, there's like four things that have to be true for that to make sense.

One of them is there has to be a policy consensus. The reality is one state at a time, if those states happen to have similar policy goals, that's a top down plan. That's not a bottom up plan.

The regional generation outlet study was all about grouping up the states that had similar kinds of policy goals and seeing if there was cheaper way to do this collectively than there was if everybody did it themselves.

What we discovered as we were working through all that is that any single project doesn't sufficiently improve the efficiency of a market to pay for itself. That's how we got to the portfolio. The reality is if you're going to change the efficiency of that market, you need more than one transformer some place. So that's an important attribute.

You have to have a business case for this at the end of the day. The states ultimately decide whether or not transmission investment is in the public interest. You have to get through that hoop.

You have to have to the cost allocation that matches that over time or the club will blow up, right? The policy consensus is important around the cost allocation, because the policy consensus reveals itself in the cost allocation that's more or less agreed to.

And then finally, don't forget the investor needs to get their money back. So the reality is work on those four things. That's how you get through this.

The RPSes in the Midwest are all similar in terms of their size and in terms of their qualifications around in state/out of state. It's the nexus of two public policy goals that the legislatures did not understand were in conflict: local jobs and low cost renewable energy.

The process that got us to this regional generation outlet included engaging with the governors' offices and commissions of all of those states before we picked what the energy zones might be, so the resultant transmission was in fact a reflection of the collection of the state energy policy goals.

It took, since 2006 or 2007. So here it is, five, six years later that we're finally to the spot where the region has similar kinds of goals and we think we're going to make some progress.

The other thing that trips you along the way is the partisan flips. The new guy can't agree with what the old guy did, even if it made sense, because he's the new guy. We've got a bunch of that going on. But what's important is that broader conversation so that you can achieve that policy consensus.

The two policies that are out there are efficient markets and state by state choices of what the generation portfolio is. It's not that hard to put those two things down on a piece of paper and work that top down plan, but you got to be real patient.

That's the big thing about this. Is it's a long, slow patient game. I don't think that was a question.

Question: Thank you. I wanted to react to something that was said earlier and then try to turn it into a question for you. I'm not sure I agree that it's an impossible task for states that FERC has set out in Order 1000 on the public policy. And I think there are really very good examples--I can't remember the name of the project but there's a transmission project in the New England states where all the states got together and agreed, or several states got together and decided that they wanted that project.

And I think that Order 1000 got this one right, actually. There's some things about the Order that we don't support, but on this one they seem to get the point that met everyone's need. They enable the public policy planning where the states do agree, but they don't mandate it, and they don't require a certain cost allocation.

The question I have is I'm listening to all of these comments and I agree with so many of the different pieces. Like Speaker 3's point. We don't have a federal RPS. We don't. Maybe we will in the future. That would certainly solve things, but we don't. We don't have eastern interconnection-wide planning although the EIPC is working very well together--another example of how states are working very well together and trying to solve things.

But we have regions like MISO who are charged with planning, and they've come up with $5 billion worth of transmission that they've decided they need for their region. And they have the right to do that, and they've obviously decided that it's worth paying $5 billion.

To the extent that has any indirect benefits to neighboring regions, and I know this is an inter-regional example, and maybe a little bit different than some of the regional. But to the extent that has benefits to PJM, for example, they didn't participate in that planning process. They didn't have any say in that planning process. And we keep coming back to example--almost like government decisions. You know, a government decides to build a park. You voted for those people, you decided to support them. They build a park and everyone has to pay for it because everyone's benefitting.

But transmission to me seems so different. It's still a private industry. There is no federal mandate to meet a national RPS. All these decisions to meet state RPS goals are just that. Decisions by those states and those regions to do certain things.

So how do you differentiate, or maybe you don't differentiate, the case where you benefit and even though you didn't see a value, someone else is determining your benefits so you should pay, from the case of just this kind of indirect socialization that could result from that theory?

Speaker 3: No, but I think you articulated well the central issue here, which is that FERC is trying to build a national transmission system. I think that's what underlies Order 1000.

It's a view that electricity is no longer a state and local business. It's become a regional, inter-regional, and national business. And it’s a view that that's the most efficient way looking 20 years forward to build out our grid. And there are a lot of people who disagree with that.

I'm seeing cost allocation being used as a stalking horse to sort of have that political debate played out rather than--I don't know if there is a rather than. And it gets to issues like for example was it a mistake for PJM to expand to the West?

I mean, the utilities along the East Coast have their own viewpoint on what they ought to be doing, and now we have this tussle going on with the Midwest. On the other hand, I can identify a whole lot of efficiencies by having the two together.

So looking at it from a broader national standpoint, it's a good idea. And until we have an energy policy, it's really hard to decide what transmission grid you're going to build. I'm coming from the perspective of people who want to build transmission and think it's a good idea to have a robust interstate grid. And that's why I am where I am.

Question: But if I could just add then, we do have a national policy on reliability. That is distinguishable from the lack of policy on renewables.

Speaker 3: It is a national policy but the reliability solutions are local. In other words if you build a line in New Jersey that enhances reliability on the PSE&G system, they don't get any benefit from that in Illinois. So to try and distinguish reliability, that just gets really dangerous as well.

Every yin has its yang. I really am coming from the perspective that we ought to be looking at the transmission system as broadly as we can. Based on what we know about the economics of generation and our public policy needs, build the most efficient transmission system on as broad a basis as we can. And then enjoy it and let the marketplace take advantage of it. And I may be wrong.

Question: Thank you. Speaker 2, in response to my last question, you indicated that if states want to basically ignore the economics and engage in public policies that weren't the least-cost solution in terms of environmental goals, that it's all well and good as long as they pay for it.

I think that what we're struggling with here is the allocation of those sort of above-market costs. You also mentioned the minimal offer pricing rule that was in response to some proposals that I consider to be very similar to these issues.

I'm wondering if by sort of being fuel agnostic with regard to generation we can solve the problem of allocating the costs to the cost causer there through that mechanism. Sort of being fuel agonistic, whether it's renewable, fossil, whatever the states' proposals are.

And say that if you're going to do this in spite of the least-cost solution, then we're going to make sure that the costs fall into your lap, as opposed to the rest of the system. Is that an approach that we can possibly take with renewables?

Speaker 2: Well, I think the answer is yes. And I gave examples of things that I thought illustrated what that would mean. I'm open to counter examples, because we haven't looked at all these things and I think we should be working through examples like that in trying to think about it.

But I think the answer is yes. And I think it will have a positive, virtuous effect, which is that people will then start recognizing the costs, and then they might wants to rethink things, and so forth.

I've read a lot of these RPS standards and most of them--I haven't read them all but I've read many of them--and most of them have got a footnote someplace that says essentially that our goal is 20% renewables as long as it doesn't cost too much.

And they haven't confronted actually how much it's going to cost. And if you look at other places in the world, I mean Spain is the best example where they had a feed-in tariff and they just retroactively lowered it because it turned out it was too expensive. And that caused a lot of commotion there.

So I think it'll have that effect, but if people want to go forward, and they have good reasons and so on, at a minimum we shouldn't be spreading the cost to other people who are not benefiting.

Now there's a second question which is, even if they pay for it themselves, might what they're doing essentially manipulate the markets so they benefit over here from something else, and that's where the minimum offer price rule issues come up.

Or you might even say for those things, "No, you can't even do that." But that's a much more contentious issue, which is I think is outside the scope of the present conversation. I mean I'd be happy to take that up, but I don't think that's an issue. So I think at a minimum they should have to pay for what they are doing.

Question: I just want to raise a very practical concern that occurred to me while I was reading Order 1000. And I just wanted to know if anybody else saw that issue and if so, if you have any comments on it.

I think Speaker 3 is right that that goal of the Order is to have more national and regional planning. On the other hand, as to the lack of definite standards about what constitutes a planning region--you know, it's wherever two or more public utility transmission planners are gathered together. God is there. You know what I mean? [LAUGHTER]

That, in effect, is what the Order says. That leaves you a lot of leeway in how you define a region. Especially outside of RTO regions, where regions are more fluid anyway, I could see that as really having an economic incentive to go small.

Because if you go small, then a facility which would have been in one region and for which cost allocation is mandatory, becomes inter-regional and then you have to voluntarily agree to assume the cost because the rules are different, as inside a region and between two regions. So I could easily see scenarios developing where people decide they'd like to be in a smaller region because that way they have more control over the costs that are allocated to them.

And when you started talking about sub-regions for planning within an RTO, that really raises some issues, because you may lose the ability to allocate costs across the entire RTO if you break it up into sub-regions, because then they're going to argue that any allocation of cost between those sub-regions needs to be voluntary.

So I'd just like to get the panel's reaction. Am I missing something or is that kind of economic incentive present in the order?

Speaker 3: I've thought about this and I think the economic incentive works both ways because you also, if you're in a bigger region, you spread the costs of your transmission upgrades over a broader region. So to the extent that you are building something that has benefits outside your more local area, then if you're in a bigger region, you have an opportunity to spread the costs.

So I think it could work both ways. I think what's going to drive smaller regions ultimately is this concern about states giving up their ability to control their power supply destiny going forward and making decisions. FERC is trying to push through a certain vision of where we ought to go. But I think your economic issue plays both ways.

Speaker 1: So I kind of agree with you but I would also point out, don't assume that RTO regions are sacrosanct for the purposes of Order 1000. If you read some of the rehearing petitions, I think there's the possibility that you may even have sub-regions within RTOs desiring to become planning entities for the purposes of Order 1000.

That's one of the reasons why we thought that Order 1000 should have provided more clarity in a lot of areas. And hopefully somewhere along the line before we get to October of 2012, we'll sort of know what is and isn't acceptable rather than waiting until the final compliance filing.

Speaker 3: I would point out that the first issue that has to be addressed in the compliance stage is, who's playing with who? What are the regions? His basic point was it's up to you, which, I mean that's going to be a wild and wooly one.

Speaker 4: And to that end, again since my purview appears to be the on the ground experience, subsequent to the issuance of Order 1000, I can report in general terms that there's been no lack of interest in a non-RTO region among non-Columbia grid current participants to our planning program who are interested in potentially joining into that agreement in order to perhaps satisfy some of their compliance obligations, or if they're non-jurisdictional, the other obligations they may be facing. I mean it's been quite surprising both within the region, sub-regionally, as well as inter-regionally, the inquiries that are being floated. And not a bad thing necessarily.

Question: We were just having a side debate here about the confusion over the phrase “regional, sub-regional” and the number of different conversations and categories where those words get used. And they're not used consistently across a number of different organizations we participate in.

So just in terms of trying to keep our own identity straight (we try not to have identify crises but I think it's starting to creep in). So the Cal ISO sees itself within the WECC context as being a sub-regional organization. We're one of the people participating in these sub-regional conversations. But in terms of the FERC 1000 order, we see ourselves largely complying with the regional requirements there and that our tariff that’s in place takes care of not all, but most of the concerns already. So there we see ourselves in reasonable shape moving forward.

I think the question we already heard come up is really applicable to us. We're also trying to figure out who's on the other side of the table when we start having inter-regional coordination conversations.

Because I have to admit, Speaker 4, it's not clear to me right now if Columbia Grid considers itself a regional entity in the FERC 1000 framework and terminology.

Speaker 4: Insofar as we've received clarification, clearly Columbia Grid is a sub-regional planning entity. Our understanding of the intent behind the regional language in Order 1000 is that Columbia Grid, NTTG, Cal ISO, etc., those sub-regions within the broader WECC coordinating footprint, you can interchange those in effect for regional.

Now, I am not the lawyer on this issue, but that’s my understanding of the clarification we've received.

Question: Well, I was a little braver because a lawyer came with me. [LAUGHTER]

Speaker 4: You do raise a good point, and I think that what we're seeing even within the WECC is through the sub-regional planning group coordination efforts that include Cal ISO, that include WestConnect, etc., folks are appreciably understanding a long staple isn't going to work.

And having the additional time, the 18 months as opposed to 12 for compliance, is absolutely going to be necessary for us to come together there.

Question: And maybe I should just clarify as well that when we look at the planning efforts going on within WECC, we see that as a coordination effort as opposed to a regional planning exercise. Because clearly there's no responsibility to carry projects forward to actually make planning decisions within that framework. It's informational, in our view.

Session Two.

FERC's Planning and Cost Allocation Guidelines: Will They Alter the Dynamics of Siting Multi-State Transmission Lines?

The power to carry out transmission siting continues to be borne by the states. Most state laws governing siting tend to emphasize local needs and requirements over broader regional considerations. While the legal paradigm for siting is rooted in a market milieu quite different from what currently exists in much of the U.S., the question of who pays, both in economic and non-economic terms, is critical for most siting regulators. The non-economic issues have to do with balancing the economic benefits a new facility promises against the environmental and other costs to be borne along the proposed route(s). That type of asymmetry is difficult enough in single states, but when the costs are borne in states different than those where the benefits are provided, the siting officials in states where the costs are borne but the benefits are not (or at least not in the same proportion) find themselves in a particularly difficult position to approve a proposed facility. Do they, for example, agree that the proposed laws and cost allocation are fair to the consumers in their state? Can regulators ignore cost allocation in deciding whether or not to site the facility, especially if they are of the view that the allocation is somehow unfair to their state's ratepayers? New lines will change the congestion dynamics and rates, and change the access to and for generating resources. These economic development implications will almost certainly enter into regulators' thoughts in making decisions. The new FERC guidelines may well change the dynamics of regional transmission planning processes, as states try to influence both planning and cost allocation in order to shape the nature of the siting proposals that may come to them for decisions.

Moderator: I've been asked to moderate the panel, which is sort of a continuation of this morning's panel on FERC Order 1000. We're going to talk about cost allocation and siting.

I would say that thus far, in the West, the question about whether state commissions should work together on siting regional transmission projects has been largely in the abstract. There's a willingness to engage in regional siting. We are engaged in regional planning, very actively engaged in the WECC equivalent of EIPC (the Eastern Interconnection Planning Collaborative). We don't have a catchy acronym like that. We call it the SPSC, the State and Provincial Steering Committee. There's a lot of interest in planning. We're very actively engaged, but we're not at the stage on siting.

I'm not old enough to remember if there ever was a debate within state commissions with regard to cost allocation and siting for projects that would be built in one part of the state, have an impact, but would benefit customers in another part of the state, or conversely, when you've got within a retail utility, postage stamping the rates so that the folks in the more densely populated areas are subsidizing customers in the more rural areas.

By the time I came on board, those debates had been resolved, and we look at the broader community, whether it's within one IOU for cost or within the state boundaries in terms of siting—the greatest good for the greatest number. But as soon as you cross the state line today, it's certainly not that way, and what the FERC is asking us to do is to look at our neighbors in our regions as maybe not citizens of a region, but not as our hostile enemies.

Speaker 1:

In looking at the impact of FERC Order 1000 on state siting processes, there are a couple of preliminary points. One is that obviously FERC doesn't have the authority to give itself power over siting, although there is this blowup over whether DOE can give its minimal authority to FERC or not. So statutorily Order 1000 doesn't change the power. There's nothing that FERC has done that at least from a legal standpoint has changed the fact that states have the ultimate say on whether transmission lines get sited or whether they don't.

So I think you have to look at this first from a policy and a legal standpoint. And in doing so, you have to distinguish among the different ways states do siting, at least of those states that do that, because there's more than 20 states that have no siting process in any formal way. But there are really two elements. One is the need or the economic determination about the facility. Do we really need it? And when I say we, the question is, what do we mean by "we?" Who is "we?" And then the second question is, even assuming we need it, what's the environmental impact, and how do we mitigate those costs? Or are those costs so extensive that they outweigh the economic need for it?

So let's first look at the need determination. Because if Order 1000 has an impact on the state's thinking about siting, it's on need determination, because what FERC is calling for is regional planning, which in the organized markets, you already have. And as some of our speakers said this morning, even in areas without organized markets, you have at least, if nothing else, single state or single subregional planning processes that are there.

Now, legally, does that have any effect? For example, even in the tightest arrangements, like in PJM or in any of the ISO regions, is that pre-emptive of the state for purposes of determining need? And under most state laws and under federal law, I think the answer is probably no. Speaker 2 is actually going to talk in a little more detail about that. But Order 1000 doesn't change anything about the state laws.

And to put that in some perspective, Speaker 2 and I wrote a paper on siting almost three years ago now. We could only find three states that even reflected a need to look at regional needs. And Speaker 2 told me last night that there are some others that have gone in that direction since, but it's a small minority of states, in single digits, that even recognize, for purpose of need determination, a need to look outside the state boundaries. And there are some states whose laws are incredibly parochial. Massachusetts and Mississippi in particular are really parochial, in the way they view the need as exclusively in state.

So what seems a reasonable policy argument that states ought to be looking at regional needs doesn't translate necessarily into a legal argument that they have to. And most state siting statutes, as I say, explicitly require domestic need to be considered. Now, many siting authorities don't see themselves as constrained by that. They can look to regional needs, even though the statute doesn't authorize it. But some states, with court decisions on the issue (and that's why I mention Mississippi and Massachusetts) actually are more parochial. There, the state siting authorities actually lack enough authority to look beyond the state boundaries. And few states even require or even reference regional needs, as I point out.

With respect to the likelihood that state siting authorities are going to be talking to each other, and whether the economic determination will play out the same in organized market regions, in the Southeast, for example, there are single-state planning processes. In a sense, Georgia and Alabama and Mississippi are going to talk to each other because they're part of the same network, or they're part of the same company, for the most part. As is the Panhandle in Florida. It's all served by the Southern Company. So within that company there are some planning processes. The regulators may or may not be talking to each other.

But in other areas, the regulators may not necessarily be talking to one another about regional needs. Obviously, what FERC is going to do is require them to do more of that than they have in the past. But part of it depends on the nature of the regional planning process.

So what's the role of the states? Are the states advisory to the RTO, for example, where there's an RTO? Or are they in fact in the position of having a lot of influence over the outcome, or in some cases actual power over the outcome? And one of the reasons why it plays out a little differently in RTO regions and otherwise is that in RTO regions, generally speaking, utilities are not going to be seeking new transmission investments to be put into state rate base, whereas in non-RTO regions, that's still a likely possibility. And if that's the case, states' focus domestically is going to be stronger than they're focus on regional needs. Why? Because you're asking the rate payers of that state to bear all the residual revenue requirements of the line. And so there's an economic incentive, in fact I would argue an economic imperative, to be parochial in your viewpoint.

Now, if you're not seeking rate base, and the costs get spread in whatever way they get spread and allocated, but they're not allocated specifically to one subset of customers simply because they happen to be served by the utility building the line, that's a different dynamic. And so states have less incentive--I don't say no incentive, I'll talk about that in a minute--but they have less incentive to be parochial than when you're trying to put it into rate base.

Now, when you look at the economic determination, what are states going to be looking at? And that's a very interesting question. Because when they're looking at transmission cost allocation, that is almost certainly not where they're going to focus the entirety of their attention, and in many cases it is not going to be even where they focus much of their attention, because there are other costs that are internalized into the operation of this system. Actually, these costs are part of the operation of the system, but are external to the costs of the particular line. And some of these I've listed, and they're worth going through. One is, what's the impact on overall electric prices within the state? To pick a state not at random, one example was the decision on the line that Southern California Edison had proposed to build, and the State of Arizona rejected it. And I think a couple of the commissioners, (if I were their lawyer, I wouldn't have advised them to say it), but a couple of the commissioners actually said that the effect of this is actually going to be to drive up prices within Arizona. And if I have this right, Arizona was going to bear no financial cost for this line, and they still rejected it. Why? Because they didn't want to have an adverse effect on in-state prices, because a lot of the pent up power within Arizona might be exported to California. Therefore, that would drive up the prices in Arizona. Now, you can argue that from an Arizona standpoint, that was a reasonable decision to make. You could argue that from the standpoint of the regional grid, that was not a particularly reasonable decision to have made.

So there are incentives for states to be parochial that have absolutely nothing to do with the line, and there's nothing in Order 1000 that's going to change that focus or require a change in that focus.

Another factor in state calculations is the impact of new transmission on the state's ability to import and export energy. Obviously, if the state has the desire to be an exporter, let me pick a hypothetical example… If New Mexico wants to export to California and has to go through Arizona, Arizona may decide, "If New Mexico's got a great deal, I'd rather just intercept it and keep it here. And so why would I accommodate any additional transmission across my state?" Or they may say, "No, no, we've got our own generation that we want to export. And so therefore, we don't want to do that."

It wasn't actually in those states where that dynamic played out, but it did play out a few years ago in some of the Northeast states, where that exact dynamic did play out. And I don't see anything in Order 1000 that changes how states weigh that kind of consideration.

In addition, how closely the state looks at transmission impacts on markets is also going to be influenced by the position of affected parties. Obviously, energy companies that have access to markets that other companies don't have aren't terribly interested in making sure that their competitors get access to the same markets they have access to. And so there are a lot of interesting dynamics about how the interventions play out and who does what on that score.

There is, of course, also just economic competition among states, especially states that view themselves as exporters of energy or importers of energy. They may want to have access to or promote, as we talked about this morning, domestic production of energy within the state's boundaries for whatever economic development reasons or whatever other reasons. In that case, they may not be terribly interested in doing anything about siting transmission lines that will upset that kind of strategy. And I don't see anything in Order 1000 that requires states to do anything other than to continue to look at those things and do what they want.

Then the other question is: how will this impact the competitive balance? What's the impact on competition? You can see here, as I mentioned, the example where affected parties could actually either intervene or cause interventions to happen by disinterested citizens groups that just happened to get their money from an interested party, and basically intervene to skew things in ways that benefit them in a competitive market. What will states do in terms of considering the impact on competition? That's not clear. And state statutes vary pretty widely on how they should look at that for siting purposes.

We talked this morning about how differing RPS requirements or lack of RPS requirements will be considered, and about the effect of intermittency and wind resources. Some states are going to rely on it. Some states aren't going to want to build transmission just because another state wants to build wind or solar, which are intermittent resources and may cause other problems and other expenses. There are a lot of considerations related to that.

And then of course, also, many states (not all states, obviously) still have their own integrated resource planning, or their own planning process in one form or another, and how exactly plans for a regional lines impact that resource plan will become an important consideration.

So on the need front, FERC Order 1000 will have some impact. It certainly will force states to talk to one another if they aren't already doing so, and in some regions they already have effective communication. In some areas they don't. But I think the impact may be not as great as some people may hope it will be.

On the environmental review front, nothing about Order 1000 changes any of the problems on that front. Number one, the asymmetry between benefits and environmental insult doesn't change at all. The extent to which environmental degradation occurs in areas that lines pass through in most cases doesn't correlate to where the economic benefits of the line are. So that asymmetry continues to exist. So states that don't want to suffer any environmental insult for a line from which they see themselves getting minimal or no benefits, nothing much changes. Order 1000 doesn't change much of that.

There's another question, which Speaker 2 may get into a little bit, which is, will planning have an environmental impact component, and if it does, what effect does that environmental review have on the state's own statutory requirements for environmental review? That's another area where if there's any pre-emptive effect, this could have an impact. I don't think there's a pre-emptive effect, but Speaker 2 has looked into this more closely than I have.

Will regional planning pre-empt state environmental requirements? On the face of it, I don't see how it would, and there's no federal statutory scheme that would overrule the state. And of course, even if there was, there would still be questions about whether the state could impose its own environmental requirements that are more stringent. But in this case, I don't think you even have to get to that second question. Speaker 2 will speak to that, as well.

Will compensation to localities for environmental insult be part of the planning? How will "environmental" compensation be treated for prudence purposes? Notice "environmental" is in quotes. That means, who's going to pay for the fire house in the town that doesn't want the line to go through it? Who's going to pay for the municipal park? How is FERC going to look at those costs--the "extraction" of local tolls? (Trying to put this in generous economic terms, as opposed to using horrible words like "bribes.") How is that going to play out for looking at the prudence of the costs that are being incurred? Are there people who are going to see those costs as imposing extravagant benefits on somebody else that they're not getting? So there are a series of questions that you could see becoming troublesome in the process.

To what extent will the focus of environmental reviews change from local efforts to broad regional effects? One of the drivers, of course, of building more and more transmission is to move environmentally benign energy, wind and solar in particular, to move that to load centers that are distant from location of production. There are few, if any, states that even recognize that as a legitimate reason to build transmission, which is amazing. So the environmental reviews, for the most part, in the states, are not focused on understanding the impact on regional air quality, or the impact on carbon emissions or emissions, or SO2 emissions or whatever. The environmental impact focus is on the local effect--the effect on the river that it has to cross, the effect of proximity to EMF… All those kinds of issues that are local. Whether there's an adverse impact from EMF or not is a controversial subject itself. But even if you assume there is, it's a local issue. It's not broad scope.

So, is there anything in the regional planning that will force states, or at least cause states, if not compel states, to look at the broader regional effects? That becomes an interesting question. I don't know if it will. It might. It could cause it. I don't think it mandates it.

And then you have the question that was sort of implicit in the discussion we had of New Jersey this morning. If you build a line to link New Jersey to the wind resources of the upper

Midwest, there's nothing that says coal generated power doesn't leak onto the line, and what's the impact of that, and can you then say, "Well, we don't really want to site transmission, because it's going to lead to more carbon emissions, even if nominally it's supposed to lead to the production of more renewable energy." That's part of the argument that gets made for why some of the governors in the east prefer to have local resources rather than more distant ones.

So does anything in Order 1000 change much of that? I don't think much at all. And I just don't think it changes the dynamics very much, except in an informal sense. It may provoke states to think more about these things, but it doesn't necessarily give them the statutory authority to consider it.

Then you have the question of the institutional arrangements. I mean, first off, in more than a substantial amount of states, actually, local zoning bodies have authority. Now, to go into the local zoning board in some small town in the state, and tell them, "Well, we've gone through this regional planning process at the RTO, and they've determined this line is needed…." That will really impress the local zoning authorities. [LAUGHTER] I mean, they're just going to go home immediately knowing they have to approve this.

So one of the questions is, what's the role of the PUC? Because at least in theory, and I think in fact, they're going to be the most informed about the regional planning process, the regional energy needs, and the fact is, in close to half the states, the PUC doesn't play much of a role in the siting process. Even in states with siting institutions, the PUC doesn't always play a role. And in most states with siting processes, the PUC is one actor among many, although as a practical matter, it may be the dominant actor in some states. So the fact is, siting authority institutional arrangements in states are important, because siting authorities may not in fact be people who know much about regional planning and what's going on.

And then there's the whole economic development issue. State siting officials are always going to be subject to a lot of pressure on how the state views these lines as affecting their economic development. I talked about that earlier in terms of parochial economic concerns, local jobs, those kinds of things. That may play a role, and I don't see anything in Order 1000 that precludes states from considering that. And in fact, if states are unhappy, siting becomes effectively the means by which a single state can veto whatever the planning process is. And if they do it cleverly, it will be very difficult to challenge it in any legal sense. That's why I would have advised your predecessors not to have said publicly the things they said. That would have made great stuff in a deposition, but Edison dropped the proposal, so it never got to that stage, disappointing an awful lot of lawyers who were looking forward to those depositions. [LAUGHTER]

And then there's the question, of course, of eminent domain. In most states, eminent domain is not available for out of state entities, or even in state entities that aren't utilities. And in some states, and I mentioned Mississippi earlier, the reason is because of the Connelly decision by the Mississippi Supreme Court, which basically said that if the majority--and this is literally their position--if the majority of benefits are not in Mississippi, you don't get eminent domain in Mississippi. It wasn't even a question of whether there were any benefits. The majority of the benefits, and you could imagine the Mississippi Supreme Court trying to figure out very precisely where the majority of the benefits go. So eminent domain is just not likely to be possible. Eminent domain is not a siting issue, per se, but it's an issue I think one has to think about in terms of thinking about the impact of Order 1000 on the likelihood that the planning process will produce concrete results with facilities that can be built in economic terms.

Finally, the behavior of parties is a consideration. Obviously, for a competitor in the generation market, for example, who feels that their market position is going to be undermined (or enhanced, for that matter) by building a new facility, this is a second bite at the apple if they're disappointed in the regional planning decision. This is, they can come back on the siting, and it's amazing how quickly people can become green and be insulted by the environmental devastation being wrought by this new line, which of course if it had been built in a different place, they would have been the champion of environmental insult.

And then, what is the environmental focus? The interesting thing about looking at the environmental community on transmission siting is that it's (I'll overstate it) a civil war among environmentalists. The land and water folks think generation should be close to load, whereas the folks that are concerned about air quality issues, particularly carbon, are all in favor of (within constraints, obviously) building a much more extensive transmission system. And then, of course, there are folks that think demand response should solve most of these problems and obviate the need for new transmission. And all of them can participate in the siting process and take these positions. And to the extent to which state siting statutes provide them with opportunities for making an argument, it's going to be there. And that's what I'm referring to as the "second bite at the apple." You can participate in the planning process. If you don't like the result, you get a second bite. So effectively, what you end up with, I think, is that the single state veto in the siting process is still present and can still occur.

One caveat on that, and then I'm going to close. That's assuming the state exercises some judgment based on how it views its self-interest. But keep in mind again that 22 states have no siting process at all. None. And in some cases that means utilities--or maybe other investors, usually utilities--can build whatever they want and wherever. Or in other cases, it means local zoning boards decide everything. And so the opportunity for parochialism, having nothing to with regional planning or even concerns about electricity, remains in place, and the only way that ever gets fixed, I think, is by an act of Congress, not by action of FERC.

Speaker 2:

At the outset, I should apologize for two considerable deficits that I bring to this conversation. First, it's been about 20 years since I was in legal practice. So as a law professor, I often hear about events like Order 1000 after they're announced, rather than being involved from the ground up. I don't have as much information on the ground as many of you do. Secondly, as a law professor, I suffer from a kind of arrogance when it comes to discussing legal issues. We like to consider ourselves experts at a general level in almost anything. So most of the time I'm hovering at about 40,000 feet, and then FERC does something interesting, or someone else does something interesting, and we kind of think we can parachute in and save the day. So I apologize in advance for these deficits.

But today, I want to try to raise three pre-emption themes. The first theme I'm going to talk about is cost allocation. Part of the reason I'm going to do this is because, as I'll try to convince you later, there's a connection between the significance of pre-emption and cost allocation and the extent to which there's any legal pre-emption in siting decisions of state and local governments. Now, there may not be legally pre-emptive effect, but there could be some pre-emptive impact in what happens in cost allocation that trickles down into the siting process, as Speaker 1 alluded to.

The first theme I'm going to talk about is whether FERC's new cost allocation principles pre-empt state cost recovery decisions, and especially the extent to which they might require pass-through of transmission costs in states which have bundled rates. And the answer to this question is yes, to a large extent, as I'll try to illustrate for you later.

The second question I'm going to address is the siting pre-emption question. I'm going to echo many of Speaker 1's observations in answering the question, "Is there any FERC pre-emption of state or local transmission siting authority?" with a clear no. I don't see a legal pre-emptive effect. At the same time, I'll discuss what I see as some pre-emption implications for siting that I think flow from the cost allocation.

Then, getting back to my law professors having an arrogant perspective on issues theme, I'm going to conclude by discussing whether I think there's a federalism concern with potential back dooring of some state public policy requirements into regional and federal cost allocation decisions. And especially the extent to which Order 1000 might set the stage for down the road imposing these on customers in other states, particularly where other states might have even rejected the same goals that FERC or RTOs are endorsing.

So in talking about pre-emption, it's always useful at the outset, whether you're talking about Congress or an administrative agency, to ask what the intent of the agency is. And at least with respect to siting, I think FERC was very clear in Order 1000. If you look at the Order, over and over again, FERC claims that nothing it's doing is intended to pre-empt states. And when it says this, it almost consistently is speaking to obligations to build, planning, construction, permitting, and siting. And it says over and over again that nothing it intends to do here pre-empts siting, permitting and the like. I've mentioned five of these locations in the Order here on my slide. It actually alludes to pre-emption in several other instances in the Order. Never, though, in the Order does it speak (explicitly, at least) to pre-emption of cost allocation. It doesn't give us a really explicit sense of its intent here.

The problem with pre-emption, of course, is that you've got expressed pre-emption sometimes, and often you need to scratch the surface and try to sniff what's beneath, in terms of what the agency is really attempting to accomplish. And I think that's true with respect to both cost allocation and siting, at some level.

Moving on to cost allocation, the cost allocation pre-emption aspect of the Order can have some significant implications for siting. And here I'm just summarizing what others have really said about cost allocation. FERC, of course, claims to be addressing cost allocation, not cost recovery. I'll come back to that theme a little bit later. There's no single default, but there are six basic principles, as we know, that guide cost allocation in Order 1000. The basic move of significance is that any proposal for a new transmission facility will need now to identify the beneficiaries who will pay for the cost of the new facility in a regional plan, for purposes of cost allocation. And those beneficiaries, significantly, can be allocated costs even in the absence of a contract, according to Order 1000.

The real rub here is how we define "benefits" in these decisions. And the Order says many things about this. A particular part of the Order references this list of benefits: maintaining reliability, sharing reserves, providing production cost savings and congestion relief, and then (the issue that of course is the big elephant in the room) meeting public policy requirements, whether those are state public policy requirements or federal public policy requirements, or perhaps even local public policy requirements.

Now as an illustration of the jurisdictional impact of FERC's cost allocation requirements in Order 1000, I think it's useful to think about the implications this might have in states that have bundled rates, as many states in the Southeastern U.S. do. Southern Company, for example, claims it recovers only 15% of transmission revenues through its open access transmission tariff, which leaves 85% of the cost of transmission in its system to bundled retail rates. And if you look at the comments and the requests for rehearing that were filed on Order 1000, Florida, Alabama regulators echo this kind of a concern.

An additional problem that follows from Order 1000 that some commentators have highlighted, both in the comments and in the requests for rehearing, is that allowing non-incumbent transmission providers comparable cost recovery could potentially force state rate payers to pay for facilities that they do not benefit from, at least under state law, as to state law's definition of the benefits, because of the blended nature of transmission assets, that is the inability that we might have to separate the bundled from the unbundled components of the transmission cost, post Order 1000. This raises, of course, the issue of the extent to which FERC, under the Federal Power Act, can reach into a state's bundled retail transmission. And I would argue it's pretty clear that FERC has a sound jurisdictional basis for doing so, at least under the text of the Federal Power Act, Section 201, which as most of you know, gives FERC considerable jurisdiction over the transmission of electric energy in interstate commerce. It also speaks to all facilities involving transmission. And this jurisdictional grant of authority is pretty distinct from provisions elsewhere in the Federal Power Act that really only speak to the sale of energy, which extends to sales for resale only, or wholesale transactions only. So we've got considerable reach jurisdictionally, and FERC has articulated this free rider purpose, which many discussed this morning in allocating costs.

Certain concerns flow, of course, from the Seventh Circuit opinion, Illinois Commerce Commission versus FERC: concerns with cost causation and beneficiary pays principle which reinforce the need for broad federal jurisdiction over cost allocation. Other issues flow from the MISO case out of the DC Circuit, which asserts the need to assess "an extension of the chain of causation," all the way into the state retail rate components. So this is pretty considerable pre-emptive reach with respect to state cost allocation, FERC's cost allocation principles and the impact on states, even states with bundled rates, such as those in Southeastern states.

This raises the issue of the extent to which, if at all, state consumer advocates might be able to challenge cost allocations or disallow costs following FERC Order 1000. And this is a question that I think is of important relevance in some states, where consumer groups or state public service commissions might not want to see state rate payers paying for lines that benefit the region, rather than directly benefit, in their view, the customers in that particular state. Now, under the filed rate doctrine, in cases like Nantahala, there is a pre-emptive effect that these FERC-approved tariffs or cost allocations would have over state decisions to the contrary.

At the same time, there might be some space that's left for state regulators to play in decisions about cost allocation. There is, of course, the issue of who among retail rate payers pays which costs, and state regulators will still have some authority to decide intraclass cost allocation issues among retail customers within their jurisdiction. And moreover, there is the Pike County exception to Nantahala and the filed rate doctrine, suggesting that in a prudency determination, state regulators may still have some potential to determine that a utility acted imprudently in its purchase decisions to use or rely on regional transmission or transmission facilities that are broader than that particular utility or jurisdiction.

Now, there are problems, of course, with this Pike Country exception, post Order 1000. There's one issue as to whether Pike County even applies to transmission after Order 1000. Arguably, FERC has completely eviscerated the Pike County exception with its cost allocation principles. Even if Pike does apply and gives state regulators some space in which they can disallow transmission costs, when regulators have to deal with regional assets in geographic areas where all the power purchase options are embedded in or entangled in larger transmissions systems, there aren't many options. There are, though, some non-transmission alternatives, which FERC expressly refused to include in Order 1000. Those include distributed generation. Arguably, they could also include things like conservation. And this observation really just echoes an observation someone made this morning that some aspects of FERC's decision in Order 1000 might push some regulators and some utilities towards a more isolated sort of approach, rather than encourage them to participate in the larger regional effort.

Now, this panel is about siting. So I want to make the connection to siting. As I mentioned, I think that siting pre-emption is at some level embedded in cost allocation for a couple of reasons. One reason is that, as I mentioned before, FERC keeps expressly saying over and over again, "We're not pre-empting siting." Secondly, I think it's embedded, because as Speaker 1 argued convincingly, if you look at what FERC is doing in Order 1000, it's hard to argue that there's any direct pre-emptive effect to the legal moves that FERC's making. At the same time, I think, there are some broader connections, and I'll come back and talk about those in just a few moments.

First of all, I'm going to echo Speaker 1 here. It does not seem to me that Order 1000 has any direct pre-emptive effect over transmission siting at the state or local level. States can still control who applies for siting, as Speaker 1 pointed out. They can control the right to eminent domain, and they can limit non-incumbent utilities from these application procedures and benefits. States can arguably also still refuse to site because of environmental concerns, and FERC and RTO findings regarding environmental impacts do not, in my opinion, pre-empt state or local governments under environmental statutes.

Now, there are some federal statutes that could come into play here, depending on how, operationally, FERC and RTOs decide to implement Order 1000 statutes, such as the National Environmental Policies Act. As to the pre-emptive effect these would have over the states, I think in most of the environmental statutes at the federal level that would be implicated under NEPA review, federal law forms the floor, and the states can go higher. So NEPA could form the environmental floor, but that doesn't preclude states from taking into account even greater environmental concerns.

And of course, since we don't have a federal climate change law, or federal cap and trade, or anything like that, you don't see really carbon or climate change concerns under federal law being the primary drivers of the environmental concerns that would have a pre-emptive effect. If that were to change, perhaps we could have some pre-emptive effect under state siting statutes. That's the environmental side.

As to need, states can arguably still define benefits in the need assessment for siting purposes in ways that are particular to their state concerns. Interestingly, these have a feedback effect. If a state makes a determination of need, or no need, this arguably could become a regulatory requirement that in the future is required to be taken into account in planning. At the same time, if need defines benefits for a particular state, in a way that parallels or derives from that state's definition of benefits in other regulatory scenarios (and here I have in mind rate decisions, decisions whether to include something in rate base, or to disallow costs from a class of customers, and the like), if operationally states treat the tests as similar or parallel, there might be some pre-emptive effect here on the state, because now the way you determine the need for rate payers will be potentially pre-empted by FERC in its cost allocation approach.

Even if we don't have these direct legal pre-emptive effects, I would argue there are some indirect impacts on siting that need to be taken into account here. First--and this is pretty obvious. It's been touched on by Speaker 1 and alluded to by others as well-- FERC and RTO endorsement of transmission lines in the planning or cost allocation process undeniably will give some projects additional political leverage in the state and local siting process. A second thing I want to highlight, though, is the cost allocation pass through in bundled rates can actually reduce any opposition and siting that comes from consumer advocates. In some states, consumer advocates see the siting process as really an opportunity to get the first bite of the apple on cost disallowance, and if the costs are going to be recovered anyways because of the pre-emptive effect of cost allocation, that might discourage them from participating in that manner.

I just want to conclude with a note of law professor arrogance on the big picture issue of federalism. This is the big elephant in the room that folks were alluding to this morning. States' public policy requirements are incorporated into FERC RTO decisions here. I think it's pretty clear in Order 1000 that FERC thought Order 890 was insufficient with respect to RTOs, and even FERC consideration of local and state requirements. And my reading of the Order is that FERC is saying now that RTOs must consider these requirements in their decisions.

The significance of this, of course, is that there's an asymmetry of requirements across the states. In the Southeast, only North Carolina has an RPS. Which raises the issue of whether Order 1000 has a cooperative federalism angle. Think about PURPA (the Public Utility Regulatory Policies Act), a statute that defines federal goals and relies on states to implement them. But what's significant to me is that Order 1000 takes an additional move. It's kind of reverse cooperative federalism. It invites individual states to set requirements for implementation by regional bodies and endorsement by FERC. I'll leave for discussion later whether reverse cooperative federalism of this nature is legally permissible. I think there are arguments that it is. There are also arguments that it can go too far, and that's being played out in the context of other statutes, such as the Clean Water Act and in coastal management as well. So with that, I'd like to conclude. Thank you.

Speaker 3:

From a practical perspective, whether there is an impact on transmission siting, we probably won't know the answer for many years. You heard the legal answer, and it was fascinating. We're certainly going to have lawsuits about all of these issues. But however they turn out, there is likely to be some impact. How significant and whether it's nationwide or whether it is specific to some states and some regions and some specific projects, is yet to be known.

Today I'm going to share a utility's views of what those impacts might be. And our views are based upon our role as a transmission company, a transmission owner, someone trying to build transmission, and someone trying to build transmission in a very congested part of the country. Being located in a very densely populated state has definitely had a significant role on our transmission needs, as well as our transmission build out.

We are in the process of building a significant amount of transmission. We have some of the projects listed here. These are not all of the projects. These are the more significant projects that have come out of the PJM regional transmission planning process, as the slide indicates. Over 50% of our planned capital spending between 2011 and 2013 is expected to be in the transmission area. So siting is very important. Getting these projects actually built and completed is important from a reliability standpoint, as well as a financial standpoint. Each of these projects is a reliability project. And all of the projects, except for one, are located solely in one state.

So what have we learned from planning these projects and siting these projects and moving forward? Well, we've learned that siting transmission is really challenging. It's much more challenging than the planning process. It's much more challenging than the cost allocation process. Actually getting through the various siting requirements and the numerous approvals that are needed is certainly, from my perspective, the hardest part of the process. The construction part, our engineers keep telling us, will be the easiest part. Once we actually get all the approvals to build it, they feel pretty confident that they can do it effectively and within the time that they've planned.

And why is this? My view is that people just don't like electric transmission. It really is distinguishable from natural gas pipelines in many ways. People have to look at it all the time. It's near their houses. People have built closer and closer to those right of ways that have existed for so many years. People are in some cases uncertain about the effects of EMF--whether there is a legitimate issue, or one only in their minds, or they're just using it for their advocacy purposes, is sometimes difficult to know. But the EMF issue comes up a lot.

So at the end of the day, there's no doubt that building transmission, whether we have Order 1000 or pre-Order 1000, is a very challenging process. There are numerous approvals that we have to go through. In our state, you don't have to go to the BPU (Board of Public Utilities) to site a transmission project. You can go municipality to municipality, and often that is the way transmission is built. You can get the various construction permits. But when you're going at least through two municipalities, a public utility has the right to file at the Board of Public Utilities. If you choose the municipal route, you still have to go to the BPU to use eminent domain.

There was a little bit of discussion earlier with regard to eminent domain. As a transmission owner, that's the last thing we want to do. Using eminent domain is a last resort. People don't like transmission projects, and they really don't like when you have the government come in and tell them that you have to take away their property. Almost all extensions impacting property rights are done through negotiation.

The challenges that we face in these various government approvals are probably first and foremost coordination and timing. Transmission projects are planned numerous years in advance, but the length of time it takes you to get through these various approvals, and the sequencing of these approvals, can take multiple years. And coordination between those various approvals, as well as the outages that you have to plan a year in advance in PJM, can really be one of the biggest challenges.

Once you get into the substance of the proceedings, the issues that we generally face are whether the project is really needed. Even though the RTO has already decided that it's needed, I've never found a municipal entity or the BPU to just accept that. They want to go through the whole process again and make sure that they're comfortable that the project is needed, and whether there are alternatives to the project, and depending on the siting entity, they might want to look at generation or demand response alternatives, and they also want to look at different routing options.

The cost is always an issue when it comes to trying to understand what the alternatives are. And that's really, from our perspective, where cost allocation comes up. If the siting entity has an unknown cost allocation component that's going to be decided in the future, or potentially subject to change, it's difficult for the entity to understand how to compare alternatives. The impacts and mitigation--again, this is where the property owners come in--how close you are to schools, how construction might impact local residents, as well as viewshed impacts, and a variety of other impacts and aesthetics... Aesthetics comes up in every project. People want to make sure the towers are smaller, that they're compact, that there are less of them. We try to design our projects, as I believe all transmission owners do, anticipating this, trying to use rights of way that already exists, trying to use existing towers, trying to keep the towers low, trying to do reverse phasing, so you minimize the EMF impacts. And we always have to think about contingency planning, knowing that the reliability issues and concerns are still going to be there, no matter how long the process takes.

So you have to be prepared for what you're going to do, have a plan working with your regional transmission planner, to ensure that if the process takes too long, that you are prepared to deal with the reliability. So I wanted to use the Susquehanna-Roseland project as an example of how this has worked out and how these issues are applied in a practical context. Many of you may be familiar with this project. It's a 500 KB project. It was identified back in 2007 by PJM as needed for reliability. There were multiple reliability violations. The line starts in Pennsylvania and goes into New Jersey, almost all on an existing right of way. And the cost allocation, according to the current PJM mechanism, is that it is to be shared across all of PJM's load.

Some of the challenges with the project include that it crosses 16 municipalities. For most of those municipalities, we are not the incumbent transmission owner. It's actually a JCP&L area, and through the right of first refusal, we agreed with JCP&L to take over their construction responsibility. And PPL is building the portion in Pennsylvania, as well as the portion through the national park. And the line crosses two national parks. The line has crossed two national parks since it was originally built back in the '20s, and actually predates the park. But as I will talk about a little bit, that has become certainly one of the most controversial aspects of the project.

Both the New Jersey Board of Public Utilities and the Pennsylvania PUC had rigorous proceedings. Each one took about a year and had multiple public hearings, evidentiary hearings, thousands of discovery responses, and numerous pieces of expert testimony. And they both concluded that the project was needed for reliability, and they both approved the siting. The National Park Service (NPS) has decided that they need to do an environmental impact statement on the project, and that has been taking several years now. It does look like, according to the current schedule, they will complete that process in October of 2012. And after that is concluded, we still have a couple of more local environmental permits that we need, but that are dependent upon the ultimate decision of the NPS and the route that's approved by the NPS. We don't anticipate those other permits being problematic. But they are dependent upon the NPS. The NPS process has taken longer than we ever expected. We did not come into this process anticipating that it would take that long, and lesson learned, no matter whether you have an existing right of way, and you're using it, and you already have all your rights, it takes a long time to deal with some of these federal permitting issues.

I mentioned here the rapid response team. That is something that just recently we've started to hear about. The federal government is trying to have a more efficient process, and they are starting to identify a couple of projects across the nation, which they are going to put on a rapid response team list, and we believe that the Susquehanna-Roseland project will be on that list. And it is intended to result in improved coordination amongst the federal agencies, including the national park, to insure that the permits stay on schedule.

So the primary issues that have been raised in various aspects of this siting process, again, are need, alternatives, cost, EMF, view impact, vegetation management, (a significant issue), and exports to New York. A lot of people are very interested in where the power would be going. Is this power all going to New York City? Are we paying for this line? Are we building this line because it's needed for New York? It was controversial, but it was resolved in a reasonable manner in the Order. Among environmental issues, the coal by wire issue came up and was significant. There was something called a leakage study that was part of the proceeding in New Jersey, where an evaluation was done to look at how this line would change the dispatch of existing coal plants across the region, and how that might result in leakage of dirty air created from burning coal into New Jersey that might not otherwise have happened. So we had a broad list of issues that became very central to the evaluation here in this project.

So would Order 1000 have changed Susquehanna-Roseland? That's a question I've been thinking about over the last few weeks. I don't think so. If you have a project like this, something that's needed for reliability, I don't think Order 1000 it really would have made a difference in siting a project like Susquehanna-Roseland.

However, there are other aspects of Order 1000. For example, [ublic policy transmission projects, inter-regional projects, the potential elimination of the right of first refusal or restrictions on the right of first refusal. So you might have more unknown players coming in and trying to site projects. And cost allocation is another potential area of impact. So I went through each one of those and tried to think from our perspective, would any of those make a difference in the areas that we are building transmission, whether the approval process is in the municipality or whether it's at the state commission.

On the public policy dimension, I think it really comes down to what we were talking about this morning. Is there an agreement on the benefits? I attached in the appendix the statutory language that the state has for siting transmission, as well as eminent domain. And I think it's broad enough for the state to include projects that don't have direct benefits. There are always job benefits when you're building a project. I give Susquehanna-Roseland as an example--1,000 jobs over the life of the asset created during the construction phase. And there are certainly benefits to that, to the states, and from the states' perspective. There will be decreased costs of electricity when you add more imports. You get into the coal-by-wire issue, of course, the leakage issue. But I think there needs to be at some level an agreement that the project is needed by the siting state. It might not be the same reason why the planner chose that project or that area to build the project. But there has to be some buy-in from the siting entity. And I think that for some of these public policy projects, that might be challenging.

With regard to interregional transmission, I think it's the same thing. We actually have quite a few merchant transmission projects going from New Jersey into New York, some from our service territory, some from JCP&L's. And for each of those projects, they had to go to the local municipalities and get the approval to build in those areas. And they were successful and able to do that. They satisfied the local municipal needs. The issue of where the power was going was not that important to the municipalities. They had different drivers. But if it's a project that goes before the BPU, would that be an issue? Probably. I would suspect that it would, and there would be some focus on what the benefit to the state would be. And I can envision that there might be a transmission project from New Jersey to New York that could provide benefits to both states.

With respect to the right of first refusal, again, I don't think that is going to make a difference, because we've already seen PSE&G building in JCP&L's service territory. The municipalities didn't know us. They didn't have that relationship with us. So the trust level was different. It's easier to build when you know the people that you're working with, and they know that you're credible and that you show up when you're supposed to, and you take care of issues when they arise. And when you're an unknown quantity, that's always a challenge. But I think that's something that can be overcome, and it was overcome by us and those municipalities, and it was overcome by the merchant entities in the municipalities that they're constructing in.

On the cost allocation issue, again, as long as the siting entity believes that there is a need for or a benefit to their area from the project, and they understand how much the project is going to cost, so they can do an analysis of whether this is the right way to spend that amount of money, rather than spending it on something else, I think that cost allocation won't be the factor that makes the difference. Of course, if you have a project that is several billion dollars, and you can fix the problem for something less, and in one scenario the local siting entity is going to pay zero, and another, they're going to pay 100%, that changes the dynamic. So having that information up front about how much the cost of the project will be to that siting entity, or the area that they're responsible for, is very important. And it's important that it's transparent, and that they know what it's going to be at that time, I think, is the most important factor. Thank you.

Speaker 4:

I'm at a little bit of a disadvantage here, because one of the questions here is, does this impact the statutory authority of the states? And I'm not an attorney, and while I can't argue with Speaker 1 on this actually changing the statutory authority, as a practitioner, I can tell you things are certainly going to change.

I do want to say up front that I commend FERC for issuing the Order and using a lot of the right words. But I think Speaker 2 this morning kind of had it right--the beneficiary pays clearly is something that makes sense, and we want to carry forward. But it seems to be done in a backwards way, and it's having the cost allocation essentially drive things.

And I think that we cannot take Order 1000 in and of itself without also looking at the recent DOE delegation of authority. And Chairman Wellinghoff himself told the EIPC (Eastern Interconnection Planning Collaborative) states on a phone call that the two maneuvers have to be looked at together and taken into consideration together. So I'm having a tough time separating the two, hearing that from the chairman himself. So I am going to talk a little bit about the DOE delegation of authority as well.

The Ohio Power Siting Board is an independent board in Ohio. Its mission is support sound energy policies that provide for the installation of energy capacity and transmission infrastructure for the benefit of Ohio citizens, promoting the state's economic interests and protecting the environment and land use. It sounds like it is parochial, but as Speaker 1 said, Ohio is one of the states that does look beyond state boundaries. The Ohio Power Siting Board, as I said, is independent, and it is tied to the Public Utilities Commission. The Chairman of the Public Utilities Commission is the Chairman of the Board. You can see from the makeup of the board that the members' interests are very wide, and it is a difficult process. But it is a workable process, and Ohio has been held up as one of the prime models around, not only this country, but around the world. And Ohio has had several other states and other countries pretty much adopt its model.

On the left of this slide here are the planning requirements of the FERC Order 1000, and on the right are the statutory criteria and responsibilities of the Ohio Power Siting Board (listed on top) and on the bottom of Ohio's Public Utility Commission.

I'm not going to go through the Order 1000 planning requirements, because I think everybody in this room is painfully familiar with Order 1000. But the things that we believe will be impacted are the statutory requirements that our siting board has to consider. And one of these is the need for the facility. That is first and foremost, in transmission issues. We do have to look beyond our state borders and consider the regional plans for expansion of the power grid of the electric systems serving Ohio and interconnected systems, and that a proposed facility will serve the interests of the system economy and reliability. And then we have a flavor du jour, which is anything that our Ohio Power Siting Board decides it will be, and that's service to the public interest, convenience and necessity. That is a catch-all.

Now, I think that, again, our statute isn't changed. We need to look at all this. But the whole dynamic of the siting process is going to change, because we have to look at the cost, which we'll get to under cost allocation, of various alternatives. The actual cost of the project is not necessarily an issue in the siting case, because that, then, may or may not go to the Commission for decision. But currently, our Ohio Consumers Council is one entity that has no right to actually intervene in the siting process, because there's no immediate rate impact. If FERC implements Order 1000, and more or less determines a need, and we then need to do a need determination that may or may not require cost recovery, I think that we're going to have a whole different set of interveners, including our Ohio Consumers Council. I think we're also going to have competitive interests that are going to intervene. I think Speaker 2 covered a lot of this in his discussion about what interests, then, are going to play a part in the siting process.

The bottom three points on this slide are the things that our Commission has to consider, and even though we are a semi-restructured state, we still do resource planning and forecasts, and we have rate based determinations and Standard Service Offer proceedings. And these things are, I believe, all going to be impacted by whatever comes out of Order 1000.

On the cost allocation topic, we have to determine whether the facility represents the minimum adverse environmental impact, considering the technology that is available and the nature and economics of the various alternatives. This is no easy task, and we often will take our resource plan and forecast filings and incorporate that record into our siting proceedings. But I think that it will certainly affect the dynamics of how the siting cases are going to come out.

Now, relative to the Commission, again, there is the issue of cost recovery, and Speaker 2 also mentioned allocation between the classes, if you will. I think all of this is going to be impacted by FERC decisions in Order 1000.

The other thing that I'm concerned about is that this whole thing, as Speaker 2 this morning said, is kind of gaming the system with cost allocation to back into planning, if you will. In our alternative energy requirement, for instance, we have a statutory requirement that the alternative energy or renewable energy has to be deliverable into the state. Now, we went back and forth with a lot of folks about what that meant. But we now have a policy that there has to be a load flow analysis done, and there has to be an impact to the transmission system in Ohio of greater than 5%, and the size of the facility has to be greater than one megawatt. If this Order 1000 is decided to be used to kind of change the dynamics of that, this is going to really potentially change what qualifies in Ohio as renewable and what doesn't. And right now, there have been some facilities denied, because there is no impact to the system. Therefore we don't believe that it's deliverable.

On the topic of limitations of federal rights of first refusal, there, again, this is not something that is necessarily going to affect our statute directly, because right now our jurisdiction trigger is not "Public utility," but rather the definition of "Major Utility Facility." So we have merchant facilities that could come before the power siting board. And I think that it was interesting that Speaker 2 mentioned that at least five times in the Order, there was lip service given to the idea that "Nothing affects state siting." But I believe it absolutely does affect the dynamics.

This slide shows some FERC Commissioner comments. I think Moeller had it right when he said that the Order did not address something that is in dire need of addressing, and that is "that it is in some instances Federal agencies that are causing delays," and maybe trying to push forward this rapid response team is really important.

Let's move on to the DOE proposal. It's a little scary, the way this thing kind of came out with no formal docket or anything. It was just simply announced. But I think if you look at this in conjunction with Order 1000, you can see that this is a much bigger policy issue that is being back-doored, I think.

So in this proposal, there are just a few things I want to mention. There is no statutory authority for FERC to do this siting stuff. Congestion studies and corridor designation is the authority that was given to DOE. This proposal actually takes it a next step and makes it project-specific. If that is not "state siting responsibilities," I guess I don't know what is.

The other concern with this proposal (there's a whole host of concerns, but I've just highlighted a few) is that it creates a federal process that is literally in parallel with the state proceeding. The original authority of DOE that FERC had for backstop was a sequential process. Now this proposal proposes that there be a pre-application process, concurrent with a state proceeding. The state decision makers cannot participate in that. We cannot be a judge and a litigant at the same time. So we are going to be totally pre-empted from participating in that, and the result is that we're going to have federal decisions more or less come out at the same time or concurrent with state decisions that are essentially going to get shoved down our throats, as we like to say.

There's also, in this proposal, a discussion about FERC making a corridor suitability determination. And again, I think that this goes to specific environmental impacts, and whether they are minimum adverse environmental impacts--the impacts on land owners, the impacts on agricultural lands. Again, if they are doing a suitability study, we think that it really does reach right down into the core of state siting decisions.

Now there is a book, *The Recognitions*, about a lost artist, if you will, that was trying to seek order in the world. And along the way he was trying to study all the master artists, and he learned to paint after them and became such an expert at copying their work, that he got entangled in a lot of plots and ploys with some pretty crooked people. And he found that the order that he found after this long journey was not very good order. So I think that, again, Order 1000 has kind of found us in this place. The proposal, actually, sets the stage for applicants to pick forums and game an outcome without any regard to state siting considerations. I think, too, that this dictates to states--not only transmission routes, but the fact that the DOE delegation, and the cost allocation in looking at various alternatives actually lets FERC more or less dictate generation resources--that clearly is not something that FERC has any right to do. And then, without regions agreeing with neighboring regions, there is no regard to beneficiaries necessarily, and FERC is just going to dictate who pays for what as they wish. They've punted on reliability issues to NERC, and they've also punted on how to define beneficiaries. And I think that that is a whole other week's discussion on what a beneficiary is and how that's going to be determined. But it is a bit scary to us.

One thing that we're not convinced of, certainly in Ohio, and I think this is true of a lot of states, is where is the problem? You've heard Speaker 3 say the states did fine in getting these things routed. It is the federal agencies that are slowing things down. Ohio alone, in the last ten years, saw $376 million or thereabouts in transmission investment. And Ohio has got a pretty robust system. And FERC would never have been able to implement wholesale markets in the country without the system in Ohio, as well as a few other dominant states, so it's not like we really needed a lot of transmission. But that amount of money there, and that amount of investment, is one state, one process. And we have a very efficient process that goes very quickly, and we get very few problems. So we basically want to ask, where is the problem? And we believe that this is a solution that is in search of a problem.

So even though lip service is given to the fact that state siting authorities are not going to be impacted, we certainly don't see how that is an outcome here. We think that these decisions are in fact going to be counter to congressional intent, as well as to what FERC says the intent is, because we are going to have litigation up the wazoo every step of the way.

This is really not about cost allocation. This is about a serious public policy question. Instead of back dooring everyone, why don't we back up? In looking for a new order, if you will, let's start from the new beginning, like the artist did, and see if we can't make this work a little better, and really tell the public what it is you're trying to do. And again, beware of the stalking horse. There are serious energy policy issues that I think are more or less hidden and swept under the carpet.

What scares me most is the unknown. We don't know what "beneficiary" is. We still have so many uncertainties with what FERC is going to decide. And I think that the Charles Dickens quote in *Tale of Two Cities*, "Whatever is, is right," is a scary proposition, because I think that that's what FERC is trying to just tell us. Thank you.

General Discussion

Question: I have a question for Speaker 3. I think you're absolutely right that siting is, at the end of the day, the name of the game, particularly in more highly populated areas. But I think it relates to cost allocation in a certain way and I want to ask you about it and I hope this doesn't end up being uncomfortable.

But I worked on the transmission upgrades to 345s in Connecticut, which were to relieve a reliability problem in Connecticut. And I think you know some of that because you guys own some generation up there. But I am absolutely convinced that the cost got spread throughout all of New England, even though it solved a reliability problem in Connecticut. And the siting process was very, very difficult, and I'm absolutely convinced that, if Connecticut had to pay for 100% of the cost of those lines, they never would have been built, and who knows what would have been done to fix the reliability problem. So my question is, if, hypothetically, someone exercising a beneficiary-pays principle decided that the cost of your Rosemont 500 line should be paid for primarily or exclusively by folks in New Jersey, do you think you'd be able to get your line sited in New Jersey?

Speaker 3: It doesn't make me uncomfortable that you asked that question, first of all.

I don't know. And it was definitely an issue in the case, but what was more of an issue was the uncertainty of knowing how much it was going to cost. And I think the uncertainty is the hardest part for the regulator, and I really do believe that all these siting processes should and will ultimately come down to whether the siting body believes that this project is either needed to fix a particular problem which they agree is a problem, or beneficial because it does something that they agree is beneficial. And the cost of alternatives to either address that need or to provide that benefit, should be evaluated. And I think that is where it comes up.

Actually the lines I had up before, even though they're all being built, except for Susquehanna-

Roseland, in New Jersey, the cost allocation is not all to New Jersey customers. Some of it goes to New York through the merchant transmission line. Some of it goes to Pennsylvania. But let's say the majority of the cost for the project was being allocated to New Jersey. I believe that still, there was no other alternative to fix those reliability violations at a cheaper cost. And some of those other 230 KV projects are all being allocated using a DFAX model. For many of them, around 80% of the cost will be to our customers, and I believe that the Commission or the municipalities, whoever ends up siting all of them, will make that determination, "For this pot of dollars, do I agree this is the best solution to solve this problem or provide this benefit?"

Question: OK. Then why is the rest of PJM paying for a portion of the 500?

Speaker 3: OK, well, that's a longer discussion, and we filed lots of briefs on that, but ultimately our view is, on the 500 KV line, it was planned for regional reliability. It's needed for regional reliability. It's not needed to solve a particular problem just caused in New Jersey. It doesn't solve problems just in New Jersey. And the regional planning process identified the need and agreed on the solution. If it was a smaller, sub-regional planning process, then the cost should be allocated to that sub-regional planning process. I don't think costs should be allocated to people in New York, other than the merchant transmission lines, who are participating and have a role in saying whether that's the right project or not. So I think it's consistent with all of the principles we've talked about. If you believe there's a regional benefit, from a reliability standpoint, and that project was planned for that regional benefit, then the cost should be allocated on a regional basis.

Question: That was basically my question. But to just follow up on it a little bit, you talked about providing alternatives to the Commission, at least in terms of the siting. Did you provide a DFAX alternative? What I'm trying to get at is if a commission is considering these issues and only looking at it as a PJM cost allocation issue, as opposed to some sort of beneficiary model, whether it's DFAX or other--did you provide that alternative, you know, sort of reflecting the Seventh Circuit decision, so that, when the commissions or the siting boards are considering these issues, they're considering them bookended between what the alternatives are?

Speaker 3: I can't recall if we actually had PJM do a DFAX for Susquehanna-Roseland. I can follow up and check. But the Seventh Circuit remand and the potential consequences of that case on the cost allocation to New Jersey customers was front and center in the proceeding before the BPU and was part of the BPU's order approving the project. So my view is, they had full knowledge of what the cost allocation might be. We believe that that project, even under the Seventh Circuit remand, will end up being allocated in the same way, but the BPU made its decision based upon a full understanding of the Seventh Circuit case.

Question: So you think, no matter how the cost allocation sorts out, that the decision stands, with regard to the Commission?

Speaker 3: Yes.

Question: I read a very interesting paper by Brown and Rossi about siting, and they made an argument that focused on, not for every state, but in many states, the transition from local siting decisions to state siting decisions, the argument being that as the electricity system grew, transmission investments grew, that it began to transcend local interest and became a state interest, and therefore not all states, but some states, had created institutional frameworks to build a larger regional entity. They created a larger regional entity to make these siting decisions. And then the analogy was to going beyond states and into regions and then to something like FERC and making these siting decisions in ways that are parallel with what we do with natural gas.

I agree completely that Order 1000 doesn't do that yet. It doesn't provide that authority, although it does change some of the dynamics and some of the pressure on the system. But it seems to me that it's pointing very much and almost very strongly in the direction of some kind of legislative effort in Congress to give

FERC this mandatory siting authority. And when the DOE announced they were going to transfer this authority for the analysis to FERC, and I think it was Bingaman who said, "You can't do that. If we wanted FERC to have that authority, we could have said that, and that's not what it says." But I also remember something implying that maybe that's what we should do, or we will do that, or something, or at least that that's the direction that it's going.

Now, I spent a lot of time talking to half of the co-authors of that project, who has this, who keeps telling me that it's just impossible, the states just won't allow it, this is a hopeless cause. But it doesn't seem to me that that's true or that it's outside the realm of imagination that Congress will, in fact, intervene for exactly the reasons that were argued in the paper. Now is this what's coming, and should we be planning as though that's the way it's going to go?

Speaker 1: Politically, I think it would be very difficult, because not only would the states oppose it, but probably even more importantly, from the political standpoint, there are a lot of actors in the electricity marketplace that would oppose it, because they're always forum shopping, and if they think they have more clout at the state level, they're going to do that.

Now if you ask me as a matter of policy, should FERC have a backstop role or even more, I always argue that FERC should have backstop siting authority. Not quite in the convoluted way that Congress created it, by having you stop at DOE, which is what the Secretary now wants to eliminate--and actually you could argue that Congress, by delegating that to DOE, was actually trying to kill the idea by giving it to DOE. But it seems to me as a matter of policy that there should be a backup role. I say a backup role, because I don't think FERC ought to have the primary role, simply because there are so many local effects that the states need to have a lot of say about it. But you're right, the logic is, every state that created a siting board did it, at least in large part, in order to preempt local zoning authorities and local other authorities. And the same logic would apply to regional markets, and it's hard to make a policy argument to say they shouldn't.

Now can you make an argument that states should have a powerful role in the process? Yes, absolutely, unequivocally. But should they be the sole determinant? I don't think so. And it's not like I'm criticizing FERC, because FERC doesn't have the power to change that dynamic anyway. But there's nothing here that keeps a state that wants to kill a line from having the opportunity of doing it.

And in a sense, and I'm responsible for this, this panel is a little bit jaundiced because I picked Speaker 4, from Ohio, which has one of the better state siting statutes. Maybe what I should have done was pack the panel with the folks that made the decisions in Connecticut on a cross sound channel line or with previous members of the Arizona Commission, to get more parochial points of view. But there needs to be a federal role. What I'm not sure about is whether the politics will ever quite line up to let that happen.

Speaker 2: I agree with everything Speaker 1 said. As a matter of what should be, I've advocated for an expanded FERC or regional role in siting, that could have a preemptive effect over states. But the problem is political obstacles in the process, and I do think FERC and DOE have done a nice job of getting the attention of Congress. So this might be a way of trying to move these things along, given that they've been backed into a corner following Piedmont in the Ninth Circuit case last year.

Question: If I could break in here, those decisions you alluded to, like the Arizona Devers – Palo Verde 2 decision, and I'm not as familiar with the one in New England, but using those economic considerations--they're illegal, obviously in violation of the commerce clause. And you're not an attorney, but --

Speaker 1: I am an attorney.

Question: You are an attorney. So wouldn't you tend to agree? And so when you say nothing changes with FERC 1000, nothing changes because nothing needs to change. Those sorts of things are not permissible grounds for a state to use to deny a siting plan. Are we all in a tizzy over a problem, as Speaker 4 says, that really doesn't exist outside of a couple of examples, and even with, again, with Devers - Palo Verde

2, at this point, Arizona wants to build that line and it's California who doesn't want to do it.

Speaker 1: Actually, it's interesting. Certainly you had a strong commerce clause argument against the Arizona commission, because two of the commissioners were bright enough say publicly they did it because it was going to cause lower cost power to be exported to California, and they wanted to keep it. So that's why the depositions would have been a lot of fun. The Connecticut case is a little more complicated, because the siting agency in Connecticut actually rejected the line on environmental grounds, having to do with the impact it would have on the mussels in New Haven harbor. And that was the original grounds. And then the developers of the line actually did whatever they needed to do to mitigate what most people thought was a trumped-up reason. But in any event, whatever it was, they mitigated it. And then the siting board actually approved it and then the legislature said you couldn't build it.

So I think, from a legal standpoint, Connecticut was on shaky ground, because of the legislature actually intervening to reverse a decision by a state agency that was nominally independent. So it was complicated. But what's interesting is, because of the original siting board decision in Connecticut, if states wanted to find environmental reasons to do something, they could do it very easily, for two reasons. One is, as Speaker 2 pointed out, even if the federal government had an environmental standard that applied, which there isn't now, because there's no federal siting statute, there's nothing that precludes the states (in fact, the law generally goes in the opposite direction. As Speaker 2 pointed out, states can always erect more severe environmental requirements. So all the feds do is set the floor. So if a state wanted to find an environmental handle to reject a line, they could. And then, you know, you could go to court and litigate it, but you're basically in state courts litigating a lot of that issue, and it becomes a lot more complicated. So I think that the opportunity exists for anybody that's devoted to being parochial. For whatever reason, maybe a legitimate environmental reason, you can find a reason to reject a line.

Question: I think this question probably starts with Speaker 4. It's a two part question. First of all, you critiqued Order 1000 because it talked about beneficiaries without specifying what benefits are, but you also pointed out that in Ohio, at least, and in several other states that I'm aware of, most of the siting authorities have this catchall thing called something like the "preponderance of evidence shows that this is in the public interest," without bothering to define what the attributes of public interest are. So first, I'd like you to contrast the difference between the states that seem to have a great amount of latitude and Order 1000 that seems to try to preserve that latitude. And then second, if you could talk about how we might close the gap so that the definition around who benefits is more clear, I'd be interested in that response.

Speaker 4: Sure. I really can't close the gap on the difference. We just think that we're entitled to that. I mean, when FERC says that "beneficiary pays," I think that has a different implication than the "public interest convenience and necessity," necessarily. I mean, what we're doing with that piece of the statute is responding to the public needs. EMF was big back in the 80s and we still do EMF evaluations on all the transmission lines. And, for instance, in wind, we've got noise and shadow flicker. And so I think that our use of the statute--yes, it does give us flexibility and a bit of broad authority, but we are using that to actually respond to the public interest. In beneficiary pays, I think that there is a general expectation that, if we're going to do that, and if FERC is going to assign costs based on that, that we should have some reasonable understanding of what that is going forward, rather than just accept that "whatever is, is right."

For our deliverability test, we get essentially DFAX analysis, and I think that when FERC puts some definition on beneficiary pays, I think you need to do a DFAX analysis, you need to see what the cost implications are to the different rate payers in the different states to determine whether or not they should be paying for something. So I think that, to the extent that FERC says, "OK, beneficiary pays," I think it's owed to people to know what that means before they go forward.

Speaker 2: To follow up on Speaker 4's thought, I think the relevant statutory requirement for FERC would be just and reasonable rates that it's applying in this context. And while I think a lot of things in Order 1000 are very defensible, one of the concerns that arises for me, at least, is that the universe of values that will be reflected in the future in a just and reasonable rates determination is not bounded. It depends on whatever states define as public policy requirements, which then, in the future, RTOs must consider in making their just and reasonable rates determination. So you don't have a bounded set of parameters.

Question: And neither do the states, right? So to push this hypothetical a little further, perhaps the states have a policy that they promulgate that says, reduce the exposure to EMF. Would you handcuff the process so that that couldn't be considered as a benefit because it wasn't part of a DFAX analysis? That's the kind of question I'm asking about.

Speaker 2: No, no, and it's true, often we have open-ended delegations to agency. The overlay here that makes this more difficult, I think, is the federalism overlay, where we have an unbounded set of determinations that in the future will be influenced by public policy requirements, some of which have been made in the past and some of which will be made in the future. We don't know what those are at this point.

Speaker 1: There's another aspect of this which we really haven't talked about. Historically, when siting agencies made decisions, before you had regional competitive markets, and siting agencies made determinations on need, that was, in many cases, ipso facto a prudence determination: this line is prudent, so 100% of the costs get imposed on the ratepayers whose utility is building it.

There's an irony here that in some sense, any kind of cost allocation or some shifting of that revenue responsibility away from the local ratepayers, at least on that score, might reduce some of the opposition, because the rate impact is going to be less in the state than it might otherwise be. Now there are other reasons why, as I pointed out, somebody might oppose it. But from a purely rate-making standpoint, any sort of allocation away from the ratepayers of the local utility may actually reduce the opposition to the state siting the line.

Speaker 4: Or the opposite. In Ohio, for instance, because we have to look beyond state boundaries, we might site something that our ratepayers wouldn't necessarily have to pay for, because it's a merchant or it's another utility, not a local utility. And I've been doing siting for a long time. These are very, very passionate hearings. Now the utility commissions, with rate proceedings, there's a lot of angry people when money's involved, but siting is a whole different game. And now you add those two together in the siting process, and I think it's a mix for disaster.

Question: Thank you. I'd like to pick up on something that was said earlier, because (and maybe Connecticut is an outlier here, but it seems to me a rather important point) if you have a proposed line that clearly is justified for the reliability of Connecticut, Connecticut would only approve it if they're not paying 100% of the line. I think that's what was said.

Comment: Nobody is admitting any of that.

Question: Oh, I understand. So in a lot of states, at least in Illinois, I believe using the least cost alternative is a requirement. And it raises the question, what cost are you comparing? If you're analyzing the cost of the facility, that seems to be the correct thing. If you're saying only the cost that's allocated, it seems that you may very well be skewing the analysis, and in fact may be approving transmission where DSM or generation may be a better alternative. So I'd just like people's thoughts. It's something that's troubled our people in Illinois-- when something finally gets in front of the Commission, you know, what's the right rule of law. And there may be 50 rules of law.

Speaker 4: That's a difficult question to answer, and I'm not sure that there is a definitive answer. In Ohio, because we're restructured to some degree, the least-cost analysis is not necessarily the only analysis that's done. We call it a "reasonable cost" analysis now. But I think, in looking at the different alternatives and different technologies, I think that the reviewers owe it to the ratepayers and to those markets at large, be it the applicant or the applicant's competitor, to try to take as big a picture view as they can.

We have not necessarily separated out an allocation only to Ohio for a transmission line, and maybe if FERC determines who the beneficiaries really are and what the benefits are, it will better enable us to go through that exercise, knowing that up front. But I think it really is incumbent upon us to try to take all of that into consideration. Certainly with some of the lines, we kind of expected that none of the costs might be allocated, depending on who's building it. So I think it's complicated and it's going to have to be looked at on a case by case basis.

Speaker 3: Our position is that while the siting process always seems to look at need and reevaluate that, it's not where the need is determined, and it's not where the project is selected, it's where you're getting confirmation of that. So I completely agree with you that the entire cost of the project should be part of the process in identifying whether this is the right project to solve the problem. And that's done in our region by PJM, and they look at the total cost of the project, compared to what it is they're trying to solve, and they should be looking at the least cost.

But when we get to the siting, it is more bifurcated, and I think the state should be looking at how much it is costing the state, and alternatives for the state, pursuant to their roles.

One of the challenges we've seen is that the PJM process is questioned because it seems to favor transmission over other alternatives. And the reason for that is the misalignment between RPM (the Reliability Pricing Model) and RTEP (Regional Transmission Expansion Planning). Our view has always been that regulated transmission should be a backstop. It should be what you build to solve reliability or address congestion, after the market has responded. And I know it's different in states with IRPs (Integrated Resource Plans), where they have that all looked at it in one place. But our view is that the RPM model should identify the right supply options, and only after that is put forward should you then overlay the transmission solutions.

But right now it's not happening that way. The transmission's getting identified first and it's affecting the supply. So there does need to be better alignment between those two things, I think, for it all to work better. But we do believe that in the siting process, it is appropriate for the siting authority to look at, what is the impact on them, and that may be 100% cost allocation, it may be 50%. It may be a merchant line where they get zero. And they can look at the question, "Is this the right solution for this problem that I agree on, or this benefit that agree with?" which may be very different than the RTO's assessment of the problem and the benefit.

Question: I think that the Order envisions, at least for the planning at the regional level, that things would operate in the way you suggested, that is, looking at generation, demand resources, and transmission side by side in planning. But I think this also illustrates the connection between cost allocation and the planning and siting part of this, because FERC in its Order says that they don't intend to say that cost recovery for non-transmission alternatives is provided for in our cost allocation approach. It says that that's beyond the scope of the transmission cost allocation reforms. And the concern is, if that's just left to states now, are we going to end up with fragmented, myopic approaches at the state level for the issue of cost allocation as well, that doesn't allow us to take advantage of the larger system benefits of micro-generation and demand response?

Speaker 1: Actually with regard to the specifics of the need determination, basically Speaker 2 and I have argued that you don't really need a need determination anymore, for two reasons. First off, in light of Order 1000, the need determination is going to be made through the regional planning process. What Speaker 3 said is right. All that happens in the siting process is not the determination of need, it's confirmation of it for legal purposes. But nobody's going to propose that line, or propose to pay for it, if they don't see a need. And presumably that ought to establish that the need is there. So the real review occurs on the other side, which is the environmental dimension (and when I say environmental, I include aesthetics and all the other things that go with what comes up in a siting proceeding). And that's really where the action is, and that's where, interestingly, states have the most subjective opportunities to deal with things, even more than need, particularly in light of 1000, where if there's a regional determined by somebody else, the state could say, "Well, we don't agree with that and so we're going to kill the line."

And then, as Speaker 3 was pointing out to me during the break, then they're taking the risk that if there are reliability issues they are to blame. That may or may not be the case, but what's clearly the case is, on the environmental side, they have an infinite variety of reasons why they could kill the line if they wanted to kill the line.

So, you know, in light of 1000, if I were advocating truly from a policy standpoint, or a legal argument in terms of what the law ought to be, as opposed to what it is, there's no more need for a need determination. That's already, established. Now what we need to do is the environmental review.

Question: Let me just then ask a hypothetical. Say Midwest ISO or PJM or both of them together determine that the best thing to do is to build the line (let's just say a line non-stop from Iowa to Indiana) and by the physical system, that will be, by its nature, go through Illinois. Say there's no need in Illinois for the line. It doesn't stop off or anything else. You're then saying Illinois has nothing to say? I think the Illinois statute requires them to say that the line is needed and the least-cost alternative for the use as specified by the statute.

Speaker 1: What I was saying was what I would advocate as a matter of policy. I wasn't saying that's the state of the law. And I haven't read the Illinois statute, but presumably you're right, that there's a need determination, although they could say there's a need because Iowa and Indiana say there's a need and the MISO has blessed the need and there's a need. But they've got to make whatever determination the law requires. But from my point of view, what is relevant, and what Illinois does need to review, although I still think there ought to be a federal backstop, is the effect of that on Illinois, even if there's not a need issue. There's still going to be an impact on Illinois, and so therefore of course Illinois ought to review it in some fashion.

Speaker 3: I'd also like to comment on that scenario. I would expect that in that scenario, if there really was a reliability need, for the region, and Illinois as part of the region agreed with the analysis that PJM did, that Illinois would probably site the line, even though there's maybe not a violation in Illinois, if they saw a regional need.

If it's a public project, where the other two states get together and say they want to transport wind across one state, that's where I think it becomes a completely different animal and where a state like Illinois, or a state like New Jersey, between Pennsylvania and New York, could really decide they don't agree with the need. So there has to be this agreement with the need, and it has to be something that the state that is siting buys into. Maybe it's jobs. Maybe it's not the same need the project is built for. But they have to agree that there's a benefit for the project.

Question: Speaker 3, why do you say that a policy for renewables is somehow less of a need than reliability? I mean, reliability is ultimately an economic question--do you want to have the lights on all the time? It seems to me that the FERC 1000 actually tries to answer that and said these are all values and you've got to take them all into consideration. Can you justify why it would be appropriate to value reliability more than meeting an RPS?

Speaker 3: I do distinguish them, and I think there's a significant difference, and it goes back to that discussion we were having this morning. We have mandatory federal reliability criteria that we plan for. We don't have a federal scheme and we don't have any federal obligation for renewables. We have individual states deciding what they want to do, and we have New Jersey, for example, who has very aggressive renewable goals. They plan to meet those through their own means. There is not that same federal overlay of a requirement. So when you're crossing interstate boundaries and you have a state that does not agree with the need for a public policy project, I think there's a significant difference, from a legal perspective as well as a practical perspective.

Moderator: Can I add something here? I also think there's a cultural issue. I think the electric industry culturally has always put an extremely high value on reliability. Correctly or incorrectly, I think there's a cultural issue and I think that the federal law, which imposes penalties on you if you violate reliability, reinforces that long-standing sort of industry schtick.

Speaker 1: Actually just supporting that, because of the importance of culture, actually at Ohio commission we literally had two PhD anthropologists on the staff, who wrote their dissertations on utility culture [LAUGHTER].

Question: I want to go back to the question of whether we're still really working around the issue of two inherently conflicting paradigms – a desire at FERC for a optimally-designed, economically, or however, most efficient electric system we can configure, versus what I think is increasingly a hardened environment where states' rights skepticism of federally imposed solutions is reflected in the fact that FERC probably went as far as it could on the issue of cost allocation beneficiary designation. And we may stick with a system where we're trying to solve a very complex linear programming problem with 50 constraints reflecting each political jurisdiction's definition of its own priorities and such. And those constraints will vary over time as states change their priorities, whether it's jobs, renewables, whatever. But ultimately we may be sort of at a point where we can't really go much further right now, with the current political environment, and when you look at it against the Seventh Circuit decision and the other constraints on what FERC can do. So the question really comes down to, are the expectations really unrealistic, in terms of trying to get FERC to be more definitive with regard to benefit allocation, criteria, cost allocation, those kind of issues? We just probably are at an impasse right now, which is not going to change in the near term.

Speaker 3: I think you're absolutely right. I think we are at an impasse and my biggest concern is that this impasse is going to cause chaos in the meantime, and I'm concerned that without a little more structure and determination up front on the meaning of beneficiary as well as some other things laid out there, that it is going to be way more chaotic than it already is. So I think you're right, I think we're at an impasse. I'm not sure where we can go, but I was pleased to be invited, to at least put my view on the table, that we are in chaos.

Speaker 2: I guess I see a third path. You've got the extreme of, on the one hand, designing the most efficient system. On the other hand, you've got the states' rights and the fragmented approach. But it seems to me that this is an invitation, almost at a constitutional or process level, for sub-national innovation. There could be a variety of different solutions moving forward, and Order 1000 lays out the architecture for those solutions procedurally, by saying, those sub-national solutions must consider the relevant policy requirements within those sub-national jurisdictions. And it tries to move it forward in that sense.

The problem is that a lot of that's undefined, so until we see how it plays out...I suspect they'll be "arbitrary and capricious" and all kinds of legal challenges to this rule. But until it plays out, I don't know how reviewable all those things are going to be and maybe you'll see the real challenges once these things are proposed at the regional level.

Question: Is there enforcement? There's enforcement if you don't form your regional planning and cost allocation groups, but how does the enforcement work if you do that but then don't follow FERC's principles? Is it just that FERC will come and backstop you and re-do it the right way?

Speaker 3: Are you asking from the planning perspective, or the state siting perspective?

Question: I'm thinking about it at siting and allocation, particularly on the cost allocation side, not so much on the siting, but on the cost allocation.

Speaker 3: My view is the states don't have to report to FERC on this. When it comes to siting, the ultimately will do what they think is right. And I think most state commissions want to do the right thing, at the end of the day. But obviously the RTOs have to do what FERC requires, and the transmission owners will all have these Order 1000 provisions in their tariffs, and it will be what FERC requires, because there are significant consequences in not following that. And as a result there'll be certainly some public policy and hopefully some inter-regional transmission projects that come forward, and I think we'll test the waters on the siting and see how the states react.

Moderator: I think you make a good point. State commissioners tend to rub shoulders with our colleagues and it's hard to have a completely parochial perspective. States do want to do the right thing. They don't want to be at odds with their neighbors. Going back to the Devers – Palo Verde 2, the first go-round, it was acrimonious between the ACC (Arizona Corporation Commission) and the CPUC (California Public Utility Commission), but it turned out that the two protagonists on each side, Commissioners Gruenich and Mayes, wound up collaborating as a result. So maybe that's the good news.

Question: So far today we've kind of been talking about satisfying public policy requirements that are maybe different among states, but are complementary. But there's also a possibility that state public policy requirements could conflict with one another. The hypothetical I like to use, as ridiculous as it may sound, is suppose West Virginia passes a law saying that it's the responsibility of West Virginia utilities to export five gigawatts of coal-fired electricity every year. And they provide that to the RTO and tell the RTO to go plan the transmission system to do that. Meanwhile you've got states surrounding West Virginia that all have RPS requirements. How do you deal with that through this FERC Order 1000 process, or through the siting process? Can the siting process discriminate against the technology being used to transmit power? Is that within federal law? How would that work?

Speaker 2: I think it's a great question. And I don't think it will come up until you see these tensions played out. But as I view the requirements of Order 1000, all that's required of the RTO and FERC is to consider those various state public policy requirements, and then that consideration will just be subject to "arbitrary and capricious" procedural review. I don't think Order 1000 favors one set of requirements over the other, and I think that's going to be left to the governance rules and to RTOs, and to FERC's general policy stamp.

Question: So presumably West Virginia would just be outvoted, within the RTO planning process?

Moderator: My state has a law that you can't sell antifreeze unless it's got a bittering agent so that no one's dog gets poisoned. And we've got other laws like that and I'm sure most states do. Under our commerce clause, a state, using its public health and safety, has the right to control what's sold within its boundaries, subject to certain kinds of explicit federal preemption. So I would maintain to you that a state does have the right to say that we want our electrons to have this certain quality of being green. On the other hand, it's pretty well established that a state doesn't have the ability to interfere with what's being bought and sold in another state. So I would just say that your example with West Virginia would have a real commerce clause problem that an RPS does not have.

In Colorado they are litigating the RPS and they're litigating the in-state preference, but they're also litigating the RPS itself as being a burden on interstate commerce. I don't think they'll win, but if they do, then I guess you're right and I'm wrong, but I think, as I understand the law, those are not opposite sides of the coin.

Speaker 2: But you don't need the blatant discrimination against commerce to get a hypothetical like this. You could have an RPS standard that includes, as some do, clean coal, and an RPS standard where states made an explicit policy decision not to include clean coal. Those could be neighboring states, and there are very different policy requirements.

Question: But they're both additive at that point. You've got to have clean coal coming to state A and something else coming to state B, and FERC 1000 would say that those are both policies that need to be recognized when you're doing your transmission planning and cost allocation.

Speaker 1: Your sort of outlandish example actually is not that far out of whack in the sense that, if you remember, 20 years ago, West Virginia and some other states were trying to figure out a way to do coal by wire. And I'm putting this example out because it points out the dynamics. We could talk about states being parochial, being non-parochial, whatever. The fact is, what killed that idea had nothing to do with the environment. It had to do with the intervening utilities not liking Ohio Valley coal plants getting access to markets they felt were their captives. And so the interventions of players in the marketplace may have greater influence than public utility commissioners, because commissioners don't have a financial interest that allows them to invest zillions into lawyers.

Question: Maybe I misstated the example or made it sound too discriminatory. Suppose the example were just that West Virginia's public policy was that all generation in the state be coal-fired. And suppose that in order to make that happen, that required more regional transmission, which would result in exports of West Virginia coal, ultimately, because of the free-flowing nature of the system. In any event, I still think that there is an opportunity for conflict between state public policy requirements. They're not always going to be in synch with one another, and I think we're still going to have to figure out how to deal with that, because I'm sure that is going to arise somewhere.

Speaker 3: And why shouldn't West Virginia have the right to do that, to be honest? Again, we don't have a federal policy that says that they can't. And until we do, it's up to the voters and West Virginia to decide what's right for them. As long as they're willing to pay for the transmission to facilitate their goal, why shouldn't they be able to? And I think the FERC Order 1000 allows them to.

Question: I'd just like to go back for a minute to the differentiation between the reliability and the public policy analysis. When you're talking about the transmission system, you're really talking about providing reliability and economics, and the public policy part comes in in terms of how you make the assumptions that go into the reliability analysis and the economic analysis. I mean, there isn't a model out there that talks about public policy. It's all about the assumptions that you put in.

And so the reason I believe FERC put that in there about public policy is that there's a real issue out there. Let's talk about the EPA requirements for a few minutes. I represent a transmission-only company, so obviously we don't do integrated resource planning, because we only do transmission. So if we need to wait for the supply market to totally sort itself out (which it never does, because it's changing every single day like everything else) we can't build anything, and we can't plan anything. So here we sit with EPA regulations that, in theory, are going to come into play between 2014 and 2017. If they cause the retirement of some key powerplants in our system, which they might, we don't have enough time to do the transmission to provide a reliable system, so we're going to be caught between a rock and a hard place. And the same thing with the RPSes.

The reason that we asked MISO to do the regional outlet study was because the current approach, or waiting till the generators all figured out where they were going to be, just wasn't working. So the public policy consideration really goes into the assumptions that you put into the model. It's really still about reliability and economic savings and the least cost choice.

Speaker 3: That is the way it is in MISO; that's not the way it is in PJM. And who knows how it's going to be after they complete their compliance with Order 1000, but from our perspective, if a line is needed for reliability, it's needed for reliability. If the line's not needed for reliability, or if it's close to the line, then I think that makes cost allocation much more complicated. I think it makes siting much more complicated, unless you have all the states, which it sounds like you might, in MISO, completely in agreement about what the objectives are, what generation they all want to see built, and where they want to see it built. In regions where you don't have that, it's going to be much more complicated to do it that way. But if everyone's in agreement, then you can combine the criteria.

Question: The question I would ask to PJM is: reliability under what set of assumptions? What assumptions are you putting in the model?

Speaker 3: Absolutely, how the generation forward capacity market plays into that transmission planning is important. And our view is that it's not integrated well enough at this point. PJM is looking at scenario planning where they take EPA regulations, for example, and try to estimate what the impact might be, and then go through certain scenarios. And that might be appropriate. When it comes down to actually implementing that, it will have such a significant impact on the scenario, that it will put transmission really as the driver of generation, it seems like, rather than the backstop. So I think we need to make a decision. Is it a backstop? Is it a driver? If you're doing it first and putting in the transmission assumptions, generation retirements, and a certain build-out, then the transmission that is built with those scenarios will facilitate that build-out, I think.

Question: I will definitely agree that it's a very complicated question, but it's not as easy as saying, it's going to be the driver or it's going to be the backstop. To your point, it's more complicated than that. And the more you have to consider scenarios in different futures that might evolve, and the more uncertainty you have, the harder it gets.

Speaker 2: Your question does raise the issue of what counts as a legal requirement. Is it just a federal requirement? Obviously, it includes federal and state requirements, but only existing requirements? Future requirements? Does it include local requirements? And then, also, as we've been talking about siting, is refusal to site a requirement? If it is, then conceptually the whole thing kind of collapses.

Question: Going to the issue of whether it's siting or backstop siting, I continue to believe that there is really a fundamental difference, as one of the speakers indicated, between the siting of gas pipelines and electric power lines. But it seems to me that the problem really isn't that hard. There actually is a model, and that is that the state commissions could do the siting. They wouldn't be required to if they don't want to, but they could do the siting much like they conduct arbitrations under the Federal Communications Act. If FERC ordered a line to be built, then the individual commissions would be responsible for siting it within a certain timeframe--something like 12 months.

One problem that was only touched on I think by Speaker 4, is that these transmission cases are enormously complex. We recently had one case with over 1000 interveners, and another case with I think 980 interveners. And those folks really have to be able to go to somebody within a reasonable travel time and make their case. If they don't, then I would predict FERC would have siting authority for about 24 months, because Congress, whether Republican or Democrat, would just be inundated by local landowners, or other local interest groups. But if you had the commissions with the right to site, or the authority to site, then they could make the little accommodations that are always necessary in these cases to satisfy the landowners, whether you move it to the property line, you put monopoles instead of lattice towers, whatever the adjustments are.

Speaker 4: I think that's a workable solution, and that has certainly been something that Ohio has raised over and over and over again. It really is a local issue. We need to provide a forum for the interested parties to be heard.

I guess my skepticism comes because FERC can have joint hearings in their gas pipeline cases. We have formally requested that, because our statute allows us to have joint hearing and make joint decisions just as FERC's statute does. And we were told, "Over my dead body" more than once, when we made a formal application. So

I'm just skeptical that we can go down this path, I think you're absolutely right, it's a local issue, and we need to provide convenient forums for participants. But I'm skeptical that FERC is going down a path and the states are going to be cut out, if you will, as well as those affected.

Speaker 2: You know, it's interesting, because the proposal that you were saying is actually not that different than something that was proposed 20 years ago. The proposal included a federal backstop, and, for exactly the reasons you're talking about, you needed to provide a convenient local forum for issues to be heard, which is obvious logically the state, and there were certain things that the state had to do and if didn't do it, then there would be a federal backup. But if the backup is invoked, the record that's made at the state level has to be used by the FERC. You could set that up.

Unfortunately that's not what Congress chose to do; they chose to set up this convoluted process where you study congestion, designate corridors, and then, you know, the Department of Energy gives that to FERC. But it's a convoluted process. You could have the same concept with a lot simpler process.

Speaker 1: Speaker 2, is the questioner talking a little bit about the cooperative federalism that was in your slides?

Question: Yes, I mean, you've got the ultimate threat of action by the feds, if the states don't find a way to effectuate the goal on their own. And then you rely on a process that facilitates greater participation, as we do under the Telecommunications Act of '96.

Comment: I would just point out that, again, in the last year we had two cases where the administrative law judges had to hold the hearings, literally in the Austin convention center.

Speaker 1: The other issue, by the way, with the current regime, is, of course, illustrated by the Piedmont case in the Fourth Circuit, where the question is, what happens if the state does take action? Say it rejects the line, does FERC still have backstop authority? The Fourth Circuit said no. But there's a whole argument about whether that was the right decision. If that's the right decision, then the backstop role is more academic than real. If it's not the correct decision, then there may be a more serious backstop.

Question: What I'm talking about is something analogous to the arbitration proceedings under the Federal Communication Act. You could have a federal regulatory scheme that said, for an interstate transmission line, the states will have the power to site it, and they have to site the line within 12 months. And that would still afford local landowners due process. It would make it infinitely easier to make the adjustments that always occur in these cases. And it would also save FERC, frankly, from the headache… Now, there would be states that would say, "No, I'm not going to do it. If I don't have the ability to say no, if I just get to address where the line goes, then I'm not going to do it." But there are already states that don't site the lines anyway.

Moderator: As one of the speakers today said, if participants are willing to pay for a line, that's tantamount to a proof of need. So I think in your conception, you'd have that, and then states would just be responsible for deciding where it goes—or, even given the need, whether it still fails some really important environmental test, so that you can't build it.

Question: Just to possibly clear up a confusion, when FERC sites gas pipelines and hydro facilities, they go out and have local hearings in auditoriums in high schools and things like that. So, it's not that there's not a chance for people to gripe. And certainly the people who don't get satisfaction in those hearings go to their congressmen and we hear from their congressmen. So I'm not sure what the difference is, other than the fact that the state does it as opposed to FERC doing it. Either way, people get their chance to air their grievances.

Comment: There's a big difference. When they come before the state commission, you know, there's a proposal for decision, with a route. And the affected landowners can still come in and say, "Well, I want it down my property line, not right across my land." And then we make a decision, do we want to pay for that? And we actually make that decision, from the dais, evaluating the costs and delays and all that. So I would suggest that's very fundamentally different from staffers being at hearing, listening, and saying, "Thank you for your comments," and the person doesn't get any justice. That would be their view of it. I'm not suggesting FERC just ignores it, but…

Comment: Obviously the states are a lot closer to the problem and may feel a different amount of political heat. But oftentimes that's the role that the federal government has to assume, if this is an interstate line which has interstate benefits. And we don't do the same process, but the Commission (FERC) eventually has to sign off on the environmental impact statement, and even, on occasion, commissioners will go out to hearings, although it's somewhat rare, they prefer to have staff take the heat in these local high school gymnasiums. There may be slight procedural differences, but everybody does get their chance to gripe. As a matter of fact, interventions in our certificate processes have gone up significantly, and they're almost all landowners.

Speaker 1: Let me make a point, though, because I think the benefit of having that initial hearing at the state level is not just that they're closer to the problem and they may be more likely to be sensitive to it. They also, I think, have a better command of what the options are and what to do, because they jhave local knowledge. I think there's a need for a federal backstop role, I want to be absolutely clear about it, but I think the way you ought to exhaust things before you get to that really are at the state level, because I think you're much more likely to get an accommodation that makes sense, than otherwise. And if the state chooses to be parochial about it, there needs to be a backstop.

Comment: I wasn't arguing against letting the state go first, but I'm saying that the federal process gives all the landowners the same due process that the state would have, except it's not as sort of locally connected. But there are certainly lots of opportunities for landowners to get upset and for environmentalists to get upset and for the commissioners to hear their complaints. And, you know, if you want to see some fireworks, look at the LNG terminal proceedings.

Speaker 4: I'd like to just echo what Speaker 1 said. I believe that the states know their resources and can react and accommodate significantly better than the feds.

The other thing is to take it to next step. You know, we have oversight on construction, and we get calls every day during the construction process, and we send staff out on the ground to make sure that the conditions are adhered to and to react to the concerns. One of my favorite stories on siting a transmission line is, I got a call from a woman (they all had my cell number and my home number, and it rang 24/7) and I got a call from a woman about 5:00 in the morning one morning, and I literally got in the car and drove up there, because she was holding her portable phone up (this was before cell phones) trying to make me listen to one of the construction guys going to the bathroom. So I literally drove up there and halted construction until they got a port-o-john on site. I don't think the FERC staff is going to accommodate those things. I mean, being closer, we understand the resources, we know the people, and we are able to react to situations to mitigate problems.

Comment: I'm sure FERC would have ordered a port-o-john also [LAUGHTER].

Question: My question is for Speaker 1. Given everything that's been said about why we might want the states to do it and why we might want the feds to do it, I don't understand why people are fighting to get it rather than give it away. Rule number one in politics, as I understand it, is, you don't want to make decisions that are guaranteed to make a lot of people unhappy with you. And I'm trying to figure out why it is that the states are fighting so hard to be put in the position where they've got to make these kinds of decisions. It's contra-logical, from what I know about political beings.

Speaker 1: I think the issue is that some of these lines will always have impact over the folks that live along them, and they have a lot of impact on other issues, as I was trying to point out. It's rare that the issue about siting is really just about siting and transmission lines. There are all kinds of other agendas at work. And I think it's natural that they're going to want something significant to say, if not control, over what happens in regard to that. Now, because of the possibility they could be overly parochial, you need some check on that power, but, on the other hand, I think there's a legitimate reason why you'd want local people…

Question: I'm not disagreeing with that. I think that's a very powerful argument that I don't disagree with. What I am finding baffling is that the fact that lines are going to go along thousands of people's property would normally be a reason why someone would want to make sure somebody else was responsible for it, rather than them. Most of the politicians I know (maybe I've been in Washington too long) are not looking to take on that kind of responsibility.

Speaker 4: The reason that we're all fighting for this is because we care. It's because we think we can make a difference. And I really think that there is a little bit of a distorted view with us public servants, because FERC's in the same boat, and here we are fighting, both trying to do good.

Comment: That's a great answer.

Speaker 2: Could I just end on a less public-spirited note and a much more cynical one? If state regulators, like other regulators, are seeking in any way to maximize their own power over the kinds of issues they regulate, that might be an explanation. I mean, access to transmission is one of the most fundamental issues with respect to access to the wholesale market. And a lot of state regulators are very interested in controlling market access, in part because many of the firms they regulate are also interested in that issue.

Session Three.

Retail Pricing: Is It Time To Get Real (Time)? Or, At Least Dynamic?

Wholesale markets, especially where there are RTO's, have grown more sophisticated in providing accurate price signals. Renewable resources, particularly wind, have had and are likely to have a growing impact on price variations everywhere regardless of whether there is an organized wholesale market. More technology is being rolled out which is capable of providing end users meaningful and actionable price information. Despite all of that retail pricing has, with few exceptions, remained largely unchanged, especially for the bulk of residential and small commercial customers. Prices are based on average costs and passed on to customers in an end of the month bill, too late for a user to do anything about it. Regulators and utilities have persisted in shielding customers from any real signals as to how and when to use electricity most efficiently.

What is driving the policy on a retail pricing regime? What are the political dynamics that make changes in retail pricing so difficult to carry out? Are these changing? What have we learned from demand response in wholesale markets that we might apply to retail pricing? Are there new uses of electricity, plug in cars, for example, that might compel a fundamental re-examination of the retail pricing regime as we have known it? If not full real time pricing, are there proxies for real time that are easier to implement but reflect the dynamics of the market and are sufficient to capture most of the potential efficiency gains?

Moderator: Good morning. I'd like to welcome you back this morning for our session about whether it's time to get real with real time pricing.

So in terms of beginning to think about this, I like to think about real time pricing by thinking about where we are today and where we've been for the last 100 years, which is that most consumers see flat electricity prices, regardless of when they use electricity, and get their bills--well, they get a monthly bill, but only every other one is really based on an actual meter reading. This is roughly the equivalent of going to a grocery store where they charged the same price whether you were buying chewing gum or caviar, didn't have a display at the checkout counter to tell you how many items you bought, and sent you a bill several weeks after you went to the market. I submit that probably not very many consumers would want to shop in that kind of a grocery store. And it's actually even a little bit worse, because we all know that what consumers really care about is their hot shower and their cold beer and their comfortable room in which to watch the game of the week or Dancing With the Stars, or whatever their personal taste happens to be. And electricity is only one component of the services necessary to meet those needs. So it's really like being at this grocery store where there are no prepackaged products. Some assembly is required for anything that the consumer would really want to do.

So as we think about this and how to get started, I'm going to just lay out a couple of concepts for us to think about. What would be some objectives that we might be thinking about as we look at how to price electricity going forward? There are, I think, three things that I would want to bear in mind. One is transparency. Are we providing dynamic price signals that actually reflect the time and location varying cost of the next kilowatt hour of energy that someone is choosing to either consume or not consume? Secondly, the question of acceptance. Have we dealt with what behavioral economists call the "loss aversion" that consumers feel with the potential of having perhaps one month of a very high bill, where other months it might be a much lower bill if they're managing their usage effectively? And finally, are we giving consumers choice? This means both, if you're in a retail access state, are we enabling competitive suppliers to offer and are we enabling consumers to have different combinations of energy, of pricing and services, that best match their individual preferences and needs?

So those are some high level objectives to think about. But also I think we have to think about real time pricing within various enabling contexts. So we ought to think about it not just as an item by itself, but by the things that make it possible for us to transition to a world of more dynamic or real time pricing.

So think about it within the context of education. This might mean consumer engagement. It might mean information feedback, and information feedback is becoming progressively more sophisticated. So it might in a very simple form mean a bill comparison to your neighbors on your electric bill. It might mean detailed energy usage information on a website. It might even mean software that reads the frequency signatures of different energy usages in your home or place of business and can tell you that you've got a 1982 Whirlpool refrigerator, and it's really breaking down, and you ought to think about getting it replaced or repaired. And education can also mean defaults. We know that in a lot of contexts, defaults matter, and that it may be that a way of educating consumers about dynamic pricing is to start consumers on a default kind of dynamic price, like a critical peak rebate that you'll hear more about on the panel, as a way of introducing them to the fact that they have control over their bill.

A second enabling context is technology. Now, technology can mean something like what one of our utilities is implementing in a residential real time pilot, where the consumer will see a thermostat that has a simple slider between more savings or more comfort. But behind the slider is an algorithm that will actually be bidding into a local 15 minute market about whether or not the air conditioner should be operating in this interval or in a future interval, given current and likely future interval prices. And there are other efforts going on around the country. For example, in the Smart Grid Interoperability Panel, to begin looking at whether we can have current and indications of future interval prices broadcast through some near ubiquitous medium by the RTOs, such that appliance manufacturers and the Consumer Electronics Association can have their products actually begin to optimize relative to those varying price signals. So that's a way to enable responses that are back of mind for the consumer and automated.

Another context is hedging. One of the classic ways of thinking about real time pricing is a two part tariff, where there is a fixed quantity purchased at a fixed price, but the increments and decrements are priced at a real time price. And there are other variants on that. For example, a consumer subscription model, where the consumer has a price guarantee that is prepurchased, along with a variable price, so in economists' language that would be like a call option plus a real time price. And the consumer could choose a higher or a lower quantity of kilowatt hours to be part of that call option.

Another kind of context is competition. There are varying degrees of retail competition in different retail access states. You know, in some places, retail competition means simply you have a POLR (provider of last resort) price, and you have one or two suppliers that are bidding in another flat price that is a few percent lower than that. And that's the only choice that a retail customer has. But in other places retail competition has taken off with a much wider variety of choices. So for example, last week I had a retail supplier who was coming into Ohio come into my office and actually talk to me about an application that I had spoken about at conferences two or three years ago. An application that they could put on your smart phone such that when you and your spouse drove away from the house, your house would know how far away you were and would begin to power down as you drove away and power back up to the right temperature as you were driving back into the neighborhood. So that is one of the things that competition can bring, and that's another potential context in which we can think about real time pricing.

Speaker 1:

Good morning. Many, many years ago, Samuel Becket wrote a very famous play called *Waiting for Godot*. And he didn't realize he was creating a metaphor for dynamic pricing. What we have really, as our moderator has mentioned, is a very, very slow process of analysis. You could almost say paralysis by analysis has crept in. And my hope here in the next ten to 12 minutes is to try to change that by sharing with you evidence from a variety of different experiments and pilots and demonstration projects that have been carried out during the last decade in three continents, featuring more than 100,000 customers, that show that customers can and do respond, even before they get that smart phone that powers down the house as they drive away from it.

People have something called a brain. And it responds to signals. When they shop for clothes, or they shop for airline tickets, or they park a car, they are facing a time of use rate in all aspects of their life. The same people, when they come to electricity, are regarded as being inert, unresponsive, and almost looking like people from another planet. Well, they are the same people. And so my hope here in the next few minutes is to share with you some data to prove that they are the same person and not a conflicted person.

We all know that the smart grid is rolling out. There's a lot of momentum in that train, particularly when you look at smart meters. We have at this point in time 22 million smart meters in the United States. It is projected that the number will grow threefold in five years. And some people are saying that in the next ten to 15 years, there will be no dumb meters to be found in the United States. So that's about 135 million smart meters. We also know that dynamic pricing, which obviously is enabled by smart meters and requires smart meters, is not rolling out at anywhere close to that other pace that I showed you on the previous slide. Right now, only 1% of the customers in the United States are on time-varying rates, referring to residential customers, and only a tenth of 1% are on dynamic pricing rates. OK? Hesitation seems to be the best way to characterize the institutional reflex whenever dynamic pricing is mentioned. I was at a conference a couple of years ago where there was a very big panel with several state commissioners at the end of their conference, and it was called the "grilling the commissioners" panel. Your chance to ask whatever you really wanted to ask but were afraid to ask. And so that panel was up there. And somebody asked if any of the commissioners disagreed that dynamic pricing would improve economic efficiency. Not one disagreed. And then they were asked if they were planning to require the utilities to roll out dynamic pricing. Total silence. So it's too good of a thing to oppose, and it's too risky of a thing to do. And that's the conundrum. So I think this is like a Socratic moment. Take a deep breath and look at the hemlock. [LAUGHTER]

The tide may be turning, though, so don't yet touch the hemlock. In a recent survey, we have seven state commissions indicating that they support dynamic pricing. Now, seven out of 50, right? 14%. Well, I'll take 14% and hope at some point that the others will come around. But there's a lot of movement. I mean, it wasn't like that just a few years ago. I've been going to the NARUC (National Association of Regulatory Utility Commissioners) meetings fairly regularly, and several of you who are here from that group know what I'm referring to. It is beginning to make a dent. It takes a while, though, right, for the tide to turn. And so we'll just have to be patient.

Now, 50% of the advanced metering business cases that have been submitted by utilities around the country reference dynamic pricing. So again, I'm not saying that they're talking about default dynamic pricing, or what kind of dynamic pricing, or with or without technologies. But at least a reference is being made to it.

And then what was even more interesting is that in a recent survey of utility executives, they were asked to name the top five issues that keep them up at night. One would be enough, but they were asked for five. And so dynamic pricing was mentioned as fifth on the list. It made it. And critical peak pricing in particular was a rate they mentioned, not peak time rebates, which I would have thought would have been the easy option. They actually mentioned critical peak pricing.

And I was actually at a conference in July in Washington where the CEO of one utility actually said that they were going to roll out smart pricing with the smart meters and made a public comment which really stunned the audience for a utility CEO to say that they were going to be rolling it out to every customer. Now, admittedly, it was the peak time rebate, I believe, that he had in mind. But even then, that's major progress. A few years ago, the CEOs wouldn't know what critical peak pricing was, and a few would perhaps know what pricing was. Most of them would know rates, but pricing was a new term. And critical peak pricing has moved very fast.

Now, Brattle has done a survey of 50 experts around the country. The survey did not include anyone from Brattle. It included other people, academics, utility folks, commissioners and what have you. The survey invited 200 people to respond, and 50 did. You know how those surveys go. I don't respond either. So you have to work on it. But the survey got 50 to respond. There were some very distinguished people responding. And in that group the survey asked a number of different questions. One of those simply was, "What do you expect will be the adoption rate of dynamic pricing ten years out?" So the focus was on the year 2020. And we were very surprised with the results, maybe too surprised. Up to 20% in some cases. The range was between 10 and 20%. So it is beginning to show up, at least in surveys. Whether it will show up in our bills is another story. But there is a lot of talk.

So what has made a difference? I believe you have to give credit to the experiments. Now, there are some people who don't like experiments. They say people are just doing these pilots just to not do what they need to do. It's a case of pilotitis. But it has made a difference. The evidence has become so compelling that it is hard to ignore, especially when you have smart meters, were you're not to do it, it is almost going to look, well, I won't say criminal, but it will look something like that.

If you look at the pilots, what you find is that there are a total of 109 tests now that have been carried out with time of use pricing, with critical peak pricing, with various kinds of real time pricing. And here are the results. We don't have enough time to go into each bar, so I will spare you that, but just take my word for it, and there are papers to back this up that I'm happy to provide. If you look at the evidence, it is striking. You have time of use rates on the very left side, and you have critical peak pricing rates with smart technologies on the right side. As you make that progression, you see higher and higher impacts, because you're seeing higher and higher prices with smarter technologies. And that shouldn't be a surprise. Right? The more of a price signal there is, the more of a response you will get.

Many people have a time of use rate. Actually, I have yet to find a utility today that doesn't have a time of use rate. If you ask them how many customers you have on that rate, most of the have no customers on those rates. The rates are terribly designed. They have peak periods that are 12 hours long, and they have a price differential that's as mild as Dove soap. So why would anyone bother? You need something strong. You need something that is cash based, and then you get people's attention.

So what I will show you next is a chart that bears that out. Not every pilot has this kind of data, which provides you prices and quantities. So we were limited to the best pilots that have provided that data. And we just plotted the data. This is a simple scatter plot of demand response on the vertical axis and the price ratio on the horizontal axis. And you get what I call an "arc of price responsiveness." The higher the price ratio, the greater is the response. It is not linear. It does taper off. You'd kind of expect that. Right? You can't get beyond a certain response. But look at the numbers. They are approaching 25% and above for those very high price ratios. So what do you want? You want a 5% response? You can figure out from this diagram what the price ratio needs to be. Of course, if you trust the data. And I always run into somebody who says, "I won't shift." I say, "Well, that's fine." There are many customers, even in these experiments who don't shift. Some do and some don't. No two customers are identical. But what matters is the collective behavior of large numbers of customers, not the individual behavior of one particular customer.

You know, I've had debates about this, people telling me that they'll have a divorce if they try to force this on their spouse. And the spouse will have to do their laundry at two in the morning, and all kinds of reasons why they are ready for a divorce. Why blame it on the time of use rate when they're going to have a divorce anyway? So I mean, the reality is, some respond and some don't. No people are identical.

Then we come to the issue of smart technologies. The smart technologies, without a doubt, lift the curve upwards. And that's what we see. And these technologies here, by the way, are just a simple kind. They are the in home displays that you are talking about with the grocery store example. By the way, if you grew up in a country where the only option was one grocery store, and that grocery store did what you were describing, that's what you would be stuck with, and that would be a norm. So for 100 years you have had flat rates for electricity, and that's why this change looks so abrupt, so difficult. But you talk to the customers, you message it correctly, you tell them about all the other things to do where there is dynamic pricing, and you will get acceptance.

So there is certainly a marketing challenge. It's not an easy task. I'm not trying to minimize it. But we have plenty of evidence from real customers who have lived through the experiments. They are not playing with Monopoly money. This is not just getting in a graduate student seminar and doing a game. This is real people. And as far as I know, by the way, there were no divorces that were reported.

All right, so then comes the ultimate clincher, which is, this is going to not be a good thing politically, that this is going to be a terrible thing for low income customers. And then the argument is extended to include senior citizens, people who have medical conditions, people who are at home for a long time. Well, so the only way to settle that ideological argument is by looking at data. And so what we did was, we said, all right, let's take a dynamic pricing rate, which like most of these rates is revenue neutral, and if it's a revenue neutral rate, you take a random sample of customers. What you're going to find is that about half the customers are going to see bill increases, and half will see bill decreases. Now, if you go ahead and focus on another sample, which is just of low income customers, well, because they are more at home, they have a flatter load profile. Because they often don't have air conditioning and those big houses, with all of those guzzling appliances during the peak hours, they actually have a higher load factor. And what matters for bill impacts is load factor. So they're actually, based on this sample, much better off than the average customer. Which is the very opposite of the viewpoint that you see being put out by consumer advocates.

And I have shared this data with several of those consumer advocates to see if this will help move the needle. I mean, some of them are looking at it. Some are saying, the only data we get is this data you gave us. So I said, "Well, show me your data." They have no data. And so it's all ideology. And what happens is, you get the extreme left wing folks opposing it, because of this issue. You get the extreme right wing folks opposing it because somehow it represents interference and a form of Communism to tell customers when they should run their air conditioning. So it's caught in between those two.

All right, so that was simply if the low income customers do not respond. I believe I've shown you, based on that one sample, and we have another one coming soon from Michigan, that they are actually better off. But then comes the issue of, well, but they can't really respond. They don't have the load. They don't have the time. They don't sometimes at all even have the education to respond. So here is some evidence on that issue. We have the average customer response here as an index of 100%. And from a range of studies where they have separately estimated price responsiveness for low income customers, versus the average customer, you have a range. And I would say about 2/3 is a good number to use. So you will get lower response from low income customers, but not zero, and not even a quarter. You are probably going to get something like 2/3 of the response from low income customers. And so, they are better off, even without shifting, because of the flatter load shapes, but they are even more better off, because they will respond, and there'll be more people better off than just the figures I showed you on the previous chart. So all of what I described to you is documented in several papers. And why don't I stop at that.

Question: Just one question on the survey of dynamic pricing being on the top five issues by utilities. Do you know if that was a prompted survey, where you had a list to pick from? Or were utility executives picking dynamic pricing out of the air? Did it come to their minds? Because that seems surprising to me.

Was it recognition, where it was a list of things? Or was it recall, where it's open, and you write down five things that are at the top of your mind?

Speaker 1: The pricing options here were prices that were really high during the critical hours.

Question: No, no, I'm sorry. The survey. You said dynamic pricing was one of the top five issues that utility executives listed. What keeps them up at night?

And I'm actually surprised dynamic pricing was one of the five. And my question is, was it from a list of ten things, and dynamic pricing was there? Or did you just ask, here's write down five things?

Speaker 1: I did not do the survey. I just saw the report.

Question: OK, so you don't know.

Speaker 1: And the report said the executives were asked to name the top five issues. And they mentioned critical peak pricing as one of the top five issues.

Question: OK, thanks.

Question: On the low income slide, if you could go back to that. Your conclusion on this slide is that the low income customers, even when they don't respond, are not harmed. But I'm not seeing that from the graph on the bottom.

Speaker 1: All right, let me explain the graph. So basically, the graph is showing the people whose bill went down, as well as the people whose bill went up. So looking at the lower panel there, there are about 65% or so of the customers who saw a bill decrease who are low income customers. If you look at the lower panel, that's the low income customers. And then the rest saw a bill increase. If you compare that to the average sample, which is up above, then 50% saw a bill decrease and 50% saw a bill increase.

Question: And the level of the increase on the right is going up. Is that 10% of their existing bill?

Speaker 1: Yes.

Question: Or 10% of the customers?

Speaker 1: No, so the vertical axis is the percent of their bill, their monthly bill.

Question: OK, thank you.

Question: On the same slide, do you have this information by residential homeowners versus renters? And was there a difference?

Speaker 1: I wish I could answer that question. We don't have that data. So this is regardless of ownership. It's just by income status. And the problem is that the utilities that do these surveys often do not ask about ownership. I mean, in a future study, that would be a good question to ask.

Speaker 2:

I'm going to follow up on a lot of comments that Speaker 1 discussed, focusing mostly on what's it going to take to get a transition, or whether we are really, like Speaker 1 mentioned, sort of stuck in this level of stagnation.

And I think the first question that we need to ask is, are the preferences of all the different stakeholders aligned? And this obviously very glaring graphic on the right hand side is taken from a group that clearly doesn't share the position that the smart grid is a good thing.

So you know, you look at the preferences of all of the major different stakeholders that are out there. Economists have an objective of efficient pricing. And so they prefer real time pricing for price efficiencies. Consumer advocates, on the other hand, their objective is really consistent billing, cost causation, things like that. They prefer rebate programs. You see there are a bunch of white papers that AARP and others have put out. And they're clearly focusing on those kinds of rate options. But they're willing to entertain voluntary time of use or critical peak pricing type rates. Utilities' main objectives--well, for the most part, they want to capture their allowed ROE. So they won't do really anything that's going to potentially cause that to suffer, and rates are obviously one of them. Regulators, as you heard from Speaker 1, they clearly see value in time based rates, but again, there isn't this ground swell of proceedings out there to open up and make mandatory these kinds of rates. So one can sort of conclude that the risk associated with opening those kinds of dockets isn't justified.

So if we can't agree on all these things, is there anything we can really agree on? And I would say, yes, we can. As Speaker 1 mentioned--his graphics illustrated we can all basically agree that customers can and will respond to prices. We know that as the slide that we were just talking about showed, these changes in bills, changes in rates have bill implications. I mean, you're inherently altering the cross-subsidies that are in a flat rate when you introduce any sort of time based rates. We know that customers can and will accept utility controls. This has, obviously, implications for some of the smart grid and customers' capabilities to respond to prices. But we also know that customers can and will utilize their own control technology to alter the response level. And in some cases, it can increase the level of persistence of that response. We know that once exposed to these rates, customers are actually pretty happy with them. The sky doesn't fall. They're not sort of running around in the streets. This is something that they can handle, if we're willing to expose them to that. And we know that customer education and marketing, again following on what Speaker 1 said, is a very crucial issue here for success.

So if we can all agree that customers respond, do we know enough about that response? And this relates to the question that someone just posed about renters versus owners, with respect to the bill implications of variable pricing. But I think it's also relevant with respect to customer response. Speaker 1's graphic and this graphic as well are relevant here--this is taken from a 2008 EPRI report that looked at 18 different studies that were out, focusing on elasticity measurements, as opposed to peak demand reductions. And it shows, again, overwhelmingly, that customers do respond. But it also shows there's a fair amount of variability.

And that variability, I think, is one of the crucial elements that is holding us back from achieving a transition to time-based rates. Consumer advocates and others have these concerns about very niche areas. They don't understand why some customers respond and some don't. And so I think that's one of the key elements that we need, among others. There's just information that I think is necessary in order to try and create a more unified decision making process. And response is one of the key areas where more information is needed.

But it's not just response, and not just understanding the short term response-- most of our present pilots, that are one or two years, have provided us information on short term response. We need more long term estimates. Something you often times hear consumer advocates and others talk about is, "Well, customers can do this for a year or two, but three, four, five years down the road, are they just going to peter out and become disinterested, and then you've exposed them to all these risks, and they're not really changing their behavior?" So I think that a very critical element of this is, both short term and long term, understanding of response to reduce that level of uncertainty.

I think we also need to better understand who's even going to join these rates if we offer them. Again, I think we have a pretty good idea that customers will be happy when they get there. But we don't know what kind of customers want these things or will actually accept them if we offer them. And we don't know which customers are actually going to stick around if they get on it. Some folks may be more likely to leave than others. And we want to better understand what that looks like.

I think we need to do a better job of assessing the financial risks and figuring out which risks we want customers to manage themselves and which ones we should protect them from.

We need to figure out where we're going. Is the purpose of pricing to just avoid a CT four years down the road? Is it to make a smart grid a reality? Is it to integrate renewable generation? Is it to do any or all of those things? We have to have a sense of what it is we're trying to do, and how pricing can get us there. And I would say the last issue here is, again, education and marketing. How can we inform customers most effectively of not only what their current consumption means, what the bulk power system looks like, but also why these kinds of rates are good for them?

So again, is more information needed? Or are we just in a state of pilotitis? And I think again, to address the information gap I just talked about, I do think more study is required. But I think we need more focused study. And that's one of the things that the DOE's smart grid investment grant program is actually attempting to do. It's running 11 studies. They're relatively well coordinated. You can see from the graphic at the bottom, all the different types of things that they're going to be looking at. In fact, I think, of the 11 studies, eight of them are going to be looking at critical peak pricing. So in terms of scope and breadth and coordination, these pilots are being done at a far greater level than most have been done before. With maybe the exception of the TOU experiments that were done in the late '70s and early '80s. So with 150,000 customers under these pilots, the goal would certainly be to provide a lot more specificity, to reduce the level of uncertainty around a lot of these issues where we have information gaps.

Now, as the guy responsible for managing this stuff, I would love to think that once these are over we will have answered every question out there, and everybody will move forward together hand in hand. But that's pretty naïve. So the whole idea is more to get enough information out there that we can really whittle down what are the key issues that still remain. Or can we just acknowledge that people are being obtuse, that they're just standing in the way of these things?

Well, one of those issues clearly seems to be consumer protections. And this great Calvin and Hobbes cartoon to me sort of is emblematic of this issue, where the concept of protection is in the eye of the beholder. In this case, Calvin's parents view the babysitter as this necessary person there to protect their child from both himself and the rest of the world. Now Calvin has a very different opinion of that. He sees this person as a dictator, a tyrant who keeps him from doing all those wonderful nefarious things that Calvin is known to do. And I think that's part of how some people view consumer protections, that they mitigate price level. If you protect customer from prices, that's the worst thing you can do for them.

So what's the current experience with consumer protections? And how does that help us moving forward? Well, if you look across the country, you'll see almost all jurisdictions have time based pricing on an opt in basis. And so is that helping us move forward to get out of this level of stagnation? If we have no experience with opt out, or with mandatory pricing, what does that say for the future? Because if we need that information to base our decision making on, we don't have it.

In terms of the smart grid investment grant--as many of you may remember, the funding opportunity announcement explicitly focused on real time pricing for mass market customers. Not a single entity on that slide I just showed you is looking to pursue that. So I think that that's a very interesting element to remember, that none of those rates being offered are on a mandatory basis.

So the second issue, from a consumer protection standpoint, looks at bill protection, and whether that's a viable thing to look at and understand. Again, there are opinions on both sides, and I think it's an area we need to study more. It's one that has been looked at in a few cases, and the consumer behavior studies and the SGIG (Smart Grid Investment Grant) program are going to be looking at it as well, to again, provide more information in this area.

Well, is it rate designs that are sort of keeping us from achieving our goal here? Are some of us fixating too much on specific rate designs? Well, the economists, again, really have always focused on real time pricing. But again, if you sort of look at the evidence out there, it's clear that there just isn't an appetite for that at the mass market level. There may be at the larger commercial and industrial sector level, but clearly not at the mass market level. There's one instance in the country right now where RTP (real time pricing) is in place. It's in Illinois, and it's only done on an opt in basis. Participation levels are less than 1% at both utilities.

So I would contend that I think in some respects we need to stop lobbying for that at this level of customers. I think we need to find a better rate that we can try and rally the troops around and get broader based support for. And one of them might be critical peak pricing. There clearly seems to be much more acceptance of that at the regulatory levels. It's a dynamic rate in the sense that it illustrates and changes prices on an infrequent basis in response to system conditions. But it's very narrowly defined. It's relatively inflexible based on current designs. And it's not very conducive for smart grid requirements going forward.

Time of use rates are gaining some traction in the country. Connecticut is now mandating that as default service and will be rolling it out over the next couple of years from large customers to small customers in the residential sector. This rate clearly seems to have a little more traction with customers, as Speaker 1 mentioned. It's a concept that everybody understands. I mean, going back all the way to the nights and weekends long distance rates in the early '90s when deregulation was going on in the long distance markets. Customers get it. You know, it doesn't have the dynamic element of CPP (critical peak pricing) and CPR (critical peak rebates), and that's clearly a shortcoming of it. But it does have some implications, and it can allow for smart grid requirements.

And so, can we find a rate design that sort of marries the dynamic elements of RTP and CPP, and can make that work with a rate that's a little bit more palatable to customers, and they can understand and is more manageable from their perspective, like a TOU (time of use) rate? And I would contend that's a variable peak pricing rate. And I think that's a rate that has a lot of promise, that we should look at a lot more, as a rate offering, whether it's default service or heavily promoted opt in or opt out service.

Variable peak pricing is like a time of use rate, where you have just very well defined peak periods and off peak periods. The prices themselves can either be directly linked to the wholesale market, as they are in Connecticut, where it's offered right now. Or it can be done as a series of well defined, pre-defined prices, where it's being tested in Oklahoma Gas and Electric right now. So whoever the retailer is can either set the price a day ahead, based on the clearing of the LMP (locational marginal pricing) markets, or they can just simply look at their own system, looking forward, and say tomorrow's a price level two day, or tomorrow is a price level five day. So it provides that dynamic element of rates, but has one price effective in the peak period and a different price effective in the off-peak period, and that changes every day.

So this sort of begs the question of, OK, if we can get enough information from a lot of these pilots and these studies that are going on, can we agree that we want to change default service? And if we can, what kind of transition strategy might we need to get there? So I've created the peak capper's six step program to get us there. And the first one is, not surprisingly, identify our long term goals. What do we want the utility to achieve? And how do rates factor into that?

The next step, once we've decided what our long term goals are, has to be a set of short term, medium term milestones to decide, as we're going, how do we know that we're going in the right direction? But I think to mitigate some concerns that certain segments of the stakeholders are going to have, we need to have off-ramps as well. We can't be viewed as just being lemmings. I think some would contend that the deregulation exercise in certain areas followed that trend of just, we're going to blindly move ahead, because we believe in the theory. And in some cases, when the benefits didn't come to fruition, you know, it was viewed that we were just lemmings in that case. We should have had off ramps. We should have seen the signs and been able to change course. And I think that's an important thing to get buy in from certain stakeholder groups.

So once we figure out where we're going and how we're going to get there, we need to educate customers on why this is important. Why is it important for them? We've got to educate them to understand both the opportunities associated with this transition, but also the risks associated with this transition. And they need to understand how to manage those. Enter the role of technology, but not just technology solutions, but also services and incentives, so that customers are willing to get over that financial hump and purchase these things.

Now, this is obviously all done before there's even a value proposition at stake. We haven't even changed rates yet before we've started this process. But I think it's a necessary step to get customers to be prepared for what's to come.

And the last step of that preparation, again, going back to Speaker 1's slide that illustrates that there's going to be structural winners and losers, is we need to identify who those folks are. Even in the low income example, there's 65% of customers who, before they even do anything, are going to be better off. But what do we do about the other 35%? Do we just let them go? Is that just considered the American way? There's winners and losers, and that's just the way it is? Or do we try and do something? Do we try and mitigate these bill effects for them? And what does that look like? And we put a plan together before we even introduce rates.

So education, technology and this bill mitigation issue I think all need to come about before we even get to the point of finally putting in new rates.

I don't believe I have a lot of time left, so I'm just going to quickly leave this slide up for you to see. You know, these are three just very explicit examples of how this could be done. One, a traditional approach where you provide some education, and you just throw the rate on. A second approach that says, what's the end goal? What are we really trying to get to? And let's introduce a series of rates over time that transition us inevitability to that promised land down the road. And the last transition strategy says, well, maybe there are some customers that are better able to manage this transition than others. And so we should expose them first. And the ones that need more time, need more effort to succeed at the transition, those we delay.

Again, as Speaker 1 mentioned, there's lots of research and literature out there to back up the information that I've got here. It's listed. But with that, thank you for your time.

Question: If you would just expand a little bit about why you see critical peak pricing as being so inflexible.

Speaker 2: In its current form, it's purely a set number of hours with a set price. Usually in tariffs, it's predefined what conditions you can call the critical peak event in. Over time I think that can change. That's the current design. There are certainly more dynamic designs that are being introduced, where the period can change. It can be multiple hours, or just an hour. Where the price level can vary, depending on the level of response that you expect. As economists, we all believe there's an elasticity, so the greater the price, the greater the change in consumption. So the opportunity is there to make it more dynamic. But at the end of the day, it's still an infrequent event that you're calling. So it has a role to play. But if, as economists, we believe that RTP is the promised land we want to get to, I don't believe critical peak prices gets us nearly to that point, which is why I would focus on variable peak pricing. Because I think it combines the elements of CPP, of that relatively infrequent event-driven kind of response that's needed, but gives us the day to day dynamicism of RTP, where prices change, and therefore you're better reflecting system conditions and wholesale power costs.

Question: Quick question. On your last reference that you had on the references slide, you say it's forthcoming. When it is going to be out?

Speaker 2: I was hoping it was about two weeks ago. But our DOE program manager went on vacation to Italy and didn't want to review it. [LAUGHTER] So it should be coming within the next couple of weeks. (And I don't blame my DOE program manager for not wanting to do it on vacation.)

Speaker 3:

I guess the first thing I'd like to do is complement Speaker 1 and Speaker 2 in terms of their presentations.

So to put this in context, what I'd like to do is just briefly talk a little bit about TVA, because it's really a very unique model. In particular, the seven states that we serve--most of Tennessee, a large part of Mississippi, Kentucky, Alabama and just pieces of Georgia, North Carolina and Virginia--give us a whole lot of opportunity to look at what type of customer behavior we have a role in influencing. We serve those seven states both at a wholesale and at a retail level. 85% of roughly $11 billion is coming from our power distributors, 155 of them, and they're as diverse as you can imagine. By the same token, our direct serve customers, our retail customers—we have some that are residential, and we have some that are small commercial, and we have others that are the equivalent of probably ten to 15 to 20 of these distributors aggregated together. So a very diverse group of customers.

And then by the same token, we have a very unique responsibility of serving as the regulator. And what I'd like to try and challenge the colleague that I had breakfast with this morning is to put me on the hot seat during the discussion period, based on some of the remarks that I'll make here.

This slide is our north star, if you will, in terms of carrying out our mission. It's founded in the federal mandate of providing power at the lowest feasible rate. So what we do is, we basically work around the edges with a vision, which is to be one of the nation's leading providers of low cost and clean electricity by 2020. So that 2020 reference, I think, demonstrates a lot of the points that Speaker 1 and Speaker 2 were making--this stuff is not going to change overnight, and we've got to take a calculated path towards getting there.

I'm going to skip this slide and go to what I call the "TVA Jeopardy table." And I do so in a manner to try and generate some good dialog during the discussion period. And to show you how this works, we're going to take "rates" and "good" and talk about the alignment of our customers' interests and our ability to provide rates at the lowest feasible level. And quite simply, this is the easiest quadrant to address, from my perspective, in that it's a no brainer in terms of our customers' interests, and in particular some of the large industrial customers that we serve. No disrespect to Speaker 1, but they don't care what the empirical data shows. They want to know what their bill is going to be next month, and not what it was last month, but what it's going to be next month. So we're very well aligned in that regard.

Moving to regulation, as a regulator, TVA enforces the wholesale power contract. But by the same token, we're in a unique situation where we actually generate the rate schedules and rates that our distributors provide to their customers. So with this wholesale rate change that I'm going to focus on, I'll just put it in perspective that we developed 5,000 rate schedules with over 185 rate parameters and implemented that on April 1st.

The next piece I'll discuss is with respect to feedback. And in the paradigm of public power, if you will. Trying to get 155 distributors and 60 direct serve customers on the same page just doesn't happen. And more importantly it doesn't happen overnight. So again, to Speaker 2's reference, we have to identify what it is that we want to accomplish, identify milestones along the way in terms of getting there, and then try to build consensus around getting there. And in the public power model, there's really two ways to go about this. One is command and control. And the other is to build consensus. And neither one of them is perfect. But neither one of them will work by itself either. So we've spent a lot of time the last three years in discussion with all of our customer base in terms of trying to get them on board, and prior to that three year discussion period, we spent five prior years. And then I was reminded by Speaker 1 that he had discussions with TVA ten years ago on trying to introduce some seasonal differentiation into our rates. So this has been a long time coming.

Now I want to talk about the real live experiences, and this is where I'm going to focus most of my time this morning. The rate model that has been in place for the last 24 years has been a great model for distributors. And I don't want to offend anyone, but I'm going to say something that's going to generate probably quite a few raised eyebrows here. That model was the equivalent of a distributor walking into his office each day and pulling the cash register handle, reading the meter, identifying the bill, sending the bill to the retail customers, collecting the money, and then sending the money out to TVA.

Now, in terms of trying to generate customer behavior and price response and things of that nature, it just does not happen. And I think one of the speakers yesterday talked about culture. And you could imagine that type of culture. For 25 years, distributors have just been coming in, pulling the handle, and collecting the money for the invoice that TVA sends to them. This model that existed for 25 years had absolutely no differentiation in prices, and it didn't matter if you were served in Southern Virginia or Southern Mississippi, and whether you had natural gas as a heating source or used a heat pump, for example, for heating and cooling. You paid the exact same rate across that entire geographic region for every single hour of the day, 6.8 cents for kilowatt hour at the wholesale level. And it did not change. So you could imagine the excitement, if you will, when they brought me in to speak to these 155 distributors to try and discuss consumer surplus, demand response, marginal cost pricing and things of that nature. I was quickly shown the direction to the woodshed. [LAUGHTER]

But the point of saying that really is that over the course of three years, we found a way to get from the woodshed back to something that worked for all of us. So the model that we have today--we have mandatory time of use for 155 distributors, effective October 1' 2012. We've gone completely from that model of the cash register to a wholesale rate design that's based on time of use pricing at the wholesale level. And we've done so basically introducing seasonal rates that Speaker 1 mentioned to me about ten years ago. We have provided customers with choices in the short term, namely giving them the ability to gradually step into this new model by taking seasonal demand and energy at the wholesale level, and if I were to put these rate designs in front of Speaker 1 and Speaker 2, they would say, in fact, I think Speaker 1 mentioned, "mild as Dove soap." Well, in hindsight, that mild approach, or that measured step in a directional basis may have actually saved the work that we've been trying to accomplish for the last 18 years.

So I'll talk a little bit about some of the programs that we've introduced over the course of the last three to four years. We have every type and variety of time of use-type product that's available across the country available to all of our customers. 39 of the 155 distributors elected to take time of use early in April of 2011 as their wholesale rate choice. The remaining are taking service under the Seasonal Demand and Energy design, and we have a series of smart grid programs that are in place today and another number that are under development with the cooperation and feedback from distributors with the intent of introducing those over the next two years.

From a retail basis, we have that time of use pricing that Speaker 2 mentioned, having something that mimics the wholesale level. We have something that is much more aggressive in terms of trying to facilitate real price response behavior. We have a default rate for our largest customers, those customers greater than five megawatts. There are about 600 of them, with a mandatory default time of use rate. And then we have an optional seasonal demand and energy rate that they can elect to take service under.

And then to the subject of today's discussion, real time pricing, we have actually two forms of real time pricing out there today, one of which has been available since 2001. And to Speaker 2's comment, it's a little bit disappointing that out of this very large industrial base, many of these customers having plants across the country, no less the world, we have two customers subscribe to real time pricing now. Two customers. So to Speaker 2's point--real time pricing, I've drunk from that sacred chalice. It has its merits. But it also is met with some non-acceptance from a customer perspective.

So 25 years have gone by, and now when I speak to distributors, they're comments to me are, "You know, I was looking at my demand at noon yesterday, and then I looked at it again at 5:00 at night before I left." That just did not happen for the prior 25 years. All right? So to Speaker 2's point, the education, the awareness, the outreach, that's what's really going to drive customer behavior at the end of the day.

I've touched on the retail pricing programs, the demand response programs. We have those as complements to some of the TOU programs. And as you can see, I've noted some of the megawatts there that we're anticipating from them. I'm going too quickly, because I believe we'll have the majority of our discussion in the Q&A, and I just want to point to how this acceptance changes over time.

These are our time of use rated--the "pilotitis" that Speaker 1 mentioned. I can live with pilotitis to the extent that ultimately it gets us where to go. And if that's what it takes to build consensus, I can do that. But more importantly, we have real pricing signals here on a seasonal basis. You're looking at about a 4 ½ to one ratio during the on peak period.

Excuse me, I skipped a slide here on seasonal time of use enrollment and contract quanitites. The red line in terms of customers being read off this axis, we've got about 160 of those largest 600 customers. So 25%, not a bad step right out of the gate. And then in terms of megawatts, we have an equivalent of about a half of the megawatts from the entire system that I originally started working and pricing at Niagara Mohawk, almost 3,000 megawatts worth of customer load.

This next slide is proof in the pudding, if you will. This was our peak week last year. The dark blue lines indicate the off peak periods. The light blue bars represent the on peak periods. And on that peak day of the year, we had about 400 megawatts worth of demand response when we were over 33,000 megawatts of demand, and natural gas prices were trading on that particular day at a fairly high level. The price response that I was referring to here was roughly 200 bucks a megawatt hour during the on peak, so there was a very strong pricing signal relative to the off peak period of about 45 bucks a megawatt hour.

I mentioned earlier that one of the other initiatives that we have is energy efficiency and demand response. And I've included the good, the not so good and the ugly with respect to energy efficiency and demand response. And I'll leave this slide for you. It's a large part of our portfolio going forward. And it's a key element to us being successful in terms of the cleaner energy by 2020.

Lastly, I wanted to share some observations with you in terms of this work that we've done, representing the equivalent of 18 years, if you will, most notably the last three. And in terms of customer behavior and price responsiveness, I mentioned the idea of "pilotitis." Go slow, go easy is not necessarily a bad outcome, and giving customers and constituents an opportunity to participate in the solution and in generating a solution, as opposed to taking a command and control approach that says, basically, this is what you're going to do, because this is what the economics say you're going to do.

The speed of change is directly proportional to trust. And I firmly believe that it took the better part of 18 years to get this wholesale change in place because of the lack of trust. And pendulums swing from time to time, and they have swung that way with TVA. I've only known it mostly from a historical perspective. When I came in, I was given a direction to build consensus. To build trust. And effectively to give customers a large part of being part of the solution. And I believe we've gained some of that trust through these last three years that we've implemented this.

Sometimes small changes are much bigger than appearances might suggest. I will stand here before you today and tell you that had I come in on June 9, 2008, at the outset of these discussions, I would have presented a clean sheet rate design founded on all the principals that Speaker 1 mentioned here in terms of real pricing signals. And I'll stand here before you today to tell you that had I dug my heels in and demanded that we go in that type of fashion, everything that we've accomplished would have collapsed on May 1, 2011, one month after its implementation. And the reason being is, on April 27, we had a series of horrific tornadoes come through the Tennessee Valley that basically separated a large part of our distribution system from our overall transmission generation and transmission system. And that separation and these, and the wholesale rate structures that we had in place, and basically created the situation where distributors were getting billed for 27 days' worth of service, and having 30 days' worth of potential service, if you will. And let me just follow that with maybe a more classic situation. That is, on May 31, under this new wholesale structure, and TVA service territory, we hit about 98 degrees, and our peak demand jumped on the very last day of the billing period by 8% on a system-level basis. But on an individual distributor basis, it jumped almost 20% for some of those distributors. So that mild Dove soap actually served as a little bit of an ointment, if you will, to take some of the sting out of that, because wholesale bills went up on the order of 10-15% on that last day. So if the distributors didn't have the retail recovery in order to pay their wholesale power costs, we would have effectively undone everything that we had accomplished over the last, I'll say eight years, in terms of trying to get to that end state.

And I'll just close with the last point that I had, which is that change in itself creates more change. I think that goes back to my comment about discussions with distributors. They get it now, and they're taking a large role in our success of rolling this out. And they now watch what their peak demand is more so than just pulling the cash register bar at the close of the business day.

Speaker 4:

It's an honor to be part of this panel. I was just thinking that a lot of what I've learned about dynamic pricing comes from people at this table and some of their colleagues.

I actually don't have a whole lot to add to what we've heard already. But I am happy to offer my perspective as a regulator and to share some insights from our experience with a smart metering pilot that we've done in DC, which was quite successful.

Every chance I get, I try to tell anyone who will listen that I believe we're on the verge of a revolution in electricity pricing. I don't think it's going to happen overnight for some of the reasons we've been talking about, and it's certainly not going to happen as fast as some of us might like. But the smart grid, I believe, is destined to change the way we think about electricity. And much of this revolution is due to advanced metering, which I think is one of the most significant developments to occur in the electricity industry in my lifetime.

The existing technology, what I call dumb metering, is a century old technology. It's a relic of the Thomas Edison era. It has very limited functionality. The traditional electromechanical meter charges one price for all kilowatt hours. It's tallied monthly. I'm going to skip the grocery store analogy, which our moderator provided very aptly.

In contrast, dynamic pricing reflects hourly variation in the value of electricity. Of course, it does this in a number of different ways, depending on which pricing method you use.

But it does allow customers to save money during system peaks. And it provides an incentive for emerging technologies, like electric vehicles, solar photovoltaics, and so on. But dynamic pricing does pose challenges for regulators for a number of reasons that I'll explain in a few minutes.

Why is dynamic pricing so important? There are large potential savings, both in terms of peak load and in dollars, for customers who respond to dynamic pricing. Providing customers with the ability to respond to price can help to control price spikes in power markets by basically shaving the peak during the time when power supplies are most expensive. We can bring down those spikes and lower prices not just for the customers who've reduced their load, but for all customers.

And then the legacy dumb metering technology leaves behind a lot of missed opportunities. Traditional rate designs blend costs. They dampen price signals, so that consumers don't actually see the true value of what they're buying.

Advanced metering infrastructure (AMI) provides new options for utilities and consumers. On the supply side, it can help to boost green technologies. It's very well suited for an efficient, reliable electricity distribution system, because you've actually got the data that shows you exactly how much load each customer is putting on the system. You can size your distribution system much more efficiently. AMI and dynamic pricing helps to facilitate distributed generation technologies, as well as storage technologies, which are starting to become available.

With dynamic pricing, consumers are empowered to manage their energy bills. It gives them, as our moderator mentioned, an opportunity to choose between economy and comfort for any given hour. How much are you willing to pay to have your house kept below 70 degrees? It may be that if the price is above a certain level, you'd be willing to dial back your thermostat a little bit, or maybe preprogram it so that you don't even have to think about it. It also encourages energy efficiency. We've found that customers can clearly see the connection between their consumption patterns and their utility bills. And dynamic pricing opens the door to new technology options for consumers, smart appliances that are beginning to enter the market, plug-in electric vehicles, because of the potential to have charging of those vehicles during off peak periods, if we get the prices and the incentives right. Solar photovoltaic generation, there's a potential to compensate those behind-the-meter generators for providing power just when it's the most valuable, instead of just giving them the average rolled in price the way we do in most cases now.

As Speaker 1 pointed out, the low income customers have a lot to gain from dynamic pricing, for the most part. With traditional blended rates, customers that have big air conditioning loads tend to be subsidized, often by those smaller customers that are more likely to be low income. And even customers who don't respond to dynamic prices can benefit simply because of the actions of other customers. So it's not a matter of anybody losing out. We're really all in this together.

The traditional rate stability that customers have come to expect actually has a price in the form of what some call a "hedge premium" that customers pay just for the privilege of having the same fixed rates 24/7, and these hidden charges that are in pretty much anybody's utility bill could actually be avoided through dynamic pricing as the prices begin to reflect real time grid conditions, and it's not necessary to have the same kind of hedge premium that we do now.

In the District of Columbia, we're fortunate to have had a chance to get some real world experience with dynamic pricing through a smart metering pilot that we call PowerCents DC. And the results have been very encouraging. The purpose was to test customer response to dynamic pricing. It involved about 900 Pepco residential customers that were selected through a random process. We tested three distinct dynamic pricing plans side by side, and we had live billing from July, 2008, through October of 2009. So that encompassed two summers and one winter. The program had a strong emphasis on the low income population, which is a very important part of our community. It was facilitated by advanced metering with two-way communications between customer and utility, as well as enabling technologies, particularly smart thermostats. And we also had a sophisticated energy information feedback system to customers, so they could see, in some cases in real time, how they were responding and how that was saving them money and reducing their peak loads.

One thing that set PowerCents DC apart from other pilots is that it was run by a nonprofit organization with broad stakeholder involvement. Some people refer to it as Pepco's pilot, but in fact, it was not just Pepco, but also two consumer advocacy groups, the utility regulator, the PSC, and a labor union, which encompassed Pepco's organized workers at the IBEW.

Now, this gives some idea of how customers responded, and there's more information in the final report (on the next slide you'll see the URL for that). All customer segments reduced peak loads in response to price signals, especially during the summer. The low income response was only slightly smaller in comparison to the 13% number you see for CPR, that's critical peak rebate, of 13%. The low income part of that sample reduced their load by 11%. So it was only slightly less. Participants on all three price plans responded, as you can see here. The biggest response was critical peak pricing. We got less response from hourly pricing. Some of that was problems in the way that the program was designed.

It turns out that testing hourly pricing, which is tied to what's going on with market prices, is a very difficult thing to do. And in the final column, you'll see that the winter results were not as clear cut as the summer. And given the nature of the peak in DC, summer is really where the action is in terms of trying to reduce load.

For me, the most compelling result came from the post pilot participant survey that we did last year. PowerCents DC participants clearly liked dynamic pricing. We asked questions like, would you recommend PowerCents DC electricity pricing to your friends and family? And they said yes by a margin of nine to one. And then we said, well, which pricing plan would you prefer if you had the choice? Would you like to stay on PowerCents DC pricing, or go back to the original pricing plan, basically Pepco's flat rates? And here we got a yes response of 14 to one. So it was just really a remarkable vote of confidence for dynamic pricing among the participants.

And on this slide, here are some things that participants have said about smart pricing. I'm not going to read them all, but they said things like, it was awesome. I loved it. Bring it back. And we just got lots and lots of favorable comments—there were just a very few negative comments, but almost all of them were positive. And we also did a series of videos that we just completed recently, and there are URLs here for a couple of them, which you can watch on You Tube if you like. And they include some very compelling testimonials from some of the participants in the program who talked about what it meant to them and how it empowered them to be able to control their utility bills and save money and do it in a way that they found was really quite simple and trouble free.

And here's where we stand in the district regarding implementation of AMI and dynamic pricing. AMI has already been approved, in part due to action by our city council and the availability of ARA (American Recovery and Reinvestment Act) funds from the federal government. Pepco is currently installing advanced metering and its whole communications and billing systems as I speak. And it should be completed early in 2012. It's a little bit longer than we had hoped, but we can see the light at the end of the tunnel.

Among the issues that still need to be resolved by the Commission are the development of a plan for customer education and engagement, and work on that is underway. There's the AMI cost recovery issue that's before us in a rate case right now. We have opened a generic proceeding exploring dynamic pricing options. This will include selection of a dynamic pricing method or methods. We're looking at critical peak pricing, peak time rebate or critical peak rebate, whatever you prefer. Real time pricing is a possibility. And there could be a combination of the above. We need to decide on issues about what pricing methods would be mandatory versus voluntary, or opt in versus opt out, and to explore possible transition options over time.

Another important issue for us is the integration of dynamic pricing with default service procurement. Pepco is a wires-only company. And there are issues about sending price signals to end use customers, particularly for the portion of the load that is getting energy from a provider other than Pepco--in our case, roughly 2/3 of the load in the district have switched to other providers. That's mainly commercial load, particularly government load. There's the issue of third party access to customer data, as well as data security, issues like cost benefits of smart grid investment, and also performance metrics for use in evaluation of these programs.

We have benefited from regional collaboration. We've for years been working closely with some of our neighboring states. We've had an organization called MADRI, the Mid-Atlantic Distributed Resources Initiative, where we have worked together on a whole series of distributed resources issues. And among other things, we've gotten some technical assistance from LBNL from the regulatory assistance project. The highlight was a workshop that they put on this past spring for the five PUCs in the Mid-Atlantic region, which was extremely helpful.

One critical issue that has been percolating recently, at least within the PJM footprint, which covers 14 states, and I think to some extent in other regions like New England, is the integration of dynamic pricing with wholesale markets. And this is something that our moderator has actually done quite a bit of work on. Unless markets are coordinated, retail customers may not actually be compensated properly for the value that they create by responding to these price signals. And so PJM has launched a price responsive demand, or PRD, initiative in the context of its capacity market. And this involves applying new business rules that would offer reduced capacity obligations for load serving entities whose customers respond to retail price signals. So the achievement of savings through this program would actually require having AMI in place, as well as dynamic retail rates that are linked to what's happening in the wholesale market. PJM is expecting to make a filing with FERC to propose this next, later this month. The rules would be effective sometimes in 2012.

Another example of integration with wholesale markets is that PJM is exploring potential wholesale incentives for plug-in electric vehicles. As I'm sure you're aware, grid managers are concerned about this potential for having a six p.m. peak if everybody plugs their electrical vehicle in at once, and they're exploring possible technology and policy solutions. At the same time, PEVs offer a value to the grid by offering storage. The batteries in those vehicles can provide a significant increment of storage to the grid if we have enough of them. And it can also provide regulation services, which can help to maintain the frequency within certain bounds. Right now I have to pay somebody else for that. If electric vehicles could be providing that while they're plugged in, then that creates another benefit to the grid. So you see the potential for benefits flowing both ways. And I think that really has the potential for striking a deal. And it's interesting, because there's some companies out there that are selling vehicle charging services that don't want to have any part of being regulated. We have one in DC where they're charging customers not for electricity, but for premium parking, because they don't want to become a utility. And if there is the potential for actually getting paid for hooking into the system and allowing your charging to be dispatched in a way that not only insures that your car is ready to be driven the next morning, but you're actually providing them with storage in these other services overnight, I think that's a pretty compelling business model.

Finally, state regulators are often blamed for things that go wrong, and also for the fact that things may take longer than we might like. And I think the smart grid is a good example. Barely a year ago, I heard a chorus of voices from both industry and the Obama Administration saying things like, "state regulators are a major barrier to the smart grid." Some of them have even called for a regulatory shake up. I think there is a kernel of truth in the notion that regulatory approvals for smart grid technologies and deployments are proceeding slower than some of us might like. But I think people have to recognize that as regulators, we're required to apply a rigorous review to major investments. We kind of learned that the hard way during the nuclear era and various other eras in recent decades. And also the fact that we have 51 regulatory bodies that each have their own ways of doing things, so you're not going to see everybody working in lock step and on the same timeframe.

At the end of the day, though, I think having a regulated industry does have a lot to offer for proponents of the smart grid. Regulated utilities can count on recovering prudent investments in the smart grid. PUCs also have embraced smart grid in a big way. We've seen a lot of activity at NARUC. We've got the collaborative that meets three times a year working between NARUC, FERC, and a lot of industry organizations. We've passed a number of resolutions on smart grid, one just at the summer meeting that our moderator helped to author. So there really is a lot of activity, and I see a considerable amount of movement going forward, even if it's not as fast as some people would like.

We do face a number of challenges in implementing dynamic pricing at the state level. There are significant due process requirements. There are resource constraints in terms of funding and expertise. That's certainly been an issue for us in the district. We've got to deal with utility motivations which may be different from our own, and sometimes there are things that need to be worked out in order to make sure that we're all pushing in the same direction. There is consumer resistance that we've already talked about, interference by elected officials, something that all of us are used to dealing with. And this is manifested in concerns about rate impacts, which sometimes become an issue, even if investments in smart grid actually are part of a lowest cost solution. I've heard consumers who are just plain suspicious of anything that their utility wants to do. And that applies to dynamic pricing and AMI as well.

So there's resistance to change. People concerned about RF exposure from the advanced meter. They allege smart meters have started fires. Or the idea that they put security of customer data at risk, thinking anybody could drive down the street, turn on some kind of radio and capture their data and find out their usage pattern. I think it really boils down to some extent to fear of the unknown. I mean, we've all been used to having the same price for electricity 24/7 going back 100 years. And I think that kind of gets in the way of change, even when the benefits are just overwhelmingly positive. And I think that's part of what we're up against here, and I think it's going to require a lot of effort to educate the public and engage the public, because it's really a lot more than just education.

There's the disconnect between wholesale and retail markets. Obviously we're working on that, but a lot more to be done.

A need for coordination with federal policies and initiatives with FERC, with DOE, with NIST, particularly with the smart grid standards. And then coordination between the 51 PUC jurisdictions. And one of the things that we did find out in our work with MADRI is that the benefits of demand response generally are greater than the sum of their parts, that if we all do it together, we'll get a much bigger bang than if we just work separately.

And I think maybe the biggest challenge of all is just finding the right path forward, because implementing dynamic pricing can't be done with just one up or down vote. It's going to be a long, complicated process. It's going to have a lot of permutations. And the path forward's going to be convoluted with a lot of steps along the way. We won't see dynamic pricing overnight. But I think the regulatory community is becoming more comfortable with it. I think the potential benefits are just simply too great to ignore, and I think Speaker 3's description of how they worked through that within TVA is a good example. So as I said at the beginning, I think the technology is really destined to change the way we think about electricity and how we price it. Thank you.

General Discussion

Question: I'm going to make a bit of a comment and it's going to end with a question, so bear with me.

So clearly this panel favors dynamic pricing, however I'd like to play devil's advocate. I'm hearing that dynamic pricing is the direction that we should be moving and that we shouldn't worry about low income customers because they're going to benefit as well. Speaker 1 stated that basically everyone is a consumer and likened the purchase of energy to the purchase of any other consumer item. But in reality, we're discussing a life necessity. We're not talking about the purchase of a luxury item. If I buy a dress tomorrow and I don't like it when I get home or decide I can't afford it, I can take it back and that's fine. But if I sign up for one of these programs and hypothetically I'm having a party at my house on that critical peak pricing day, you know, and it's the Fourth of July, I can't turn off the air, I'm going to have to pay that added expense and I know there are a few days you get out of it, but let's just say I'm going to have a party on every one of those critical peak pricing days that summer.

So my concern is that this energy is a moving target, this is a complicated area and we're talking about exposing the average Joe to understanding this. Now down the road, I think there will be the technology in place where the average person won't have to think about this. I mean, that will be a hurdle in and of itself, but perhaps we'll be able to get the smart thermostats in or whatever is needed so that everyone is on a level playing field. They don't have to think too much, they can flip the button and they can do that.

So let's assume that we get the technology in place, so we're on a level playing field and pretty much everyone has access to be able to control their energy usage. Now my question is this: isn't this actually a zero sum game? So in fact if, let's say, 90% of folks actually do choose to save and they do choose to buy at the lowest times and we're all conserving, aren't we really just shifting a load and ultimately how can we all win? How can we all win if we all save? Don't there have to be some losers? Thank you.

Speaker 1: A great question and I think that question certainly is going to require a much longer answer than at least I can provide in a few minutes. But I'll give you at least my perspective and I'm sure the panelists can add theirs as well.

I do not think it is a zero sum game, because as people reduce their load, there's going to be less need for building more power plants and the savings of not building the power plants would be shared among all the customers. It's just like an energy efficiency program or any other demand response program. There are opportunities to save not only by the participants, but by all customers collectively. That's my first response.

The second response is that going back to your example of having a party on every one of the critical peak days. Well, you *should* pay more for it, because you are causing the cost to rise on those critical days and the other people who are not having the parties, they shouldn't have to pay for your party. So you can move your party or you can buy through. And that's just how it is for all wholesale customers today. It's also true for all large customers and all the restructured markets. They are defaulted on to hourly prices, and they can switch out to flat rate if they don't want that unpredictability element, but they have to pay for it through a hedging premium.

And so I think what we are talking about is a different way of looking at options. Each one of them is priced on the cost of electricity. Electricity cannot be stored; it has to be consumed instantly. And because there are these unpredictable peak loads, you have to build the combustion turbines which sit idle for just about all the hours of the year except 200-300 hours. But we have to pay for that. So why are we buying more insurance than we need if we can, through smart behavior, modify our usage? Not everyone has to do it. Some might say, "I don't care, I'm going to have the parties; I'll just pay my fair share of that."

So that's kind of my take on it. Yes, there will be some winners and losers. There is no doubt about it. I don't know of any single solution to any of our energy problems where we will not have some losers; even for all the green energy options, the price is going to rise. So people are putting in solar, people are putting in all kinds of renewable options; there are feed-in tariffs that are going to charge people higher prices in order to encourage those. Nothing is free and it will just go back to the old expression there's no free lunch here.

But what is happening today is not good either. People fall for the status quo as being the best thing that there ever was. It just hides the cross-subsidies to the people that have the flat load shapes, the high load factor customers--they don't know it, but they are subsidizing the people with the poor load factors. That's already happening. It's just not transparent, and because it is not transparent, people think it's the best thing.

I think that what we have to do is to make those subsidies transparent, bring out the benefits that can be created, and then give people an opportunity.

If I can just provide another example, people have coupons every day in the newspaper, to go to the grocery store and buy things at a discount. How many people actually do that? Relatively few. Many people just don't have the time or they forget there was a coupon and they just pay the full price. Others have the coupon. So dynamic pricing is just that kind of opportunity. You can pay the full price, or the coupon is there and you can lower the usage in the peak hours and that's how you'll save money. Not everybody does it.

The last thing, I think, was your first thing, which was that it's a necessity, electricity--that it's unlike the other luxuries and other products. Well, I cannot think of anything that is a bigger necessity than food. Food is the biggest necessity for any person out there in the planet. Without food there is no life. And so what do we do for food prices for low income customers? We don't change the prices for them. But we give them food stamps. We give them an income subsidy, but they still face the same food prices. They see the seasonal variation and they make economic choices. So I've long argued that maybe we need to create energy stamps; something to offset the income effect of higher energy prices. Not just for dynamic pricing but for energy generally. We should have gasoline stamps. Why don't we? I think we should ask the politicians. It is not an issue for electricity rates to be sort of subsidized and made flat just to protect the low income customers. The best way to protect them is to deal with their income issue. And by the way, if you look at the share of income going to this necessity, electricity, the national average is 2.5%. For low-income customers, it is not 40% or 30% or 20% or 10%. It is 4%. The share of income the low-income customers are spending on electricity is 4%. So shouldn't we be concerned about the other 96% a bit more, and not worry about 4%? I think that's the tradeoff. That's the perspective we need to have when it comes to electricity pricing.

Speaker: I don't have a lot to add to that, but I want to thank my colleague for an excellent question, and a provocative one. I think we need a little more controversy here.

On the issue of the potential in equities associated with dynamic pricing, I think it's important to recognize that flat pricing is not without inequities. It's full of inequities. And I think Speaker 1 kind of touched on that and so we can't start by assuming that the existing rate design is fair, but what we can do is, as we look at these different options we can pay attention to how we can make it more fair and also deal with any dislocations that we might find, especially for sensitive income groups. And in fact, Speaker 1's graph shows that a majority of the low-income customers would be better off and there tend to be more low income winners than for other groups. I did notice that way over on the right there's sort of a tail that sticks way up. So there's certainly a group of low income users that are very large users. And that is something that absolutely will need attention in my opinion.

The other thing is I think that it's important to recognize that not everybody has to respond or be able to respond. Those who don't respond are likely to receive spillover benefits from customers who do respond, to the extent that we can bring down those super-peak prices. And the other thing is, for customers who do have large loads, especially during the peak, under current rates they're likely to be subsidized, and if somebody really needs to have their air conditioning running on the Fourth of July that's fine, but should everybody else be subsidizing them? I mean I think that's a question that we all need to ask. And I think dynamic pricing at least gives us a chance to think through all these issues and I really believe that at the end of the day it's going to be a whole lot more rational and absolutely not a zero sum game. I think there are just tremendous gains of economic efficiency here that can reduce prices for customers and reduce electrical loads.

Speaker: I'll add just one more thing to that. I agree with everything that's been said but the other thing that I just suggest here is that consumers are also pretty creative and thrifty, and what you may find is that consumers find a way to operate outside that critical peak event. If you're having a party suddenly it may be a shopping party that's much more attractive to have. And I just think that if we discount the creativity within the customers themselves then we're discounting what benefits can ultimately be achieved.

Question: I wanted to start with a few comments and then sort of lead into a question. Just for a point of reference I want to talk a little bit about Illinois in terms of the transition, which I thought was rather lengthy, into 750Kw. In Illinois currently, every customer 100Kw and above faces an hourly default price. For those customers 100Kw and below, currently much like you have in DC, the Illinois Power Agency procures default power on behalf of those customers at a fixed rate. And so my comments are going to be basically around that fixed rate portfolio.

But just as a point of reference, the hourly default pricing is not managed with a Smart Grid or with smart meters. It's done with legacy interval meters, old technology, and we didn't suffer ratemageddon when all this occurred, so it can be done.

But I think most of the comments here are about residential and small commercial. I also wanted to comment on our RTP program. It has not taken off like I would have hoped and there are a number of reasons for it. Speaker 4, you talked about a couple of reasons. The disaggregation of capacity and energy is one reason—basically, customers are trading on energy-only price, and over the last three or four years, as we've all seen, with demand decline the wholesale price has declined as well. So the differential is not as large as one would expect in the times before this recession. So we've had less uptake on that, but again, our current RTP is based on old technology, it's not Smart Grid, it's not communicating technology, it's interval meters. But we do have a lot of success to talk about within that program. So that in and of itself is encouraging, even at low on peak off peak differentials and even only trading on the energy portion of the bill.

A lot of the discussion around Smart Grid and dynamic pricing has circulated around the low income and the low use customers. What we've experienced in Illinois as we've transitioned to a restructured market, in each of the customer sectors--industrial, commercial—is that as they've been introduced to alternative providers, the alternative providers went after the large customers, they cream skimmed. My thinking is rather than approach this from a position of "Let's just roll out RTP or default pricing or some sort of pricing to all customers," why don't we do this more strategically? Say for example, if we had a year's worth of operational meter data, after a Smart Grid rollout, and we could look at the demographics and say, "Which customers do we want to target here?" I mean, to me it would be fairly obvious--the guy with two heat pumps, two EVs in the driveway, a pool pump, they both work, no kids at home. So we've got a virtual peaking plant there and I want to aggregate those customers and target my RTP plan to them for my dynamic pricing or my direct load control over the pool pumps, et cetera.

This seems to be a process that we've engaged in rather successfully as we've gone through the other sectors, and can we be more strategic in our approach and lessen the political pushback that we may see by doing this? There would be an opt in, but basically through marketing, with data, explaining to customers the value proposition of being on this rate and going after that value. If we have sufficient response, it may lessen the need for rapid roll out down the chain.

The other point I wanted to make is, can we be more strategic in our approach with Smart Grid roll outs in general and attack not only those customers, but the rate design issue at points of congestion in both the distribution and the transmission system? I mean, why wouldn't we go to the points of congestion in the distribution system and at the transmission and say, "That's where I want to target my pricing program now and I'll deal with the rest later." So can we be more strategic in this in terms of who we're targeting and where and when as we roll these programs out? And can we avoid a lot of the political pitfalls by doing a sort of mandatory default type of program?

Speaker: I think to do that you need that customer segmentation and as Speaker 1 mentioned and I mentioned in my presentation and I think as you heard from Speaker 3, that hasn't really been done a lot of up to now, or has only very recently been done. I think most utilities have the address of their customers because they can get a bill put out to them but they don't really know a lot other than that about their demographics.

And so to approach what you're talking about--that kind of like "Let's go out and find these customers that will consume my service…" In a competitive market that's what everybody does, but in a monopoly environment, I would contend that has not been the paradigm. There's no need to go out and get all this information about folks. So if you want to do that, and I think that's a good first step, you have to then agree you're going to collect all this information.

We need to better understand to target these programs, but I also thing that sort of says, what's the role of default service? That's the other question I think that you raised, is can default service just be flat and we target individual customers for individual programs? Is that anymore effective or less effective if your default service is flat? Or what's the goal of default service in general?

Question: Well to clarify I think I'm basically talking about a restructured market. I understand the incentives are quite different in vertically integrated markets, so I'm just talking from the perspective of a restructured market and how that market has been approached--I mean the operational data from the integral meters that the utility did have was delivered to the third party provider. So they had that information to be able to target their marketing to. And that's all I'm suggesting, that if we have a year's worth of Smart Meter data, operational data, with all the appropriate security and protocols of allowing the customer to allow a third part to access that data, can we move forward in that style like we did in the industrial and large commercials instead of just rolling out default RTP or default CPP or CPR or whatever?

Speaker 1: So suppose I was one of those customers with two heat pumps and the plug in vehicles and all of that peaky load and somebody approached me and said that here is a chance for you to get on this rate that we charge you more because you have all that equipment in place. It would be very difficult for me to feel excited about that opportunity, because my bill would immediately go up. Unless I'm not home and unless I have that excessive load. And so I think being strategic is good, but opt in programs generally have not been very successful in enrolling large numbers of customers. Your own RRTP program is an example of that with only 8,000 or 10,000 customers out of four million or so on that opt in program. So I personally worry about the opt in programs as being a good approach as a long term energy planning exercise because there's nothing opt in about marginal costs. They are what they are. Whether you opt in to seeing them or not should not be a choice given to the people. They should have to pay what they are imposing as a cost to the system. I mean just as a philosophical issue, I try to put myself in the other side's perspective and just don't see getting excited about that person getting an out because they opted out of seeing the full costs, and others were not aware of it and therefore were stuck subsidizing that person.

Now that's sort of the economist in me, but then I look at what Arizona Public Service has done with their opt in program, also Salt River Projct, both of them have time of use rates that are opt in and they're the most successful residential time of use rate programs in the country. They're not pilots, they're full scale programs going back a decade and longer. And they have between 30 to 40% of the residential customers with large air conditioners, two air conditioners in some cases, average Kw of 7Kw. Well, why? Well, because in many cases they're avoiding an inclining block rate, they're avoiding that second tier of the inclining block rate, because they are larger customers. They're actually getting a discount just by switching over to the time of use rate without doing any load shifting. And of course when there's a significant price differential, they see the opportunity, and I'm told that they always have the opportunity to go back to the other rate. So an appropriately designed rate could attract large numbers but outside of Arizona I haven't seen it being done anywhere else.

In the Province of Ontario, the whole province is rolling out smart meters and time of use rates within six months of the meter coming out. So you have four million customers. We will see very soon what that is going to do. They have elections on the 6th of October. It's become a political football, there is the backlash issue. Maybe there should be eligibility criteria. So if you have a medical condition or you're genuinely low income, maybe you get an exclusion.

So I guess I am conflicted on your question. There's a part of me that says it should all be defaulted. At some point maybe five years from now, once the meters are there, and they have a history of data on these dynamic pricing rates, then they can opt out to a flat rate which is fully hedged and they pay more for it, and then they can make their choice which one they are going to pick, but if you start with the flat rate and then try to get others to opt into the dynamic pricing rate, you will see very slow migration patterns. And that's partly inertia and partly just the human psychology there.

Speaker 4: I think it actually makes a difference what the conditions are in your jurisdiction. I think that there's so much variation in if you haven't invested in smart meters yet and you can come up with a business plan that makes it possible to do sort of a limited deployment of advanced meters for just those target customers; that might be a sensible approach. There's some limitations you'll run into because you're going to need a different marketing strategy that's targeted just for them, rather than if you've put smart meters on everybody like we're doing in DC, we're going to, we anticipate PEPCO will be marketing to everybody at once. So there, but again there are other differences; in some jurisdictions if you've already invested in automated meter reading, the old AMR technology, then the value of going to AMI may be less. And so There are all those different permutations that you want to look at. DC, by the way, had a time of use rate that was applied to the largest residential customers, some small percentage of all of them, this was back in the 80's, and that rate actually still exists, although it's closed. So there is some precedent for doing something like that. In fact if those are the customers that are really peaky, that's something you might be able to justify, is perhaps making it mandatory, which is what we did.

Moderator: Let me add one point and then I'm going to move on to the next question because we're going to run out of time. Just to give you one example of a pilot that we've had under discussion with one of our utilities, it would be to combine RTP plus a call option based on a year's history of what that customer's actual peak load was so that the customer would have bill protection based on their individual historical peak.

Question: So I think this has been a very interesting panel and there are a lot of issues to discuss. I want to raise one question though, out of the list, and to the panel.

When you're doing tests and you're doing pilot programs and you're designing these alternatives, having CPP and CPR and VPP and TOU and all these different kinds of things is interesting and it provides some information and it certainly gives us a lot of insight into customer responses and the kinds of thing that Speaker 1 was reporting, I think is very helpful and it generalizes to the problem. But one of the things we know is that one of the most common mistakes when we're working on policy is to forget what we're trying to accomplish. And I want to make an argument that these alternative rate designs are actually not solving the problem. And that they're actually not going to get us very much, at least to the extent that they're different than real time pricing.

So you have to think about why is the peak period important. Well, typically it's not the peak of the individual customer that's important, so it should be correlated with something else. And then what is the something else? Well is it the peak of the utility or the peak of the state or the peak of the system the PJM or something like that and what we know from that is that there's enormous variability and heterogeneity in that problem, so that not only at different times but at different locations and often things which are geographically close are electrically distance and so the conditions are actually quite different.

And although it's imperfect, the best approximation that we have now is the locational price that comes out of the wholesale market that we can look at. There are problems with that which we'd like to fix, but that's a pretty good approximation. And when I've looked at that it's all over, you get negative prices, and none of these programs envision negative prices as I think in the time of year. And if your price is positive and the LMP is negative, then you're sending people exactly the wrong signal about what to do even in the off peak periods and things like that. So it leads me to the belief that to the extent that the RTP is actually addressing the real problem, which is we've got transmission constraints and voltage limitations and all kinds of other things that are going on and we'd like to change the load signal by what the price is at that moment at that location, which is going to be all over the map in terms of different times of day and different things--just look at the data, you can see this happening. To the extent that any of these things are materially different than the RTP, they're not solving the right problems, so they're actually sending the wrong signals, and so when we get past pilot programs and trying to see how customers respond and we want to actually provide incentives for people to make the system better, to make the operate consistent, if you're not using RTP, you're missing the point.

Speaker: I contend that's a pretty extremist position, that it's RTP or nothing. Can we all agree that if that's the definition of the problem, then clearly real time pricing solves that problem 100%? And I think the question then becomes one of how much do the other rates that you talked about-- variable peak pricing, TOU, Critical Peak, solve that underlying problem, or address the underlying problem. And we live in the real world where regulators and stakeholders have a say in what rates are and what they're going to look like. I don't think we do a service by continuing to stand on our head to say it has to be RTP or nothing. I think if that's the goal, we need to think in terms of either how can we get to RTP down the road or how can we get as close as possible to something that looks like that that is agreeable to all the stakeholders that have a say in what rate design looks like.

Speaker 1: I'll just add that it is very, very difficult to imagine widespread adoption of RTP at the residential customer level without automation. When automation arrives, yes, prices to devices has been the EPRI vision, but they've been talking about it for 30 years. When I began my career at EPRI they were talking about it. 30 years later they're talking about it. It hasn't happened. And it may not happen for another 30 years. So to try to do LMP for residential customers on a universal scale--I support it, but it's hard enough to even get across time of use pricing as a fair concept, through the regulatory process, through the consumer advocates and ultimately through to customers, so that's kind of I think the conundrum.

Now, if you can have the bulk of the load that is non-residential on RTP, maybe you have addressed a good chunk of that problem and then for the residential load you have a proxy and yes VPP. Connecticut Light and Power has that rate and they have no customers on it. So again, any time you begin to move away from constancy in rates--like in California just two or three years ago, I thought they were going to move to default CPP, but they have run into a big stumbling block and they are now revisiting the whole issue. All the IOUs, as fair as I know they're saying maybe we should just do time of use. I was very surprised when I heard that, because that again is even further in the other direction. So the feedback was that customers are not ready for it, they can't deal with unpredictability. And I guess that's where the challenge is.

Moderator: I guess I'm going to take a slightly more optimistic view than that, in that I think automation could come much faster than people anticipate. We're having some very productive discussions within the Smart Grid interoperability panel with the Home Appliance Manufacturers and with the Consumer Electronics Association, and we're actually looking at whether these manufacturers, in return for Energy Star recognition, or some other point of purchase incentive, can begin putting chips in these devices that can receive signals, potentially all the way down to frequency response level timing, and if we can get mass market recognition of that, the cost of these chips is less than a dollar a device. And that then begins fairly rapidly to get a large number of devices out there that could enable consumers to actually be in a position to respond to a real time price.

Speaker 4: I'll play devil's advocate for a second. Do we really believe that customers without automation can respond on an hourly basis? To me, that's one of the first and foremost challenges I have with RTP. In theory, I think it's a great idea, you look at industrial customers and you look at the evaluations of those and the evaluations are oftentimes done on a period basis. There's only one or two that I actually know of that have looked at hour to hour evaluations. Almost everybody else assumes that it's peak and off peak. But yet as economists we all sit here and rest on our laurels and say, "Oh, but it's hourly pricing, we have to have this very granular pricing, because that's efficient." And I understand the theory of that, but the practicality to me says you have to then presume customers can respond at that level of granularity. And if you're only doing it through automation, is that what default service should look like? Or if you're asking customers to respond through automation exclusively, unbeknownst to them, totally out of their control, should that be more of the demand response program that they sign up for to provide ancillary services regulation, but their default service rate is consistent or commensurate with what their capabilities are?

Moderator: Well I guess I'm going to respond that I think you can go a fairly long ways, much more quickly than people may anticipate, with automation. I think that's part of one of the context, along with education, along with hedging, and along with the competition, that really begins to make this potentially work. But I think the other response to that is that going back to what Speaker 1 said earlier, is that the real time price really is the cost of that energy and the question is really not one of should you have a flat rate or a real time rate. The question is: what's the degree of hedge and what's the nature of the hedge that should be provided or that should be available to customers with respect to that price? And if we can make the hedge sort of separate and transparent so consumers can have a choice over the degree of hedge that they have, then they can live with a two-part tariff, part of which is a real time price that their automated devices can begin to respond to.

Question: To follow up, I think that's a very important part of the story and I'd like to actually personally talk about that, but I'm not going to, I'm just going to say one other thing, which is I think, this always bothers me, but if you gave people the real time price and then you gave them instructions that say, "You're too dumb to keep track of this, but it's there if you really want to pay attention, but you might pretend that it looks like this, time of use." And then set your life up according to that. On average it won't be so bad, and if you want to take advantage of the real time price, go ahead and do that too. That's one model.

The other model is, "We're not going to give you the real time price. We're only going to give you this time of use rate; we're not going to let you take advantage of real time pricing because we think you're too dumb to take advantage of it. And we're only going to give you this one." Why do we do the latter? Why don't we do the former? [LAUGHTER]

Moderator: I don't consider it an issue of intellect, personally. I don't think it's that they're too stupid, I think it's that they're not home, you know? If --

Question: But you're mandating what you think the options that they should get are. Why don't you give them the option to use real time prices if they want to, and if they want to pretend it's time of use, that's ok?

Moderator: So let me just say one other thing in response and that is that the other thing to bear in mind is that if this is really valuable and we really have robust retail competition and not what we see for a lot of residential customers in the auction states where we see a flat price and then a small discount off the flat price by one or two competitors, but we go to the degree of competition that we're seeing for example in Texas where we're beginning to see some of these offers come into play, we may see service providers who are willing to do the automation on behalf of customers and begin to see this come into play.

Question: I have two questions, related. First of all I think most of you know New Jersey really has had a few pilots on Smart Meters but that's about it and I have had a personal disagreement with that for residential. And it's really because they go into rate base and they probably need to be changed and there's no real standards as to really what works best. So where are we with that? And then the second question is what type of dynamic pricing can work with the traditional meter that's not a "smart meter?"

Speaker 1: I think I'll respond to the second one. I don't think you can do any kind of dynamic pricing without a smart meter, but you can do a time of use pricing rate with the old fashioned time interval meter. Because of the nature of dynamic pricing, that you don't know when you will call it and you need to measure the load as well, I think the AMI meters are the only way to really do dynamic pricing of the kind that we are talking about. But you can do time of use with the old meters. And does anyone else want to comment on the first question?

Moderator: I think we're a little bit confused by what standards you're referring to when you said what standards would be --

Question: Standards for the meters. I mean, you have all types of meters out there being called "smart meters." They cost a lot, even though the prices have come down, so it's going to into rate base. So a standard for what we need for your basic smart meter that will be good for this for a while.

Moderator: Let me respond to this a little bit, since I'm on the interoperability panel. There is a current issue out there between meters that are what are called smart energy profile 1.X and smart energy profile 2.O, and we're getting very technical, but you're beginning to see 2.0

products start to come in the market. We'll see more products in the market next year. 2.0 gives you an internet protocol, more open standard than 1.0, and so there are some people who are making the decision to wait until 2.0 to expand their deployment. Others are deciding we get enough functionality from the 1.X, and that's a decision that you need to look at there.

Question: Has 2.0 been approved officially?

Moderator: It is not officially approved, but there are companies that are beginning to have 2.0 products. The testing protocols are at various stages in development depending on whether you're Wi-Fi or ZigBee or whatever communication medium you're at.

Comment: And to be clear, 2.0 is supposed to be finalized last January or the January before. In other words it's in a big state of flux, I guess. That's the way I would view it.

Moderator: Although there's been significant progress in the last three months.

Question: Aren't there some differences in how the communications system is structured versus the meters themselves? Where does the intelligence reside? Is it in the meter? To what extent is it in the meter versus in the communications system? I mean there are different kinds of architecture right?

Moderator: Yeah, I mean we're going to get very technical here -- but the two fundamental things going from 1.x to 2.0 is it becomes communications medium independent. So that you could be using ZigBee, you could be using Wi-Fi, you could be using home plug-in connection. Secondly, you're building in an internet protocol layer in the middle of the stack so that you have a much more open and flexible standard that the original ZigBee 1.x. I just was with a manufacturer yesterday who was telling me they're putting 2.0 product out in the field right now in a pilot program.

Comment: The last piece related to standards is where does the jurisdiction of the utility lie, and where does it end? Does the utility have the exclusive right to go all the way from its head end to the meter and then into the house? Does it stop at the meter? That would mean suddenly you've got a third party that can go from the meter into the house to provide services. In California they've been dealing with this issue relatively recently, trying to figure out the most robust way to handle this. How do you deal with the cyber-security and all those things associated with it? I would contend that's a pretty crucial element of your AMI system. Is the utility just a one-stop shop, or do you want competition for some of those in-home services that you might get? And how does that factor into, rate making?

Question: Does anybody have competition for the smart meters at this point in any state? Is California doing that?

Moderator: I think they're still trying to figure out what to do but I have not followed the regulatory proceeding there, but they are trying to figure out who has that right and where does it stop.

Question: In California there is no competition. It's the utilities that are putting in the meters. And they are rate based.

Moderator: In most places the AMI system itself (and this is in part to create a consolidated head end and the software), the AMI systems are being done by EDUs (equivalent domestic units) in this country. That's not so true abroad.

One other thing in response to your question about how you could do it if you didn't have a smart meter? There are some manufacturers that have collars that can attach to meters that read the spinning disk and can broadcast information from the home, and there are some competitive suppliers who are looking at those kinds of options, but it's very much a more difficult sort of thing than doing the AMI.

Question: I have a three part question-comment, but hopefully all of them will be pretty short. The first one is just going back to the zero sum game topic that we were talking about, I guess I'm just clarifying that in the short run it's probably going to be closer to a zero sum game, but as more dynamic pricing is rolled out it probably becomes more sort of net benefit, just because it takes time for the system to adapt, that sort of thing. So I just wanted clarify if that thinking is right.

Speaker 1: Yes it is because in the short term all you're doing is reallocating the costs. And so some people will come out ahead who have the higher load factor. Some customers will see the lower bills, but as people begin to respond, and as new appliances new technologies come in, you'll see even more response than we saw in the pricing experiments, then it will become a win-win, but even there some people would argue that not it's not a true win-win, the generators are going to lose, right? So there will always be somebody who will not be getting the business that they otherwise would have gotten, so it's a question of how widely do you draw that circle in the Venn diagram.

Comment: I'll just add to that as well that, please don't take too much exception to this, but the notion of high load factor, I think we should really be thinking high coincidence factor. Because coincidence has a relationship back to capacity and the capacity is what long term planning is going to require in order to meet those peak demands. You can have a low load factor customer that takes service in a low demand period that has a much lower cost to serve than a high load factor customer that goes through the peak.

Speaker 1: Absolutely, I always think of coincident load factor. When I say "load factor," I'm assuming the load factor at the time of peak, because otherwise you could have totally different results.

Question: The other question I had was picking up on a couple of comments that Speaker 1 and Speaker 2 brought up. Speaker 2, you said something about one of the impediments being regulators finding it risky to implement such a dynamic pricing scheme, this was in one first slides. And Speaker 1, in one of your graphs you had something like on the order of for a 10x peak to non-peak price ratio, like 15-20% peak reduction. I'm just wondering: is that in your opinion going to cause some sort of a tension when regulators think about implementing an effective dynamic pricing scheme that actually leads to significant peak reductions and savings?

Moderator: So your question is whether meeting a high enough peak to off-peak ratio for TOU is affecting the acceptance of it from a regulatory standpoint?

Question: And would that cause greater hesitation on the parts of commissioners to actually approve these things?

Moderator: I think in the end there are two issues and Speaker 1 actually mentioned them in his presentation. A lot of the existing time of use rates are very poorly designed from a customer acceptance standpoint. Price ratios are really low. Like you said, you've got 12, 16 hour peaks, so there's no reason for a customer to really see a differentiation. So from a regulatory standpoint ideally you should be dealing with cost causation. You know, how reflective is the rate of the underlying costs? You clearly have lots of design tradeoffs in that. Do you want a narrow peak? Do you want a big peak? What's the price ratio?

The second issue then goes to the winners and losers, so to speak. If you do this price ratio when it's high, it's a seasonal rate. Then you've not got really high bills in the summer, but customers in the other nine months have these very low bills. So you have to understand the implications of the rate design on the underlying bills. Which then gets to a regulator risk assessment decision—does the regulator want to try and convince stakeholders that even though their bills are going to be higher in the summer, they'll get a huge bill discount for the other nine months of the year? And is that enough to sell to folks that it's worth supporting? That's a jurisdictional issue. I can't answer whether a high price is supported or not, I think more importantly the issue is whatever comes before a commission for a TOU design needs to be supported by the underlying cost structure, and you've seen rate filings being done or cases being opened that say, "These are the general guidelines for a TOU we'd like to see; you the utility coming back to us with under those guidelines of lengths of peak, seasonal variation things like that," and it I think narrows the scope of what you're going to argue about.

Speaker 1: And I agree with everything. It should be cost based, but you know the ratio also says that the off peak is very low. It says the peak is high relative to the off peak. It's not raising the rate level. The rate level is still the same as it was. On average it is still the same rate, so the lower the off peak rate relative to the peak rate, the greater the savings potential which that rate has. I mean just think of it like this. If there was no ratio at all, if it was a flat rate, there would be no savings. So the more you drop the off peak and the more you raise the peak, the more you create savings opportunities.

But unfortunately the public perception always immediately goes and looks at the critical peak price and says you're going to charge them a dollar per kilowatt hour. I actually was at a meeting where somebody said, "Why don't you shoot the customer?" [LAUGHTER] So I think that the problem is that you have to say to them that it's a revenue neutral rate--it's a dollar during the critical peak hours, only something like 60 hours or 200 hours, and then the off peak is lower during all the other hours to make up for that. And that's the way to sell it.

Now obviously it has to be cost based. Those ratios were based, for example, for Baltimore Gas & Electric, on the PJM cost of capacity. And that's what they're backing it out of. So that is what it does cost during those hours to meet that load. Now that's a shock to some people, because they don't understand electricity economics, so we do have a training program that has to be put out there, because just about any person I talk to who's not in the industry is shocked and wants to shoot me.

Question: We've been talking about the fact that technology is creating the opportunity for the AMI smart meters to make the potential of these dynamic pricing programs possible, but advancing technology is also resulting in an increase in things like photovoltaics that produce when it's sunny, which is highly correlated to when it's hot and when loads are high. With electrification of transportation, where there tends to be a fair amount of flexibility and the likelihood is that as that grows we're going to see a off peak load growing in a way that's going to affect the ratio we've just been talking about. And potentially as well, energy storage is also going to be able to mitigate the price differences that we're seeing. If you add on to that the potential to someday improve rate design so more fixed costs will be recovered on more of a fixed basis, instead of recovering fixed cost through variable charges… As all these things potentially happen over the next decade, isn't it likely that the very price differentials that you're saying we really need to make these programs effective could go down substantially, and we may have kind of missed the boat on timing of when these dynamic prices may really be valuable?

Speaker 1: Great question. When I was starting my career in the rate design study at EPRI, that question had come up in 1979 as well. The idea being that if you're very successful with this it will do away with the load profile problem and you will now no longer need to have these differentials. Well, it's been 30 years, it hasn't happened. Now maybe we have new technologies and maybe just as I'm entering my last few years in this career, it will happen, but I think that's a good problem to have. I personally don't think that's a bad problem to have.

Comment: I'd agree with that completely. That was some of the context of the pricing that we've rolled out. Basically, the idea was to flatten the load profile so we have to invest less in those combustion turbines that are going to run just a few hours out of the year and get more towards base loaded generation, which it overall lowers the cost for everybody.

Question: Two questions. One is picking up from an earlier question, which is as you move away from RTP, do we have any notion of what levels of efficiency we lose by moving further and further away from RT and scale back all the way to time of use and then obviously flat rates?

The other question is what happens if we simply unbundle metering and billing? And simply spin that off, so it's no longer a utility function, it's now competitive market function? There are some practical problems with that, but from a theoretical standpoint, it takes it out from under all the kinds of process considerations, all the kinds of regulator dilemmas, it provides opportunities for entrepreneurs to offer customers lots of different options, including fall-back options.

So those are the two questions. One is, what do we lose the further we move from RTP? And the second is, what happens if we unbundle metering and billing and it's no longer a monopoly function?

Speaker: I can address the first one. In order to understand what the loss of efficiency is, you have to understand the difference in customer response at the residential level to real time pricing versus all the other suite of rates that are out there. You've only had three experiments that have looked at real time pricing at the residential level that I'm aware of. As I indicated, the Federal Government thought that this was a great opportunity with funding advanced metering infrastructure with the SGIE program to do those kinds of studies. And one single utility was willing to come to the table to do that. So I think that's very telling. In spite of us saying that's what we think is the most efficient thing to do, there is simply not the support to do it. And I don't think you can get the support if you're not willing to do the research to understand how customers respond to that stuff. You can't do this efficiency loss until you have that information. You can use the existing information that's out there; response to Amaren and ComEd's real time pricing programs as a means to get a sense of it. I've never seen it done. But you certainly could do that. But to me that's the fundamental problem. There is not the support for this in spite of us saying it's the best thing to do.

Question: Is part of that then maybe you open up the metering and billing market, and then you get more people willing to try to respond to do that? If I understood you, maybe I got it wrong, but you had one utility in the United States willing to step forward and even try it out. Well, maybe that's part of the problem.

Speaker: Well my understanding is, and I don't know the Illinois context that well, but if I recall correctly, Commissioner Lieberman really pushed that very, very hard through the Commission. I know there were some individuals that commented, and they had a consumer advocate who was on board with it. So I would contend the reason it's gone through is because you had two very influential stakeholders at the table pushing it. Whether you functionally unbundle all this other stuff and it creates the opportunity for it I don't know, and you're right, we haven't tried it. So it's not clear whether it will or not.

Speaker 1: Two quick reactions. For the New York ISO we were asked to look at the benefits of hourly dynamic pricing for all customers in New York State. Not CPP (critical peak pricing) or VPP (variable peak pricing), but the kind of pricing that didn't have a locational price, but it had elements of that. So we did that study and it showed, as you can imagine, significant benefits.

It became political, and it was not published. We just filed with the New York Public Service Commission and the Public Service Commission was not terribly enthusiastic about it. So to this day it remains an obscure document. We cannot even publish in the *Electricity Journal* because of the fear that's there, that who knows what it could cause to happen. And then we were told that there is a law in New York that says you will not have real time pricing. It turns out that the law just says you cannot mandate real time pricing, it doesn't say you cannot have default or optional. So it is lost in that political cloud, but what I believe can be done to get to your first question, is to rerun that study with just critical peak pricing now put in and VPP, and then see how much do you lose. Because it is a system-specific analysis that could easily be done.

Moderator: I think just one thing to bear in mind is that Texas does have a model where I think the metering is still done on a consolidated basis but the billing is now with suppliers.

Question: I have a short comment but then I have a couple of questions about the DC project. I really do understand the frustration that the advocates for dynamic pricing are having. One of the really key area is the issue of low income and special needs populations, and the potential that some people in those groups can possibly be hurt and because those groups are pretty much of the ilk of groups that will not be hushed until their concerns are solved, I think that it's really important that we come together on that and move towards solutions, because I think they can be moved off the table if there are assurances that are built into programs.

In Illinois we've gone to a 6% of income payment plan, which won't take care of the whole population, but it certainly takes care of a big chunk of the highest needs low income people. And I would suggest teaming up with low income advocates in advocating for programs that can help mitigate the impact on these populations. I think the biggest one is the advocacy for the LIHEAP (Low Income Home Energy Assistance Program) at the federal level, which I think everybody that follows that knows is in some considerable trouble right now. But also there are options that can be explored at the state level, and in Illinois we have a meter charge program that brings in about $85 - 90 million dollars a year, which we have effectively used to roll into that percentage of income payment plan. So I think that there are some ways that we can deal with the frustrations by moving forward, by creating new partnerships, maybe the team of rivals approach is a good one in that regard.

But to go specifically to a couple of questions I had, and this is for Speaker 4, can you explain a little bit of what the mechanics of the rebate portion of your program was? And also you mentioned that the education and engagement aspect of the program is pretty much underway. I have a number of questions about who's involved in that, is there a curriculum being developed, who's going to teach the curriculum when it is ready, and maybe most importantly who's paying for the development of the curriculum and the people that are going to teach it?

Speaker 4: First of all, I completely agree with you about the low income issues. This is absolutely going to need a lot of attention.

Regarding the critical peak rebate pricing, what we did is all of the customers who were on that rate--and they were preselected, it's not like they had a choice of which rate to go on--they stayed on their existing PEPCO tariff. The only difference was that when a peak event was declared (and it was a max of about 60 hours a year), they would be offered a rebate for reducing their load below a baseline level, and we had an algorithm to calculate their baseline. That's something you have to do in order to have that rate. And people just found it very simple and there was no down side and there was no possibility of winding up with a higher bill. So that's basically how we did it.

And incidentally we decided, I guess you could say for political reasons, that anybody who was on our existing low income means tested rate would be put in that group because we didn't want the specter of having any low income customers have their bills go up because of the pilot. And those are the kinds of compromises that sometimes you have to make in doing pilots like this.

As for education and engagement, we have a working group that the Commission set up that includes the company, the Office of the People's Counsel, and basically any other parties that want to participate. And I think there are about half a dozen of them. AARP is one of them, and I don't remember all the others. And they've been meeting about once a week and they have subcommittees. I'm actually not privy to what's going on there, but my general sense is that right now the focus is on educating customers about the meter deployment, because that's what's happening right now. The Commission has not adopted any rate designs. That decision is still out there to be made. So they can't really do education about that. But I think they're starting to think about it. But they're really focused on helping people, on just what kind of message you should give people, and what kind of procedure you should have for alerting them that their meter is about to be changed over, and what that means--and there have been fights over that too. I don't want to get into all the details, but we have a long way to go with that.

Question: I had to step out for a minute so I'm not sure of where we are on this discussion. Are we still, do we still believe short run we're zero sum?

Moderator: No.

Question: No? OK, so it's a positive sum game even in the real short term for real time pricing?

Moderator: I think we all think so.

Question: Oh, OK, because I thought I heard a zero sum argument for the short term. Thanks.

Question: Just a point of clarification: the RTP program in Illinois is legislative. It wasn't a Commission initiative, though it was supported by the Commission. But it is in the statute.

Also, I wanted to sort of piggy back on the prior comment about what this is all about after all. And it is about asset utilization. And we're here and talking about this because we're at a 50% load factor in the United States and declining. And the issue is how do we utilize our assets more efficiently, and the problem is that we're doing this so poorly because of 50 years of watt hour meters and flat rates. And so we now have the technology at a price that's affordable. We've seen the transformation of productivity in other industries and we should be doing what we can to implement it.

To Speaker 1's point, when this phone came out, there weren't any apps. So the apps came as the product made it out, and to the degree that we are not allowing RTP to come into place, we won't see the automation, we won't see the applications in development until the market clears. And to that point, I recommend going to the national town meeting on demand response for anybody here that hasn't been there. If you want to see the vendors who are blue in the face trying to get their innovation, their products, and their entrepreneurship into the marketplace, and who need dynamic pricing and RTP to extract the value that they know they can bring…I mean that's the thing that drives me. We are standing in the way of an awful lot of entrepreneurship and applications guys that are more than willing to automate these functions for us. So let's keep that in mind. We have a wealth of that.

Speaker 1: I would just make a very quick comment, which is that two companies, Google and Microsoft, well-known brands, who had products and designs to enter this space have exited because of what they perceived as total inertia--no movement, no changes in rates, customer apathy, huge educational gaps--so we are blocking them out. We are not letting innovation come in by becoming stubborn about not changing, so that's what the game is about. I think the attitude that the industry is radiating is negative and radioactive. And so why would innovation commit? I think we have to have some leadership. We have to have some positive thinking and some open statements. Only then will those other companies come in. And I'm in touch with all of them, just about, who come to the town meetings, and that's the message I hear from them.

Question: I was going to withdraw my question, but what are you standing in the way of if you've got retail choice? The competitive supplier wants to provide a real time price and provide the meter to the customer. Who's standing in the way of their doing that? And if the market's not providing this service, isn't that a signal that the value isn't quite as great as you think it is?

Speaker 1: Not for residential customers.

Comment: Well, I know in my state and I know in I think probably in a lot of other states, there are some significant barriers to retail competitors really being able to do that. Just to give you one example, most retail suppliers want to be able to do a consolidated bill. Today in our state they can't do a consolidated bill unless the tariff they're offering is a tariff that the utility is already offering or they're willing to pay the utility to reprogram their system.

Question: Fix that problem. But forcing customers to pay for new smart meters when you have retail choice and the market's not responding seems to me not the right thing to do. That's why you have the market.

Comment: Well, except that there are tremendous economies of scale with doing advanced metering which suggest that that may be a solution that is a legitimate utility solution.

Speaker 1: And you know those smart meters have many benefits besides just demand response. Those meters are there for operational benefits, distribution automation, preventing outages…You can't do Swiss cheese deployment and get those benefits. I think that's pretty clear for anyone who has studied the topic. So the only issue is, why is the market innovation on pricing not happening? And that's because the default rate is a flat rate, which is also the lowest rate. It cannibalizes all innovation, that's where the road block is. And we have known that for a long time.

Question: I see your point, I see your point. OK.

Question: In a competitive market, is real time pricing really necessary, as opposed to real time demand response? In other words, if you have an aggregator that come to you and says, "I'll pay you or you'll share in the profit if I take your pool pump and bid it in; if it's running in the afternoon and bid it into ERCOT," as an ancillary service, and they can turn your pool pump off for an hour or two hours in the afternoon. Don't you get the same effect?

Speaker 1: Well, not quite. You don't deal with the cross subsidies that exist in the current rates. The major purpose of real time pricing is not necessarily demand response, at least as I look at it. It is to send a correct price signal that shows the time variation. You don't get that with those programs. Those programs are good, they're pure DR program, they're like load management, or direct load control programs. And that's about all they do, so what you get additionally from real time pricing or any kind of dynamic pricing is that you incentivize the customer to change their behavior. All hours of the day with all the appliances, not just one or two loads.

So you know, it is definitely a second best solution to do what you are describing. It shouldn't prevent the first best from being pursued as well. But effectively what we have done by not doing the first best and taking it off the table, we have got all the aggregators excited about the second best solution. That's where the industry is going, is the second best avenue.

Comment: They're not mutually exclusive either. In PJM, for example, they've been doing very active load response. They've been quite successful at making demand response a resource, and yet they're still pursuing dynamic pricing or "price responsive demand," as they call it, because they think there's still a lot of untapped potential there, and one clear distinction between the two, is if a customer signs up for their utility for their LSE to control their load and turn it off under certain grid conditions, they're ceding that control [from] the customer. But if you do it through pricing, what you're doing is you're sending a price signal to the customer and it's the customer that's controlling the switch, and that really empowers the customer to take control over their load, and I think there's a big advantage in having the customer make that decision based on price, whether it's the real time price or critical peak pricing, which may be a second best, but I think there's room for both of those.