BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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TRANSMISSION BARRIERS TO ENTRY : Docket Number

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Hearing Room 2C

Federal Energy Regulatory Commission

888 First Street, NE

Washington, D.C.

Tuesday, October 14, 2008

1:10 p.m.

The above-entitled matter convened pursuant to notice at 1:10 p.m., Steve Rodgers, presiding.

Also present: Chairman Kelliher, Commisssioner Spitzer and Commissioner Moeller.

P R O C E E D I N G S

(1:10 p.m.)

MR. RODGERS: If everyone can take their seats, we're going to get started this afternoon.

Welcome to the Transmission Barriers to Entry Technical Conference. We have two panels today, with the first panel dealing with the Western Interconnect issues and the second with Eastern Interconnect issues.

In a moment, I'll be calling on the panelists, but before I do that, I want to see if the Chairman or Commissioners have any opening remarks.

CHAIRMAN KELLIHER: Why don't I ask Commissioners Spitzer or Moeller to speak.

COMMISSIONER SPITZER: Thank you, Mr. Chairman and Mr. Rodgers, thank you, Staff, and all of those who have come from higher and yon to participate.

I'm appreciative of the national scope of our jurisdiction and this undertaking. I'm appreciative that folks have come from all over the country, representing a variety of interests and every region in the U.S.

I'll make some brief remarks and let my colleagues speak as well. The ultimate objective of this conference is clear: The strength of the U.S. transmission grid will determine whether Americans will receive reliable, affordable and environmentally responsible transmission.

The commencing and construction of high-voltage transmission -- even before the current credit crunch, construction of transmission was often arduous, lengthy, and controversial.

Citizens are reluctant to site projects, even when the benefits can be clearly articulated. From siting high-voltage power lines successfully in the state of Arizona, I learned that there is no political constituency for transmission.

This conference is to identify barriers to transmission created by preexisting FERC Rules, Regulations, Orders, and to discuss the elimination of those barriers, consistent with FERC's obligations and powers.

This conference is not to criticize transmission owners, who have been quite successful in many regions of this country, nor is it wise to impose artificial barriers, rather, given the urgent need, this conference seeks to ensure all viable financial and business models and strategies that are considered to get transmission built in the U.S.

Joint ownership has been extraordinarily effective in financing and achieving political consensus to site large energy infrastructure projects in the West. Joint ownership is not a panacea, nor feasible in all cases, but someone needs to explain to me the difference in the concept of public and private ownership of power.

Merchant lines have the prospect of increased investment in non-utility areas. Staff has proposed a number of dramatic questions.

The overarching question is the principle of open access and whether current FERC policies strike the proper balance between encouraging new investment and protection of third parties, particularly transmission customers.

I thank the Chairman for scheduling this conference, and I thank Staff for its efforts leading up to this conference today.

COMMISSIONER MOELLER: More transmission, to me, is the common denominator for all of the mathematical problems of energy policy facing us. The numerator may change. It may be the concern on over-reliance on natural gas, or concern over the question of climate policy.

Perhaps you're concerned about market functionality, whether you're in a organized market or a bilateral market. Perhaps you may be inspired to get wind resources that are location-constrained to their load.

Those may be the numerators of the mathematical problem, but the common denominator, to help solve them, is additional transmission.

I appreciate the fact that all of our panelists, our Staff, my fellow Commissioners, and those of you watching, either in the audience or at home, are paying particular attention to this issue.

Barriers to transmission, is a wide-ranging subject. Not only do we have to deal with siting issues, cost allocation issues, but you could also argue that the Federal Tax Code is, in itself, somewhat of a barrier to more transmission.

Nevertheless, today, our focus is on eliminating those barriers, particularly those in which we have jurisdictional matters, is a subject close to my heart. It's actually what I prefer to be talking about more than just about any other policy issue.

And, again, I hope you would agree that more transmission is that common denominator. I hope today's effort leads us to eventually constructing more, Mr. Chairman.

CHAIRMAN KELLIHER: First of all, I want to address the question of why the Commissioners are sitting on the side table.

(Laughter.)

CHAIRMAN KELLIHER: Or, as we call it inside the building, the kid's table. I've been assured there's no palace coup at the Commission.

(Laughter.)

COMMISSIONER KELLIHER: And we maintain all of our authority. But, really, it was a comment that Commissioner Wellinghoff made at the demand-response conference a few months ago, when he said that was the best technical conference I've ever been to at FERC.

I asked him why, and he said, because Staff were asking the questions, rather than us. We accept our limitations.

At this technical conference, we want Staff to ask a lot of questions. We'll probably ask questions, as well, but the purpose of this technical conference is to explore some of the barriers that exist in transmission development in the United States, and we're going to hear from a broad spectrum of speakers, from vertically-integrated utilities and a transco, private equity firms, public power, regional transmission organizations, representatives of real estate investment trusts. We're also going to hear from respected state officials.

The wide range of speakers, shows us the diversity and nature of grid ownership in the United States, and perhaps that may be extended to additional entry. The Commission has demonstrated its flexibility with respect to ownership arrangements of major transmission projects in the past.

We've granted incentives for large regional grid projects by vertically-integrated utilities. We've also encouraged entry of independent transmission companies and merchant transmission projects.

Our focus throughout, has been clear: We encourage development of a more robust interstate power grid and recognize there may be more than one path towards that goal.

The speakers today may recommend more than one change in Commission policy, and there's no reason we can't explore more than one approach.

With respect to overall investment levels, I think the United States is on the right track in overall investment levels. They are roughly double what they were five years ago, but investment is not yet at a level in the United States that can meet short-term reliability and support competitive wholesale markets.

The Commission has been flexible in the past, with respect to ownership arrangements. We have more discretion, which we have demonstrated, for example, with respect to proposals from independent transmission companies in the June 2005 Policy Statement regarding evaluation of independent ownership and operation of transmission.

We're trying to also take some of the lessons we developed on the pipeline side. The Commission has shown flexibility in our approach on natural gas pipelines, particularly with respect to anchor shippers and previous ownership of pipelines, and that has produced the most robust network in the world, and we may provide some of the lessons on the power side.

I want to thank my colleague, Commissioner Spitzer, for suggesting this conference, and Commissioner Moeller, for his laser-like focus on transmission issues, since he's been here at the Commission.

I want to thank the speakers for helping us today, and Staff for organizing this conference and asking better questions than, apparently, Commissioners tend to ask, but I look forward to hearing the views of my colleagues and the speakers today. Thanks.

MR. RODGERS: Thank you, Mr. Chairman and Commissioners. We will now turn our attention to the first panel. I do want to mention some of the instructions to each panel.

If you would, please turn on the button of your microphone when you're giving your presentation. We will have five to seven minutes f presentation remarks from each of you.

I'm going to have a timer here that I think should be rather conspicuous, so when you hit the six-minute mark, the yellow light will come on. I'm not sure what happens at the seventh minute, but let's not get there.

(Laughter.)

MR. RODGERS: I also wanted to mention that we'll proceed from the right to the left of this panel group. We will also have an opportunity for questions from the audience, if time permits at the end of each of our two panels today.

The microphone for that, is over to my right, your left, and we will entertain questions or comments from the audience, if we have time at the end of each panel.

Without further ado, why don't we introduce Mr. Richard Hayslip, the Associate General Manager of the Salt River Project. He is here today representing the Large Public Power Council. Welcome, Mr. Hayslip.

MR. HAYSLIP: Thank you, Chairman Kelliher, Commissioners, and members of the Staff.

I said earlier this morning that it was a pleasure to be here, but I think I'll defer on that description of the experience, until after I'm over it.

I do represent two entities here today. One is the Large Public Power Council, a group of 23 publicly-owned utilities that have significant assets around the country, particularly in the Western Interconnect.

In total, LPPC is responsible for 75,000 megawatts of generation and over 34,000 miles of transmission.

More personally, I represent the Salt River

Project, which is a complex organization. It's a hundred years old.

For the purposes of today's meeting, we are a political subdivision of the State of Arizona, serving some 930,000 retail electric customers.

We have a peak demand of over 6,000 megawatts, and it's a diverse mix of resources. The Western Region that we serve together, is immense.

It's a very large part of the country, not densely populated like the eastern half of the country. It comprises almost two million square miles of 14 western states and the WSCC, which is the Reliability Council for the West, is comprised of some 40 utilities and was formed in 1967.

That has since been superceded by WECC in 2002, which oversees some 1800 generators and 163,000 megawatts of load.

As you can see on the map in my PowerPoint presentation, those publicly-owned utilities are a part of the WECC region, a major contributor. Part of the history of the region, I think, is important to understand, because of its influence on how we own and operate transmission.

The West consists of a number of metropolitan areas, separated by huge expanses of land, federally-owned land, state land, some private land, and some Indian reservations.

It adds to the whole complexity of siting and operating of the power lines.

The incidence of the fuel resources we rely on for generation, is not related to those urban areas. As a consequence we have an historic need for long transmission lines.

Our power plants are generally located near water sources or a fuel source, and the load is in urban areas in Southern California, Phoenix, Albuquerque, Salt Lake City, and Denver, so we've always had a vexing problem of long lines of transmission, and we've always had a need to collaborate out in the West.

At time most of baseload generation was being developed, our annual load growth and the incremental appetite of utilities such as the Salt River Project, wasn't such that we could be justified in constructing a large 750 megawatt super-critical power plant.

But we found there were other similarly situated organizations who had a similar need, so we began a process of collaboration in the development of power resources. Similarly, in a part of that whole process, was the collaboration in transmission, as well.

We have in these power plants -- ownership of these power plants includes not just of investor-owned or not just publicly-owned utilities, but a commingling of those, just as it does in the transmission.

Early on in the process, it was encouraged by the then-Secretary of Interior Udall, that if you want rights of way over federal lands, if you want water service agreements, you're going to have to cooperate; publics are going to have to be included at the table, and that historic culture that we have of cooperation among publics and private utilities, remains to this day.

We're still developing projects jointly and operating projects jointly. You can see on the next map, the basic backbone of the western United States, which developed as a result of those large coal-fired power plants that were developed primarily on the Colorado Plateau.

There was a real need for collaboration to be able to finance the network of 500 KV transmission of that magnitude.

I've included just a listing -- I'm not going to go through it -- of some of the large power facilities in the West that are jointly owned by the collaboration of public and private utilities, and even in the case of Navajo Generating Station, which is on page 9 of my package.

The Federal Government is a participant; the United States Bureau of Reclamation owns 24 percent of the Navajo plant, for purposes of pumping Colorado River water into Phoenix, but in all of these large plants, there's a generous mix of privately-owned utilities, publicly-owned utilities, and, as I said, in the case of Navajo, the United States of America.

The transmission lines are similarly owned, as well, sometimes not the precise same allocation, but very similar.

Kind of the agreement structure for those: We're tenants-in-common. We have an operating agent who operates the facility on behalf of the other owners, but we share in the investment and we share in the benefits of the transmission, as well.

As I say, it has worked well for over 50 years now. I have included some examples of lines that were built under this concept, that more specifically were associated with those power plants: Southwest Power Link, the Oregon-California Transmission Project, and the PC Pacific Intertie, all of whom have publicly-owned, privately-owned, and in the case of the PC Intertie, with the BPA, a Federal interest.

The colorful chart that comes next in my package, shows the transmission lines that are under consideration in the West. Each of these transmission lines has been proposed by different entities.

Those proposals have been made public, they have been published on the Internet, through the WECC website, and through the regional website. Any entity who is interest in participating in those projects, has access to the planning for those projects and can be a part of those projects, if they want to. That is facilitated by Internet communication.

Again, there are some projects that are in development. There's an alphabet soup in my presentation -- and I'm running out of time to kind of describe the WECC network and the various entities within that network that facilitate this planning and make possible, access to these projects by virtually anyone.

Our concluding remarks, would be that there is a need for expanding the infrastructure, the transmission grid in the western United States, to facilitate access to renewables and access for developers to customers.

There's a need to strengthen the grid for simple reliability purposes. Our belief is that we need to be able to figure out a way to work together to collaborate to make that happen, and I think that experience in the U.S. is evidence that it does and can work. Thank you. I apologize for exceeding my time.

MR. RODGERS: Thank you very much, Mr. Hayslip. We appreciate your remarks.

Next we will hear from Tom Wray, Project Manager of the Sunzia Transmission Project. Tom?

MR. WRAY: Thank you. I'd like to thank the Chairman and the Commission and Katie and Sarah for helping put this together and for permitting me to speak today on this matter, that is increasingly important to resolve.

If you refer to the handout, I'll give you some metrics on Sunzia, on the project itself. It's about a 460-mile interstate 500 KV project in two separate circuits. It traverses parts of both Arizona and New Mexico.

The route crosses some dozen counties in the two states. It crosses predominantly publicly-managed land, BLM and Arizona and New Mexico state land.

The important aspect of the project, is that it was conceived to provide access for a vast renewable resource in the form of wind generation and a fair amount of solar, CSP-type generation in southwestern New Mexico, southeastern Arizona.

In the case of the wind generation, it's been estimated that that wind resource is in excess of 15,000 megawatts. With respect to the solar and some geothermal in the southern part of the study area, in Hidalgo and Cochise County, it's as high as 5,000 megawatts.

The project is supported by a joint partnership consisting of private and public companies and is moving forward into the licensing and environmental stages. We're including as part of this project an analysis of making one of those two AC circuits a bipolar GT facility to increase power transfer, given the high demand to reduce the facility, depending on the development of those wind resources.

The AC capacity of the two AC lines, will be in the neighborhood of about 2,000 megawatts, with one of those facilities being a DC facility to increase that bidirectional transfer, in the neighborhood of 4500 megawatts across that same area.

The project was conceived from a regional planning effort that started about three years ago and wasn't developed, necessarily, by developers getting together and thinking about building a project. It really came from a coordinated regional planning effort, largely led by the Southwest Area Transmission Planning Group.

And a lot of our projects in that part of the country, come from a regional planning effort. We all work very hard so that numerous interests are being heard in that project.

I think I mentioned the route. It's about 450 miles. The calendar for the project's progress, the EIS and NEPA process, the state siting process, will probably take at least three years.

We've looked for possibly a Draft EIS being published by the Bureau of Land Management under that NEPA process, to be available to the public, sometime in the middle of 2010, with early operation for the first circuit in late 2013.

I want to now go from sort of a direct discussion of the project and talk a little bit about one of the policy implications that the Commission may want to consider or hear about, arisen from this effort.

The distinction -- and my colleague, Richard has made some distinctions with regard to the Western Interconnect, so they'll have to work the routine a little bit.

The West is also characterized by predominantly federally-managed and tribal land, that makes the siting of linear facilities, particularly high-voltage transmission, typically a longer process, by virtue of the fact that almost any action in the West involves some sort of NEPA action and an Environmental Assessment, if not an Environmental Impact Statement stage, in most cases.

This is particularly if they cross federal land. Arizona is something on the order of 13-14 percent of that land, is either federal or state or tribal land.

The risk that's undertaken to develop these projects, has to be recognized and reflected in the rate, which is available in the filed tariff, to sort of underpin the risk that is taken.

In the case of Sunzia, Sunzia, one way to look at it, it's a large radial facility, which is reaching out into a renewable resource. It's not going forward in the ordinary course of business, to provide for adequate generation for load growth or for improving reliability to some NERC standard. It's reaching out and tapping into a renewable resource that the public is demanding, be that measured in the form of RPS standards at the state level, or developing a national RPS standard.

The public is demanding more renewable resources being made available for the generation of electricity. Here is a case where a group of private and public investors recognize that. Resting on the laurels of a regional planning study, they have provided underlying planning for it. And that's how the project has come to be.

I also point out that the concept of projects like Sunzia being, quote, "renewable-only" transmission facilities, is really a fantasy.

There has to be sufficient generation that is either fossil in nature, base-loaded, or intermediate in nature, particularly in the intermediate character, to be able to respond to the lower capacity factors that you encounter with renewable generation.

They're all a bit different. In the case of wind, in this region of New Mexico, for example, the capacity in the summer is around 35 percent. It's intermittent intra-hour, so in order to keep the frequencies and the voltage stable on these facilities, you have to have fast-starting rotating machines that can solve that problem.

So there will always be a mix on these transmission facilities either importing or exporting renewable generation. They need more permanent generation where they will be using a non-renewable fuel of some kind, an immutable law of the system in the West, with the exception of the desert Southwest.

My last point here, I think -- I'm sure there will be some questions later -- in the desert Southwest, the only RTO that we have, is the California Independent System Operator and the origins of major projects like Sunzia come from -- and I believe should continue to come from -- the results of regional planning, the cooperative voluntary process that has numerous stakeholders. It's very open, very transparent, and something we believe works well and is not broken, and we don't think needs to be repaired.

With that, I'll stop.

MR. RODGERS: Thank you very much, Mr. Wray, I appreciate that.

Next, we're going to hear from Robert van Beers, the Chief Operating Officer of Tonbridge Power, representing the Montana-Albert Tie Ltd. Project, one talking point that Mr. Wray mentioned.

We're going to proceed directly from one panelist to the next, and then ask our questions. Thank you.

Welcome, Mr. van Beers.

MR. van BEERS: Thank you very much, Mr. Chairman, Commissioners, members of the Staff, ladies and gentlemen. Thank you very much for inviting me today to your technical conference.

It's very exciting to be part of an innovative wave that's taking place, and I hope, share the experience of Tonbridge Power in responding to the energy needs of America today and tomorrow.

We are a small publicly-traded merchant transmission company. Tonbridge Power is building the Montana-Alberta Tieline, referred to by the acronym MATL, and, for a brief description, it's a $195 billion project, 203 miles in length, 230 kilovolt, single-circuit transmission line with a bidirectional pass rating from the west of 300 megawatts.

It will provide the first direct interconnection between the Alberta and Montana transmission systems.

We're undertaking the MATL project as a merchant; that's without subsidy, without certainty of cost recovery, and without public ownership. If great hope rests on the belief that the merchant model will solve America's transmission development backlog, then there's a lot of work to be done.

Our experience so far has been that merchant finance and budget development is extraordinarily difficult. If the financial market events within the last few days has taught nothing else, it must at least underscore the need to manage risk better, particularly in capital-intensive businesses like transmission, so I will address both regulatory, industry and land owner issues in my remarks. But our experience is that each finds their clearest expression in the willingness of shareholders and lenders to invest in transmission development.

Although enormous pools of capital are potentially available for this venture, investment is constrained by the risks and uncertainties that flow to developers such as ourselves. The development -- and by development I mean that expenditure before revenues are received, is roughly taking us twice as long as we had anticipated in our project.

Nonetheless, what Tonbridge will expect to do, is bring that full line into service early in 2010, roughly taking half as long as many traditional projects would have taken. But time is a terrible waster of resources. It saps the commitments of generators, politicians, financiers, and shippers, and has enormous costs.

We have to find faster ways to do projects. Development costs can be reduced by focusing regulation on the things that matter, and while I will make many remarks critical of regulators, I'd be remiss if I didn't say that in our repeated interactions with the FERC, we have found the FERC Staff to be decisive, direct, and focusing on matters that are important. We were extremely grateful to the FERC for the support we've had.

But, focusing on regulators, it must exercise judgment and a willingness to approve projects before every conceivable aspect has been studied from every angle and to every possible stakeholder's complete satisfaction. That is simply not how decisions are made.

Development costs are particularly hard to meet, in the face of regulatory uncertainty. Equity investors demand high returns, and every regulatory regime punishes the investor for having taken a risk, and increases the systemic risk for transmission. This is particularly the case when the delays are unanticipated.

If the commercial transmission industry is to develop, clearer hurdles will need to established at the outset, and will need to find a balance between industry and public interests, and articulate that, and regulators will need the incentive to get the job done, rather than be caught in their own processes.

As Tonbridge Power moves on to the second and third projects, we'll need to rely on the financial support of those most dependent on our success, and that is our shippers.

We expect to enter into development agreements with anchor shippers, to finance much of the upcoming development, in exchange for certain access to transmission capacity.

The FERC could help by permitting the pre-sale of known capacity at a known price and capacity, with the remainder of our capacity to be auctioned in line with standard open-season rules, to ensure fairness, transparency, and competitiveness.

Without the ability to obtain support from anchor shippers, development will simply be too expensive to finance commercially.

As a merchant transmission developer, we have experienced problems, both from landowners and from the industry, NIMBYism from landowners and from industry. While we believe we've succeeded in getting industry to tolerate our existence, but some of the landowners are taking longer to get there.

I believe that industry receives no gain from accommodating or supporting us, but much complexity, uncertainty, and risk for being engaged.

I don't know how this has changed in the West, but one of the key sticking points was reliability. Some of my colleagues have alluded to this already.

Let me explain: As an intertie, the model may potentially download all of the reliability issues associated with the variability of wind generation to Northwestern Energy, the balancing authority in Montana, and Northwestern was rightly terrified of the prospect of accommodating 600 megawatts of new wind.

Resolving reliability, shouldn't be a tough one. It required a market where all systems are held accountable for imbalances, in the absence of price signals for imbalance.

Our shippers were eventually forced to solve the problem entirely inhouse. This is surely not the most efficient route to a solution, but it was the only practical one under the circumstances.

The lack of power market development, hugely injures commercial transmission development, particularly in the West.

Alberta is one of the world's most well endowed energy areas, yet is the northbound flows on our line that have the most value. Why? Because southbound flows find no market response and no clear price incentive, except for more distant markets in the Pacific Northwest.

We just simply need a better power market and more transmission.

I was not surprised by landowner NIMBYism, but I was surprised at how little support for transmission development, would be available from our siting regulators.

Political support was enormously valuable, but it will always depend on local circumstances, and it is time bound and individually dependent.

If the FERC believes, as we do, that bringing renewables to market in an increasingly competitive power market, will require new transmission, then landowners need to appreciate that opposition to specific projects, while perhaps understandable, does not afford them unconstrained license, which adds delay, costs and appeal risk to each and every project.

Our rights and responsibilities need to be reset. Perhaps, in a perfect world, transmission would have recourse to FERC and the federal certificate authority, but such a role is not politically or constitutionally achievable.

Then the next best thing we'll have to, would be active involvement on the part of the FERC in ensuring that transmission developers do not stand alone in their struggle to get routes approved.

Commercial development of transmission, hinges on identifying market niches and completing projects on time and on budget. As a merchant, Tonbridge needs to build more efficiently and more rapidly, but the regulatory delay in our marketplace, greatly frustrates our ability to achieve this.

Regulatory costs, both in their composition and their predictability, are the single largest impediment to a robust transmission sector.

Regulation is also unnecessarily inflexible. For example, we needed to obtain multiple permits, but with regulatory delays and financing needs coinciding with initial permits, how could we keep our project going.

Doing so requires enormous energy, ingenuity, nimbleness, and costs, all of which would better be invested in building transmission, rather than performing a juggling act that serves neither customers, investors, or the public.

Thank you kindly. I hope my remarks have been of interest, and I look forward to the discussion.

MR. RODGERS: Thank you very much, Mr. van Beers. Next, we will hear from Paul McCoy, the President of Trans-Elect. Welcome.

MR. McCOY: Thank you. Good afternoon, Mr. Chairman and Commissioners. Trans-Elect is a developer of merchant transmission projects throughout the country, especially active in the West, where the potential for clean energy is enormous.

As we in this room know, electric transmission will be a key component of fulfilling our national ambition for renewable energy, energy independence and addressing climate change.

I believe that the merchant transmission model will play a significant role in these matters, and your attention to these matters, is very welcome. I also serve as Vice President of WIRES, the Working Group for Investment in Reliable, Economic Electric Transmission, a national nonprofit association of transmission providers, develop;ers and customers dedicated to quality transmission investment.

I mention that without elaboration because I'm submitting today, as part of my submittal to you, a study published by WIRES which surveys how industry and regulators are currently addressing a range of critical commercial, regulatory and operational obstacles to the integration of location-constrained clean-energy resources, such as wind and solar energy, into the grid.

WIRES and I will be happy to discuss the study with you, once you've had a chance to digest it.

This afternoon, however, I want to focus on issues specific to Trans-Elect Development and the merchant transmission sector, generally. As we have heard, the West presents a special challenge for transmission development.

It's blessed with abundant, high-quality renewable resources, generally in remote areas, hundreds of miles from load centers. We agree that these require the construction of long-distance backbone projects, sometimes crossing multiple control areas and states.

However, the West, other than California, does not have an RTO/ISO to rationalize the planning, construction, and cost allocation of long-distance projects.

Not surprisingly, utilities in the West and elsewhere, are more focused on transmission to serve their native load customers, rather than on extending their transmission grid to serve regional or export markets. I further recognize that western policymakers are working hard to lend coherence to grid expansion.

They recognize the challenges, but the diversity of transmission ownership, regulatory culture, resource bases, and operational control -- the WECC alone, has 23 control areas in 11 states -- compounding the difficulties of bridging the difficulties between energy resources and energy consumers in the West.

The free market has emerged to help fill this vacuum. Merchant transmission projects have been proposed to move renewables from the load areas to major load centers.

While most of these are currently focused on wind, an increasing number would also tap solar, geothermal, or biomass resources. Many of these are designed to provide market access to high-quality, renewable resources within the Rocky Mountain states.

Trans-Elect has two such projects under development, the Wyoming-Colorado Intertie and the High Plains Express project, a map of which is included in the handout. We also include our descriptions of these two projects.

The development of merchant projects is uniquely market-driven. A shipper will only sign a long-term contract on a merchant transmission project, if it provides a cost-effective for delivering power to load, regardless of whether that shipper is a generator or a utility.

The merchant transmission developer, will not be able to obtain financing for the project, and thus build the project, unless it has a sufficient number of long-term contracts from creditworthy shippers.

This model ensures that only economically viable projects are built. It also ensures optimum allocation of costs.

Expansion shippers contracting for capacity on the merchant transmission project, pay for the costs of that project. Investors and the project developer, not historic ratepayers, bear the risk of permitting and shipper default.

It therefore goes without saying, that this exposure to financial risk, makes regulatory certainty and the need for flexible business arrangements, extremely important to the merchant developer, especially to the extent that the sector is willing and able to step up to invest in major long-line facilities that have greater potential impact on the regional network and real public policy significance.

For that reason, I strongly suggest that the Commission seek ways to adjust its approach, in recognition of this inherent risk.

To illustrate this, the WCI Project will take approximately seven years from inception to commercial operation. We'll have to go through multiple jurisdictions for permitting in Wyoming and Colorado.

During that time, we'll have to bear all the risks associated with construction, land acquisition, and financing. At the same time, the wind energy generators, who are WCI's principle customers, and, in fact, our only customers to date, are able to develop their projects over as short as a three-year period.

This timing difference represents risks to the transmission developer and it will necessarily need to begin its work and expenditures, substantially in advance of actual generation project construction.

If this timeline is not met, for reasons beyond the transmission developer's control, this also represents risk to the renewable resources developer.

One way to help mitigate the development risk is to change the way a project's capacity is allocated, consistent with the Commission's policy of avoiding undue discrimination.

Merchant transmission developers should be allowed to contract with anchor shippers for a significant portion of the project, prior to holding an open season. Much of the risk of WCI's development, could have been lessened and the project timetable shortened, were such an option available to Trans-Elect in the development of WCI, in particular.

Conducting a FERC-compliant open season, currently is a very expensive undertaking, the cost of which is borne by the transmission developer. It's a cost that also occurs relatively early in the life cycle of the project, generally about two years or more prior to the initiation of construction, at least in the western U.S.

When legal and consultant costs are added to the cost of open season design and execution, they can't exceed $750,000 for the full auction process. Of course, this carried cost, must, itself, be financed, usually by the equity partner, a cost ultimately paid in the rates borne by shippers.

Conversely, the ability to contract early in the project with a shipper, an anchor shipper of the bilateral negotiation, would significantly reduce risk.

One recommendation to you today, is that you specifically allow such a process to occur for merchant electric transmission development. An example of how this process would work might be as follows.

The transmission line developer secures a binding commitment from a shipper for a material portion of his capacity, say, 50 percent, prior to the open season. The binding commitment includes a locked-in price for the service. We would then offer, through an open season, the remainder of the capacity and terms, conditions and price, that clear the rest of the capacity at whatever price the market will bear.

Being able to negotiate with an initial user, a project's capacity, significantly lowers risk, reduces cost, and accelerates project execution. This advantage becomes more pronounced, as project size increases.

Some of the western backbone transmission lines that have been proposed as examples of this, include the potential merchant components of the High Plains Express Project.

In the limited time we have today, we have suggested that for a truly merchant project, the adoption of a suggestion we're making, would be the single most important thing the Commission could do further the advancement of merchant transmission projects.

Thank you for your time today. In the interest avoiding running over time today, I'll stop here, and I'm open to questions. Thank you.

MR. RODGERS: Thank you, Mr. McCoy. Next, we will hear from Marc Lipschultz, a member with the Kohlberg Kravis Roberts & Company. Welcome.

MR. LIPSCHULTZ: Thank you for having us here today, Mr. Chairman, Commissioners and Staff. I appreciate being included.

I'll start with maybe a few comments on the challenges of investment in electric transmission infrastructure.

As Commissioner Wellinghoff stated in the Congressional hearing in May of 2007, a decade-long decline in transmission investment and a precipitous decline in investment in demand response, primarily in the last decade, threaten to impair the reliability and cause billions of dollars of congestion costs, which is to say that the magnitude of the challenge is great, the costs are great.

As Commissioner Moeller commented in the first instance, I think we can build a consensus that more investment is required. The question, of course, today, is how is that additional investment made?

I start with a couple observations: The development of a strong energy infrastructure, depends ultimately on the participation of utilities, merchants, and independent developers, and now, more than ever, watching the last several weeks, as we all have in the capital markets, it will, indeed, require all of those participants to succeed.

What we really need to do, is create a set of rules and set of processes that encourage participation of all forms of capital providers and all forms of developers and operators.

There are a number of challenges that have to be dealt with, both regulatory, economic, and technical challenges. At least a few of them, from my point of view, are as follows:

Number one, transmission investment competes with all forms of investment. There is no dedicated pool of transmission investment capital that can develop transmission that can go to distribution, can go to generation, but, quite importantly, and, I think, more importantly, it can also go to retailers, it can go to a liquefaction facility and it can go to businesses well outside the energy complex.

As we stand here today, there are two sort of core themes I'd leave with you: What we have seen in the world, really in the last 15 months, and, quite roughly, over the last month, is that there is a fundamental contraction of the supply of capital.

There simply is and will be less capital available today and for some time, going forward, than there has been over the last several years, also, the cost of that capital has risen. Certainly, the risk-adjusted cost of capital has risen, and it follows the rules of supply and demand.

Number two, in terms of these challenges we all face, merchants and independent developers have to secure long-term commitments to finance projects. We've heard some very incisive comments from prior speakers on this subject, and I think there are a number of creative ways to address those challenges.

Third, investors may be reluctant to back transmission projects, because the benefits of that kind of investment, really may be quite uncertain, and very many years in the future.

Again, this gets to the question of ultimate risk and reward, and having to address both sides of that equation, are going to be necessary to drive sufficient capital into the sector.

The sector needs a lot of capital. Depending on the study that you look at, the Brattle Group has commented that over the next 20 years, $1.5 trillion is required across the power sector, and that's before the carbon costs, with transmission costs alone at $233 billion.

These are very large numbers, especially in a world with a contracting pool of capital, and the regulatory system today has not fully dealt with the fundamental shift in paradigm from vertically-integrated utilities, to really developing transmission solely to serve native load, to one where we have a variety of entities investing in transmission infrastructure and have used transport production to load in remote locations, and that is driven, of course, by a number of problems and leads to a number of problems.

First, there is the free-rider problem, which is, rather than invest in the problem itself, people often hope someone else will take the lead, build a project, and they will be able to basically free-ride on the back of that project.

In addition, transmission projects are simply larger; they're more complicated, they're more expensive, they're more time-consuming, and that all speaks to this question of risk.

We're looking at multi-state projects, multi-billion-dollar projects, and the risks are simply higher, the timelines are simply longer, and there is, fundamentally, a mismatch between jurisdictional boundaries and market realities.

The fact is that jurisdictions don't, in fact, overlay exactly where the markets operate; in fact, the markets are often much broader than the jurisdictional boundaries, which creates some incredible tensions, of course, in trying to site projects.

Certainly, you often have certain siting authorities or regulatory authorities, who may view a project as irrelevant to their particular constituency, perhaps even negative, to the degree they view it as exporting quote/unquote, cheap power from their market to another market.

Just to give you a very brief history on our experience that we bring to these observations, KKR is fundamentally in the business of investing for the long term. Over our 32-year history, we've made over $400 billion in investments, and a meaningful portion of that has been and will continue to be in the energy sector, and particularly around the power sector and infrastructure, and transmission, in particular.

ITC, the company we were a majority investor on, you'll hear from the company in the next panel, but this is a company that has met head-on, some of these transmission challenges in fulfilling many of these needs.

During the duration of our involvement with the company, capital spending increased over tenfold. That was, frankly, just to get started. We are building the system and the kind of capacity we need in this sort of changed environment, changed paradigm.

We've also been very involved in the investment and further expansion of the former TXU, now known as Energy Future Holdings, a company we acquired in conjunction with some other investors, which in terms of electric delivery one of the largest transmission and distribution-only utilities.

To some degree, the model of the independent transmission company, may have no interest in the market. They only develop backbone infrastructure, and I think the experience and what we have found, is that certainty and predictability, are the secrets to capital formation.

It certainly relates to ultimate rate of return, but there's two side to the return-and-risk equation. There's the ROE, but there is the risk entailed in achieving those returns.

The risk entailed in investing capital and ultimately earning a fair return on that capital, in both instances, in the case of ITC, with FERC jurisdiction; in the case of TXU, with a single regulator in the form of PUCP, with the oversight by one state jurisdiction. And in both cases, models that had formula rate-like structures or trackers that helped ensure recovery of capital and earned a fair return. Those have been tremendous enablers for capital investment.

ITC, I commented on the numbers. In EFH, likewise, even since our acquisition, we have already identified millions of dollars of additional necessary investment, which we're more than happy to support, given the proper regulatory context.

So, in the end, I think what I would bring as a conclusion, is that we have less capital in the world, demanding a higher return, and, frankly, what transmission investors need, whether a merchant utility or an independent, is going to be certainty, which I think suggests a real focus on how you set about developing rate compacts.

Certainly, some of the tools FERC has already implemented, like catchment-only formula rates and certain factors on the long-term durability and recovery of prudent investment, will serve to drive capital into the sector, that is much needed. Thank you.

MR. RODGERS: Thank you very much, Mr.

Lipschultz. Next, we will hear from Roy Piskadlo, Managing Director of Merrill Lynch. Today's he's representing the Real Estate Investment Trusts.

And for Commissioners and others with briefing books, following along, Mr. Piskadlo's presentation can be found at the very back of Tab No. 4.

Welcome, Mr. Piskadlo.

MR. PISKADLO: Thank you very much.

Thank you, Commissioners, and all of you for having me. Our interest as a financial institution, is in the fees generated from financing these assets, as well as selling thejm. What I'm about to describe here, is very different from the financing, and it's a later stage financing than what Mr. McCoy and Mr. van Beers are after with their merchant development of these assets.

These are later-stage capital, but nonetheless very important. We believe there is significant capital, although there isn't enough of it these days, significant capital to be invested in transmission assets.

And the reason for that, is that transmission assets offer, once they're built, offer stable, annuity-like cashflows from the regulated returns, as Marc was alluding to a moment ago.

What I'm about to describe here, is a tax-efficient method of financing those cashflows, which will allow for owners of assets, companies like Marc's or integrated utilities, to sell those assets or monetize those assets with other investors, free up capital and use it to reinvest and develop new assets.

Other asset classes that have taken advantage of this type of structure, are regulated pipelines, in the form of Master Limited Partnerships or MLPs, as well as Real Estate Investment Trusts, or REITs. We believe that the REIT will likely appeal to the widest range of investors.

In the end, we believe this could provide a new type of independent ownership and operation for existing transmission lines and, ultimately, development, as well.

The initial catalyst for that, was an IRS Private Letter Ruling received by a private equity investor who happened also to own a transmission company, a utility. The IRS concluded that the transmission assets are real assets, and, therefore, can generate rents, which then can be owned and modified with either REITs or MLPs, and this will give access to a lower cost of capital, and, more importantly, I believe, expand the investor base.

What is a REIT? The REITs have been created or were created in 1960. They are pass-through entities, meaning they are free from entity-level taxation.

What that means, for both capital-raising, as well as the investor's perspective, is that cash that would otherwise be used to pay income tax at the entity level, can be distributed, and, therefore, capitalized, distributed to your shareholders and ultimately capitalized, which reduces your cost of capital.

The REITs were generated or created to give participants direct ownership in real property. In order for REITs to qualify as REITs, 95 percent of the income, must be from rents from their property, hence, the importance of the Private Letter Ruling. Ninety-percent of that taxable income, needs to be distributed.

The investors in these types of entities, are looking for cash-on-cash returns, steady cashflows that are regulated, that tend to grow with general economic activities, because many insurance companies, for example, have long-dated liabilities and they need to meet those liabilities with these types of cashflows.

MLPs were created in 1987. They are partnerships; they are just publicly-traded partnerships. Income, as well as tax losses, et cetera, are all passed through to the individual unitholders.

What's important, from their perspective, is that this income will qualify for MLP status, if they're rents from real properties. MLPs, if they are earning rents from real properties, they will be able to take this revenue stream and sell it into the capital markets.

For MLPs, as I mentioned before, they are partnerships. The unitholders in those investments, get K-1s. K-1s are rather complicated and tend to make it time-consuming to fill out your tax returns at the end of the year, as compared to REITs, which are corporations; those are just common shares and you get a 1099, which is a much simpler exercise.

In the handout that I sent to you, in our conversations with about 35 integrated utilities around the country, many of them asked, what is the benefit, what is the tax benefit associated with going from a C-corp, where we're taxed at the entity level, to a pass-through entity like a REIT?

In the handout materials I gave to you, it shows a sensitivity analysis of how much benefit can be shared between investors and ratepayers alike, if used properly. I won't bore you with the numbers, but there's roughly around ten percent in this example, where there's a ten-percent reduction in rates that can be spit between equity holders, as well as ratepayers.

On page 9 of my handout, another benefit that we see in this market, due to looking at other capital markets, is what we call multiple expansion. We believe that an asset like this, that is a pure-play transmission asset, where you have regulated cashflows, from the comments that

Marc made, will trade at a much higher multiple, therefore driving up the share price, which is reducing the cost of capital for these assets.

On this page, you'll see it's a multiple expansion, and that is accreted to an integrated utility who can then sell their existing transmission line to free up that cash and use it to invest in new transmission.

So, therefore, you ask, why is it that integrated utilities don't appear to be embracing this, just jumping in and trying to finance their assets this way? As I said, we spent a lot of time talking to various integrated utilities.

All are very interested in this idea. In the last page of my handout, you'll see kind of an informal survey from the people that we spoke to around the country. Most fear that the regulators won't share the benefits.

As I mentioned before, there's about a ten-percent reduction in rates that can be split between ratepayers and unitholders or shareholders in this case, for the integrated utilities, and the fear is that regulators are going to take it back.

That really can show up in two forms: One is a fear that once these assets get contributed to a REIT or an MLP, that, subsequently the return on equity gets ratcheted down, saying, you don't need it anymore, you don't have to pay taxes, so, therefore, you don't have to earn this higher regulated return on equity.

The second one is more nuanced and much more difficult, and I don't personally see the solution to this; that is that integrated utilities that sell their assets into these structures, realize that those assets are going to move out from outside of state jurisdiction, regulatory jurisdiction, into FERC.

Many of them would like to see their assets move into FERC jurisdiction, but fear the retribution that is going to be put upon them by the states that are regulating the rest of their business. They fear that, even if it benefits their shareholders in the short run, to sell this, and, ultimately there's a more efficient form of financing, once the assets are separated from the state-regulated utility, they fear the rest of their business is going to suffer for that.

So, the message from people like myself, is, yes, the capital is there; we see a lot of it. Obviously, there are issues in the markets today, but that's what makes cashflows that come from these types of assets, seem more attractive, not less.

However, there needs to be some way of working with states to help encourage them to allow these assets to move into these types of vehicles, because I believe there is benefit that can be shared with ratepayers, and it will free up capital to be invested in other types of transmission. Thank you.

MR. RODGERS: Thank you, Mr. Piskadlo. Our next panelist will be Roy Jones, the Vice President of Transmission Development for LS Power Development, LLC.

MR. JONES: Thank you, Commissioners and FERC Staff, for hosting the technical conference here today. Your accommodations have been very nice and we do appreciate that.

LS Power is a leader in the independent energy industry with a track record of successfully developing large-scale energy projects. LS Power has expertise in all areas of the energy sector, including project development, power marketing, construction management, operations, regulatory, environmental, finance, legal, and tax issues.

LS Power has successfully developed approximately 7,200 megawatts of power generation assets in the United States, representing a capital investment of over $6 billion, and has a number of generation and transmission projects in active development.

LS Power has also managed over 20,000 megawatts of generation projects, which are either owned or managed on behalf of third parties. LS Power successfully controls -- or fully controls; I apologize -- over $4.3 billion in committed capital, for private equity firms, for the purposes of investing in power, utilities, infrastructure, and opportunities.

One of the active development projects currently being managed by LS Power, is our Southwest Intertie Project. It is a 1,800 megawatt, 500 KV line from southern Idaho to southern Nevada.

We are anticipating hosting an open season to identify interested parties to supply to the transmission facilities later this year. We will be filing our transmission tariff seeking market-based rates underneath that transmission facility, later this year, and we anticipate energizing that line in approximately 2012.

Additional details on the Southwest Intertie Project, are included in your informational briefing materials.

LS Power appreciates the actions taken by federal and state policymakers and all the stakeholders, to address the challenges this nation faces to promote alternative sources of energy, embrace and encourage new demand-response programs, and solve problems that we face in eliminating the serious deficiencies in our nation's transmission infrastructure. Specifically, the steps the Federal Energy Regulatory Commission has taken in Orders 890 and 890-A, applying the lessons learned over the past ten years, and anticipating and taking the steps necessary to address the need for regional transmission planning, to bring together the coordination and providing an open, transparent process; the recent actions also taken by the Department of Energy on September 19, to publish a set of interim procedures and proposed adoption of others, governing their role as the lead agency for coordinating the federal authorizations for the siting of interstate electric transmission facilities.

We've also seen actions taken by the states to create joint transmission expansion planning, and cost recovery initiatives to promote electric transmission investment, and to support the regional and subregional transmission planning processes in the Commission Orders.

All these steps are positive and are certainly in the right direction, but much work still remains to be done to move the barriers that still exist in order to achieve our desired goal of getting the transmission infrastructure up where it needs to be in our nation.

Specifically, market rules and adoption of legislation, including clear guidelines for the treatment of competing projects, will be needed.

The creation of transmission interconnect rules, with standard transmission interconnection agreements; the development of guidelines for the treatment of rights of first refusal to construct reliability, economic, and projects supporting renewable portfolio standards.

Siting transmission lines across multiple jurisdictions, as you've heard today, has been a problem. We would encourage the Commission to look at sanctions around or considerations of some type of federal siting. As we move forward and start anticipating some of the other constraints that we will see in this country, working with the equipment manufacturers to identify solutions for obtaining the materials we need to construct transmission facilities, as we compete with other countries for the resources we need.

We also need to ensure that we train and develop a skilled workforce that would be ready to meet the demands of constructing the transmission facilities.

Last and most importantly, we have to resolve the issues surrounding cost recovery. This will allow the financial markets to lend the needed capital.

LS Power understands that these issues are complex and is willing to provide the support, staff, and creative solutions to problems and the capital to assist in resolving the nation's growing transmission needs. Thank you.

MR. RODGERS: Thank you very much to our panel. I wanted to ask if the Chairman or any of the Commissioners would like to begin the questions.

COMMISSIONER MOELLER: I wish to thank all the panelists for an excellent presentation. I get pretty excited when people are talking transmission all the time.

(Laughter.)

COMMISSIONER MOELLER: One of the things that frustrates me, is how policymakers at the federal level, and also, obviously, at the state level, miss the forest for the trees on the costs of transmission, versus the ultimate benefit of expanding capacity in the commodity market, and that, often, it's a disproportionate gain for consumers when the transmission bottleneck is resolved.

I guess I'll open it up to any of you, hopefully disproving the Chairman's thought that we can't ask good questions as to how we could help rectify this situation, because there clearly is a misunderstanding as to what these investments and what benefits could emanate from these investments, for the ultimate consumer's bottom line.

So, to any of you, I open up how we can get that point made more effectively.

MR. McCOY: If I could, I'll take a first stab at it. One of the things that appears to be a leading issue, even in those parts of the U.S. with RTOs and ISOs, is the issue of cost allocation, the who-pays issue, if you can solve that.

Solving that is not the end-all and be-all, but it's a critical component. As I mentioned earlier, Trans-

Elect is associated, as are several other utility customers and developers in the United States, with an organization called WIRES.

Last year we produced a report on cost allocation which we recommend to everyone. Our view is unchanged, that we should allocate cost to beneficiaries, and those beneficiaries should be identified as broadly as possible, and should include both reliability and economic benefits.

It's easier to perhaps conceive of that in the RTO/ISO world than in parts of the West, where that structure is not present, but certainly it's difficult to go forward without that.

MR. LIPSCHULTZ: I guess I might add that I think part of this is the burden on all of us who invest in and those who operate in utilities and transmission settings. The good news is, we're no longer dealing with theory. There has, in fact, been a significant amount of capital invested in transmission.

As the Chairman actually testified in July, the numbers have actually increased materially over the last five, six, seven years. Projections are for a further increase.

I question whether that will happen in today's environment, but, in any case, there is some proof yet to be cited. The people who have spent that capital -- and I certainly know this is true for ITC, and I'm quite sure it's true for -- highly true for most of the major investments -- one can demonstrate impacts, the impacts on congestion and on reliability.

Some of the things have to be disentangled from the other effects that are occurring in the market at the same time. We have rising commodity prices, rising costs of construction, so, naturally, we have rising rates.

That's a coincidence with, not a caused-by this increased investment in transmission; quite the opposite. Investment in transmission, is probably mitigating these increasing costs.

So I think the burden is probably on all of us who have access to that kind of data, to put it together and present it and demonstrate to folks, that we are actually seeing increased flows, reduced congestion, and improved reliability from these investments.

The R&D is proportionate to the dollars invested and the cost to customers.

COMMISSIONER MOELLER: We'll take all the help we can get. Other thoughts?

MR. van BEERS: Commissioner Moeller, it's a very good question. I hesitate a bit to jump in here, because I have both Canadian and American investment, due to the nature of our lines, but I think it's true that there are substantial externality benefits at both ends, and those are not recognized, but any externality costs are immediately to my account.

I guess, if one stands back and says, you know, how does a merchant company like Tonbridge look at this, we recognize very much, that we operate, having the right of land condemnation, and being a perpetual co-inhabitant of people's land, imposes on you, the obligation to take seriously, the public interest.

I guess I'm looking less for a direct cash-to-bank approach, to measure the externalities, and say I need to be paid for all of them, than to go to the heart.

I guess what my argument was, we need to reset the balance of our public interests and rights when it comes to siting regulations. Siting regulations, to be blunt, now appear to be a process of identifying and then quelling defense, rather than choosing and approving a project. I don't think that allows the transmission to be built.

Noting that siting regulations would be inherently and primarily a political exercise, they should be a technocratic exercise, and the public benefit of the project, is lost in that discussion, and you deal with specific landowners' costs, and individual landowners appear to have a right of veto over progress, which is, I think, unfortunate for the industry.

COMMISSIONER MOELLER: That could be one example from the tax code. Windmills are popular in the midwest, especially when those checks come in every two or three months.

The REIT concept is fascinating to me because, in general -- I'm going to ruffle some feathers here, but the independent model disproportionately getting more transmission built, not exclusively, but disproportionately. And to the extent that the REIT model results in essentially financial functional separation, it seems to be one that has a lot of promise. So for any of you who want to comment on that that will be my last question.

MR. PISKADLO: I think it's a matter of getting critical mass. We've spoken with a number of independent transmission owners that have assets that are the size of $100 million, $200 million and it's not quite big enough. Yet, as a stand-alone transmission company, we have spoken with others that own large DC transmissions and those are ongoing discussions, but I think this type of structure could be used as an alternate way of monitorizing these merchant projects.

Some of the ideas that were put forth in terms of selling the capacity forward outside of the FERC process to stabilize the cash flow I think are very good. This is basic project finance and we believe that those types of projects could actually be brought into this REIT structure sooner rather than later. If you leave all to get built and then run the auction, the type of investors that normally would be attracted to these types of investments just would have no interest. They want to see it in rate base. They want to know what it looks like so that they can then say I'll pay this much.

MR. MOELLER: Thank you Mr. Chairman. And again, I thank all the panelists.

MR. SPITZER: Thank you. Two separate issues, there's obviously a lot of frustration. Mr. van Beers, in your testimony -- and this really addresses also the REIT issue, politics is relevant, whether you like it or not, in the sighting process. It's a function of government to attempt to accommodate. Is there any silver lining? Where you are operating, I would venture to say most people would feel that the politics, although it's not techcratic in Montana. It's a little it be more so and a little be less political than in certain other areas of the country. The Eastern Transmission people can come in and tell you things that will curl your hair.

(Laughter.)

MR. SPITZER: But nevertheless, we discuss we discussed the joint ownership issue and I can tell you from a very personal experience, having public power and some large, some small participating power lines have a great deal of cachet and a great deal of ability to move the ball forward in that regard in expediting the process. I'd like your reaction as to whether that's a potential consideration in Montana, and also the rest of the panel.

Now, the REIT issue, my feeling from my prior life as a state regulator is that it's not so much an attempt to -- the concern about the state regulators is not so much an attempt to disgorge or claw back potential tax benefits. It's a lack of jurisdiction. There was a trend in the '90s to create transcos and the state that elected to be vertically integrated to reserve the bundle rate regulation. They made a deliberate choice to maintain that model to preserve their authority. Whether that's right or wrong, it's very difficult to persuade the regulator to voluntarily relinquish jurisdiction. I think that's the problem, not necessarily the financial aspects. And the state regulators in Transco see the disappearance of their jurisdiction. So this calls for some little "p" political considerations.

Have you looked at the potential, public/private issues, with REITs? You may or may not avoid some of the unrelated taxable income issues that you have in these formulations. So perhaps this could be a means for discreet projects quelling some opposition given that you've got a public/private investment in a pass-through vehicle without having jurisdictional problems and you get some of the benefits of public/private. I guess it's a joint ownership question for the entire panel, maybe starting with Mr. Jones.

MR. JONES: Sure. Yes. As we've looked -- and I'll speak once again specifically as we looked to advance the development and construction of our project, just as you suggested, we actually did seek opportunities to enter into joint ownership of that facility. What we ran into, though, was that we had competing interest or competing business strategies with those parties that we were trying to partner with to build the transmission facilities. As we continued to try to work through those and find common ground, we found ourselves -- we were not able to resolve them. We, if you will, will continue to try to pursue the project on our own.

Now, this entity was not an independent developer. It was a vertically integrated utility that we were trying to partner with and we just weren't able to reach any common ground to move forward because of differing and competing priorities. But I think the joint ownership model, while it may be successful in some areas; it is going to be limited in its success on a wide scale, widespread basis.

MR. McCOY: We agree with the Commissioner. The trans-elect experience has been quite positive in the involvement with public power in amber in working with our Wyoming and Colorado inter-tie project has again the Western Area Power Administration as a technical partner. And we have experienced the utilities, as we own a common transmission pool with the Wolverine Power Supply Cooperative. So our expoerience has been positive, to the extent that we would have a willing public power partner in a locale that we could take a walk with and resolve the process, we would view that as very positive.

MR. VAN BEERS: I'll moderate a little bit my colleague's Paul McCoy's comment. Just structurally, I think what we have explored with public utilities is joint development arrangements. I think we would want very, very clear, crisp delineated roles and responsibilities in that and an exit strategy if milestones aren't meet. I'm delighted to hear that Mr. McCoy's experience is positive. I'm just speaking for our experience. I think we would find that dealing with multiple utilities would be a problem for us. I'm just saying trying to deal with these entities, you're quite correct, they do bring a lot of political weight to the table, but they also bring a lot of political interest. And if we're going to interconnect jurisdictions, then we're dealing with the problems at the state level, but also dealing at the utility level. I think that's challenging and I don't think that's worked for all of us. I'm glad it's worked for Paul. I don't think it's worked for everyone else.

MR. WRAY: Commissioner Spitzer, let me add that our experience with Sunzia has been truly positive partnership public power. It's very likely in the future that that partnership will expand more in the direction of having a sponsor group behind the Sunzia Project with additional partnerships. And although I agree with the observation that we bring a certain cachet in certain jurisdictions, they also bring something that I think is probably more important to the success of a large interstate transmission project and that is years and years of experience in operation and how to manage control areas.

These issues that have been talked about here earlier that may not necessarily -- it's again a blending of attributes that everybody has. It's more of a symbiosis than anything else.

MR. HAYSLIP: First of all, I'm delighted that we're characterized as having cachet.

(Laughter.)

MR. HAYSLIP: It doesn't happen often. I would just say the reason for my little historic vignette earlier was to make a point. Sometimes necessity is the mother of invention on these matters. As these challenges become more and more complex, there are always going to be differences related to insurance states and those types of things. But I think public power entities and investor-owned, for that matter, are much more open to entertaining alternative business models with partners on the line. We're not dogmatic about that and I really think that people of goodwill can sit down and figure out how to make these things work. And we've had experience with that that is positive.

MR. SPITZ: The words of Mr. van Beers sort of require that the planning process -- the planning process before had a lot of benefit, but some of these criticisms pre-date this. But they're criticized as a barrier to independent transmission. Now, you describe, Mr. Hayslip, and your projects arose from that. That was the good side. Maybe those who have concerns of being kept out, what can FERC do to ameliorate your view? And I think in the transmission industry how do we storm these barricades?

MR. VAN BEERS: I don't know if there's any answer to that. I also don't know that it's fair to characterize us as being the people with pitchforks. But one of the panelists made a comment about needing a world in which queue rights and development rights were more clearly interrelated. I think that would be very helpful. You must remember that we operated in an odd circumstance, straddling the Canadian/U.S. borders. So our circumstance is perhaps different because we're dealing with different regulatory regimes and different ways to do regional planning. But going forward, it's strikes me that Q rights and the ability to negotiate what transmission development looks like needs a little bit more structure than it has now. The default would appear to be a franchise area. Regional planning is an effort to get around that, particularly transmission. It's too early to tell whether we've gone far enough with that.

MR. McCOY: One comment that I would make is that our experience is a WECC experience. When you approach the existing access owner with an interconnection requirement, they understand how to take a request from a generator onto the LGIA report. But when you approach them for what I would describe as a transmission to transmission request and isn't part of a long-standing operating agreement among two neighboring entities that recently added another connection there is a bit of confusion over what to do with it and where does it go on the queue, vis- -vis, are we an LGIA? Maybe the Commission could help in that regard to clarify what are the rules of the merchant approaches. By the way, it could be an existing merchant asset as time goes on. But what are the rules for transmission.

MR. WRAY: If I could, let me just add one thing. I think in those situations I think solutions are ultimately found in the absence of regulatory directives. The situation described by Mr. McCoy is a market responding on a bilateral contract basis, not necessarily a regulatory directive, also, a pro forma provision. You're never going to have a regulatory regiment that addresses all situations. It addresses most of them pretty well.

MR. JONES: I would like to comment. It was one of the ideas that we actually discussed here would be the creation, if you will, of a transmission interconnect set of rules and even a standard transmission interconnect. If you work through the market rules and work through the necessary orders to get you that, I think, as you work your way through that you also work your way through a lot of the other issues that you have to consider and work through, such as the treatment of competing projects. So you get to deal with and address competing projects. You also can then address and deal with the rights of first refusal.

So as you work through the mechanics, if you will, of doing the transmission interconnect set of rules and a standard transmission interconnect agreement, I think, in and of itself it opens up the opportunity to let out, shall we say, a level playing field and it establishes ground rules that we can all look to, to build transmission under an equal set of rules.

CHAIRMAN KELLIHER: I have a couple of questions. I'm going to want to turn to staff. My focus is a very practical one. I said at the beginning there are a number of barriers to transmission development. Not all of them are in our power to remove. So we are focused on the subset of the ones we can do something about, so I want to follow up on some of your comments that touched on that. But the market question -- there's a logical implication to what you said, but I'd like to make you take one more step.

You point out that credit is smaller. The cost of credit is higher. The logical implication of that is that this is not the right time for the Commission to lower returns for transmission investment if we want to consider a high level on investment in transmission.

MR. LIPSCHULTZ: That's absolutely correct. The term "requirements" in all asset classes is going up. They're certainly not going down. So we can debate whether there needs to be a further increase or not, but I think a decrease is not going to be successful in driving capital formation. The amount of capital available is simply lower and I think you have done a tremendous job, frankly, of driving, over the last several years, an increase in capital. We should stay the course and probably manage the risk side of the equation down and you want to continue to attract capital versus going with the only other parts of the economy.

CHAIMAN KELLIHER: That's something you raised. You're an admirer of an Attachment O. Are you suggesting that that's something we should consider in other regions or a similar mechanism?

MR. LIPSCHULTZ: Certainly, as an investor we are drawn to formula-like rate structures, a tracker-type structure, a way to get a near-term recovery, the time value of money, in parts more certainty. But I think having the ability to employ capital, which is in many instances the required need to meet stakeholder requirements and having a way to achieve a return sooner and with certainty will allow you to draw capital at a lower return, all things being equal. So yes, whether Attachment O specifically a formulation, there are probably a lot of varieties, the proposition of formulas and ways to achieve near-term recovery. In classic rate cases, I think that's a significant benefit.

MR. PISKADLO: If I could add, talking about the east capital market factor is the tax incentive is a great incentive. It's something that's work very well. We believe if you were to look at something like the returns demanded by investors in utility groups is what we think investors would demand from this access class. If it had an

Attachment O, it would be much lower. You can see that in the multiples demanded by investors typically including 15 times in earnings, four to five times. You could see it in water company assets. You could see it worldwide. You could see it in Europe. So formula-type returns where there's a level of certainty are much better than the alternative.

Also, in addition, another question you asked about lowering the cost of return on equity, one thing that should be considered when you're thinking about all these new built assets, at least what I'm seeing in other markets is there have been an EPC or construction bubble, if you will. Everybody was chasing after the same construction workers, et cetera. It's kind of gone, vanished. So I think a lot of those materials are going to free up and that's why you're seeing commodity prices come up. I think the construction costs are going to come down, so it's not all that bad.

MR. LIPSCHULTZ: I have one other thought on this question of formulas because I don't want this to be thought, well, this is what works for investors. The thing about the formula approach is we should in all these instances all be stakeholders. It's not a question of who can develop more political muscle during the prosecution of a rate case or who can develop the more clever argument rather it's what is the cost. What is the capital? What is the proof rate of return and that's what you should earn. You shouldn't over earn. You shouldn't under earn. I think the other elegance of this from the stakeholder point of view is the fairness. Nobody's going to be on the wrong side of that trade. It's going to be is the trade is approved by the Commission at this standpoint.

MR. PISKADLO: To add to Mark's point, the scarcity of capital it's going up in price primarily because people perceive risk across all capital or asset classes. It's gone up so therefore the return is gone up to the extent that you could offer people visibility and it's fair. It's going to be better for everybody, including the ratepayer.

CHAIRMAN KELLIHER: A question for Mr. McCoy about merchant projects. Two years ago we had a comeback, if you will, on merchant projects, on wind development. But you're saying, I think, what is the most important thing we can do is importing the anchor shipper concept into merchant projects in the same way that we do for gas pipelines? Does that involve a recourse rate? Are you saying there ought to be a recourse rate for wind or would you have to negotiate that?

MR. McCOY: Thank you for the clarifying questions. In my prepared comments I got to be too wordy, but it's the latter. It is not the high-flying models. It's the suggestion. It's to negotiate commercial anchor shippers. That is bound by commercial contracts and you use the example if the commercial contract with the anchor shipper involves a most favored nation's clause. To use an example, the anchor shipper produces at $4 a kilowatt per month rate and the auction clears at $3.90 and the owner decides to take that. If the anchor has negotiated a most favored nation's clause, they can negotiate to lower this $4 down to $3.90. But it's a commercial term.

CHAIRMAN KELLIHER: What kind of contract terms do you think the anchor shipper would have versus the shipper today that signed in open season?

MR. McCOY: We would see a difference. They would have to be long term in terms of 20 years.

CHAIRMAN KELLIHER: There'd be a difference in rate, perhaps, but not in terms of the contract?

MR. McCOY: That's how we would view it at this time.

MR. PISKADLO: That technique Mr. McCoy is talking about is something we've used on behalf of power plants, et cetera. Actually, one for LS Power where we sold the power forward as a way of stabilizing the cash flow. So why did we do that? Because lenders to the project wanted to make sure that after you get through the construction period that they can work ahead in a low commodity price environment and then suddenly the project was bankrupt. You needed visibility for the cash flows once the thing was commercial in order to attract the lower cost debt financing during the construction period. I think construction lenders and investors will invest into a project if it has permits and take construction financing risks. They won't do that if you have that response on top of I just don't know what the asset is going to generate. You need just enough to kind of get the capital to stabilize and that includes not only the amount up front, but also in term so you can get an appropriate right sized capital structure and reduce the amount of equity they need.

CHAIRMAN KELLIHER: Mr. Jones, you discussed the ten criteria in order to sell at negotiated rates. Do you think we need to test those? Do we have the right criteria?

MR. JONES: I think from our perspective you have the right criteria.

CHAIRMAN KELLIHER: You can say otherwise. We're open.

MR. JONES: No, I think you do have the right criteria. I do believe, though, as I said a moment ago, as we continue to move forward with standardizing the transmission rules I hope that will help better round out those criteria as well.

CHAIRMAN KELLIHER: Any other witnesses think what we need to revisit our criteria, our ten criteria?

(No response.)

CHAIRMAN KELLIHER: One last question for Mr. Piskadlo. Is there anything in FERC regulations that impedes the development of REIT?

MR. PISKADLO: No, it comes back to the question that Commissioner Spitzer asked a moment ago. He made the statement that it's a jurisdictional question. Clearly, I think you can get the most access from the existing holders and free up that capital if you can get them to give up their jurisdictional rights, if you will. If not, you can think about these cash flows as one group of people and the regulation is really being managed by a person who's operating the asset. My understanding is once these assets are separated from the integrated utility they immediately fall under FERC jurisdiction. Most of the people I've spoken to that have their assets with distribution as well as transmission and everything else seem very reluctant, with or without a REIT, even if they put it into a sequence -- I've spoken to a number of people who are trying to separate their assets in a sequel, forgetting the rates because they want attachment or they want that clarity in their rate-making process. But they have a hard time getting pass the barrier of getting out of the state regulator's hand. And I personally don't understand what the attraction is of having that control. I don't know. You might.

(Laughter.)

MR. VAN BEERS: Mr. Chairman, if I may add one additional thought to your line of questioning about anchor tenants. We, in our naivety, thought we needed an anchor tenant. In 2005, we auctioned the Montana/Alberta line. We essentially sold 100 percent capacity. You'll recall our history as being the credit standards of those thinly capitalized shippers was more than adequate to finance the company with that financing arrear, it would undertake the development, the standards in the market for creditworthiness in 2005 and late 2008 are worlds apart. So effectively have had to go to some of our shippers. And having to do that after we'd struck a three-year agreement with others in the area.

What we need to be able to do is sit down with our shippers and begin to say in exchange for you financing us through the development stage, ensuring the financial burden there, we can give you a material contract for capacity for 20 years if that's the appropriate term, 50 percent of the capacity and perhaps a most favored nation's clause. There's a number of things that could be worked out, but that does strike us as being a lot cheaper than trying to get a contract, and with the contract going to market to arrange for the venture capital giving neither the renewable shippers -- they don't have deep pockets and nor do we. This is a way of sharing the risks perhaps much more cheaply than through an intermediary.

CHAIRMAN KELLIHER: Staff, back to you.

MR. RODGERS: Against the backdrop of great expectations, the staff has created for staff questions. I'll ask the staff, first, if they have any questions.

(Laughter.)

MR. RODGERS: To Mr. van Beers, what is happening on the Canadian side of the border that has not happened on the U.S. side that makes mark down rights easier to sell?

MR. VAN BEERS: That's easy. The Alberta power market is much more trans-market. It's the only bilateral line. There's an instantaneous price discovery. There's a robust market power there, which makes any kind of power immediately fungible. If you move power into Montana, you'd better have a long-term bilateral agreement or you must have a transmission capacity impact out of Montana elsewhere.

MR. RODGERS: Mr. van Beers, you also mentioned that the industry, in your view in general, is hostile to merchant development in the West. I wonder if you could explain that.

MR. VAN BEERS: I think the honest answer is that when we began this project we began it outside of any kind of regional planning context and we arrived unannounced, and we arrived as a possibly destabilizing force for a liability in the region. And perhaps, arising in the context of the regional planning process, we would have greatly facilitated our entry. The underlying issues that made our arrival in Montana so difficult were the issue of reliability. Montana has 120 megawatt. We find it presently has and the ancillary services regulating the service for that had been very different for Northwestern Energy to obtain, and when we arrived we were very proud of ourselves having served out 600 megawatts. The shippers had not fully contemplated what that might mean for the balancing authority. So there was a head-on collision of expectations on our part and theirs.

I think it goes to Mr. McCoy's remark too that there really isn't a good framework to be able to explain why wire-to-wire agreements need to be undertaken. I'm happy to share with you now that we have what I regard as an outstanding relationship with Northwestern. I'm very pleased to work with them, but a lot of that has been ad hoc, person to person; but we've worked through it. I think our framework where we've understood that they would be the balancing authority and they'd be the operator of our line we had to make a lot of that up as we went along.

MR. CANNON: I was a little confused earlier, building on some of the Chairman's questions about whether people are content with the ten criteria that are out there. I heard from a number of you that we need to revisit or do something different with regard to our anchor shipper construct and maybe import that from the gas side over to the electric side.

What I'm wondering is does that fit under the open season requirement as it's being interpreted on the electric side? If not, why not and what do we need to change? I see you nodding, Paul. I'd like to start with you because I know you obviously did have open season. I'm just curious what you might have achieved if you'd done it some different way or been able to negotiate bilaterally.

MR. McCOY: I'm sorry I'm being slow on the uptake with the Chairman's question. In my remarks I talked about the allocation of capacity thinking, perhaps, making the leap that you still had to have a process of allocating capacity that did not involve a fall back to rate base in effect. The issue that we had is somewhat parallel to what Mr. van Beers said because we didn't negotiate an anchor shipper arrangement. We went through the process -- initially, there were perhaps 30 to 35 entities -- I'm doing this from memory -- expressing initial interest. When you sorted them down through a funnel of people who went through the process of applying, people who went through the process of meeting today's credit strength, you end up with an expensive process to get to the point and you end with a small number of people bidding. And of course, by public announcement we had two successful bidders.

We would suggest that the ability to have gone almost straight to one or more of these two entities early on would have saved, perhaps, half a million dollars in cost. The remaining capacity would have been a much simpler process than the way we offered it. So we're not talking about that being the allocation process, but we do think that especially in parts of the United States that don't have organized markets that the ability to negotiate an anchor shipper would greatly lower costs and speed the project along. The Commission may want to consider having sort of a flexible view on whether or not an anchor shipper is required. There may be cases where the Commission is convinced it's not, but I suggest that in the areas where we're in business in the West that it is.

MR. RODGERS: Kevin?

MR. KELLY: Good afternoon. I took notes on what I thought I heard on what FERC can do to remove barriers and I came up with three or four things. I'll tell you what they are. My question is did I miss something? What I came up with -- I think this is for rate-based transmission -- is to provide a formulaic approach to revenue so you'd get an initial revenue stream.

Second, and I think this is just for emergency transmission, to allow pre-sale of capacity to so-called anchor shippers. The third is that there's a need for transmission interconnection rules parallel to generation. And a possible fourth is Mr. Jones says there's a need for guidelines for treatment of competing projects. It wasn't clear to me if FERC was the right entity to meet that need. You might want to comment on that, Mr. Jones. But the question for the panel is, is there a fifth thing? I certainly took a lot of notes on the state sighting processes, restitution against the entities that moved their jurisdiction toward FERC. But in terms of what FERC can do, that's what my notes came up with.

Mr. Jones, maybe you can go first.

MR. JONES: Sure. On the treatment of competing projects, maybe the approach would be to let the regional planning processes evolve and see if this issue is treated within the regional planning processes as those begin taking shape. That way the unique attributes of the regions around the country can be considered as well. That might be the best place to let this start to play out. That provides you with the opportunity to review those plans and the processes and see if you believe that they are, in fact, providing equitable treatment of how the competing process was evaluated in the regional planning processes.

MR. KELLY: Just to follow up, is it premature to apply that kind of review now to regional planning or do the rules get better developed in different regions?

MR. JONES: I'll have to defer to your judgment. I don't believe now is the time to project on whether you would choose to wait and see how the rules evolve and then pass judgment, shall we say.

MR. KELLY: Thank you.

MR. WRAY: One more point on regional planning, and it's important. I can tell you in the Southwest my company added as if Order 890 applied directly when we were looking at the rules. On some of the other matters, we all participated with the jurisdictional companies because we felt it was in our interest that we all understand how much transparency and planning were possible. So we self-administered that, whether or not that should be formalized as an extension of that order is another matter. I will defer to your judgment on that. But I can tell you from my experience in the Southwest sort of followed it, as it were.

Secondly, we haven't talked about it today, but some of the correspondence published in the notice it's a matter of whether or not any of these transmission problems should be saddled with ancillary service. Typically, those services pro forma ancillary services, in general, there are going to be things like load fall and things like that to the degree that the Commission decides it's a policy that requires ancillary services be sold by or part of OATT for transmission services. All that entity is going to do is go out and purchases those on the secondary market anyway. I'm not sure that's an issue from a policy standpoint. FERC ought to consider the benefit that just come naturally from the generator going out and purchasing those ancillary services.

The wind generators, for example, or the buyer at the other end of the transaction seeing the importance of making that wind generation more dispatchable and maybe going out on his own and finding those services. In either case, the ones on the end of the line, the end of the transmission project have more ready access to generator-based ancillary services than do the wires only.

MR. RODGERS: Did you have a question, Jeff?

MR. WRIGHT: Just briefly, Mr. van Beers kind of opened the door slightly saying in a perfect world FERC would have certificate authority. But absent that, active involvement on the part of FERC would mean that transmission developers do not stand alone in their struggle. That would be the next best thing. Could you elaborate? Is that what Kevin was speaking to in terms of these or was there something else you had in mind?

MR. VAN BEERS: I think the FERC has consistently and clearly spoken with a view to what was helpful to the industry. And a little bit to Mr. Rodger's question earlier, it was enormously helpful in our dealings with the public utilities. But I would believe it would helpful also to deal with state regulators. That the issue not become applicants versus landowners, but that we have a more wholesome discussion about what is the public interest. It's very difficult for us to speak from the perspective of the partial industry observe, whether it does or does not add value, and that's a critical part of the discussion around permitting. That has all been lost.

So in a perfect world, I would look at the FERC as the first port of call for certificate approval. That's not policy or possible, I think we might be looking for a way in which the FERC can articulate its views on the value and merit of particular projects to other regulators.

MR. RODGERS: Rick?

MR. O'NEILL: Just continuing the inquiry of -- what would you need from us to negotiate your anchor shipper concept. I guess alternatively, what do you think is prohibiting you from negotiating your anchor shipper?

MR. VAN BEERS: I suspect -- I'll answer very briefly. I think what we're looking for is within what area would a contract with an anchor shipper would be acceptable to FERC because in a commercial negotiation we have 50 percent of the capacity, but FERC would deem that was too much or we have it for 30 years. FERC might deem that too long. Should we have it for "x" dollars? FERC would deem --

MR. O'NEILL: Would you tell us what would be the sandbox you'd like to play in?

MR. VAN BEERS: Sixty, seventy percent of the capacity, maybe plausibly 50 percent of the capacity to be pre-arranged.

MR. O'NEILL: Would you discriminate among who could become anchor shippers other than say for creditworthiness?

MR. VAN BEERS: I think as a practical matter what we would do -- I think a little bit like Mr. McCoy said the parties we knew of we'd be perfectly happy to post that period of time, see if others came out of the woodwork pursuing a similar deal. What we don't have now is the understanding that, in fact, we can go to one or two parties, cut a deal and have that stand the test. What we have now is, if I'm prepaying --

MR. O'NEILL: What's kept you from asking for this authority.

MR. VAN BEERS: I don't know if anything has kept us. Our situation is that we're now at this juncture in our life cycle where we're actively beginning the ways in which these projects -- in our experience with Projects II and III, in our experience with Project I is that we thought the revenue would be securitized. Well, the finance and credit standards have gone up so rapidly that's no longer possible.

MR. PISKADLO: This ultimately comes down to a finance question. As Mark was saying, standards of credit and what's an acceptable amount of debt versus equity in the projects have changed. I can't sit here and tell you exactly how it's going to work next week, but it typically was or used to be about six months ago 80 percent debt, 20 percent equity for a power plant with seven years of cash flows. It's not going to be anything like that. So coming up with parameters around anything about 50 percent to 80 percent of capacity for a period of time from commercial operations to some period of time thereafter or anywhere from 7 years to 15 years is probably within the range of being able to find something that's financiable because I think ultimately what Mr. van Beers is trying to get at is financing is 100 percent equity all the way to going commercial is very expensive.

MR. O'NEILL: Do you interpret our rules as requiring that?

MR. PISKADLO: I'm going off of what he is saying, Mr. van Beers is saying. I find that is a lot of new-build projects and if what he is saying is he has to get his project very far along to appoint -- or it's a month or two away -- I'm just making something up -- before he can go and get a whole bunch of shippers, and therefore give clarity to his cash flow that's very expensive. Maybe you can do the day you get your permits and you know you're going to be able to, once you have the money, then you build it all the way to the end. You add clarity to what your capital is going to be like. I think you'll lower your cost of funding.

MR. RODGER: I think that's going to need to be our last comment for this panel so we can have time to get our next panel. I want to thank our panelists very much for their excellent presentations and we will reconvene in ten minutes, at 3:20.

(Recess.)

MR. RODGERS: If you could take your seats, please, we could go ahead and get started.

(Pause.)

MR. RODGERS: Good afternoon. We're going to continue with our Eastern Interconnect Panel. Just like we did on the previous panel, we'll be moving from that direction to this direction among our panel. Each of them will be asked to speak for about five to seven minutes, and do have a timer here that will let me know where you are.

You'll have a yellow light when you have one minute left on your allotted time and at the end of the presentation, when all of them have spoken will have time for questions and answers.

So with that, I'd like to welcome our very first panelist, Sharon Reishus, chairman of the Maine Public Utilities Commission. Welcome.

MS. REISHUS: Thank you for inviting me to speak on this panel as the lone regulator. The comments today are mine alone and do not reflect the views, necessarily, of my colleagues on the Maine Commission.

I'd like to start by stating the obvious. I'm an economic regulator, not a commission member. As such, I'm interested in striking the right balance between cost and reliability. But I'm very aware of the high cost of failure. I'm equally aware of the impact of rising costs and rising energy rates on consumers and spending too much to create a system that is, in effect, too reliable for what we use it for. So before I turn to today's topic, I couldn't help but ask myself first what is the right amount of transmission that New England needs to achieve, given the growing impact of energy efficiency across the states, coupled with the extraordinary amount of demand response that we've seen.

State regulators are in a position to question the basic assumptions by the stakeholders that the rate of new transmission is seriously lagging behind, at least for the next few years. In the longer run, more transmission projects may be built because of the need to address climate change. Certainly one possible solution will be to link transmission lines over long distances using low carbon resources to bring to market all of the non-transmission services.

As a state commissioner, it is my job to seek the appropriate amount of reliability cost and the balance to be stricken by reliability costs and other issues. In any case, one concern about the term commission project will be built in New England over the short term let me suggest that the new projects in my region in the last years, in our perspective, there will be a barrier to new transmission construction. With all due respect, state regulators have and will continue to argue that this has created an unwarranted bonus to the transmission project that would have been built anyway via of the opportunities for full cost recovery.

The tenfold increase in transmission investment that we've seen in the last decade have left state regulators worried about the potential impact of their construction out of the many proposed projects yet to be built. The transmission owners have been through ISO New

England's planning process and in addition to the sheer amount of transmission required, other area of concern that I share.

Among New England regulators is transmission costs. This is now a position for reviewing a project or under the current system the project review may not be thorough enough for accurate cost estimates. These are among the issues that state regulators will be pursuing directly in discussions with the ISO and with other stakeholders. With our alternative transmission arrangements for the New England construction of transmission projections, including joint ownership and regulated utilities. A great majority of these projects are constructed by regulated entities, plus reliability and transmission projects are reviewed and coordinated by ISO of New England.

The ISO New England's recent planning process has this incentive. By my count there were 212 projects completed at a cost of about $1.5 billion, but the projected cost of new projects for 2012 is expected to exceed $8 billion, a dramatic increase in both the amount of time for project and the escalating costs. This will triple the current network service rate in only a few years. One of the issues before you today is the question as an area of active discussion in Maine. Typically, stakeholders from

New England Governor's Conference on asking whether OIS New England plan will encourage transmission projects to be built that are designed to collect from load generation to load centers. Although hundreds of reliability projects are under various stages of review and approval, only one project is currently under review by the ISO for market efficiency transmission upgrades.

There's a direct proposal by two regulated Maine utilities to achieve, among other purposes, to northern Maine resources to bring into southern Maine. There's a working group within the ISO co-chaired by a number of people, including myself and Chairman Hibbat of Massachusetts to explore whether there are ways to reexamine the criteria to evaluate this type of project as well as the underlying fare is concerned and directly related to cost allocation. The cost allocation scheme is New England is currently 100 percent. It's a cost allocation for both reliability and economic transmission issues. The Commission is aware of continued concerns about the socialization of the liability, which will results in saving PTM's transmission projects cost of non-traditional alternatives.

More recently, other state regulators and politicians have been concerned about the cost impact of economic transmission projects. That has lead to uncertainty about how the tariffs should be interpreted by the ISO and how the state will help pay for them because the first such project is in Maine currently under certification. I'm precluded from discussing the project in more detail today, but I would note that there are various efforts underway to discuss the cost allocations and we may enter a litigation before your Commission.

I appreciate the fact that regulatory uncertainty has been a detriment to investment, plus state regulators and other political bodies in New England continue to work for our individual states and our commissions.

Finally, I note the active participation by states on these transmission issues afforded by several of the principles that were outlined in Order 890, and I appreciate the Commission's interest in keeping states fully involved. And I appreciate ISO New England's continuing efforts to reach out to state regulators. The recently formed regional state committee for New England or NESCO will have the resources to deal directly with the issues on behalf of the state. My state commissions are self-regulators. We're also actively engaged in the ISO in transmission planning and market power activity. Thank you.

MR. RODGERS: Thank you Chairman Reishus. Next we will hear from Roy Thilly, president and CEO of Wisconsin Public Power. Today he's representing the Transmission

Access Policy Study Group.

MR. THILLY: Thank you for the opportunity to participate on this panel. My utility, WPPI, serves 50 communities were owned by 45 Wisconsin municipalities and we serve the upper peninsula of Michigan and Iowa. We're taxed as a group of transmission dependent utilities, a smaller system instead of -- and I'm a big advocate of a robust transmission system. As a matter of fact, I spoke to the panel here in 1993 just after the '92 act was passed. I couldn't find my notes. I suspect there's a lot of overlap.

(Laughter.)

MR. THILLY: I do want to talk today about two successful ventures in getting transmission built and the lessons from those. WPPI is part of two joint transmission ownership organizations that have been and are getting major transmission built or in the approval process with significant public support. The first is the American Transmission Company, ATC, which is an inclusive load-serving entity owns Transco, which has an open planning process and statutory obligations to meet all of the load-serving entity needs and the support of robust wholesale markets. We've got 5 investor-owned utilities, 17 municipalities, 6 rural electrical operatives that have ownership. So far, $2 billion has gone into rate base since 2001 and those $2.7 billion addition, and this is solely within the state of Wisconsin. That doesn't include participation in the regional affiliates.

The resources to the West or to tap the Great Lakes wind potential so far there have been no applications turned down for construction. Most have proceeded in a very timely fashion and no complaints.

Second is the TAPSG 20/20 Group, 11 utilities in Minnesota and Wisconsin. The projects are for 345kV lines that have been designed to meet the load-serving and reliability needs of all 11 utilities. Phase I is $2 billion, plus an additional billion dollars for local improvements on the systems. Three out of the four have been filed before the Minnesota Commission. One will be filed with Minnesota and Wisconsin in the first part of '09.

They had no interventions. Some of the others do. One of the issues is that the lines should only carry renewable energy, which is an engineering challenge, I understand.

(Laughter.)

MR. THILLY: The second is that the facility actually should be larger, should be upgraded from 345 to 500 kV, which is also a twist.

Two obvious points that I think were made by the Commission is the first is that we really need a robust grid for optionality. It's got to be multipurpose and meet the needs of multiple parties. Its keep infrastructure for markets and it's essential to address the climate change issues we're all facing. This came about maybe ten years ago. Everybody got price signals. Now we have different progress and that is reaching low-carbon constrained resources. It's very different. Where there's geologic sequestration capability, nuclear units are not going to be built close to load and I suspect kV and hydro will be built in Canada.

(Laughter.)

MR. THILLY: We need transmission for all of that. Second, it's very hard to build transmission. Lots of landowners are affected. That is inevitable. Power plant and state regulation often requires alternative routes, which will double and triple the opposition. So we have to do a very good job. And then there are environmental concerns, particularly, cost concerns related to the benefits to make sure that we address and match the benefits. Our biggest challenge, I think, is incredibly demonstrating need through careful planning, not overbuilding or under-building, showing that we're doing the conservation and efficiency and distributed generation. And if we still meet the transmission for the optionality.

The Commission has done a fair amount. I know DOE is looking at one-stop shopping. That's very important at a time they cost a lot of money, but the Commission as reduced risk of transmission construction substantially through CWIP, by rate base desertification, extensions of the formula rate. You take that together with the attractive returns that have been provided and attractive equity ratios and you have probably the best investment out there. As a matter of fact, I think people are lining up from here to Omaha because Omaha is the front of the line to invest in transmission. In today's world, where else can you get a 12 percent, virtually very low risk investment?

Moving back to the joint ownership model, just to point out the grid is jointly used. It is a network. We can't tolerate unnecessary duplication. It has to meet multiple needs and joint ownership aligns the ownership model with the realities of the network. It also produces a collaborative and inclusive process as opposed to a competitive process that facilitates and makes joint planning real. It leads to a better system than appreciating proposals, which plan for parochial needs. It provides credibility in the sighting process through diversity of support. All sighting is local and having 50 communities, rural electric cooperatives supporting this is tremendously helpful.

State regulators would much rather receive one proposal with all the facilities together than a lot of different proposals. You see fewer disputes on tariffs and it helps the cost allocation issue. Our rates have gone up from $1.30 to $3.40, but we offset that 30 to 40 percent on investment, which makes it much easier for us to support because we have skin in the game and an investor in the facility, similarly, has an earning potential. So I think encouraging joint ownership more actively as part of the Commission through rewarding and encouraging it in your ratemaking process helps. And also providing consequences where there are REIT systems, a failure to be inclusive, a failure to be proactive in planning, would be very beneficial. It needs to work both ways. Thank you.

MR. RODGERS: Thank you Mr. Thilly. Next, we'll hear from Susan Tomasky, president of AEP Transmission with the American Electric Power Company. Welcome back to the Commission.

MS. TOMASKY: Thank you very much. It's a pleasure to be here. Thanks so much for having me here. I'm president of AEP Transmission, which is a business division of American Electric Power. Those responsible for the owning and operating of AEP's existing assets, which are in both the Eastern interconnection as well as in the Southwest power pool. And also, for purposes of today's discussion, I want to talk specifically about our new business activities, which are really involved in the development of extra high voltage transmission systems in various parts of the country.

This is actually true -- it's different from AEP's current ownership. It's through transmission-only subsidiaries, often in the form of joint ventures with other strategic and financial partners. And I want to talk a little bit about how that works for us.

Let me start by saying that our view of what should be built in this country has very much informed our business strategy and it really has to do with the conviction that as we meet the various needs of our nation's energy policy, which I think Mr. Thilly said extremely well in his comments, the need for integration of renewables, the need for more efficient use of the regions that we already have, the need for a backbone system that overlays the current system that we have today, the need for region integration, the need for dealing with sources and the integration of sources and the integration of load, not only over broad geographic regions, but also over long periods of time.

All of that compels the development of a system of some consequence for the company and for the country, and there are many opportunities, both for those of us who are primarily interested in that kind of investment as well as for many others who will invest in the supporting transmission system, which is part of the ultimate system that we need going forward. So there is, in principle, more than enough investment to go around for everyone who wants to participate in it. Really, the question is how to get it done and how to get it done in something that even approaches a reasonable timeframe that we need to meet all the other national energy policy goals that we consistently link to the development of transmission.

I will do my very best to focus on the question that you wanted answered, what can the Commission do? I share the view of many that you've heard today that what we ultimately need to add to the Commission is federal sighting authority in order to be able to move forward. But I do think there are some important things the Commission can do in the meantime.

First of all, let me address the issue of the Commission's incentive and provisions. I firmly believe that is the single most important contributing factor to the number of transmission projects of significance that are on the table today. That's not to say there aren't transmission projects that grow up within the confines of retail plans, by replacement of an existing line, upgrades and improvements. That's not to say there aren't projects or that the Commission has accurately described the circumstances in its orders around incentives. Not all projects do, but many do and the projects of consequence, the projects that will integrate regions absolutely need these incentives. And I think the reason you have seen so many projects come forward in recent years at the proposed level is precisely because of that. So my first piece of advice to you is maintain that policy with consistency going forward.

People have to know that it will be available for future projects. And perhaps, just as importantly, it will continue to be available for projects that are currently underway. There are very long lead times with respect to these projects and we do not have consistency with respect to the permitting processes. Some process work well. Some work poorly. It's not all about states. It's sometimes about issues around federal agencies as well. But it is a long process and it's an expensive process. To get to point, at which steel is in the ground. Prices are highly variable. Financing costs go up and down as well. So the consistency of that policy and of availability of incentives over time may well be the single most important signal the Commission can send in the interim.

I agree with the comment that was made on the earlier panel that current market preservations are quite significant. I do believe capital is going to be available over a period of time at a cost to fund these projects. But really the heart of it, the alternative structures that you see on where to put merchant aside a lot of these structures are really all about how do you make sure that you can mitigate the risks and get returns around the structures that grow up over the regulated entities.

The Commission interest I believe in this, first of all, you want to make sure that you do have a regulated entity to which all the responsibility of regulation attach. You want to make sure that you have someone who actually knows how to operate the system and works quite well with others in order to be able to get all these things done and upgrading reliably. But I do think there's the ability to accomplish a lot of that, such entities by contract. So I don't think the Commission needs to be in the position of having to penetrate every entity. I think that's counter productive if you're satisfied that the return is just and reasonable, and you are satisfied that they have the regulatory requirements and the regulatory entities you need. Then the ability to tolerate alternative financial structures is strong.

Second, I want to talk a little bit about planning processes because I do think there are opportunities for the Commission to do more. That is really the planning processes and the cost allocations are really the two issues that the Commission can begin to tackle. One of the issues with respect to current planning is does tend to favor what we could consider to be sub-optimal solutions in many cases. The stakeholders' process tends to bring together folks who battle it out based on localized views. There is a planning design for a system that we need that is more optimal and may well be focused on congestion as opposed to narrow reliability.

The second point is we feel pretty strongly that we're getting to a point that those things in between reliability and congestion projects is primarily artificial. The key difference is time. The congestion project is basically a reliability problem waiting to happen and I do believe that if you can encourage RTOs, super-regionally and within regions to not differentiate in terms of the facilitation of a project between economic projects and congestion projects, it would go a long way towards assuring that the projects you do build are optimal. That will give you the overlay basis in order to be much more efficient right away through the use of capital dollars and the other things with the other projects.

The last issue I'll mention is one of cost allocation. We think it's absolutely critical that the Commission investigate the full scope of its authority, which we know is pretty broad, to move forward and to really look at the ability for these projects to be financed across a pretty broad region. We think there's plenty of opportunity to do it and that will give you the opportunity, I think, for the Commission to look at all these other external values that come into play. Thank you.

MR. RODGERS: Thank you Ms. Tomasky. I appreciate those remarks. Next, we'll hear from Joseph Welch, the chairman, president, and CEO of ITC Holdings.

MR. WELCH: Thank you. Good afternoon. Who is ITC? First of all, we're the nation's only independent transmission company. We currently operate about 15,000 miles of transmission lines and serve probably 25,000 megawatts of load. We cover five states. We're about 25 percent today of the MISO load. And over the past five years, we've invested about a billion dollars in transmission infrastructure.

What we have today is all the energy issues that face us are national issues. They're not local, they're not state issues. They are national and we need desperately to develop a high voltage transmission system to address these. So from the very top we have no national policy to direct us. Therefore, we have no coordinated outcome, and that's something I don't think FERC has fixed, but it's something they can help us fix. Parochialism is one of things that is taking place as we try to develop a high voltage overlay system. It comes from the vertical integration of utilities. It comes from state regulation. It comes from all of the different things that you've over the years. But the issues we have are national. I think they need to be solved for the good of this country and we should have to start developing policies to break down those barriers.

I don't think this is something FERC in and of itself can fix, but it's something they can help us fix. We have no independent planning process. The RTOs were intended to be independent, but aren't. By their very nature they are voluntary. People vote with their feet. As a result of that, the RTOs have been reduced to seriously negotiating with all your stakeholders to keep them all in alignment, to keep their revenue streams healthy and to keep it in normal operations. We've seen it time and time again. We act as if it doesn't exist, but in fact, it does exist. You probably can't fix that either because you don't have the statutory authority to mandate participation.

One of the things we do do that's very significant, and it starts to lead to a lot of different outcomes, is within the RTO we mix the market and the transmission plan function. Time and time again, what we come up is rather than fixing the transmission problem that we have before us, we then implement generation redispatch. Sometimes called security constrained economic dispatch. That's how we get around construction. That's how we get around dealing with congestion.

We not only do that, but we add inefficiencies by doing that to the system. We've seen losses increase from the '70s to today they're virtually doubled. Yet, we're raising all this entity, but we don't seem to have the fix right before us and that's to build transmission. We could probably fix this one by just looking at how you want to structure the RTOs.

When I got in the business, I thought this was going to be an easy thing. There's so much congestion out here and the transmission problems are so simple and really relatively small in costs that people should be banging our doors down to say, listen, we need more of this. So we looked at why that didn't happen. Lo and behold, it became crying out to market design. The use of FTRs and the markets simply reduce all the incentives to transmission development. It neutralizes everyone from the effects of congestion and actually, in a sense, no action. I was told that in the MISO market that there were over $1.8 billion of congestion last year and nothing was done about it. I think you can fix that. I think you can deal with that.

Currently, today we have no transmission-to-transmission interconnection standards. So even if a project is identified, if it crosses multiple jurisdictions, we have very little ways to facilitate getting it built, unlike a generator which can interconnect and pay for the transmission on those interconnections. The transmission provider, like ourselves who is trying to do something, can't do the same thing that the generator can do, even if we're willing to pay for it. I think that' something you can look at and you can fix.

When you start to look at renewables, one of the things I found very frustrating and it ties directly to the transmission and the lack of a cohesive planning policy is the rule by which these generators are now interconnected. Today, at least for wind generation, which is the predominate dog in the fight; we know where the wind blows. We absolutely know where the wind blows. We know where the loads are going to go. We know absolutely beyond the shadow of a doubt what the RPS standards are.

Yet we want to design these one at a time and build a spaghetti network that's both inefficient and ineffective, where we could just make the calculation. You can develop so much and also take into account the problems that we have with operating. They're connected at a high voltage, where we don't have the operational issues that are so predominant with wind. We could fix that.

One of the questions that you've asked that not many others have addressed and I'd like to talk about is called the right of first refusal. We support a utility's right to have the right of first refusal, but we don't support the various ways that this right is being manipulated.

If properly applied, the transmission owner (a) can build the identified project, (b) partner with another to build the transmission or forego the opportunity. It was never intended to delay a project or give utilities the right to roll over some smaller utilities and coops.

They should have the right to build in their region. They should build it. If they don't, they have all those options available to them. I think that you have the right to set rules that are fair and will work.

Two last items, quickly stated. Cost allocation. You've heard it from many people. We know it's a problem, it needs to be fixed. The RTOs can't do it and probably won't do it. FERC can. Then last but not least, siting is an issue, but as I usually tell people in ending my talks, I'd like to get to the siting problem and have that problem.

But I can't through the maze of other issues, that allow us to get to that big siting issue.

MS. RODGERS: Thank you, Mr. Welch. Next we will hear from Raymond Hepper, vice president, general counsel and corporate secretary of ISO New England. Welcome.

MR. HEPPER: Thank you. I would say thank you for inviting me, but after three of the first four presentations, I'd have to disagree with the commissioner that has a lot of authority in the region I serve, as the gentleman sitting next to me. So I'm going to wait to thank you until a little bit later.

(Laughter.)

MR. HEPPER: Depending on where I find myself sitting today, but nevertheless I say thank you for democracy so at least we can all disagree. So with my political statement New England, it was on the first panel. I think it was very enlightening to sit and listen to things like anchor shippers and open season, and things that are beginning to be talked about in New England.

But we really haven't gotten there. It's sort of back to the future in some ways. New England is a relatively small, tightly-integrated system that operates as a fully open access transmission system under a markets regime.

That is very different than what we heard about in the west this morning. We operated the transmission systems on the transmission owners or revenue owners. Much of the pro forma OATT doesn't exist and has been replaced by the ISO tariff, that works under the markets regime.

That's an important distinction. From ISO's perspective, contrary to what some others have said, we do think we have a structure that's open to merchant development, and other alternative forms of transmission ownership where it's appropriate to solve the problem.

Before I explain why, however, it's important from our perspective to emphasize one point. We urge the Commission not to disturb markets as it seeks to support alternative forms of transmission ownership. New England actually gets to the point that Commissioner Reishus made earlier and I'm going to disagree with her on this point.

New England had a long history of not upgrading its transmission systems to meet the liability needs of the region. Over the last five years, with I think strong stakeholder and FERC support, the region has completed three major transmission projects, one of which was a full 354 loop.

Another is integrating Boston through three underground cables, much more tightly into the system. Third in Maine, to add another interconnection between Maine and New Brunswick. There are two more major projects in the planning process.

One, the Maine Power Reliability Project, which is full 354 loop system in Maine, that's needed for reliability. The other is the New England West Project, to connect more tightly Connecticut, Rhode Island and Massachusetts to allow far more reliable operation of the system.

Commissioner Reishus' number is probably about right. 212 projects that are smaller, but are still critical to protect reliability. There is no doubt that costs have gone up, but when you look at what it cost to build transmission from 1960 to 1970, and now operating the system in 2008 dollars, with the prices we've seen on a lot of materials, there's always a need for better and tighter cost control.

But I don't think we should be surprised that costs have gone up. All these projects are paid for by load throughout the region, which is a benefit from reliability. That's one area we don't believe a change is necessary, and we believe that because of that, a lot of transmission that's needed has been built.

Any action the Commission takes to further alter transmission ownership structures we hope doesn't impair our ability to get things built for reliability, and I want to digress here for a moment on the right of first refusal.

It exists in a slightly different form in New England, but it's clearly still there. I think it's an important right from a reliability perspective. From ISO New England's perspective, we have a planning process that, if needed, we can effectively order within a number of confines that transmission owners build needed transmission for reliability. That goes along with their obligation to do it effectively, with the right of first refusal.

But I think it really has benefits for the reliability of the system. Why do I say that ISO New England is open to alternative forms of transmission ownership? First, New England was one of the first regions to have alternative transmission projects built.

How to put this in an odd context, but in 1980 we built two lines, interconnecting Quebec with New England that were not socialized. They were actually done on elective basis. A number of utilities that wanted cheap energy from Quebec.

The parties agreed to go forward and construct the lines for energy and transmission, which has worked effectively. Some of them have tried to get out of the deals for the last 20 years but it actually has worked. The

Chairman mentioned the Cross Sound cable, which has been in service for a number of years now, interconnecting New England and New York, again a project that was not paid for by New England's ratepayers. There's history that alternative rate structures are actually working.

The second point, I would disagree with the gentleman on my right strongly on this point, is the planning process. I think the planning process does a very effective job of meeting the needs of the system, both from a reliability perspective and now even moreso from an economic perspective. Congestion's somewhat different.

Last year, total congestion was only in the range of $125 million when those numbers were shown, so it's not nearly as big a problem. That doesn't mean there won't be needs to avoid congestion, and to bring quite a bit of renewable energy.

Transparency, I think, was greatly expanded through Order 890 and our implementation of it. That planning process has really enabled projects to be built, and has enabled developers to look at what might be needed, and what can solve problems.

Third, and I don't want to spend too much time here, but the whole process of upgrades and option revenues does provide merchants with an opportunity to collect revenue for transmission upgrades. Finally, there are no barriers that we see in joint ownership of transmission throughout New England.

In fact, many of the projects, the Hydro Quebec project is a joint project. Many of the reliability projects were done jointly in terms of public-private partnerships they haven't happened as commonly in New England. That's partially because it's just the nature of the system.

I suspect if you look at New England versus LADWP. I think LADWP is bigger. The municipal sector of New England is fairly small and transmission-dependent. We are certainly open to working with the municipal participants we have in terms of looking joint ownerships.

I guess now's my time to say something about AEP's proposal. I don't want to get into the vague priorities, which we very carefully stayed out of in front of this Commission. We think the transmission owners themselves can fight that battle very effectively without us. So that's one fight I'll stay out of.

I think the cost allocation issue is huge. Commissioner Reishus has mentioned that, but we've seen the beginning of the discussion of the who benefits and who pays. I think it has been very contentious in New England. John King from DPU is here. That controversy is completely out there in New England.

But I think it's fair to say that those who pay and those who benefit have very different perspectives. We are working with our stakeholders, with the transmission owners, with the state regulators, to try and create solutions to that problem.

But cost allocation, just within the small area of New England, is a very difficult issue. Again, we're not taking a position on whether we need any system nationally or not, how people get to pay for that is going to be huge, whether people are told they have to pay or agree that there's a benefit they want to pay for it. It's going to be a very large issue.

What's the solution to that? Where merchant projects are economically efficient, customers who will benefit should be willing to pay for them. We've learned that through the open season comments, in making these projects elective with broad support by those who will pay and those who will benefit.

In our view, it's a very good model for us to look at how merchant projects have worked before in New England, and should continue to work. The second barrier, siting, it's another issue. For purposes of loading my time and having time for questions and answers, I'm going to stay away from it.

But simply say siting. I think in New England, we are seeing changes in siting in east versus the west that's here. But I think it's usually difficult in all areas, whether through long areas with federal control or a lot of residential and commercial neighborhoods in heavily developed New England. It's always tough. With that, I'll end and leave time for questions.

MS. RODGERS: Thank you, Mr. Hepper. Next we'll hear from Edward Stern, President and CEO of Neptune Regional Transmission System and CEO of Hudson Transmission Partners. Welcome.

MR. STERN: It's a pleasure to be here this afternoon. I appreciate the invitation from the members of the Commission and the staff's work on all these related issues.

Let me first say that I'm a merchant developer. I'm trying to overcome that, but I would like to share with you a couple of lessons that I've learned in developing projects, one so far in the ground successfully and two are well underway.

I say that with some reticence, because I'm sitting here with three levels of regulators. I've got a general counsel of New England ISO sitting next to me; I've got the chairman of the Maine Commission; and of course I've got a quorum of commissioners here. So I have to be careful about how I address these issues.

But let me say that first, with respect to the Neptune Project, which was successfully developed and has been running since June 2007, it's interesting to hear comments about the operations of these facilities. That project since September 30th has provided over 22 percent of the power on Long Island and has operated at over 99.5 availability.

So I think at any measure, it's been very successful. The folks that are here from LIPA would tell you that it saved them tens of millions of dollars in its first year of operation, and even more money than they expected.

Our second project, called the Hudson Project, was selected in an RFP process for the New York Power Authority and we hope to start construction on that next summer. Unfortunately, we've had to educate FERC staff on a number of elements of our two projects because we're down here on many, many issues.

I think the kind of lessons that are sort of learned kind of goes to the first part I'd like to make. When you think about barriers to entry in business, the first thing is I think you have to reduce regulatory uncertainty.

There are a lot of ways to do that, and we've heard comments from speakers about the costs of participating in this process, and the length of time due to signing whether it's due to multiple levels of regulations or whatever it happens to be.

But I think at the end of the day, one of the easiest things to do might be to implement mandatory time frames for decision-making. I note in New York State, with respect to Article 7, which is the comprehensive environmental permitting process, they actually instituted a time frame that says in the time you are deemed to have a complete application, the Public Service Commission of the state of New York has a year to make a decision.

I think it's important to start putting in some mandatory time frames on the processes, in order to get a decision taken timely.

The second comment is that I think it's important for the Commission to endorse and support winning projects. The question then becomes what's a winning project? Who decides? Frankly, with the three levels of regulators here, I don't much care.

I'd be happy to have the chairman of FERC or the general counsel of New England ISO or the chairman of the Maine Commission make a decision, as long as someone knowledgeable on all the issues makes the decision.

That decision, I think, can encompass every aspect we've heard in the dialogue today with respect to technical issues, the liability issues, economic issues, all those aspects will be dealt with in the same way that the Department of Defense or any other government entity fundamentally has to make decisions, to buy tanks, build buildings and other levels of infrastructure.

I don't see why in the energy business we can't do the same thing. So I would encourage whatever the Commission can do. Once the decision is taken, we're going to build Project X. Whether it's AEP's project, Joe Welch's project or our project, they go back to the project.

Don't expect to go for some other project somewhere else, because we don't work together. These projects are complicated all by themselves, from a technical perspective, and if everybody works together they will happen. If they fight each other, they won't happen.

The third point about them is to seek regional, not state by state solutions. I won't spend a lot of time here, but our project, the Green Line project from Maine on down to Boston is mired in an interesting process that Ray described in terms of the ISO New England process.

Six public service commissions, six governors with a say. It's hard to work your way in a system like that, and it sort of takes forever. Our Neptune Project, I should point out, took eight years from concept to commissioning. We had $35 million at risk until we finally started construction.

Huge risks are taken and there is plenty of capital available. To undertake those risks, the public marketplace is at risk, from what we understand at the moment. There's plenty of capital.

The second point I want to make is to level the playing field to encourage new entries and to encourage competition. I think we would have new entrants and have competition, and you'll have low costs. You'll have better projects, you'll have better technical solutions.

The end result will benefit rate payers, and will benefit the wider goals of the overall system. If you do that, I just heard a comment from Ray with respect to the Hydro Quebec project. The project manager of the Neptune project in fact was running that 2,000 megawatt facility ten years ago.

So people move. It's not just kind of whether you're with the utility or whether you're an unknown merchant company like mine. The same individuals sometimes move around from place to place. You can have excellence if you level the playing field for the independent companies, some of the smaller companies, and move a little more quickly on some of these other companies.

I think I would like to comment also on the right of first refusal. I've got a different view than perhaps some others. Generally, the rights of first refusal dissuade competition. I don't believe the right of first refusal for any kind of project is necessary.

You've got from major backing on projects, let the marketplace compete, let the best ideas come forth, let the best prices come forth and let those folks be selected. My third point is to encourage partnerships. We've heard some comments before about independence.

I think there are complicated types of projects, and where you can get folks kind of working together to support the common goal, I think the better chance you have for positive results.

Fourth, I think we should try to reward performance and not finance. I think there's a lot of discussion about ROE mandates and so on and so forth. I just want to tell you that from my perspective on the trade off of uncertainty versus REITs, I'll take less certainty. I'm sorry, more certainty and a lower rate. It's just the other way around.

The more we can streamline the process, the less development capital at risk, and have a more certain regulatory process. I think capital will come forth for lower rates of return. I think you can incent people for what you want to see happen. Time to completion, etcetera. That's what you should incent, not just come up with rates.

The last point, and I'll finish here, is I think it's important to support long-term contracts. We heard this morning from the panel commentators from the financial community. The reality is long term contracts will bring long term capital, which will bring cheaper capital and better terms. The more we can have long-term agreements, the better off we are.

Finally, I think if we kind of think back to 50 years ago, when the nation was trying to put its national highway system in place, I think there were lessons to be learned there. Primarily, I think what FERC can provide, and I think you've been doing it along the way. You can do more of it as national leadership.

As Ray has kind of commented before, you need more national leadership in this regard, and I think you're on the way to doing it. I encourage you to continue. Thank you.

MS. RODGERS: Thank you. Our last panelist of the day will be Robert Patrylo, CEO of Strategic Transmission, LLC. Thank you.

MR. PATRYLO: Thank you, Steve. Mr. Chairman, commissioners, thank you fort his opportunity to appear today. I'm Bob Patrylo, CEO of Strategic Transmission and two other companies involved in the merchant transmission development with PJM.

These companies currently have ten active projects in the PJM footprint. To summarize my message up front, in general our experience is that PJM does not institutionally support merchant transmission development, despite the benefit to consumers.

Let me try to explain that with some examples. As the Commission knows, because of transmission constraints there exist relatively high energy prices in the eastern portion of PJM. Capacity prices have also been higher in these, although that did not occur in the last RPM auction.

The slide shows LPMs peaked in June of last year. There was a very low price of $2 per megawatt hour at Mount Storm, and very high prices at Middlebrook, going to $90. The next chart shows that about a billion dollars in congestion costs have shifted from Bennington, Black Oak to the AP South interface.

As you'll note at the bottom of the slide, the Cloverdale lexicon is also a large source of congestion within PJM. The next slide lays out the fundamentals of the merchant transmission process in PJM, because energy capacity prices in PJM are based on a single clearing price at the margin.

Small changes in supply and small changes in constraints can cause big changes in prices. I'm sure the example at the bottom of this slide, of the merchant transmission project to upgrade the Bennington Black Oak circuit. Congestion costs on this line were $13.9 million in 2007. After the upgrade was installed in late spring of this year, there have been no congestion costs on this line.

Going to the next slide. Why limited merchant activity. The merchant transmission framework in PJM is basically okay, but as I stated in my opening remarks, there exist institutional problems as it relates to delays and hurdles. Time lines in the PJM tariff are not met. Studies are long overdue.

Regarding the second bullet, transmission owner conflict of interest, we are not suggesting that standards of conduct are being violated. What we are seeing is that transmission owners know the implications of new merchant transmission entry on the prices that the generation side of the business has received.

Congestion relief is not fully recognized under PJM's simultaneous feasibility test. This has happened with a straightforward upgrade like Bennington, and will probably happen, as new smart grid technology is imposed, for example, the DIMEC ratings proposed for the Mount Storm 500 KB circuit.

Finally, the RPM timeline treats merchant transmission and merchant generation differently for no apparent reason. We can provide specifics on that in supplemental comments.

The next slide relates to two of our active projects, the AP South interface. The AP South interface has become the most congested facility in APM, projecting costs of more than one billion dollars from 2008. About half that congestion would be relieved with our project, U2028 at Middlebrook. We have recently received from PJM what we believe are necessarily long studies and installation time periods.

We think the capacitor could be installed by the beginning of the summer, but the transmission owner and PJM are estimating an additional 18 months beyond that. This would cause unnecessary hundreds of millions of dollars on otherwise avoidable congestion costs.

Also, Cloverdale Lexington, which involves our Project T-132, is assessed by PJM to cause congestion costs of $318 million this year. A feasibility study for this project is long overdue.

Going to the last slide, I put this in for the Commission's consideration, is that an independent transmission monitor like the market monitor be created, or perhaps adding these areas to the existing market monitor's responsibility.

It seems to us that for markets to work, there has to be free entry and that PJM should be encouraging entry in every possible way. In the last bullet, I've also included as a concern the revised economic planning process recently adopted by PJM.

This doesn't directly relieve the merchant transmission, but our experience with the model being used by PJM for that process is that it has problems that need to be addressed. If not corrected, it may mean that no potential economic planning project in the future will meet the required hurdles.

We can offer some specifics on that, if the Commission so desires. Again, thank you for this opportunity to appear here today.

MS. RODGERS: I'd like to thank all of our panelists for their presentations. I'd like to start with the Chairman and Commissioners, to see if they have any comments or questions.

COMMISSIONER MOELLER: I have a comment or a question for each our panelists. Thank all of you for making the effort. Chairman Reishus, I think first of all welcome. I think you'll well respected and admired for defending the rights of consumers on this issue.

I would certainly like to get a chance to talk a bit more about it. You mentioned a 300 percent increase in transmission rates. Some of that is perhaps for historical catch up. But to what extent do you see the benefits corresponding to that?

CHAIRMAN REISHUS: I certainly acknowledge that there are benefits. I think it is our job as state regulators to consider the price when you consider the overall project before us. But at the same time, it strikes, I think, all the commissioners that there's historically a lot of transmission that hasn't been built that's been proposed.

The stakeholders recognize that that has to be counted. I heard the comments further down the panel as well that regulators and the public need to be part of the benefit, and I agree.

COMMISSIONER MOELLER: Roughly speaking, do you have average retail consumer impact going from transmission averaging $8 a month to 24, or is that beyond your capacity to estimate?

CHAIRMAN REISHUS: I would agree that the portion of transmission is relatively small, that it's driving some of those conversations. The transmission will have a much bigger effect on our larger industrial customers. And again, those issues have been brought forth before the Commission.

COMMISSIONER MOELLER: I'm sure they have. Thank you. Roy, we started working together about ten years ago on private usage as an impediment to transmission. I want to challenge you a little bit on your contention that this is a low risk endeavor.

It strikes me that the fine citizens of Wisconsin and the great leadership from the utilities there, that this is relatively low risk. But throughout the rest of the country, it strikes me as pretty high risk. I guess I'll give you a chance to comment.

MR. THILLY: I do come from a regulated environment, and the risk with respect to transmission, we do have recovery of recertification, if it's prudently incurred. It substantially mitigates the permitting risk. Once you get past permitting, you have your certificate fee and construction and I think the risk goes down significantly, and the returns are very attractive in relationship to this.

I'm not sure that's true of transmission that's in a competitive environment. We had a joint planning regime where the Commission required utilities to jointly plan and come in with proposals that avoided duplication, and met multiple needs. I think that has created a very safe environment for transmission.

COMMISSIONER MOELLER: And transmission was being built?

MR. THILLY: Yes. That's our AEC single purpose corporation. Transmission was losing because of the siting process. I believe Commissioner Spitzer recognized that. AEC had no choice. They'd have to do a good job at it, so it would have a much more extensive public presentation process to get transmission built.

It's been highly successful.

COMMISSIONER MOELLER: Susan, I guess I want to commend you for your relatively bold statement before this committee in July, asking to give the FERC more siting authority. I'm just curious about the reaction you've heard from various segments of the industry.

MS. TOMASKY: You know, the reaction has actually surprised me. I have a lot of secret conversations now with people who want to say that they really do believe that, but they can't really do it for a bunch of reasons.

The reality is that there are a lot of people who understand. There are certain types of perfects that need to go forward for a lot of reasons that are enumerated in here, and that the complexity of the processes we're talking about and the time frame, is just not going to match.

Whether you come at it from the perspective of wanting to advance renewables, and in the near time frame -- of course, what I always ask in response to that is if you want to take a long time to get transmission and how fast do you want it?

I do believe the dialogue has pushed us forward a lot. The issues are legitimate. But I honestly believe that we are circling a solution to the issue. But I did not get after that. I had conversations with my state commission, many of whom don't agree but many of whom say yes, something has to be done.

When you go out west, you hear as much about issues regarding federal agencies as you do around state commissions. This is not real and it's not responsible. There's just a lot of resistance to anything but intelligent thinking about what are the challenges.

The problem is we don't have in our country an agency whose mission it is to address the need for electricity for delivery on a national scale, with the goal of addressing broad national problems.

Nobody has the job of making sure of that, and I believe very strongly that's the point at which we find ourselves. While it is true that we need to look at non-transmission alternatives, it is true that we have to be mindful about costs.

I just believe it's inevitable, when you look at the nation's energy needs, that a major transmission system has to be built over some period of time to some extent. If we don't embrace that, if our agency has the ability to get it done, it is simply not going to get done.

But I've gotten to the point in my life where I can say that in public, and I'm not scared.

COMMISSIONER MOELLER: Big progress. Joe, I guess I want to hear your perspective on cost-benefit analysis. It's an easy question for you.

MR. WELCH: The whole thing around cost-benefit has been a question you'll always ask. Is it a local issue? You always want to do something for the group's benefit. The fact is, like most of my colleagues, if we start off with only cost and get down the hub, we're going to get to it.

When we look of rules of implementation, we absolutely go someplace where it looks more like manipulation. But cost-benefits around the transmission system are many and numerous. I can look to some of the things that we have done inside of RTC, and some of the things that we have proposed to do, that we can't get any traction on.

First of all, we built one ten mile line. Not very much of an investment, a transformer connecting to already-busy stations. We had about $93 million of congestion for the MISO and around $50 million of congestion subsequently.

You would think that people would give us a rousing rah-rah-rah, but it didn't happen that way. I didn't get any hate mail, but I didn't get any fan mail either, relieving $93 million worth of congestion. On the other side, we proposed with AEP to build a 765 KV line, which would be an extension of that high voltage overlay, to make it work better in the Midwest.

We looked at the benefits of that line. Let me give you some of the benefits of that line. Had that line been installed in 2003, there would not have been a blackout, plain and simple. The unfortunate thing is that if what had happened on 8/14 happened today, inherent problems exist and the problems are regional.

When you become an isolated company like RTC, and start looking and say "My God, this happened on our system," after I said that I realized that it's a regional fit. It's not a local fit.

Secondly, that line would have removed the need for 250 megawatts of additional generation, because of that much lost from the system. It also, and this is important, it also would reduce the need to do about 43 upgrades in existing utilities, because of offloads.

That's a pretty good potpourri of benefits. It also increases transmission by the tune of almost 5,000 megawatts. It makes it available in Michigan. So to my way of thinking, the only problem is none of those items I have mentioned are in any cost-benefit study used at the RTO level.

I don't know the result of that, but these have to get off the shelf for cost-benefits to help them. I look at cost-benefit from my personal perspective. It's been a huge deal.

COMMISSIONER MOELLER: Ray, Commissioner Spitzer and I have often spoken about kind of how public power and investor-owned utilities differ in their relationships. I really do think there's a big difference. I ponder why that is. Maybe it's because of the nature of the west.

But we really do hear a lot from smaller municipals in the Northeast, that they'd really like to be joint parties. I know you addressed it in your remarks, but if you can elaborate. It would be something that at least two of us would be interested in.

MR. HEPPER: It's an interesting question. You probably heard it more than we did. I'm going to make sure I reach out and organizationally reach out to the municipals and see how that would work.

The other part of it, the problem I think lies in the fact of the municipals are trying to offload transmission in any way in their service territories. There are differences of opinion between the RTOs and the municipals, as to whether and to what extent there should be municipal investment.

I think your point is very well taken. The public-private partnerships can solve political problems at times. That's very important to do. That's sort of where things stand at this point in New England.

COMMISSIONER MOELLER: That's actually Commissioner Spitzer's point that I happily take a little credit for too.

(Laughter.)

MR. HEPPER: I happen to agree with Joe for a minute there, but the whole cost-benefit issue, we're struggling with it, and it really is -- there's a lot of benefits that are incredibly difficult to quantify. Not only have I seen economic analyses on the value of cost load, but you know, it's very difficult to quantify those.

But I think there really is a need to look at all the benefits that are derived from the project as we look at whether it should be undertaken or not.

COMMISSIONER MOELLER: That's important too. My question to Ed, you talked about Neptune. We were there for the dedication. I've said before, we both have a tee shirt.

(Laughter.)

COMMISSIONER MOELLER: But the benefits to Rhode Island are substantial. They haven't come up to the expense of New Jersey is every impression I get. But I guess you talked as if you were a believer in transmission. So we're going to hear that.

MR. STERN: One of the reasons for that is New Jersey is electrically connected to one of the largest electric markets in the world. 660 megawatts move the meter at PJM.

COMMISSIONER MOELLER: But I think it's certainly improved the reliability.

MR. STERN: From an operational perspective, it's been seamless, that this does well in operation with the three New York ISOs, from all the discussions. It's all gone very, very well.

COMMISSIONER MOELLER: Thanks. I guess the last comment from Mr. Patrylo is we always appreciate hearing complaints, concerns and I'm sure we'll be talking to PJM.

MR. PATRYLO: Mostly concerns.

(Laughter.)

COMMISSIONER MOELLER: Thanks.

COMMISSIONER SPITZER: If I may, I don't mean to belabor the point. I thank Mr. Moeller for teeing up the issue of the municipals. Again, you may not be the right one to present on this issue, but you're here, I guess. The indication I received from some of the entities, although they may not be current owners of high voltage transmission, are entities who have scale of the size of the statewide association in Massachusetts and Connecticut, who indicate willingness to provide local support.

They are a good group who have good credit, even under current circumstances, and are willing to participate in the finances, and are extraordinarily frustrated. But they feel they're getting standoffish treatment.

Again, that is perplexing to me. I don't mean to put you on the spot, but is there anything? Is there an explanation offered? Explanations have not been forthcoming.

MR. HEPPER: I've probably done as well as I can do with it. I will say in response one commissioner is enough; two is even better. It really does behoove us to go back and talk to the transmission owners who are here today, and the municipals, and see where the concerns are and what the problems are.

The ISO is not the transmission builder per se. We have intentionally stayed out of the ROE battle. To some extent, we continue with the obligation to build. We have stayed somewhat out of those too, and when you look at siting and how things would be sited, that's part of it.

But it's very clear to me we need to have a conversation and come back to you with an explanation that makes more sense than you've heard thus far.

COMMISSIONER SPITZER: Thank you. I appreciate that. We heard the panel and discussion on the REITs. It's a pretty significant economic issue. You heard in '86, horror stories about double taxation in the old days. You gross up. It was part of the conversation where you gross up the federal, state and jurisdictions.

You owe 50 percent when you run the simultaneous equation. That's a pretty big hit. The elimination of that double taxation is a big savings. People pushed themselves into pretzels to avoid that gross up, and were counting every penny.

Maybe we can start with Sharon and the environment of frustration, and some of the ratepayer bills. Why wouldn't one of the first things to look at would be a way of saving over 50 cents on the dollar, in terms of tax liability?

Even a 50-50 share between the ratepayers and the investors is a great help to the bottom line. Why aren't we getting traction?

CHAIRMAN REISHUS: That's a fair question. I'm intrigued by it. Back home, I agree. I think commissioners have to be as creative as possible on financial matters to deal with this. I was not familiar with the REITs concept, but consider what sort of arrangements make sense.

COMMISSIONER SPITZER: To Roy, you've got a circumstance where the law of REITs allows non-profit entities to invest. It's not unrelated business.

MR. THILLY: I'm not familiar with the tax laws relating to REITs, but the AEC's divestiture was to a corporation that would have had double taxation with a transfer to the LLC, 50 percent of the money coming back tax-free and a single level of taxation.

We're trying to accommodate this. It's been very helpful to the extent that municipals and coop ownership, weren't taxed.

COMMISSIONER SPITZER: You've achieved the effect of a passthrough tax. The REIT would expand with potential investment.

MR. THILLY: No opposition.

COMMISSIONER SPITZER: Anyone else?

COMMISSIONER SPITZER: Let me offer some comments on REITs. We looked at it fairly carefully. The first comment is that under the current tax law, transmission assets -- I'll make up a word here -- are not REIT-able assets. There is one letter ruling from the IRS, and you know from your tax background first, Ms. Spitzer, that fits those particular circumstances and they're allowed to put that particular asset into a REIT or into an LLP.

One of the things we looked for when I look approach the Commission and staff to look at, as to whether or not they could change the tax law to make transmission access REIT-able or MLP-able.

With respect to sort of single assets, even a large asset, generally if it's more of the MLP market, which has single assets in it, those REITs up until the recent marketplace tend to have larger market caps and don't fall well for sort of single asset deals.

I think there's also a question as to whether or not a REIT market would finance the construction. We're talking about barriers to entry to getting new investment into transmission. I think there's a real question as to whether or not the REIT market or the MLP market would finance the construction of the assets.

I see Joe nodding his head. I think the answer that we've kind of come up with is generally no. However, I do think what it does accomplish is, to the extent that investors are told of that before. With respect to Neptune, tens of millions of dollars of development capital has been put at risk.

It is pure risk capital. As long as it moves forward, we get a return on it. To the extent it does not go forward, we lose our money. It's as simple as that. We don't have the same protection. I was talking about before a level playing field. We don't have the sort of protection that the utilities have. I think that's something that needs to be considered.

But I think that for investors, to the extent that investor, let's take a private equity investor, is aware that there is a re-exit opportunity post-construction through the REIT or MLP market, I think that they're more willing to take the up front development capital risk, because they see liquidity and they see a major opportunity, and many more potential investors for that asset going down the road.

So I think even though it won't advance construction per se, and under the current laws it can't do it, I do think it does open up one barrier to have a broader investment group come in. You may want to comment on that.

MR. WELCH: We looked at taking one or more of the operating companies we have and putting it in a REIT. The confusion we came to, whether it's a REIT or not, was the fact that because of this loss, we had such a heavy need for capital and investment into the system. The REIT structures just do not work for us.

As a result of that, the ITC in most recent years, we have spent about 200 percent of REIT cash reinvesting in the system. As a result of that, the REIT just doesn't work. We'll probably start to offer an opportunity for it when the system was built up it didn't.

COMMISSIONER SPITZER: Of course, you have prior IRS rulings, and the question is whether the new construction, the logic of that prior ruling would hold.

WW Right.

COMMISSIONER SPITZER: Mercifully, we've leave the tax area.

(Laughter.)

COMMISSIONER SPITZER: The concept of merchant transmission is like the concept of merchant generation. The ratepayers don't bear the risk; the shareholders bear the risk. The shareholders are entitled to reap the rewards, and ultimately as a regulator, it's got to be extremely thought-provoking to eliminate ratepayer risk. I want to start with Sharon and anyone else, Ray and Roy.

Why not entertain this concept as a part of the ownership and stakeholder process? What are your global thoughts on this concept, to take the burden away from the ratepayers?

CHAIRMAN REISHUS: I'm all for taking the burden away from ratepayers. I've consistently supported competition in generation, the development of plants by Calpine and others. Then Calpine took the hit and it didn't pan out. So the ratepayers were not on the hook for that.

So I've actually had direct experience in Maine of that competitive model. Speaking for myself, I'm very open to the idea of merchant transmission, to shift the risk away from ratepayers. There's no problem with supporting the transmission charge.

You've seen the one example. In that project, it can deliver power, for example, from Maine to New England. I think we should look at merchant transmission.

COMMISSIONER SPITZER: Roy?

MR. THILLY: There's been no merchant transmission in our area. One reason may be because of a law in the state. The purpose is to avoid duplication and to have a system that meets the needs. There may be a place for it.

The thing about a merchant transmission is the ability to secure long-term rights associated with it. That is a problem. We spent $2 billion relieving transmission congestion in Wisconsin. I disagree with the comments that, you know, that construction hasn't relieved transmission congestion. It has.

Because of the inadequacies of the system in West Virginia, we've run the model. That frankly creates tremendous uncertainty and takes away a lot of the value of putting money into transmission. So when asked what can you do to help, certainly it would be very beneficial to make the long term process much more secure and predictable.

It comes through the RTO, the difference, and my point is, of course, that it builds transmission and does the cost-sharing through the MISO tariff. And you're rights are to whatever the tariff does, and of course the merchant concept, where you secure the rights.

COMMISSIONER SPITZER: Of course, assets throughout many areas. My final point is a question for some reaction. Government is about balancing competing interests, and there are competing interests and efficiency. What underlies the ten criteria?

We've heard some consensus on the reasonableness criteria. The application, particularly in the complex to an active shipper. There's room for creativity perhaps by FERC. But in terms of the forces of inertia that are afflicting potential public-private partnerships that were described in PJM, that caused some of the merchants and Mr. Stern's successful project that nevertheless took a lot of money and six years.

The stakeholder processes are important, but there's a certain point at which decisions need to be made. As a lawyer, I'll tell you I don't care whether you're liberal or conservative. What would be your global thoughts on the concept? We all want change, but if the process is so -- I won't use the word "dilatory," or the process is so extended, what can FERC do in terms of its oversight of RTOs, or even in the planning process, if not RTO regions?

MR. HEPPER: I can't resist. First, it's interesting to go back to a prior Commission, when we saw, shall we say, some problems with the project getting built in Connecticut. I'll go back to a historical memory of

Lyndon Johnson and the notion of jawboning with the steel industry, as I recall.

I think it's an important role for the Commission, for the Commission to stand up and get behind it. We've got huge support from the Commission in getting things done in Connecticut, when frankly that project had languished for far longer than it ever should have.

I think that's one rule for the Commission to really play, and whether it's an official role or not, the stakeholder process can't be ignored. But I think it's incumbent on all of us to come tell you if there's something.

COMMISSIONER SPITZER: For us to play the bad cop?

(Laughter.)

MR. HEPPER: Absolutely. Better you than us, but a last point, I agree with Commissioner Reishus completely. It's great when you can take the risk off of ratepayers and put it on developers. But I think it's also very important to look at a project and see what it really is.

We're seeing a lot of people coming in in New England and saying "We're a merchant project. Please help us. By the way, we want rates when we're built." I'm not sure that's a merchant. We do it for what's really being done.

There are a lot of creative ideas out there. They all need to be looked at. We can't wait for everybody to find the perfect project. It's like finding the perfect marriage. We want market rates and hit those big dollar merchants.

CHAIRMAN KELLIHER: I really have a question for Susan, to see if there's an agreement. Now this problem with siting is less direct if you accept the cost allocation. It's less clear what the solution is. I'd like your ideas on what is the perfect solution.

MS. TOMASKY: I think first of all, you need to find the universe of projects for which a cost allocation is appropriate. As I suggested in my earlier comments, I think if you're really going to plan an optimum system, certainly that in the first instance is appropriate for cost allocation.

There may be other projects in which that's true as well. But you need to be able to say this is the universe of what we need to build. I do think there are ways to do that. If you look, for example, at what the SEC was doing in examining the overlays, some of the progress that's being made, thinking about those multi-regionals, MISO should be engaged and PJM should be.

We need to find the universe of projects. That's the point at which you don't spend a lot of time trying to model everything to get, to figure out whether or not it's going to be a reliability project in 2012, but it's only a congestion project today.

I think you need to get away from that, and sort of draw the line around hey, here's basically what you need. The Commission can be in a position to create some expedited processes, and RTOs are as well, for moving forward with this project, that will meet that criteria and cost allocation. That's a critical part of that.

I think the dialogue needs to go beyond that. I understand traditional principles of cost, causation and I understand there are many projects in which those are still the right way to think about it. But I just think we need to step back. The total cost of building these things in the long term is going to be very small. It's certainly going to be small in relationship to the issues.

So we ought to just say that I think we ought to allocate it as broadly as possible. I think it's something that has benefits to the regions, that should be allocated to costs to the regions. There's three regions I would not spend a lot of time trying to figure out who, over a short period of time, is going to be the beneficiary.

The large overlay project whose goal is to have new generation coming out over time, new road comes out over time. It serves the integrated need of that overall market.

It will be beneficial to everybody.

CHAIRMAN KELLIHER: Thank you.

MR. THILLY: I agree with the economic liability, but I don't think we can just -- I think it's our burden, with Commissioner Spitzer's questions, to demonstrate in a convincing way the public need, and that means there has to be more planning.

Then as you know, if you've got as the lead issue all your siting options, then it's an argument between alternative routes, when someone has to make a tough decision, like the person sitting next to me.

CHAIRMAN KELLIHER: Thanks.

MS. RODGERS: Among staff, on this side of the table, do any of you have questions?

(No response.)

MS. RODGERS: Mary?

MS. CAIN: I noticed on the panel, almost everyone said that FERC needed to look into having to have a hand in the process. I didn't hear about any of that from the people on the east panel. My question was is it as much of a concern in the east, or if it's not, what's different in the east?

MR. WELCH: It is a concern. I think I listed it as one of the major impediments to getting transmission built. My statement was that we don't have transmission to transmission interconnections. As a result, you're being stonewalled. "Please get that done."

Combine that with the right of first refusal, he could forego it or he could stand on his rights.

MS. TOMASKY: We haven't encountered it because of our strategy with local utilities. I don't disagree with Joe. I think you do need standards to make that happen. There needs to be some framework.

MS. RODGERS: Dick.

MR. O'NEILL: You mentioned something about PJM modeling in West Virginia, affecting transmission rights. Do you want to expand on that?

MR. THILLY: In the allocation of transmission rights, in the MISO, they run a very complex model, which I don't fully understand. If your transaction has an impact on a facility within the model, then you don't get the right.

In the first round of this conference, they all got denied rights, because of service in West Virginia. Terribly frustrating. Most of it got restored in the restoration process, but not all. It's just the way the system works.

MR. O'NEILL: You don't have a fix to that?

MR. THILLY: We've toyed with a possibility, but it is the modeling is way, way, way too complicated, in my judgment, for a working long term transmission model. It's a snapshot with hundreds of assumptions, but it's really not a very sane one.

MS. RODGERS: Grace, did you have a question?

MS. GOODMAN: Yes, I do. My question has to do solely with merchant transmission projects. In the earlier panel, we heard quite a bit about the wish for anchor shippers who would have fixed rates over a long period of time.

We heard a little bit about that today, this afternoon, just in passing. What I'd like to get is clarification, maybe from Ed and Bob and Joe, as to if you were, for a merchant transmission project going forward, to have an anchor shipper, would those costs associated with the anchor shipper be at risk, meaning there'd be a separate set of books and the costs would never be allocated to rebates? Or would they still be stand-alone costs under the negotiated rates, and would not have to be at-risk for them?

MR. STERN: I will give it a shot. I think there's two potentially different models. You have a rate-based model You basically get paid for and reimbursed through your transmission service, through the rate base, or you can have the merchant, which can be, in the case of say Neptune, where the Long Island Power Authority is basically paying us for our transmission service pursuant to a long-term negotiated agreement.

Or you could have a series of wind companies we being creditworthy, paying you as a shipper for that transmission service. I think there's several ways you're going to do it. At the end of the day, it comes down to the creditworthiness of the counterparty that's providing you the revenue stream, and provides some return on your equity.

It can be done in many, many ways. How long is that agreement? What's the creditworthiness of those counterparties? To the extent that you have both those things, you then have a financeable asset. If you don't have those things, you don't.

This sort of traditional kind of rate-based situation is different. Where the financial world sort of recognizes the liquidity and depth of capital rate markets. If you're a New Englander in PJO, wherever you happen to be, the financial marketplace will recognize it. That's a deep, liquid market and you are in the rate base. They're going to count on those revenues coming in to pay for the transmission service.

MS. GOODMAN: If you had the anchor shipper and you had the revenues, you knew where the revenues would be over a 20-year period, you'd still say the merchant shipper.

MR. STERN: To the extent you have the same confidence in one of the elements of LIPA, in the case of

Neptune and Hudson, those are both highly rated investment grade entities of the financial markets.

If you look at the ratings of those entities and say these financial markets have confidence that those entities, or somebody else coming along. To the extent that they're replaced in the future Because they're able to kind of pass through the costs ultimately to the ratepayers, those are creditworthy entities. To the extent you have ABC Company putting up 100 megawatts of wind, then you have another few megawatt wind facility, etcetera, etcetera.

It then becomes more complicated financing to determine whether or not those folks and those particular assets are going to operate for a long period of time. So I think it's a sort of standard credit analysis, given the length in terms, if you will, of the commitment to buy.

MS. GOODMAN: Okay. Bob?

MR. PATRYLO: I'm not familiar enough with the concept.

MS. GOODMAN: Anybody else?

(No response.)

MS. GOODMAN: Thank you.

MS. RODGERS: That concludes our conference for the day. I do want to just mention a few housekeeping notes. One of those is I wanted to thank very much our panelists. We appreciate that very much. I also wanted to mention that the conference today is transcribed.

Copies of the transcript will be available as set forth in the Commission's notice of October 9th. Actually, I wanted to mention that written comments can be filed on the topic of this proceeding until November 13th, and I wanted to mention that some of the comments I heard from the panelists today were not in their written comments that were provided to us thus far.

I encourage you, if you have comments that were not provided already, to please think about providing those. Thank you very much.

(Whereupon, at 5:05 p.m., the conference was adjourned.)