UNITED STATES DEPARTMENT OF ENERGY

NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

WORKSHOP

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P R O C E E D I N G S

(9:00 a.m.)

MR. MEYER: Well, good morning, ladies and gentlemen. I'm David Meyer from the Department of Energy. Welcome to this workshop, we appreciate your participation and your input to our 2012 Congestion Study.

I'm going to make a few brief remarks here to establish a context and a perspective about the Congestion Study. But before I do that, let me introduce some of the people from our team who are here with me. I have Lot Cooke, who is with our general counsel; Suzie Lemieux, who is, why don't you identify yourselves a little bit, for those in the room. (Laughter) Right. And Emily Fisher, who is with the Lawrence Berkley laboratory; Alison Silverstein, who many of you know; Joe Eto of LBL will be assisting us also; he's not here today. We also have help from ICF Incorporated, Elliott Roseman and his colleagues, Julia Kane, I don't see Julia, is she not in the room at present? And Sheri, tell me your last name.

MS. LAUSIN: Lausin.

MR. MEYER: Lausin. So, all of those people are playing important roles for us, and we appreciate their help.

So, let me move on. First, a little background. The Federal Power Act as amended requires DOE to conduct and issue a Congestion Study every three years. We conducted studies in 2006 and 2009, so now we're doing the 2012 Study. We have a definition here of congestion, which is familiar to all of you. I won't go through that material.

We recognize that economic congestion can be mitigated in at least three ways, or through some combination of those ways. But we want to be clear that the Federal Power Act directs us to show where congestion is occurring but it does not direct or authorize us to prescribe solutions or to undertake mitigation.

So, in the 2006 and 2009 studies we relied on a three level conceptual framework, three different kinds of congestion areas, critical areas and areas of concern, and then conditional congestion areas. And we expect to use that framework going forward for the 2012 study. If you have comments or suggestions on ways to sharpen the focus or improve those concepts, let us know.

The Power Act also authorizes but it does not require the secretary to designate geographic areas as national corridors, as we call them. There is an acronym which we try to avoid because a lot of people don't know how to pronounce it or don't know how to spell it. "National Corridor" is a much classier term, I think.

A national corridor may be designated only after issuance of the Congestion Study and review and public comments on the study. But we want to emphasize that identification of a congestion area does not necessarily lead in any automatic way to designation of a national corridor.

Designation of a corridor has several effects. It emphasizes that the federal government believes that it is important to mitigate the congestion in question. It enables the Federal Energy Regulatory Commission to approve the siting of the transmission facilities within the corridor, under certain very limited conditions, conditions that are spelled out in the Federal Power Act.

And finally, if a proposed facility to be sited in a national corridor is also within the footprint of either of these two listed power marketing administrations, those entities may then exercise certain third-party financing authority that they have.

So, we are holding four workshops, two East and two West, to explain the study process and to obtain data and ideas, concepts from you, about appropriate data sources or studies that are now underway that are relevant, or just general perspectives that you think are particularly applicable, particularly at the regional level or sub regional level.

We plan to examine a wide range of data. I'll be candid, we -- the availability of systematic data is limited. We have to use whatever material is at hand, and it varies from one region to another. So, we are always looking for additional data sources. And we've learned that it's important not to somehow regard any one source as authoritative. It's best if you can look at alternative sources and say, do they corroborate the particular story? Do they support the story so that you look at as much material as you can pull together? And then say to yourself, now does this seem to -- is there a storyline here? Is there a pattern that's important?

We will use only publicly available source material. And we will issue, unlike the two previous studies, this time around we will issue a draft report for public comment, and we will issue a final report after considering the comments. So, we welcome your comments and suggestions on this process.

So, today we are looking particularly for information about congestion related conditions in the Northeast and Mid-Atlantic area, down through the Southeast. There will be two panels. First, we will hear from state officials, mostly regulators, and then we will hear from an industry panel. And after the panels, there will be an opportunity for others to comment and if you wish to do so, please let us know. And we look forward to a wide-ranging discussion. And I want to say that it is being recorded. There's a court reporter here. So it's important to speak into the microphone. When we get into discussion, please identify yourself so that that gets recorded.

And we're doing this so that we don't miss any of the points you make. Later on, we'll be sure we're not misinterpreting some of your comments. And in general, please show us the facts. It's important for us, to the extent possible, to get to the facts.

And with that, I'm going to turn things over to our first panel. Let me briefly introduce the regulators that we have with us. I'll just give names and affiliations.

We have Garry Brown, who is chairman of the New York Public Service Commission. We have Edward Finley, chairman of the North Carolina Commission. We have Betty Ann Kane chairman from the District of Columbia Commission. We have Doug Nazarian, who is chairman of the Maryland Commission. And we have Jim Volz, who is chairman of the Vermont Public Service Board.

So, I thank you all and I look forward to your comments.

MR. BROWN: Good morning. I want to make sure this is working correctly.

Good morning, thank you. My name is Garry Brown, I am the chair of the New York Public Service Commission. I want to start out by thanking the Department of Energy, and particularly David Meyer, for providing us with this opportunity today. It's very important as we go through this process that the states and DOE continue a dialogue, so I'm happy to begin the dialogue here today.

The good news is that I'm first and I won't repeat what anybody else has said. (Laughter) The bad news is I don't get to react to what everybody else has said. So, if you see me trying to jump up later, that's what I'm trying to do.

Let me just talk a little bit about congestion and the study. EPAct 2005 cast a wide net for the

Congestion Study to consider. It looked at reasonably priced electricity, looked at economic growth, diversification of supply, energy independence, national energy policy, and national defense and homeland security. It's quite a wide array of factors that it asks the Congestion Study to consider.

However, the study also said you can only designate -- what David was talking about, the designation process -- a national corridor if a geographic area is experiencing electric energy transmission capacity constraints, or congestion, that adversely affects consumers. So, the corridor is limited to where there's an adverse effect on consumers.

I believe that's an acknowledgment that there is such a thing as economic congestion, a situation where congestion exists but that the cost of remediating the congestion will cost the consumer more than paying the ongoing congestion costs. And I want to make it very clear from our viewpoint, the presence of congestion does not have to equal the absence of reliability. And in fact, New York City, you could argue, has the most stringent reliability standards in the country but yet we all know that there is some congestion going in to New York City. So, congestion doesn't exactly equal reliability problems or that reliability criteria cannot be met. It might be an indicator of some things, but it's not necessarily an indicator of that.

So, the Congestion Study needs to focus not only where there is congestion, but where there'd be a net benefit to the consumer if that congestion were relieved. DOE does not have to create this on its own since the 2005 EPAct order 890 in 2008 required all planning authorities to study potential economic upgrades to the electric system. You asked for data sources, we believe this may be a primary data source, those 890 studies. These studies can provide indicators where congestion exists on the system, whether the congestion is a fleeting problem or has persisted for years, whether the consumer would benefit from resolving the congestion, and whether transmission is the correct solution, or would a correctly sited generator or demand resource better resolve the issue?

I want to just spend a minute here. One of the concerns that I've seen with transmission being sited and sometimes rewarded at the federal level is the concept that transmission becomes first among equals in terms of alternative paths. We all know that you could solve congestion in a variety of different ways: The siting of generation, the strategic use of demand resources, energy efficiency measures that reduce demand in certain areas. But if somehow transmission gets placed above those other alternatives, you may not be doing a fair analysis. And we just think it's very important that transmission with all its benefits does not jump above the other options that are available.

I say this all the time, but I think it's my duty as a public utility commissioner: People are having difficulty paying their electricity rates today. We have 1 million New Yorkers that are over 60 days in arrears with their electricity bills. Raising rates do all the good things we want to do; smart grid, transmission upgrades, distribution upgrades, infrastructure improvement is a very difficult process and we have to do it very judiciously and carefully.

So, we believe planning authorities have information and resources that were not available for the 2009 Congestion Study. We'd suggest DOE embrace the planning authorities, relying on their system knowledge and expertise in assisting DOE in performing the 2012 Congestion Study in any corridor designations.

One of the other areas that I'd like to focus on is the need for consistent criteria. The 2012 Congestion Study needs to speak with one voice. The 2009 study seemed to take each area of the country separately with separate criteria for determining the seriousness and drawing conclusions that were not consistent. It was as if separate groups examined and wrote separate parts of the study. We think that DOE would be best to draft an independent set of criteria to be applied systematically across congested areas.

DOE's notice in the Federal Register identified many sources which it intends to gather data. It casts a large net for gathering information, which is good. DOE identifies drawing from the results of the Eastern Interconnect Planning Studies, undertaken with DOE support. And as a frequent and enthusiastic participant in the Eastern Interconnect Planning process, that has been a tremendous process. But in the end, I think the study is more of an analysis than a plan. The EIPC effort is the first of its kind, performs studies on a large scale, scenarios identified are constructs for demonstration purposes, not for planning purposes.

We've all learned how to coordinate planning on an Interconnect wide scale, what issues need to be resolved before doing it again, but many of the inputs were not symmetric. Again, we build up from the planning processes. A good example, as we noted during the process, was energy efficiency. How was energy efficiency included within an individual planning process' criteria? Some places it was, some places it wasn't. We lived with that, in order to do the first study. And I'm happy that we lived with that, because I think we reached a successful conclusion, not a conclusion, but at least a midpoint. But in order to really kind of apply criteria for congestion, I think there needs to be some sort of symmetric application of these sorts of resources.

Another place where I think the planning study provided information was it always reduced everything right to the reserve margin, so we lost 67 gigawatts of coal generation in the first 5 years of the study. I'm not sure anybody actually believes that that's how the world is going to go down over the first five years of the study.

So, if the results of the EIPC analysis are to be used, I think they have to be in the context of an order of magnitude, certainly not identification of areas of congestion as needed.

And then, I would suggest consultation. States want to be DOE's partner in this. I think we know our systems better than most. We have guided the planning for the entire electric system. We have sited the interstate transmission system we have today. I will let my PJM friends talk about the TrAIL process, but there's certainly examples out there of multi-state lines that have successfully been sited.

But for a facility to be successfully sited, the documentation and justification need to be developed. Real state involvement in the DOE Congestion Study will start any resulting transmission project on the fast track for successful siting. Because in the end, it's going to have to go to the states for siting process. Obviously, today is a great start and we thank you for including the states, since we get the first opportunity.

States need to be embraced as partners. Just seeking our comments on draft reports, along with other stakeholders, may not be sufficient. Conversations between DOE study staff and state staffs need to take place as DOE is formulating its positions, and I offer our staff up to DOE. At any time you'd like to take advantage of the expertise of our staff, they'd be available to you.

States want the resulting studies to be a tool that is useful to all involved in making carefully informed decisions to resolve congestion, and we believe that's what Congress intended. The study must be vetted and carefully worded to avoid errors or misunderstanding that could create obstacles to effective planning.

In the end, I think the best system is the state siting process. I understand that there may be some ability for some federal interaction in that, and we welcome that interaction. We welcome the opportunity for you folks to identify congestion. We just ask that you do it on a consistent basis using some of the studies that are already out there, establishing criteria that we all understand so that if a transmission line comes to us, on a state level we understand why recommendations have been made and where they've been made.

So with that I thank you again for the opportunity and I turn it back to you.

MR. FINLEY: Thanks. My name is Ed Finley of the North Carolina Utilities Commission, and I'm going to talk mostly about the congestion in my state, South Carolina is very similar, and what we do about it and how we plan the systems in our state.

By way of background, except for a small section of the northeastern part of the state, our public utilities, primarily Progress Energy and Duke Energy, are vertically integrated systems. There is no retail competition in North Carolina. North Carolina Utilities Commission functions as a command and control utilities commission. We set the rates, we sort of certificate transmission lines. To the extent that we find there are areas of the state where a transmission line is needed we can order our utilities to build those transmission lines to make sure that the service is provided there.

We require through the IRP process that our utilities plan their systems on a least cost integrated basis, considering integration and transmission costs, as well as energy efficiency and demand side management. North Carolina is one of the few states in the Southeast that has a renewable portfolio standard, it's a 12 1/2 percent renewable standard to be met by 2021.

Turning to the questions at hand that DOE has asked, that is, how DOE should proceed to complete the required transmission Congestion Study, I believe that DOE's study should focus on congestion that is actually occurring today rather than looking at congestion that might occur under different scenarios for the future, especially since the designation of congested area could be used to trigger FERC backstop citing authority.

The controlling statute, Section 824 P gives DOE, based on its study, the ability to designate any geographic area experiencing electric energy transmission constraints or congestion the ability to designate the area for national interest electric transmission corridor. So, the statute uses the word "experiencing" in the present tense. The statute looks -- does not ask that DOE anticipate congestion that might occur in the future. It would appear that Congress intended the designation of a national interest electric transmission corridor and related backstop authority be used only to address congestion that is actually occurring right now. DOE is required to perform this Congestion Study every three years, and can adequately address future congestion concerns on a timely basis in future reports.

The notice of the workshop asks how DOE would best use the experience and insight offered by the Eastern Interconnection State's Planning Council that we refer to as EISPC. The people to my left and right and others here in the room are better acquainted with EISPC, but I have been a participant in it, and most recently on the stakeholder steering committee. I do not believe that EISPC has officially offered any expertise or insight to DOE Congestion Study effort, as this was not part of the charter or the requirements of the funding.

The EISPC effort and the DOE Congestion Study are, in my opinion, two practically unrelated activities. EISPC has been working to define three scenarios of what the electric grid might be and might be needed in the 20-year horizon. DOE's Congestion Study is to address transmission congestion that is occurring right now, in our opinion a very different task. In addition, the EISPC studies aren't complete yet and won't be for some time, although we have reached a midpoint as Garry has said.

Finally, the EISPC members have never discussed the possibility that the study results would be used in the context of DOE's Congestion Study. Designation of a national interest electric transmission corridor triggers the potential for federal government rather than state and local governments to site transmission facilities. This potential use of EISPC studies has not been discussed by the EISPC members, and I believe this would be an extremely controversial topic if we were to take that up.

The DOE staff has attended and presented at many of the EISPC meetings. As far as I'm aware, they have never indicated that the Congestion Study was something we were supposed to be undertaking.

The workshop notice also asked each of the speakers to comment as to whether his or her area is experiencing congestion. And again, I'm going to talk primarily about my state. I don't know whether we're in the Mid-Atlantic or the South or the Southeast, but anyway I've told you a little bit about what kind of a state we have.

SPEAKER: God's country.

MR. FINLEY: God's country. (Laughter) We have no evidence to indicate that the transmission congestion is a problem in North Carolina, and I believe there is substantial evidence to the contrary. Most of the transmission grid in our state is owned by Duke Energy Carolinas or Progress Energy Carolinas, with a small portion up in the Northeast owned by Dominion, and Dominion is the supplier in our state that is part of PJM. So, much as we like or dislike, we have to follow what goes on in PJM. And I will tell you, based on my observations there, whatever we can say is our way of doing things is much simpler than what happens in (inaudible). (Laughter) As you likely know, Duke Energy and Progress Energy have a proposed merger and their merger requests are pending in several jurisdictions. Under our jurisdiction and the Federal Energy Regulatory Commission, so there's limited things that I can say about that. I would note, however, that the cooperatives that rely on Duke and Progress for transmission services have been active participants in the various proceedings. In one of their submissions to FERC, the North Carolina Electric Membership Corporation, which represents most of the state's electric cooperatives, stated that unilaterally determined, that is FERC transmission upgrades, would be disruptive to the Duke process order 890 transmission planning process, known in North Carolina as the North Carolina Transmission Planning Collaborative.

This collaborative transmission planning effort has now finalized its fifth annual round of transmission planning. Last year's plan called for 14 transmission projects, each costing more than $10 million for a total of $473 million in planned transmission investment in North Carolina over 10 years. This year's draft plan shows many of those projects are underway, with some completed and calls for $296 million of investment by 2021. All indications are that North Carolina's transmission owners are moving ahead to plan and build the transmission that is need to serve both the retail and wholesale customers in North Carolina.

I would also note that North Carolina's Transmission Planning Collaborative expressly includes in its goals to "include analysis of increasing transmission access to supply resources inside and outside" of the Duke and Progress control areas. This year, the two companies studied 11 different hypothetical scenarios of importing large amounts of power, 600 and 1,200 megawatt increments, into North Carolina as well as scenarios of moving 1,200 megawatts north to PJM.

The study found that five of the increased import scenarios would be accomplished without any additional transmission investment. The remaining 6 import scenarios would require investments ranging from $12 million to $32 million, and the scenario for exporting another 1,200 megawatts north to PJM would not require any additional transmission investments.

Through the collaborative process, this information is available to utilities that must work to serve customers reliably and at reasonable prices. The collaborative process that we use is a vast improvement over what we had in the past. We have input from the wholesale customers, the munis and the co-ops. They find that transparency much to their liking, and it has resulted in a much more healthy relationship in planning transmission in our state that once existed.

If building transmission is part of a least cost supply plan, it is incumbent upon the utilities to include it in their integrated resource plans, which the utility commission reviews annually. And we take that process very seriously, and we look at both transmission and generation additions and needs.

The market power concerns of the type that are being addressed in the Duke process merger proceeding for FERC potentially implicate the need for additional transmission facilities to upgrade the transmission interfaces between regions. However, such discussions about market power do not necessarily indicate that transmission congestion is currently a problem, in my opinion. The transmission needed to serve wholesale and retail customers in North Carolina is being adequately addressed through the transmission planning collaborative process.

Let's talk a little bit about renewables in our area. As you may be aware, North Carolina has extensive offshore wind potential. Some have said that our state has the largest offshore wind potential on the East Coast. For the last two years, the North Carolina's Transmission Planning Collaborative has studied various scenarios of offshore wind development and what kind of transmission investment would be required to move offshore wind power inland to serve our state's larger population centers; the Charlotte area, the High Point/Winston/Salem/Greensboro triad area, and Raleigh/Durham/Chapel Hill triangle region.

We now know that it would cost in the order of $1.3 billion in transmission investments in North

Carolina to integrate 5,000 megawatts of offshore wind generation. I mention this to illustrate that Order 890, that the 890 study processes required by FERC have been in place long enough now to have produced useful information and to have resulted in transmission projects that have been built, are under construction, or are being planned and budgeted. And in some cases, building transmission is quite expensive and not in the public interest.

I would encourage the DOE to seek out the transmission planning documents that have been produced by the various Order 890 study processes, as Garry mentioned. Some transmission projects that would alleviate congestion might be extremely expensive and the national interest might be better served with other solutions.

In closing, while there might be times when the national interest would be served by federal intervention to license and site transmission, I believe these instances are few and far between. This tool should be used sparingly and only as a last resort. Therefore, the DOE's Congestion Study should focus on areas that are actually experiencing congestion.

It's highly likely that state officials know where their states are experiencing such congestion and if they believe a corridor designation would bring about a reasonably priced and reliable power supply to their citizens and businesses. They could tell you.

We appreciate the opportunity to be here today, and I might mention that in the 2009 study the conclusion of the Southeast and North Carolina in particular was that there was no congestion and I think the same should be true in the 2012 study.

MR. MEYER: Thank you. Ms. Kane.

MS. KANE: Yeah, thank you. Thank you very much. I'm going to get up and show something on the screen in a little bit, but not my entire presentation.

I'm Betty Ann Kane. I'm chairman of the District of Columbia Public Service Commission. And again, I want to thank you along with my colleagues for the opportunity to participate in this workshop.

As we note, the Energy Policy Act, the first thing it asks is that DOE carry out this study in consultation with the states, and we appreciate that. The District of Columbia, although not a state, is treated for most federal purposes including that Act as it were a state. As you know, and I say that because when I was reading through the 2006 report and there was a description or list of the members or the territory of PJM, it only mentioned the states. But we are very much a part of PJM also and obviously are an active member of NARUC, of the Mid-Atlantic Utility Commissioners, and of the organization of PJM states.

The issue of congestion in the transmission system is of particular concern, I might say, to the District of Columbia. We are located in the PEPCO zone, which remains along with the Delmarva Peninsula and Northern New Jersey, New York, among the most congested areas in the PJM market, and I would probably say in the entire country. So I think it's an indication of the variety of status in the various states. Where Chairman Finley has said he's not experiencing congestion, we are continuing to experience significant congestion.

In addition, in 2012 the District will become unique among the states in that it will be totally dependent -- expect for some miniscule amount of photovoltaic customer generation -- on electricity generated in other states. This is due to the long planned decommissioning of our two remaining generation plants, which were recently just used as peaker plants, Buzzard's Point and Benning Road. They are being decommissioned on May 31 of 2012. And in addition, the owners of the Potomac River generating station, which is located in Alexandria, Virginia, just across the river from the District but exclusively serves the District, the owners of that plant have reached agreement with the city of Alexandria to close that plant in October of 2012.

The 2006 National Electric Transmission Congestion Study, in its review of the Eastern Interconnection Congestion Studies and Expansions Plans identified the need to install two new Palmer's Corner to Blue Plains, 230 KV circuits in anticipation of the loss of the Potomac River generating capacity, and these lines were completed in June of 2007. The D.C. Commission also ordered the construction in 2009 of two 230 KV lines from Benning Road to Ritchie in Maryland. That is underway, and scheduled to be completed by June 1, 2012. So, we don't anticipate reliability problems with the loss of our peaker plants and the Alexandria plant. But nevertheless I think to echo the point that Chairman Brown made, you could solve, a reliability problem may not exist, but a congestion problem still does.

We think also congestion is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. The price signaling energy market, which we used to call the locational marginal price that is at least within the PJM region, which equals to energy price plus congestion plus losses. And so, congestion can also be seen as a generation component and not a transmission component. And the congestion payment may be equal to or sometimes even greater than the congestion component, the transmission component, excuse me, depending on many factors.

Now, I have a chart, I'm going to get up and show you that, which shows the RPM price or the LMP price for the PEPCO zone varies from year to year. And we looked at the 2010 the staff did 2011, 2014 auction results. It showed an 85 percent increase in 2010 auction from 133 to $247. In the 2011 auction, the price came down but only back to the 2009 level of $136.50, and that may be as a result of the TrAIL price. Let me see if I can bring that up on the screen. It will be easier to talk about.

This was looking at the congestion prices for PEPCO zone, megawatts per day. 2010, 2011, $174, down, back up; a lot of variety, variance. Then 2013-14 auction, which was conducted several years before that, of course. And then, the auction, the 2010 auction it was $247.14. Went back down in 2011 auction for the 2014/2015 time period, but only back down to where it was in 2012. That was the TrAIL line that came on, the TrAIL line, West Virginia, Virginia, Maryland area. Didn't make a difference, so transmission does make a difference but it has not in any way solved the entire problem of congestion, which shows up in energy costs. (inaudible) put the entire text up there for you to read..

But the other point I wanted to make was that, well, as I said, we'd like to suggest that Department includes some trend analysis in the 2012 Congestion Study. Of necessity, previous studies were a snapshot type of analysis but now there have been five years of studies, five years since the first study. So, trend analysis can be possible, feasible, and it could tell us more to the extent whether congestion is persistent and the correlation, for example, of congestion versus load and the economy. Because there's clearly a direct relationship between economy and the load.

For example, our staff used the historical state-of-the-market reports for PJM and looked into a trend analysis over 2005 to 2010 for the PEPCO zone and for PJM. Overall, they found that the PEPCO congestion traced the total congestion in PJM quite well and it showed a strong correlation between congestion and the economy. We don't have data for 2011 yet available, but the trend appears to be continuing.

Based on the 2010 data for D.C., total congestion costs accounted for 2.4 percent of the residential customers' bill, and that is in the generation portion of the bill. Total transmission is only about 3.2 percent, for example, for an average residential customer's bill. And so, compared to total transmission costs 2.4 percent on the generation side is not something to ignore.

It may be that this impact or the bottom line, the customer's bill, may not be within the total scope of the Congestion Study, but we do think that for state public utility commissions this would be a very interesting trend analysis. And we note, also, for PJM as a whole the total congestion costs for 2006 was $1.6 billion, for 2010 it became only, it only went down a little bit to $1.4 billion. And so, significant congestion again looking at the congestion costs are still there.

PJM has not yet conducted specific studies to isolate how the recession as opposed to the other factors affected transmission congestion, but they have indicated that their analysis of peak loads, the peak load reduction from 2008 to 2009 was primarily result of the recession. And for the future, that continued load growth is expected to be there for the next 10 years, and so the growth in load will contribute positively to congestion costs.

I'd also like to suggest the 2012 study look more broadly at alternatives to transmission for addressing congestion problems: demand response, energy efficiency, distributed generation. Energy storage we believe can increasingly contribute to mitigation of congestion. The 2009 study did include a small section on demand side reduction, and in particular it cited the Mid-Atlantic states "ambitious energy efficiency programs, including the District's enactment of the Clean and Affordable Energy Act of 2008." And it also discussed some Mid-Atlantic states aggressive goals for distributed generation and photovoltaics, highlighting New Jersey.

We believe much has progressed since 2009.

The District, for example, has increased its renewable requirements by 20 percent for 2020, and it has also greatly increased its solar requirement. Pursuant to amendments that just went into effect on August 1 of this year solar, which is photovoltaic and thermal under D.C. law, must account for 2.5 percent of the retail sale of electricity in the District by 2023. And this is a percentage similar to that of the state of New Jersey. This is a six fold increase from the prior requirement of.4 percent, or 4/10 of a percent, by 2020. And in addition, except for about 21 megawatts of grandfathered facilities, all of this new capacity must be generated by certified facilities of under 5 megawatts each that are physically located in the District or on a distribution feeder, or serving the District.

If this capacity actually materializes as opposed to the retailers electing to pay the alternative compliance fee, the shift to local distributed generation for 2 1/2 percent of the load can have an impact on the need for interstate transmission. In the District, we also have a voluntary demand response program, which help to reduce demand by roughly 60 to 65 megawatts during the recent summer emergency hours. And, the D.C. Commission has just adopted a new residential load control program, or cycling program, that will go into effect this summer, lowering system overall energy use in the district by 1 percent a year, beginning in 2012. All of these initiatives have an impact in reducing transmission constraints and congestion.

Other developments that should be watched in looking for alternatives include the work of the Eastern Interconnection States Planning Council. And while as has been said before the purpose of EISPC is not to come up with plans, but it is to come up with a lot of data that we think could be useful. And in particular, the Energy Zones working group. This would be carried out by a grant from DOE, and with significant assistance from the Department's own national laboratories. And I want to say, I thank the Department every chance I get for all the work of the laboratories, with EISPC and particularly with the Energy Zones work group.

The Energy Zones working group was the one deliverable that DOE has required in making the EISPC grant, and most of its work is scheduled for completion in 2012. I have an update on that project, a Power

Point presentation which I can show later, but it looks at all kinds of energy zones. Some of those which were called conditional areas in the 2009 study I think would be particularly good to look at the updated information on.

We also want to suggest that the Department follow the Renewable Integration Study being undertaken by PJM, which includes 3 transmission scenarios of 4 gigawatts, 10 gigawatts, and 20 gigawatts of offshore Mid-Atlantic wind. And I want to finally bring to your attention that stakeholders in the states in the PJM region are considering the state agreement approach for adding transmission lines to the PJM Regional Transportation Expansion Plan, or the RTEP.

Under this approach, states would voluntarily cooperate to suggest new transmission lines to the RTEP, which might be needed for public policy purposes, and this is pursuant to the new FERC Rule 1000, or Order 1000, such as meeting RPS, including agreeing on cost allocation and adding them to the RTEP plan. The debate is still on the details of this, but we believe that such developments can also further affect future solutions to congestion problems.

Thank you, I'd be happy to answer any

questions.

MR. NAZARIAN: All right. Thank you, David, and thanks to everyone from the Department and everyone who's involved in putting on this meeting. We're grateful for the opportunity to come and speak with you and share some perspectives from our state.

Some of the other folks here are neighbors of ours, and we have some things in common although I suppose in some ways we're largely the mirror image, the opposite of North Carolina. We are fully restructured, we are entirely in PJM. So, if they're God's country I'll let you fill in what we might be. (Laughter)

The lesson --

MR. FINLEY: I don't think, the exact opposite of God's country. (Laughter)

MR. NAZARIAN: I spoke at one of these sessions, workshops for the 2009 study in Chicago on September 17, 2008. I remember that day exactly because that's the day that the financial markets melted down and the phone call I had waiting for me when I left was the message telling me that our friends at Constellation Energy were in freefall because of the liquidity challenges that downgrades and changes in the financial markets put them.

I tell you that story not to reminisce, but because it demonstrates why this process is probably a total embodiment of what we've come in the EISPC world to know as the Garry Brown Principle. Which is, we know no matter what we do we're going to be wrong, but at least we should try to understand directionally where things are headed and get our arms and brains around the moving parts.

When I spoke in 2009, we were very concerned in Maryland about transmission congestion. And we were concerned about it from a reliability standpoint. We had had PJM into our hearing room earlier that year and they testified that if nothing else changed, that we were looking at the possibility of rolling blackouts and brownouts in Maryland on hot summer days starting in 2011.

Now, there were some things that were planned for the intervening couple of years at that point, but remember before the fall of 2008 we were looking at increasing demand forecasts throughout PJM. We were, the TrAIL line, which is an important transmission project that goes from Virginia through West Virginia and into Pennsylvania had not, at that point, been approved by any of the three states that needed to approve it. And yet, it was in not only PJM's Regional Transmission Expansion Plan, the RTEP, but it also had been modeled in the reliability pricing model. So, the market-driven resource acquisition process and the capacity market in PJM assumed that line was going to show up, and yet as we sat there in the fall of 2008 it was not approved anywhere. So, that was another source of concern for us.

And in a restructured state, unlike the command and control model, old school model that is the way things work in the vertically-integrated world, we don't do integrated resource planning in Maryland. We're supposed to rely on the markets to deliver the resources we need when we need them. So at the time, my testimony as I recall it, I didn't go back to the transcript, but I hope it will back me up on this, was that we had real concerns about transmission congestion in Maryland from a pure lights-staying-on reliability perspective.

And I know my friends in Washington, D.C., had the same concern, because although they are very much a district and I would be perfectly okay with them being a state, electrically they are deeply connected with us. The PEPCO zone that Chairman Kane talked about also covers a portion of our state and is part of the congested area that basically starts in Frederick, Maryland, and covers the whole rest of our state to the east, which is where the overwhelming majority of our people live.

So, what's happened since then? Well, as I sit here now knowing that probably everything I say is going to be wrong anyway, there are a few critically important changes that bear on the question of congestion. First of all, because of the concerns we had back in 2008, we at our commission opened a proceeding for the purpose of analyzing our options to fill that reliability gap, as we came to know it. And we got some testimony later on that about 400 megawatts of demand response would get us a cushion that would take care, we hoped, of any acute reliability concerns in the coming years. And so we ordered our investor-owned utilities to acquire 400 megawatts of demand response for exactly that purpose.

The second thing is, since the fall of 2008 we've implemented aggressive energy efficiency and demand response programs that are required by state law, what's called the Empower Maryland Act. And most notably we've put on about a gigawatt of demand response in Central Maryland. About 600 megawatts was called on July 22 of this year, when it was 108 degrees in the 5th or 6th day in a row of it being over 100. And that caused some people's houses to get warm for an afternoon, but it kept the lights on and has worked quite nicely. And that is, for all of my ranting about the reliability pricing model and operation and capacity markets of PJM, that is one area where the short-term price signal does work pretty well.

The third change since 2008 was that the TrAIL line was, in fact, approved in all three states and was constructed and did show up, I think even a couple weeks early. And although it doesn't solve our congestion problems in ways I'll describe, it takes some of that edge off.

But far and away the biggest thing that happened since the fall of 2008 was that we went into recession. And so all of the demand forecasts we were looking at in 2007 and 2008 that were looking for low growth to continue to grow at 1.7, 1.8 percent per year have all, they might as well be blown up. The trend line is flatter and it moved significantly downward.

So as I sit here today, we're still

transmission constrained in Maryland but we are less acutely concerned about the lights on and off reliability implications of those transmission constraints because of the evolution of the demand and because we have taken measures that in our own, in the worlds we do still control as a state utility commission do take, I think, a considerable amount of that edge off.

Now, that doesn't mean that we're unconcerned about transmission congestion, and the adverse effect language that David cited earlier is still very real. We may not be up against the limits of the transmission system in terms of the ability to keep the lights on, but we are very much up against the limit in terms of the way the capacity market works in PJM and the pricing implications that flow from that.

You can see it in stark relief in our state because, again, there's a sweet spot, it's right around Frederick. Where, you know, the electrical equivalent of I-95 goes from four lanes to one kind of all at once. We still import about 30 percent of our electricity in Maryland, and we get it from surrounding states. But there is a limit to what can come in from the other, from our neighbors and that limit does matter in the way that the reliability pricing model models the accessibility of plants in Western PJM with the load East of Frederick. And we know it because, and Chair Kane's RPM graph showed it directly, that the parts of Maryland east of Frederick, so Southwest MAC and Eastern MAC DPL South portions of Maryland separate from the rest of the RTO nearly every year.

What that means in real life is that the average Marylander, average 1,000 kilowatt-a-month customer east of Frederick pays $20 a month more than the person who lives in Western Maryland. And really, I mean, you can pick little bits of that out for one reason or another, but at the end of the day that's about congestion. That's transmission congestion affecting the real lives of real people.

In a world where we are entirely in an RTO, where we don't do integrated resource planning, where unlike our friends in integrated states we don't have the ability to order transmission solutions, we're dependent on the RTO planning process, the 890 process, to look at that. But what's, and to consider and deliver transmission solutions.

But when you think about the three-legged stool, right? Transmission, demand side, and generation. The responsibility of each of those legs falls in different places. The RTO is responsible under order 890 for transmission planning. That's done purely on reliability.

Now, Order 1000 is going to change that. How, exactly, I'm not sure. There's been some interesting back and forth within PJM world about what the consideration of public policy means and whether the state, for example, the state agreement approach that Chair Kane talked about, allowing states to agree to site and pay for lines for non-reliability purposes by itself satisfies Order 1000. That's an interesting question that's going to be played out at PJM over the coming months.

Generation is supposed to be solved by the market, right? Nobody in the restructured portions of PJM is supposed to be doing integrated resource planning for generation. Now, we have some state law authority that allows us to order it, our friends in New Jersey do as well. We don't have to go into the whole storm that that all has created in the world of people who look at those markets. So I guess that's an option, but structurally that's supposed to be handled by the market.

So, that leaves the demand side to us, and we do have aggressive energy efficiency and demand response pools in Maryland. And we have pulled those levers again over the last couple of years in a way that's designed to manage the congestion problem we saw a couple of years ago.

So, right now we're comfortable that we're going to keep the lights on. We're concerned about the impact of congestion on rates. And I guess the last thing I will say about this is, when the economy comes back, and I say when, not if. It always does. But when it comes back, I think our margin of error could be thinner than we think. That if demand starts to get quickly back to 2007, 2008 levels we could find ourselves having to react very quickly to the congestion manifesting itself once again in an actual reliability situation. And the planning mechanisms that I've just described to you are not going to be able to manage that quickly.

Now, since we know that and we deal with that, it's my expectation that we will, again, be able to have enough in the demand side resources to keep the lights on, and nobody at PJM is going to let the lights go out. It's the quickest way to keep a utility commissioner up at night is to worry about that. But there are going to be limits to how much demand-side resources and distributed generation and photovoltaic installations on roofs and things are going to be able to take that edge off.

So, that's probably a very muddled picture which, again, we know is going to be wrong. But I want to acknowledge that the acute concerns about congestion, at least bearing on reliability are diminished from where I was when I sat here three years ago. But they're not gone, and the structural concerns are still very much there.

I won't repeat the points my colleagues have made about the importance of including states in the planning and congestion processes, I think, without getting into the policy debate about whether it backs up authority at the federal level is a good thing or not. I think we all understand and appreciate the complexity and importance of analyzing all the different issues that come from transmission solutions. I think we're all committed to analyzing them fully and fairly and efficiently in our states. I think we're open to the possibility of coordination where that's appropriate, both among states and with the federal government. How that would work exactly I'm not sure, but we're all open-minded. But in our federalist system, we do, I guess, have some, we are still watching for where the federal government might come in and take over, and of course we're concerned about that.

Finally, my colleagues have all said most of what I would say about the Eastern Interconnection Planning Process. It's been a wonderful thing, a wonderful opportunity, and we're grateful for the Department of Energy for making it possible for us to do what's really the first Eastern interconnection wide transmission planning and analysis.

I wonder how useful it is to this particular process, anyway, because what we've done so far in analyzing the macroeconomic and resource mix of a variety of futures, for example, and then doing production cost modeling and full build-outs of a few of those, isn't going to identify anything about transmission congestion now or in the few years to come. What it will show you is how the world changes in terms of certain resources mixes if certain policies are enacted on certain scales. And we have national and regional implementations of things like carbon and renewable policies and others, and I'll happily spend as long as anybody wants to talk about any of these futures and the sensitivities underneath them.

But I don't think it's going to tell you anything about the congestion you have now or in the coming years. So although I think it may be helpful directionally to understand where the world could go if it goes in certain ways, I don't know how helpful it would be to the process you've undertaken and invited us to participate in here.

The other thing I will say in that regard is, there is, I think, some understandable “agita” from the state participants. It's not just utility regulators, but energy offices and governor's offices about how the EIPC study process could be used in a process of designating national electric corridors.

One of the things that has really kept this group together is the opportunity to, I think of it kind of in terms of academic freedom. To explore ideas, to push boundaries, and to recognize that across the 39 states, D.C., and New Orleans within the Eastern Interconnection, that there are things that matter to different regions and different states, all of which we want to study and at least understand the implications of. So, there's been give and take throughout the discussion.

And so, I think everybody would be very clear and our cooperative agreement with the Department makes very clear that no particular state is bound by anything in here. That we retain and need to retain our independence as regulators when and if any of these things materialize into projects someday.

So, I guess I would caution any specific reliance in any case, and I know when Lauren Azar was at the NARUC meetings in St. Louis, she told all of us that the department didn't have any intention of using the study, in so many words. I don't begrudge the department the opportunity to at least see maybe some directional things or some trends that might come, but it's all future looking in ways that I don't think is going to be terribly helpful to congestion analysis you're doing here.

And with that, I will stop talking and be glad to answer any questions after we're done. Thank you.

MR. VOLZ: Thank you. My name is Jim Volz. I'm the chair of the Vermont Public Service Board. I'm also on the executive committee of EISPC, which puts me on the Stakeholder Steering Committee of EIPC. And I'm also on the board of directors of the Regional Greenhouse Gas Initiative.

First I'd like to thank the DOE for inviting us to come to this. I think this is a great opportunity and I appreciate their doing that. And I'd like to also not repeat what a lot of my colleagues have said. In particular, I thought Garry Brown's comments were on point from my particular perspective from the Northeast.

As to the question about congestion itself, the Northeast doesn't, I mean, New England doesn't have congestion right now and there are a couple reasons for that. One is, we've built a lot of transmission recently, $4 billion or so. And Mike Henderson, who is here from ICEO New England, probably has more specific information about that than I do off the top of my head.

We also have a lot of transmission in the works for the future, and so I think we've got, we have the situation well in hand. And I think the reason that's the case is that we have a really robust planning environment in New England. We have a good working relationship with ISO New England that involves all the stakeholders. We have the New England State

Committee on Energy, which is an organization of the states, the regulatory bodies of the states as well as the governor's offices of the states that is funded by the transmission owners, essentially, and the other participants in the ICEO process. And so, that provides us with a resource that makes it very helpful and easy for us to participate in the planning environment. And I think that's why we've been so successful in being able to site transmission and fund it and get it built.

In Vermont we built a transmission line recently in the northwest part of the state, and when we did that one of the questions the board asked was, you know, why are we building this? Was there some way to avoid it? And the answer was, yes we could have avoided it had we done even better planning. And so, Vermont has put in place a system for trying to identify well in advance constrained areas that might be addressable through non-transmission alternatives. And so, we've been really focusing on that in Vermont. We have an energy efficiency utility in Vermont that provides efficiency throughout the state. Our utilities don't directly do that, this utility does it. We have a wires charge that funds it.

And part of the task of that utility is to go, and the state as a whole process with all the stakeholders of identifying what the resource potential is for efficiency, and then funding that utility to obtain that resource. And, in particular, to try to target constrained areas to alleviate them so that you don't need to build transmission if you can avoid it. We have been advocating for that type of an approach at the regional level for many years. And just recently in Order 1000, FERC has now announced that they want the RTOs to, in fact, analyze non-transmission alternatives on the same basis as they do transmission. And to its credit, ICEO New England has come out with what they call their strategic planning process, and I think that's been very encouraging.

They identified that one of the problems with bringing forward non-transmission alternatives is the planning horizon and the process that you have to go through and the fact that the planning process we're using now doesn't identify non-transmission alternatives early enough in the process. And so the whitepaper that they put out lays out a planning process that tries to make those two things dovetail. So that early on, non-transmission alternatives are identified, and then they're studied along with the transmission alternatives, and then the markets, the forward capacity market and the forward reserve market, are given an opportunity to try to provide that resource. And those markets, in particular the forward capacity market, allow for not only for generation to bid, but they also allow for demand resources to bid as well, including efficiency.

So, it really I think is a good model for how to most cost effectively plan your transmission system so that it meets the needs of its customers at the lowest cost. And I think that is one of the biggest concerns that we do have while we were cooperating and working together to make sure we didn't have congestion and to build transmission that was also very expensive. And there is a great concern among the regulators and, of course, the politicians in the states about that cost, and we'd like to make sure that whatever we do is as cost-effective as possible.

So, in Vermont in particular our policy is to go after all cost-effective efficiency and demand resources, whether they address a constraint or not. If they're cost-effective, why not do them? Why wait? And so we tried to invest in that as our first choice compared to any other resource alternatives.

One example of a structural problem I think that we have in New England and perhaps in other RTOs as well is the fact you can socialize reliability projects. So, Vermont for example, our load is about 4 percent of the New England load. So if we have a reliability project that gets built, we have to pay 4 percent of that project no matter where it's located in New England. Recently, a constraint was identified in Northwestern Vermont that the transmission solution is estimated to cost around $220 million, but if you put a generator there you could solve the problem for $50 million. If Vermont chooses the transmission alternative and builds that, we pay 4 percent of it. If we choose the generation alternative, we pay 100 percent of it. And so, it's very difficult for us because the generation alternative or non-transmission alternative can't be socialized the way a transmission alternative can be. And I think that sends a kind of perverse signal to the individual states who have to make these decisions about which resources to select.

ISO-NE's whitepaper that came out on analyzing non-transmission alternatives does go a ways towards helping deal with that problem. We're hoping that as dramatically cost-effective, non-transmission alternatives appear through the planning process, there may be an ability for the parties, in particular, the states and the load serving entities, to get together and reach settlements to pay for non-transmission alternatives that can't be socialized that could be implemented instead of transmissions. So I'm hopeful that that might be a fruitful path for us, but we're just starting to go down that path at the moment.

I believe that's all I have for right now, thank you.

MR. MEYER: Well, thank you all. You've given us some very thoughtful material to work from and some leads that we certainly need to follow up.

In particular, I was struck at references by Commissioner Nazarian and Commissioner Volz to specific geographic areas. And the reason we've found both on our side and readers of the earlier congestion studies were frustrated by the lack of granularity in our results. I mean, to some extent they were saying, and understandably, that to the extent we can get down to a more granular level, the value of the study increases. And so, those particular bits of information about, hey, there's a problem roughly here. That helps us a lot.

But our earlier problem was that just sheer lack of data, relevant, reliable data, is a serious problem here. So but, with your help, and I want to extend, sort of broaden that to the extent that any of you have, and this pertains to the industry people who will speak later also. We are interested in granularity, that is kind of a special focus for us going forward.

Now, I want to go back to Commissioner Brown's earlier, or his initial remark about the possible desire for a response or to the extent that any of you want to comment on the presentations by the others. Discussion here is certainly one of our objectives.

MR. BROWN: Yeah, I wanted to start out, I was struck by listening to Chairwoman Kane's presentation and doing a little compare and contrast. I want to compare Washington, D.C., with Long Island, New York. Both have some limited transmission availability. Long Island is often fully loaded in terms of the transmission lines, but there is a requirement by Reliability Council that Long Island has to have, I think it's around, and John Buechler can correct me if I'm wrong, but it used to be around 98 percent of their

-- they had to have generation resources on-island to meet 98 percent of their load as a reliability rule. So, while transmission congestion may have cost them money, there is very little risk of outages, you know, reliability problems, because that had been taken care of through other measures by making sure of the generation.

When I listen to D.C. and I hear they're heading towards zero percent in city resources if the lines get fully loaded and they don't have enough, they're facing a real reliability problem. Both of them are congestion, but they're congestion with very different outcomes through the congestion. And Long Island, New York, if gas prices are $12, the value of that congestion is going to be incredible because there will be cheaper resources trying to get in there. At $3.80, that congestion may not show as much cost to the ratepayers of Long Island, whereas again there are no options in D.C. for in city generation. They are going to have to take what they can get from outside the resources and you mentioned, I think, 30 percent imports as well.

So, congestion is not congestion, is not congestion, is not congestion, I guess is my point.

And you can see lines fully loaded, but it can mean very, very different things in different areas.

MR. NAZARIAN: Yeah, David, getting back to your granularity point. What Garry is describing is going to manifest itself from a data perspective in a lot of different ways. I mean, I don't know what was available to the Department in total the last time around, but a difference between then and now is you'll be able to see in PJM the history of the RPM clearing prices that only started in 2007 all the way, now, through the present. And that's a specific manifestation of congestion because you'll see based on transfer limits where certain regions separate and where the price changes from the rest of the RTO around it.

And trust me when I tell you can draw a map and see, there are probably a million other engineering ways that Chuck and Mike Kormos and the team at PJM can tell you where the congestion is. And one of the things we've talked with them about over the years is ways to try and identify whether there are discrete transmission upgrades or even substation or static VAR compensator or other, phase angle regulator or whatever, now flux capacitors for all I know, but gadgets you can put in the system to manage, you know, a localized transmission problem as opposed to building a line or building a power plant or something like that. But I'm sure there's a tremendous -- the RPM clearing price data is readily available. There probably are other data sets that PJM or other RTOS could give you to help identify that.

And one other thing I forgot to mention, it's almost on topic, is the power plant research program in Maryland, which is an agency under the Department of Natural Resources prepared what's called the Long-term Electricity Report for Maryland. It was issued last week, and I've got a copy here for you. It runs a whole lot of different scenarios of different resource and transmission mixes, includes the PATH and the MAP lines, among other things. It's not the be-all and end-all, but it covers a tremendous amount of ground and I'm sure it will be useful to you, and I have a copy of it I can give you before we leave here.

MS. KANE: If I could add something on granularity also. I mentioned, I didn't show the slides, but attached to it the energy slides. I do think the Energy Zone's task of the EISPC is quite different from the scenario planning and modeling that the rest of EISPC is doing, the rest of the project is doing, because that is specifically to provide in a much more granular way in map form the location of potential renewable resources in the entire Eastern Interconnection states. And it's going to look at, again, mapping biomass, clean coal, geothermal, nuclear, solar, PV, thermal, rooftop storage, including pumped hydro and compressed air energy storage, water, and wind and actually map them.

And I think it will be bringing together data from existing sources and new sources that hasn't been available or may have been available in very scattered ways, including working with the state wildlife agencies and other environmental groups to also map out the kind of prohibited zones for developing them. So, I think that that will be data in a more granular form that can be useful, obviously intended to be useful to the states in being turned over to them with the tools so that they can make planning decisions. But it could be interesting data, too, that as I said has not been, in a very general way, maybe known but is going to be much more granular and geographically identified.

MR. MEYER: Great. I want to turn now to Alison and some of our other staff here to see if they (inaudible).

MS. SILVERSTEIN: Thank you all very much for your comments so far. Don't know if this is on, can you hear me?

Okay. Well, it may or may not, it is on, yeah. Let me ask you a different kind of question about granularity. Actually, I have one specifically for you, Chairman Brown. And I trust that you will segue from that into the broader question.

The narrow question for you is, besides Long Island is there other congestion in New York, within your state? And second, for all of you, the 2006 and 2009 congestion studies were very, very broad in terms of saying this is where the congestion areas are, whether critical or not so much. And should this study be perhaps too broad? And when David invites you to talk about is there more granular information, do we run the risk or is there a downside to the Department instead of saying, okay, everything from south of D.C. up to Marcy substation, is a congestion area and a critical congestion area? Do we run some risk of being too precise or of getting it wrong if we go too granular instead of too broad in terms of identifying where congestion areas are? Again, congestion area in the broad sense, as opposed to, this spot right here is congested.

MR. BROWN: I used Long Island as an example because it was the most extreme example because of the 98 percent requirement. New York City certainly has the same sort of, there is obviously some congestion into New York City. I think their requirement right now is they have to have 81 percent of their resources in the city. So again, there's a pretty critical mass of generating facilities within the city. The transmission lines supplement that and provide some economic energy.

Those lines get loaded mainly, in my understanding, from an economic basis. Obviously our cheap resources are north and west, our loads are south and east. And so there are hours of the year where there is congestion. As they say, most of it is what I would describe as economic congestion. We're not taking advantage fully of all the cheaper resources, but as I mentioned we are not threatening the reliability of the system in our minds because of that congestion.

So, yes, there is congestion in New York. I think it's been there since Robert Moses and the hydro plants were developed in the 1930s. It's almost a state of operating condition. The real question is, is it economic to relieve that congestion? And I'll let John Buechler talk about some of the work that the NYISO is doing, and I know the transmission owners are doing trying to determine, are there opportunities to relieve the congestion on specific segments of the line that would pay themselves off over the lifetime of the transmission upgrades.

Second half of the question, do you run the risk of getting too granular? The answer is probably yes, but you also get the risk of being too broad. Just having this big shaded area, I'm not sure what that precisely tells you, except we know that there is some congestion in those areas. But if you try to get down to an individual line, a single change in circumstances, a single plant closing, a single upgrade could influence whether that remains economic or not.

MS. SILVERSTEIN: Let me then invite all of you to offer suggestions as to what is a better way to identify congestions areas in the sense that the Department needs to do so in this study.

MR. MEYER: Fair question.

MR. FINLEY: In looking at the statute, I think what we're interested in and what you're interested in identifying is national interest electric transmission corridors, and looking at things like the national energy policy and national defense and homeland security. So, to get too granular and get into areas where the states and other RTOs can fix it without input from the DOE or FERC, I think, is, you can get too granular. It's nice to know where the granularity is, but I think your interest is broader than that.

MR. NAZARIAN: I think there is value in trying to be more granular, if nothing else from a state's rights perspective. The narrower the swath, the less likely there may be to be disputes or contention over the exercise of the authority if it ever comes to that.

At the same time, and this is where not having any engineering background may be a disadvantage, but I'll articulate a principle at least I can understand, it's one thing to identify areas of congestion. It's entirely another, at least I'm coming to learn, to know how necessarily to solve it. So for example, congestion in Maryland was relieved to some extent by the TrAIL line, which did not touch our state. That's a function of the way that the PJM system works. If you drew the quarter too narrowly to track the area of congestion but did it in a way that knocked out certain transmission or other solutions because the solution itself would fall outside the narrowly drawn corridor, that may be counter to the purpose of all this.

So, that's a principle. But, how exactly to limit that, I'm not sure. I can almost drive you to the spot that we most care about, but there may be a whole lot of different ways to address that, short of just painting the whole Mid-Atlantic region with one big, fat brush.

MR. VOLZ: Yeah, I agree with all my colleagues, but Ed Finley in particular, about what the focus of the Department of Energy ought to be. It ought to be on things that are going on that have a national import. So, because New England, I think, has the robust planning process I talked about because we don't have congestion today and we, and I think it's fair to say we're on top of that issue because we don't have congestion today, and I think it's fair to say we're on top of that issue, there wouldn't be any need for you to get a lot more granularity in our area, it wouldn't seem to me. But if we had a problem, maybe you would need more granularity.

MS. SILVERSTEIN: Madam Chair?

MS. KANE: Yeah, I think it really makes a difference whether you're talking about physical congestion or economic congestion. And you know, for the District the TrAIL line was very important to us, too. It will never come to the District. The PATH line and the MAP line are also going to be very important for us, they're totally in other states. And they're important not so much, again, for reliability but for economic congestion.

And I guess this depends on how you define the national interest. You know, what is the national interest? Is the national interest that electricity be affordable? Is the national interest that we have more renewables, more other clean air and environmental reasons, and for security -- for national security? It's a very broad term that, you know, can mean very different things.

MS. SILVERSTEIN: Well, sadly the statute left it so broad.

MS. KANE: That's right.

MS. SILVERSTEIN: So, for our marching orders?

MS. KANE: I mean, obviously it's in the

national interest that, and which is the reason for the emergency order keeping the Potomac River plant operating back in 2004, when the state of Virginia was threatening to close it down or did close it down, because that plant served downtown, the White House, the federal agencies, et cetera, et cetera. So it was very much in the national interest that they have their lights on, but it's, everyone's lights on.

But, you know, the affordability of electricity as well as national independence, energy independence, are also national interests.

MS. SILVERSTEIN: Thank you. And we're going to ask one last very short question.

MS. FISHER: Hi, Emily Fisher from Lawrence Berkley National Lab. I have a question about the EPA regulations that are new and pending, and I hope that you all know kind of which ones I'm talking about. (Laughter)

So I was hoping you could speak to how these EPA regulations may affect congestion, and your thoughts possibly on how the Department could address these in the study? And I'll take your comments sitting down so I can take notes. Thanks.

MR. BROWN: This is truly, I haven't used the expression yet and I had to get it in once, one size does not fit all. And this answer is the perfect answer that it's going to be, you could make the argument that perhaps in New York state, that perhaps the EPA regs will relieve congestion. If some of the older coal plants upstate, the cheaper plants, shut down, there won't be as much to move it down to the Southeast areas.

I am sure that there are other regions of the country where it would have exactly the opposite effect. So I don't think you can really come up with a single statement that says it's going to relieve congestion or add congestion. You're going to have to look at the mix of plants, where they are, where the transmission is, where the load is, and I imagine it will have different effects in different places.

MR. FINLEY: Yeah, I think one of the results of these CSAPR and other regulations is, it's going to cause the shutting down of coal plants. Some of the older ones, the uncontrolled plants. And some of those plants are used primarily just because of the transmission path that they provide to get the power from one area to another. And if you cut those plants off, you know, you lose that transmission path. So that all sorts of ramifications that could occur as a result of these regulations, because plants are going to be closing, other plants are going to have to be built to provide the generation that those closed plants would otherwise provide. So it's going to change the landscape, and it's a good question to look at as what that's going to do about transmission reliability and the economy.

MS. KANE: You know, FERC just had a technical conference last week I testified at on the impact of the BACT and the CSAPR and the other proposed rules, EPA rules, on reliability and meeting their liability standards. But it's the same issue in terms of congestion. So there was a lot of good information put forward at that technical conference, a two-day technical conference. It would be worth looking at in terms of the answer to your question.

MR. VOLZ: I don't have anything to add.

MR. NAZARIAN: Right. The only thing I would add is one size totally doesn't fit all, and in our state anyway where we've had our own environmental regulations in place for five years that have required nearly all of our coal plants to get scrubbed and retrofitted, my guess is that it won't have any impact on congestion in the areas that are congested. It may have an impact on what's available outside the congested area to come in.

MR. BRISINI: Mr. Nazarian, you had mentioned that Maryland has acquired I think a total of 1.4 gigawatts of demand response generation? How many megawatts are backed up behind the meter generation?

MR. NAZARIAN: You mean, how much of the demand response takes the form of --

MR. BRISINI: Are backed up --

MR. NAZARIAN: Back up generators?

MR. BRISINI: Demand response. They come off the grid but they basically turn on their own generation.

MR. NAZARIAN: I don't know precisely. There's at least 6 or 700 megawatts of it that takes the form of residential load control programs that wouldn't be backed up, unless I suppose those folks have backup generators at their houses, but that seems unlikely. There's a fair amount of DR in Maryland that is backed up by backup generators. I could probably track down a number like that, I don't have it off the top of my head.

MR. BRISINI: Have you discussed with your environmental regulators the impact on their high electric demand regulation?

MR. NAZARIAN: Yes. In fact, those regulations were revised a couple of years ago in cooperation with us with exactly that in mind. That there were a lot of uncontrolled backup generators in the state that had run-time limitations that, and one of the ways it's happened is the Department and the environment has been getting much more aggressive about making sure those backup generators have air permits. And in order for them to have an air permit, they have to get from us an exemption to our certificate of public convenience, a necessity requirement.

MR. BRISINI: So you will disclose behind the meter generation?

MR. NAZARIAN: We know because we've issued exemptions what backup generators there are. Now, connecting those to DR participants is harder, because if they've participated in DR either through, either directly with PJM or through a curtailment service provider, we're not going to be able to connect those dots.

But what I can tell you is, we can tell you how much backup generation there is, and in many cases because we've put in our application form a specific part for them to tell us whether they're interested in demand response because we want to connect them with the PJM demand response programs we'll have some understanding of their interest in participating in DR. So we'd be able to back into some of that and maybe get an order of magnitude.

MR. BRISINI: Yeah, the reason being Connecticut when they did their research they found that their emissions from behind the meter generation was three times the emissions reduction they would achieve with a high electric demand regulation.

So, I just cautioned everyone to be concerned about those issues because they are the days of concern.

MR. MEYER: Okay. Well, we've run over time. Join me in thanking our panelists. This was a very useful discussion. (Applause)

Let's return to our seats in 10 minutes. That would be about 10 minutes to 11:00.

(Recess)

MR. MEYER: Please sit down. Well, our industry panel has a tough act to follow, but I'm sure some stars will emerge here and so we look forward to their discussion.

Let me briefly introduce our speakers here. We have Robert Bradish from American Electric Power sitting here on the end. We have John Buechler from the New York Independent System Operator, John is over here. We have Jim Busbin, who is with the Southern Company right here. And we have Mike Henderson from ISO New England, and we have Chuck Liebold from PJM.

So with that, gentlemen, we'll proceed in the order listed on the agenda, starting with Mr. Bradish.

MR. BRADISH: Good morning. Can you hear me, am I close enough to the mic? Good.

As it indicates, I'm Bob Bradish. I'm the head of the Transmission Planning Group at AEP. We've got a few bullets about AEP. Given all the mergers that are going on in industry today, these bullets are going to be changing, I would think, pretty soon when we talk about biggest and largest and things like that.

AEP has a fairly substantial transmission system. We operate in 11 states, and those 11 states are involved in 3 different RTOs: PJM, SPP, and ERCOT. We're also fairly active in the MISO RTO with our transmission activities there.

This morning I'm going to spend most of my time or all my time focusing on the PJM footprint, our activities in the PJM, and to the extent they interact with and are impacted by MISO, also.

So, I tried to structure this presentation around the questions that were sent out. And so the first one talked about the 2009 study, and I think the general theme is, I'm coming to agreement with what the panelists said this morning and what I think the Department has heard previously. While the study conclusions are appropriate, they are very high-level and I think the data you used and the challenges you had with the data you mentioned would lead you down to the conclusions you got to, primarily because that is the structure of the market as it exists today. I think there are structural issues within the transmission, interaction in the markets that will lead you to that conclusion. And those structures are there today, and really the question is, will those structures change going forward? And I do think there are some issues that are approaching us or that are upon us now that will impact that and, hence, will change the ultimate congestion patterns going forward.

The challenge is timing of that. But yeah, kind of overly broad and maybe you missed some areas.

The question there again that came up again this morning, is that nationally significant? And so that's the definition. What do we mean when we say "nationally significant?" We as transmission planners, and we can point to areas that maybe the study didn't touch on, but is it just local and really not something that study ought to be worried about?

They Type 1 and Type 2 areas were very large geographic areas. Given where things have progressed today, I would argue that maybe the Type 1s maybe missed the boat a little bit given what we're seeing today in terms of where the wind has actually developed and the problems we are experiencing on our grid today. I would have moved it a little bit further east than it was probably in that report.

And then, the whole issue of a limited ability to address emerging issues. And some of the panelists hit on this morning. You know, I don't know exactly how to interpret the charge of the department, existing congestion. I will talk about in here what I think existing congestion is.

But as a transmission planner, it doesn't do me much good today to look at what's happening on my grid today and put a transmission line that's not going to come into service for potentially 10 years. I need to have that forward-looking view. As a transmission planner, I need to look forward. That by definition is what we do as planners. So, a study that's going to help us and identify corridors has to be forward-looking. So somehow we have to get past this issue of what's happening today versus what's going to happen, and what's going to drive the future needs of the transmission. I certainly don't want to go out there and build a transmission line where ultimately the need is not there because in 10 years something has changed, patterns have changed, and I didn't really capture that in my analysis going forward. So, we have to speak to that a little bit.

So, I think one of the earlier questions talked about is there congestion on your system? Has it changed over time? And what I've pulled up here is information out of, actually, it's the PJM Market Monitors Report. They put out a report every year, actually it's quarterly, and then they do an annual version of that. That shows the congestion on the AP system.

And so, the X-axis years, it starts at 2005 and goes through 2011. That's through September of

2011. The blue represents the day ahead congestion, and that cost is in millions of dollars. So, that's $350 million. Day ahead congestion, a negative 150. Balancing congestion, one looks at that and says, what's it mean when they're positive and negative? While they mean different things to different participants, at the end of the day we end up with a total of $200 million in 2005. And you can look at the trend for yourself and draw your own conclusions, but the trend over time has stayed pretty constant from 2005 through 2008. It took a little dip in 2009, but we also know what happened in 2009 economically demand wise, things like that. It started coming back in 2010. 2011 is already at 2010 levels and that only goes through September, so we've got another four months or three months, I guess. October, November, December, yeah, three months before we get the final numbers on there.

So, if you dig down deeper and the market monitor does provide further details in these numbers, there's significant volatility in individual components. Because you can look at it from a load perspective, you can look at it from a generator's perspective, and they do have very different perspectives, and some of those years the numbers were in the billion dollars range, a little bit over a billion dollars for a given component. And then that got offset by another billion dollar hit to another component, so the things end up netting out to where they netted out. But there are substantial swings in congestion when you get down to the granular level, depending on whether you're looking at a load, from a load perspective, a generator perspective, or just the overall market perspective.

There are a couple areas on the PJM system, on the AEP system that were part of PJM where I think we've got a growing concern with congestion. And it's starting to show up in 2011, and I think it's going to continue to show up, and I'm going to talk about a little bit throughout my presentation. But we do have where I've labeled the wind belt, and I think everybody's familiar now with where the wind resources are in this country relative to where the load is at in this country. And where AEP transmission happens to sit we run all the way out to Indiana and Illinois on the Western side, and Indiana and Illinois and now Northwestern Ohio are seeing tremendous growth in wind integrations. And a lot of that is now starting to show up in the way of congestion in our transmission system out there. And there's good reasons why it is, and some of it is, again, I'll go back to the structural issue, not so much physical structural issue but actually they have processes they were doing that's actually contributing, I think, to what we're seeing now as this growing congestion issue with the wind in the western part of our system.

And the other piece, and I'm going to talk about this a little bit. Well, this is the issue I want to talk about, the capacity disconnect I have down here. And this is very important because in the markets we started with the definition of capacity as driven by the resource planning team. So, the resource planning folks have a definition of capacity, and that definition of capacity is then handed to the transmission team uses that when they do their planning. And there's a big disconnect when you're looking at a transmission planning perspective and a resource planning perspective how you use or where I'm going to get the maximum demand on my system. I'm going to assume rightly and wrongly that generation is available because markets have told me you're not even allowed to take generation now, just during the summer, unless you've got really good reason to do that. So I'm assuming most of my generation is available, so I don't have to worry so much about that.

I know what the load is. Transmission outages aren't going to be an issue for me, because I'm going to restrict those, too, because I have to plan those a year in advance. So when I'm doing planning, I was a transmission planner and I'm looking at this. I've got all those, it's got lots of scenarios and lots of variations to it. I've got a lot of fairly straightforward analysis to do peak analysis.

And that's how we've planned our systems. Problem we've got is that the wind, now, shows up and the generation side of the business said, I'm going to rate that 100 megawatt wind farm as 15 megawatts or maybe 10 megawatts. So, rather than putting in a 100 megawatt wind farm in my transmission model, I'm putting in a 15 megawatt wind farm in my transmission model. Even though it can produce 100, I'm setting it at 15. And I'm doing this peak analysis and I'm finding out, well, I'm not having that much problem, I've got room on my system. The challenge you've got is that the second picture there shows what the wind actually does.

We're measuring the capacity during the summer peak period, when in reality you've got a wind farm that will generate year-round, and then the off-peak periods, shoulder peak periods, will produce those 100 megawatts from time to time. I've got an issue with that as a transmission planner. How do I deal with that?

And these percentages, whether it's 15 percent or 13 percent or 20 percent, these aren't even industry standards, they're planning authority driven. So each of the planning authorities have their own approach to doing that. And they are resource dependent in that most of the planning authorities at least look at, eventually get to how has this wind farm performed historically. And so based on the quality of the wind resource, that wind farm will get a certain rating eventually through time..

So, we expand this issue, this capacity disconnect. I've got a situation now, and I just threw up a simple example. You've got remote wind areas, which we know we have in the United States. You've got demand area that's fairly far from it, and I've got 4,000 megawatts of wind capacity that's sitting out there, wants to get on my grid, but I'm only going to assume it has a rating of 600 megawatts. And so, I'm going to plan a transmission system that's capable of 600 megawatts, firm. What do I do with the other 3,400 megawatts if it shows up?

Right now I'm doing this and hoping it doesn't show up during those peak periods, and there's good reason to believe it's not going to because, you know, there's good meteorological data that says the wind doesn't blow real hard in the summertime, it blows harder in the other periods, but it's not guaranteed. That's not a guarantee that it's not going to happen in the summertime. But I've got 3,400 megawatts that's going to show up at some point in time, or close to it. And there's diversity there and some will say, maybe not 3,400, but this is only an example. We could put 5,000, say the 3,400 is going to be there.

So, what do I do? What do I plan? Right now I'm planning the 600 megawatts firm. And so what happens to the system in the off-peak periods when all 4,000 shows up? Well, it's happening now and it's causing issues on our transmission grid. And the challenge we've got, we'll talk a little bit about this a little bit further, is that in our particular situation, AEP happens to sit on the seam between PJM and MISO. And PJM looks very closely at its system, MISO looks very closely at its system, but there really isn't anybody looking that closely at the two and how they interact together, except for us who are feeling it and we're talking to both. Very actively talking to both trying to get this thing worked out so we can deal with this issue. Because if the wind shows up on MISO, this is a free flowing network. It's going to flow in our system. Wind gets connected to the PJM system, free flowing, it's going to show up on MISO system, too. So we're dealing with that issue. So we've got significant congestion issues starting to pop up.

The challenge you have also as a planner, because I mentioned before when you're doing peak planning you're really just looking at the peak hour and that simplifies things a lot. You know, there's 8,760 of them in the year, you're looking at 1 of them. What do I do with the other 8,759 hours? How do I look at them? How do I study them? At what point do I get worried? So we can do light load studies, and folks are doing light load studies, off-peak studies, shoulder peak studies, but they're still only a snapshot. They're not like peak studies where a snapshot is only captured in that peak number. I don't know during those other 8,759 hours what I'm going to get for wind. This is going to, if this structural issue, this planning issue is not addressed, we are just going to see a whole bunch more congestion in this area.

And it's something I don't know. Again, I don't know how or what the department can do on this issue. I'm not sure how you address it, quite frankly. It's one we're dealing with, one we have to live with, but it certainly will drive congestion going forward. I don't know, I beat that one pretty hard. So, let's move on.

So, a lot of these, what I've defined today as the areas where I think, you know, the Department needs to look to address congestion issues, and I think a lot of these were talked about in the morning session. Certainly we've got lots of information, at least in the RTOs, about locational marginal prices. They've got those. You've got the market monitors putting out their reports that also talk about congestion. I just showed you the one for AEP that I pulled out of PJM's report. So, there's lots of information out there. I don't think it tells you the whole story because there's a lot that goes beyond, goes on in the markets behind the actual LMP numbers.

And some of that I speak from experience because I used to be, I used to head up our wholesale operations, so I used to manage our generation fleet within these RTOs. So I would offer our units in, I would bid our load in, and I've got a lot of experience with that interaction with the RTOs, and I'll just say that some of that's not as efficient, there's lots of good analytics, there's lots of good academics around it. But when the rubber hits the road, there's some efficiencies that pop into the process.

The other one is the coordinated flowgate transfer payments, which are similar to this LMP thing and the -- certainly the gentleman from PJM, Chuck, could speak to this a lot better. And there was recent discussion between PJM and MISO in front of FERC on this issue as to who owes who what, but basically they coordinate their flowgates and they make payments to each other based on how they're utilizing each other's flowgates. That is a form of congestion and is a cost that's there.

Transmission loading relief, I know the Department knows this one very well. The challenge with this, of course, this is the other option when you don't have an energy market, but it's hard to put a value around that. You can see where transactions are getting interrupted but it's very hard to value that type of thing.

One of the inefficiencies that I alluded to earlier is this manual curtailment of intermittent resources. I might even expand that and say it's manual curtailment and a lot of resources get it. When I was, again, head of the generation, the wholesale operations, we got verbal instructions all the time from our operators because their systems weren't quite capable of making a solution, solving things in time, so they would verbally dispatch us down. Those types of things end up not showing up in the dispatch decisions or in the LMPs. So when someone's out there manually curtailing things, unfortunately those economics, the economics of those results don't show up in the LMPs. They don't show up in other places. And I just put up a slide to show, the graph to show what MISO manual curtailments have been. I didn't have an equivalent slide for PJM, I'm sure there is one out there. But, you can see from 2009 to 2010 the numbers jump significantly.

Now, MISO has been proactive on this. They've gone after it a little bit. They've got this thing called dispatchable resource program that they're running now, that they're actually allowing wind farms to engage in the market a little bit more fully so they can dispatch wind farms. As challenging as that is, that's certainly going down. I can see it coming up may be a little more of a challenge, if the wind is not there.

Sorry, go ahead. I talk too much. Increasing transmission switching actions, certainly they're out there. The other area I want to point to very quickly, that's the generation interconnection queue. And I will argue that that, indeed, is congestion. Now some folks may take issue with that, but if the definition of it is, and I pulled the language that's underneath it, large source of generation lacking adequate transmission capacity. Then everything in the queue fits that definition.

What we've done is, as planners we were able to find the cheapest solutions possible to get as much generation on as we possibly could. So we've used up all the cheap capacity that we possibly could to get these wind farms on. Now the problem you've got is the next wind farm that wants to come on is looking at a very big investment. It's looking at a very major EHV investment. No wind farm can handle that by itself, so we've got this little issue here. Certainly it's a large potential resource sitting there that doesn't have access to the grid. And the other is capacity market congestion. I would encourage you to look at that. Others mentioned that this morning.

One of the things we had is, what brings this, makes it a national issue? I tried to use this one as an example of a project that we recently planned, submitted to FERC and approved rates on. It's the RITELine Project; it basically runs across Illinois from Iowa to Ohio across Illinois and Indiana. The point of raising this is just to simply show that something like this allows for the integration of initial 5,000 megawatts of wind and provides very significant economic benefit. Is that what it takes to get it to a national level? I don't know.

So, I'm wrapping up. Source material, you had asked for additional source material. I agree with you in terms of the quality of some of the data that you need is lacking in terms of, you know, actual load data, things like that where you can actually get your hands on that. The RTOs certainly do provide a lot of data, they do a lot of studies, I know you guys are looking at those.

I agree with the earlier speakers. RTO is much more of a granular view. EIPC has got some interesting scenarios in it. It's a much higher level view, I would say. The combination of those two together would certainly help.

There's another study that we had participated in called the SMARTransmission Study. I point to that only because there's a certain perspective we took in that that may be useful for the Department to look at in how we approach that one. It did look at integrating 58 gigawatts of wind in that Midwest region, and how you would integrate that and move that to markets..

Then other considerations. There's no question trying to study congestion and trying to get a handle on it and trying to identify where it's going to be is challenging. And pretty much anything that I said here moves faster than the speed of transmission, which in today's market seems to be just about anything, other than maybe nuclear, is moving faster than transmission. Those are things you've got to look at, and unfortunately it's not an easy task. But I'd certainly be willing to help out and do what I can along the way.

Thanks.

MR. BUECHLER: Good morning, everyone. I'd like to thank, first of all, the DOE for inviting me back again here as I've been participating in all three of the congestion studies now at this point. Thank you.

I did skip the usual NYISO boilerplate because I think most of the people here have already seen the "NYISO, hub of the Northeast" slide probably more times than you care to, so I omitted that. And I tried to address the six questions that were queued up by the DOE for this conference, and its general outline of topics I'm going to be discussing.

The first question which one of our people has already addressed is, what did NYISO think of the 2009 Congestion Study? In our formal comments that we filed with the Department, we expressed our general agreement with the DOE findings with the Mid-Atlantic region. We noted, however, that the 2009 study was primarily based on 2007 historic data and that at that point of our comments we noted that congestion had declined in 2009 and we'll have a little bit more to update on that in a moment.

We also noted, as was mentioned by Chairman Brown this morning, that in New York at least, congestion is not a reliability problem. I'm happy to say that that still remains the case, based upon our comprehensive system planning analyses. We also noted two changes in approach in the 2009 study from the 2006 study, and we expressed our support for both. One was the recognition that all resource options should be considered, not just transmission as the only solution to congestion. And also, the recognition that all congestion does not need to be solved.

In addition, DOE in the 2009 study made good use of existing regional plans and existing data, and we encourage them to do the same. And apparently, that's their intent from the comments that have been discussed here already today.

What are some updates for the New York control area since the 2009 study? Congestion has declined to a more "normal" level from the high point in 2008. There are three principal reasons for this. Fuel costs, especially natural gas costs, have declined significantly over the past several years. Additional resources have been added in the downstate region of

New York, and load growth has declined significantly due to the overall economic environment, as well as increased penetration of statewide conservation measures.

I have a few slides that provide some support for those two statements. Natural gas prices: The Transco's fixed price in New York from a high point in 2008 of about $14 to what I'll call a more normal, stable point except for the traditional winter variations of about $4 to $5 over the past several years.

New generation has been added of the total amount of generation that's been added, and I thought there was something else on this slide here, actually. It was almost, I think, 2,700 megawatts of generation added statewide and 1,700 megawatts of that was in the downstate area east and south of the Central East Constraint of New York over the past 3 years.

Oh, there it is, okay. I didn't know I had that animation in there, to tell you the truth.

(Laughter)

Decline in load growth. These are the words, but the picture probably tells it better. The 2008 forecast in New York was for an almost 1.2 percent growth rate between 2008 and '10, which we chalk up to the economy. There was a real decrease in load of almost 1.3 percent from those years, which bring it to a new starting point in the load forecast. And if you look at our forecast in our current 2011 goal book projections, after the inclusion of energy efficiency we're now projecting over the next 10 years a mere.41 percent load growth for New York as a whole.

I think I've talked about the congestion metrics as New York defines it and as we've worked out with our stakeholders many years ago. We've been keeping track of congestion, utilizing these metrics since 2003. The primary metric for congestion in New York is bid production cost. We believe that this measures the societal benefits of congestion. There are other metrics that we report for informational purposes: unhedged congestion, generator payments, and unhedged load payments. The key to some of these other metrics is the term "unhedged." While there was some discussion this morning about congestion, the definition we believe is very important. And again, we certainly would recommend as we have done in the past to the Department to consider the use of bid production cost.

If that's not done, and recognizing that the more traditional value of congestion that's used is what I'm' going to call an accounting value of congestion, which is the congestion component of LMP. You need to recognize whether that, in fact, is hedged, whether that, in fact, is paid by consumers or not.

In New York at least, there is a significant amount of hedges to congestion in the North-South region of New York, due to legacy, historic, grandfathered, whatever you want to call it -- preexisting contracts or willing agreements. You need to account for that, we believe strongly. You need to account for that factor.

We report each of these congestion metrics daily, by zone. We have 11 zones in New York. There's a lot of data there and it's all on our website at the link given.

Back to the comment I made earlier about the declining congestion from 2008. I know this is a little bit hard to see, but the yellow line is 2008, which is cumulative congestion, again with the bid production cost definition of about $240 million in 2008.

If you look down to the bottom you've got the blue lines, basically the lowest two lines on the curve if you look out at the end of the year, down to more like a $90 million congestion level over the past couple of years. This is just an example of the various metrics we report by zone.

This is a summary, again on an annual basis. And this is for what are some of the factors impacting congestion? Certainly a number of these have been mentioned before: The economic downturn; slow recovery of load growth projections; stable fuel price projections based in large measure, at least relevant certainly to the Northeast through the increase in shale gas production; new generation additions in eastern and downstate regions. Somewhat counter to that but it is a factor affecting congestion, certainly, is new wind congestion, which in New York is typically located in the upstate region, and I'll show you an exhibit on that in a few minutes; the impact of statewide energy programs and proposed transmission additions, and we have several of a proposal of transmission additions that are in various stages of study right now in New York that could have a significant impact on upstate to downstate congestion.

To remind everybody about what the typical power flow in New York looks like, and I think Chairman Brown alluded to this before, the cheaper generation is located to the north and west in New York. Large hydro projects, large nuclear facilities, some coal units up in that area. More than half the load is located in the Southeast, lower Hudson Valley, New York City, and Long Island. So that's the typical direction of power flows in New York.

I know you can't read this. This is a summary of all the projects in our generation queue as of the end of last month. The color coding you can read, however. The dominant additions or proposed additions are defined by the color code. The green is all wind, and that's in the North Country so-called, and in the west and in the southern tier, if you will.

Looking down towards the Southeast, the gray area are fossil units, largely gas fired combined cycle, if not solely, in the Hudson Valley and in New York City. And there actually is a significantly sized wind project proposed on Long Island, so that's the green out there on Eastern Long Island. You can see the listing of all of these projects, again, on our website and I have a link to that later on.

Wind is, I call it a future congestion

challenge. With the amount of wind we have currently in service, roughly 1,300+ megawatts, we have not experienced any significant congestion due to wind or significant limitations. Not that there have not been curtailments at times, which we largely handle through our markets right now. We have another almost 6,000 megawatts of wind in the queue, however, and in those locations that I showed if they develop up there that will be a challenge and will increase congestion. Again, not significantly as we've shown in a detailed study that we completed just last year.

Current or conditional congestion. I guess maybe I took a little different twist than the definition that David showed earlier on conditional congestion, and I'm viewing conditional congestion in the sense of a what if-or scenario type analyses. And in that sense, we do look at that on a regular basis on both our economic and reliability planning processes.

On the economic side, which deals more directly with congestion, obviously we are in the second cycle of our economic planning process. That is due for completion in the early part of 2012, and there we do evaluate the highest sources of congestion, those that I mentioned earlier, the historical basis, but we also use a 10-year projection. We then analyze the potential benefits of various types of resource solutions to those congestion locations, and we look at generation transmission and demand response. These are generic, these are estimates that are developed with our stakeholders, these are not actual projects. And then that information is provided in the final report as information to the marketplace to consider.

A third or fourth question that was asked, what are the potential risks of congestion? I think specifically, but I think we have two significant potential risks in New York. There could be risks of congestion and/or, more importantly, risk to reliability. One has been mentioned already in a question from the Department, the impact depending of environmental regulations, which may lead to the retirement of generation in critical locations in New York. As Chairwoman Kane pointed out, a large topic of discussion in many places all around Washington these days. That is a concern for New York, more on a local basis than on a broad general basis because we do not have a whole lot of coal units that are left in the state. A lot of the smaller ones have been retiring over the past several years.

The second significant potential risk in New York is the possible retirement of the Indian Point Nuclear Power Plant at the end of its current operating license. That would remove over 2,000 megawatts of supply from the critical downstate region.

What are some of the consequences of congestion? And again, I point back to these two general important categories of risks. They are, to the extent that these things come to pass, and some are more certain than others, we may have adverse impacts on both reliability and congestion in New York. As I mentioned before, we do study these risks, specifically for these types of risks and others in extensive scenario analysis as part of our reliability and economic planning processes.

A little different aspect is that resource retirements could lead to a reduction in fuel diversity and an increased dependence on natural gas since virtually all the new fossil fire plants are natural gas fired. The New York ISO is engaged right now in planning a study of the gas-electric interdependencies for the Northeast region, and we've been talking to our adjacent neighbors on that study. We believe these are, again, some specific questions about consequences of congestion in the DOE's invitation. That our wholesale market design and our continued market monitoring are adequate to deal with any potential market power issues that we envision from any of these potential risks. And I think I mentioned before, we consider all resources as potential solutions.

Our locational energy and capacity markets, I think also, are important in this aspect that they provide the appropriate locational signals for locating replacement resources, be they transmission or generation or demand response in the areas which tend to reduce congestion. And we've seen that historically by just that, by the location of those resources since the NYISO markets have been in operation.

And finally, the shutdown of Indian Point will likely have significant environmental, economic, and reliability impacts, and that's according to a report prepared for the City of New York and recently released a couple of months ago. What are mitigation options? I think most of these have been talked about before. Obviously the appropriate location of resources in the appropriate places, be it transmission generation or demand response.

And then finally, EIPC. I have to say, I agree with the comments made by the regulatory panel this morning that the DOE project under EIPC is not a Congestion Study. It is a broader, longer-range-looking analysis that may provide some insights for this DOE Congestion Study, but it will not provide any direct input to address the congestion impacts. And again, the project is scheduled for completion by the end of next year.

So, thank you very much.

MR. BROWN: Think you can handle that?

MR. BUECHLER: Jim is next.

MR. BUSBIN: Good morning. I'm Jim Busbin from Southern Company. I would like to thank David Meyer for inviting me here today to speak to you. And I welcome the opportunity to comment on several of the questions that were posed to us as panelists. The areas I'd like to cover this morning deal specifically, or cover the areas of metrics to be used in the study. Also, I want to cover present and future congestion, and I'll end with a few comments on our experience with EIPC.

In looking at question number 2, what factors should DOE look at when evaluating congestion and identifying congestion areas, the 2009 Congestion Study defines congestion as a condition that occurs when transmission capacity in a specific location is not sufficient to enable safe delivery of all scheduled or desired wholesale electricity transfers simultaneously. The terming or the phrasing of "all transfers" is inclusive of firm and non-firm schedules. Overall, we feel the evaluation and identification of congestion should only be based on firm schedules.

Three elements used as the congestion metrics in the 2009 study were transmission reservations, the subscription of a flowgate or interface. Transmission schedules, the schedules that are actually implemented to have energy flow, and I believe in that category LMP is also included. I do not have comment on LMP as we don't calculate LMP.

And then finally, the third element or the third metric used is in real-time operations. The metric we use with respect to reservations was a determination of congestion was made when AFC or ATC is zero. We say that the zero interface or capacity on a flowgate or an interface doesn't recognize scheduled flows. I can have a fully, subscribed flowgate or interface, that is the available capability is 0 without 1 megawatt flowing in a schedule. It was unclear to us how the tiering of transmission reservations is recognized in evaluating congestion. In other words, when you say that ATC is zero, what does that actually mean? I can have an ATC of zero with respect to weekly non-firm but I may have remaining capacity left on that interface or flowgate in a higher tiered transmission product. And I'd just say that of the three congestion metrics used in the past studies, we feel this one is the least telling as it describes very little with respect to transmission congestion.

The second metric used termed it transmission schedules. It evaluates utilization of a flowgate or an interface, utilizes a flow duration curve approach. That is, the accumulated flow on a flowgate over time. Again, we feel that the study should only examine firm usage utilization when identifying congestion. We encourage the continued use and refinement of this metric.

And then finally, the third metric in real-time operations. This deals primarily with transmission load and relief procedures. TLR procedures recognize the frequency and duration of a TLR event. It identifies the magnitude of the TLR in megawatts curtailed, it can be converted to curtailed energy to better define impact of curtailment. It stratifies the priority level of the curtailment. We also encourage the continued use of this metric and urge that it be used in conjunction with TLR levels 5 and 6, which are the firm's scheduled curtailments.

Additional points to consider with respect to the identification of congestion is when a flowgate or interface is operating at its maximum allowable capacity or limit. Is this actually congestion or is it the facility performing as it was designed?

Another point is for a flowgate or interface that is fully utilized. There are planning processes in place that yield impact studies and facility studies that allow for moving beyond the limits.

And lastly, we can only identify congestion when we can properly define it. Congestion can only be properly defined once the expectations of the power grid are known and fully understood. The metrics based on schedules and utilization and real-time operations are a step in the right direction. In our opinion, these metrics become less defining when they consider non-firm energy flows and the identification of congestion.

Moving on to the questions 3 and 4. They ask, is there current or conditional congestion in our area or region today? And 4, ask if current or conditionals exist in your area? What are its consequences in terms of liability?

And our answer to the current is no. Southern is currently experiencing no areas of congestion within its footprint. The 2009 study stated that the Southeast, or SERC, region has a unique philosophy with respect to electric system planning and construction, in that the transmission system within SERC has been planned, designed, and has operated such that utilities generating resources with firm contracts to serve the load are not constrained.

Southern continues to integrate its transmission planning with its integrated resource plans, so that least cost planning can be performed using the total cost of a particular resource.

There does exist real future risk of congestion or worse within our system, due to the given compliance deadlines for the recently proposed EPA regulations. It's our position that the deadline of three years is much too tight and that a compliance deadline of at least six years is needed for industry to meet the requirements of regulations as proposed.

A little background on our company. Southern Company's public utilities subsidiaries operate a vertically-integrated and closely coordinated system of generation, transmissions, and distribution assets, reliably serving 4.4 million customers throughout a 120,000 square mile territory in Alabama, Florida, Georgia, and Mississippi. We own and operate a diverse generation fleet comprising approximately 47,000 megawatts of generating capacity and a robust transmission with over 27,000 miles of transmission lines.

Southern Company has over 20,000 megawatts of coal-fired generating capacity; 12,000 megawatts of this capacity is in large, efficient coal units that have been equipped with state-of-the-art environmental controls at a cost of about $8.5 billion.

Because of the uncertainty in the final rules, we do not know today which, if any, of these units will be permitted to operate in 2015. Based on the outcome of our preliminary engineering work, it is not likely that a single additional unit of these 12,000 megawatts can be equipped with a new bag house by the January 1, 2015, deadline. It will take at least six years to complete the work expected.

For the remaining 8,000 megawatts of coal-fired generation, our assessment of the proposed utility MACT rule, along with other expected rulemakings due in the near future, indicates that about 4,000 megawatts would be retired. The majority of the remaining units would be converted to natural gas.

The impact on Southern Company and to industry of this three-year compliance deadline creates a risk to the reliability of the power grid. These proposed rules will require a significant change in terms of operation, construction, and cost on about 80 percent of all coal capacity Southern Company currently operates.

We project a need for 60 percent more craft labor than the maximum Southern Company has ever employed in its history. This explosive demand increase in labor, equipment, and materials will create delays and cost increases that have not been accounted for. Our estimate is that the implementation of environmental controls will take up to six years to complete. New generation will take three to five years, transmission upgrades will take three to seven years, natural gas pipeline expansions will take more than three years.

And its scheduling on a regional and inter-regional basis will be the most challenging the industry has ever experienced. I've provided a graphic here to show you some of what I've just explained to you as far as time element involved in compliance with these regulations. In the interest of time, I'll move on.

Southern has conducted a reserve margin study for our region that takes into account both retirement and unavailability of generation due to retrofits and repowering to meet proposed environmental standards. In 2015, absent any compliance extension for units that cannot be controlled by 2015, Southern Company will have negative reserve capacity and would have to use load shedding to maintain compliance with work reliability standards.

The following graphic shows the dramatic impact of the EPA regulations on Southern's reserve margins between 2015 and 2017. You can see that in 2015 we drop into a negative reserve margin and it's not until 2018 that we get back to our target reserve margin.

We cannot err on the side of putting the reliability of the power system at risk. DOE should make appropriate findings and recommend that EPA invoke all available statutory authority under the Clean Air Act to protect electrical liability by providing the electric generators an extended compliance period.

Finally, with the last question as far as our experience with EIPC. I've just simply said that this project is a first-of-its-kind effort with participation by planning coordinators, regulators, and stakeholders from across the Eastern Interconnection. The product of the study is not a transmission plan, but rather to examine transmission options that would be needed to support generation resources resulting from public policy scenarios chosen by the EIPC stakeholder group.

We found the concept of rolling up models on an interregional basis, evaluating the model, and then folding that information back into the various planning coordinators' planning processes to be of value. As far as the project itself, we are at the midway point. The study will not be concluded until the end of 2012.

And with that, I believe that's the end of my presentation. I appreciate your attention, thank you.

MR. HENDERSON: I'm Mike Henderson. Thank you so much for the opportunity to speak today.

Slide No. 2 is the boilerplate of the New England system. We have a very tight system in New England, and so from a reliability perspective issues on one point in the system will affect the others. We do have markets and economic dispatch.

I would like to call your attention to having over 13,000 megawatts in new generation that have been successfully integrated through the queue process, predominantly natural gas units, which are efficient. We have built about 4.7 billion dollars in transmission, including several 345 KV projects within New England.

Slide No. 3 shows the load concentrations in New England, which is predominantly in the southern three states. It's mostly along the coast and the Connecticut River Valley. Again, 80 percent of our load is in the southern three states. Most of the remaining load is along the coastal regions of New Hampshire and Southern Maine. But of course, Vermont is a very important state to us. On the right side, it shows the generation development which is fairly close to the load centers.

Slide No. 4 shows just some of our major transmission projects. We've had a whole host of almost 400 transmission projects developed within New England. We attribute this to success in the regional planning process, our states' ability to site transmission, and then to build a needed transmission. I refer DOE to the regional system planning project list.

And by the way, we do model also to load levels peak or peak light load, and do all sorts of great studies, including wind, which is shown on Slide No. 5. What's shown on Slide No. 5 are some of the more likely development locations of wind in blue, but some of the others are shown in green up to a scenario that we're currently studying as part of our economic studies under 890 looking at serving up to 20 percent of New England's energy with wind.

You'll note that the offshore sites aren't close to our load centers. They're electrically close to the Boston area. Onshore wind is predominantly in the North. A particular issue is shown in the one in Bigelow area, where there is likelihood of wind development, and we naturally have some local transmission plans under development for integrating that.

Slide No. 3 shows kind of the then and now. And if you look at the capacity of the New England system, I'd pull your attention to the natural gas capacity shown on the bottom, growing from some 18 percent over 40 percent in the year 2010. And oil capacity dropped some from 34 percent to 21 percent. But if you look at the energy production in 2000, oil produced 22 percent of the electric energy in New England and less than half a percent in 2010.

These oil units aren't running. Many of them are old, as are several of our coal units. These also tend to be some of our higher emitting units, and so there are some environmental challenges that those units will likely be facing.

Slide No. 7. We've had a fairly robust regional response, that Commissioner Volz referred to. We've been working with our stakeholders to address issues. There are interactions, certainly, between the natural gas system and the electric system. In fact, we're doing some physical studies looking at some of those potential reliability issues. They will be rolling some of that out, actually, next week before a planning advisory committee. There's the issue of potential retirements, integration of variable resources, and trying to better align planning with markets and operations.

So specifically, as far as the Department of Energy questions that were posed. Congestion is virtually nonexistent in New England, as shown in the boilerplate. We have less than $37 million worth of congestion out of a market that's over $9 billion. We have a fairly robust planning process and are meeting upcoming challenges as part of this strategic planning initiative. We've also done a number of studies and are continuing to do studies looking at renewable integration, and in fact for those renewables that we think are the most likely we do not believe we're going to be suffering any sort of major congestion. They're certainly in the short-term through maybe 2016/2017 timeframe.

So, what are some of the factors that we believe DOE should consider? Certainly NERC planning reliability requirements. We've had some discussions on differences between economic congestion and reliability congestion, which could be non-compliance, basically, with the standards. Historical congestion, we believe, is important. In New England, we do publicly post by the 20th of the following month all sorts of information provided by our customers, and you can find certainly zonal LMPs and a lot of other information.

The robustness of the planning process' proven ability to build facilities, and the region's ability to anticipate and address changes. Conditional congestion due to potential renewable development, again, we don't have any evidence of congestion today. Most of the resource development has been close to the load. We believe that many of those units that potentially could retire will likely be repowered or rebuilt using natural gas as a fuel of choice. And, why not? You know, it's low-emitting, the cost is fairly low, and as long as we can deal with the number of reliability issues, I think we can overcome that as a region.

Successful development of transmission. And certainly, the development of queue wind resources, as I mentioned, would have little congestion except in some small areas and we're trying to address those in our system. By the way, the NERC study, the LTRA says that basically congestion in New England is nonexistent as well.

So we believe as a region, on Slide No. 9, we're ready to meet future conditional congestion situations. We did a full-blown wind integration study looking at a number of scenarios that address many of the operating issues, and we're continuing on with these economic scenarios so that policymakers can basically help establish where they would like to see renewable development in New England. There are a number of merchant projects in the interconnection queue, and we stand ready to certainly comply with Order 1000.

A point that I would like to make in terms of renewables and so on is that New England is very closely integrated not only with our good neighbors from my home country Brooklyn to the west, but also with our Canadian neighbors to the north. And so, we have a number of interconnections with the Canadians who also have tremendous potential for renewable development. There are some merchant transmission projects and other ideas that are being teed up.

Data sources. I was very happy to hear many of David Meyer's opening remarks. We believe that the data should be publicly available and that would facilitate the DOE data gathering process. We got a lot of information that's available for you and we're happy to help you walk through the maze of our website and provide other information that you can use. We've got NERC and other public sources of information available. And EIPC, again, I think provides useful scenario information. But it's not a plan in the sense of authorizing construction.

Slide No. 10, so kind of coming to the summary here. We coordinate planning activities among the six New England states. And again, please don't forget our neighbors in any study that is conducted. And through FERC Order 1000, we're already holding a number of stakeholder meetings to comply with the new requirements, such as public policy planning and of course cost allocation provisions and interregional planning where we actually have a fairly robust interregional planning in the Northeast. My compadres here, John and Chuck and I chair a group, and we have joint stakeholder meetings to do interregional planning.

Closer to home, the New England Regional System Plan summarizes many of the challenges in maintaining a reliable and efficient operation of our system and again, that does include interregional aspects as well. But we are moving forward to meet many of the emerging issues.

A very important issue for us is energy efficiency development. We have begun doing an energy efficiency forecast now, so if you looked at gross load forecast and subtract off the energy efficiency, it's going to be pretty substantial, maybe accounting for 50 percent of our future load growth as we go forward. So that's a process we're in the middle of now.

So, I want to thank you for your time and attention, and will gladly field questions later.

MR. LIEBOLD: Thank you, David Meyer and DOE, for providing PJM with the opportunity to come and provide some information. And we are supportive of DOE's efforts to enhance interregional planning, and we are supportive of the efforts to achieve the realization of needed transmission improvements.

First, I'm not so kind as my New York friend to spare you the obligatory PJM background slide. But I will minimize it and say, with recent integration efforts in PJM with the anticipated integration of the Duke Energy, Ohio, and Kentucky companies, and with the American transmission system integration this past June, we are somewhere around 162,000 megawatts of load and approximately 185 gigawatts of generation.

If you look at the map, that little blob does experience significant historical and ongoing congestion, as I think others have reiterated. The west-to-east pattern in PJM of the flows and of the congestion is well-known and goes back to ancient history, practically, of our markets. And that congestion is experienced primarily from the Eastern Ohio area to the east, and it's caused, however, by transmission limitations that are in that area, as well as to the west of that area.

We're experiencing some new type of congestion relatively recently in the western regions around Illinois, particularly, because of wind development. And that has manifested itself particularly in off-peak hours. So, that is making the planning chores more complex in that it used to be relatively routine, that we could just pay attention to the on-peak scenarios. But PJM has recently established and has approved and is recommending transmission for needed upgrades due to a light load criteria now that looks at approximately a 50 percent peak load. And at this point, it's heavily influenced by renewable integration, and we ratchet those renewables to a high level in those scenarios in order to get a different off-peak view of congestion.

This is, you've seen it in some of the other slides that preceded me, a view of the historical congestion that PJM has experienced. It's probably good to emphasize, you know, just what is this congestion, what does it represent? Well, it actually represents the byproduct of our reliable operation of the transmission system. It's not our goal to eliminate congestion, and I'm not implying that these are the optimal levels or these are the levels that we target or shoot for, okay? But I am saying that, you know, congestion is the byproduct of the re-dispatch of the system in order to, you know, take care of transmission limitations and prevent them from being reliability problems.

If you look at the historical patterns, you can see that, you know, we have consistently experienced $1 billion to $2 billion in congestion. It did diminish in 2009, and that was primarily an effect of the economic consequences. So, you can see from this graphic also the volatility of congestion. It's not only volatile due to the economy, but loads are, you know, an extremely big weather sensitive loads are an extremely big impact on the volatility, as well as something that is often overlooked. In real-time, we have actual things that happen on our system. Actual generators that will outage, actual lines that will outage or be taken out on maintenance, so there are significant localized effects of congestion, also.

So, to drill down a little bit more on the 2010 congestion, you can see that there was a very large increase recently in 2010, however, that is due to the volatility effect that I was talking about, the recovery from that 2009 economic downturn that was relatively persistent. And we are recovering from that and we do expect that we will recover from that and I think the point, one valuable takeaway there is that you can't look at any of the historical congestion numbers in isolation, but you have to look at them in the aggregate and understand what that volatility means.

A significant portion of the PJM congestion is interface congestion, and that is representative of those west-to-east congestion patterns, as well as some specific lines and specific transformers that are reflective of a little bit what you've heard about today about how congestion can be manifest on a more granular level as well, which is certainly the case, and PJM is lucky enough to have manifestations of all those types of congestion.

Again, a little bit more on 2010. You can see that the top 20 congestion events represent 76 percent of PJM's total congestion. New York had a similar slide. They had relatively fewer top congestion elements on their list, but they show the same type of message -- where there are very specific congested elements. I would say that in markets like PJM, we manage that congestion through LMP, and LMP makes congestion manifest to all of the loads downstream of a particular congested element. So particularly, our west-to-east pattern of flows affects prices for loads and generators in the entire MAC region. So, that even granular and localized congestion can have widespread and broad effects, also.

And PJM is paying ongoing attention to RTEP upgrades, evaluations of reliability and congestion. And so, the historical patterns that you see, you could think of them as, well, yes, there's a persistent level of congestion but we are working hard to maintain that, to evaluate it, and to mitigate it. And it's required that we continue that effort. That's not something that we can rest on our laurels about. We have to continue to evaluate the congestion and continue to make transmission upgrades, as well as incorporate the other market solutions to that congestion in order to maintain a reasonable managed congestion level.

These are some very specific constraints that you are on our congestion list. These represent more than 60 percent, these top 10, more than 60 percent of the 2010 congestion. You can see several of the very top ones are PJM interfaces. And again, particularly those interfaces affect regions that you've heard about in Southwest MAC, the D.C. Area, the Maryland area, as well as the entire Eastern MAC area of Eastern Pennsylvania and New Jersey. So these particular limits can have very widespread effects. So, PJM is still in that Mid-Atlantic corridor, remains a heavily congested area that requires continuing attention.

I also point out that some of these are reactive limits, so it's not a simple thermal issue that causes these. And, reactive limits are of an interesting nature because, and we pay a lot of attention to our reactive limits. We have many reactive upgrades planned on our system, but reactive upgrades are very localized in their effects. So you'll take care of one, you'll put an SVC in one area and it'll fix those voltage problems, and you redo the studies and you find, well the voltage problems moved just, you know, 50 miles away. And so you haven't fixed your limit that much. So, reactive problems are interesting, they're challenging, and you know, they're something that you have to pay attention to.

This is a map of what our major RTEP upgrades are and the status of those currently approved upgrades. You heard a lot about the TrAIL line from the 502 junction. It's that line going from 502 junction to Loudon, that you see on there. It's one thing that I would say when I re-read the 2009 DOE study, that it sounded a little pessimistic about we're never going to get any transmission in to solve all these persistent transmission problems. But this line is in excess of 200 miles, 500 KV, crosses 3 states, and from the board approval to in service it was a little over 4 years. That's the poster child, maybe, for how everything can go right. I'd like to say that everything doesn't always go right. There are very significant challenges to, you know, achieving some of the planned transmission lines shown on this map that have not been put in service yet, and so we are continually, you know, looking at ways that we can facilitate, you know, the needed transmission upgrades that are specified in our plan.

So, this is specifics about the lines on that map. The TrAIL line is in service, the Carson-Suffolk line is in service, Susquehanna-Roseland is one of our current significant challenges to get that in service to address the reliability needs in Eastern Pennsylvania and Northern New Jersey. And as most are probably aware, that recent economic downturn that, you know, has caused the PATH line and the MAP line to be put in abeyance at this point.

So, this slide goes to very recent congestion patterns, and I like this slide because while congestion persists it does show that there is benefit to the recent transmission upgrades, particularly the TrAIL line and the Carson-Suffolk line that have been put in service, along with a myriad of other, smaller upgrades that you can't see that targeted smaller types of transmission issues. But you can see, there are, even though you heard some recount of the extremely high loads in the PJM region this past year, it was record energy consumption levels in PJM. And I believe we set some record peaks, including the integration of the new areas that we had, also. But we do see some significant decreases in congestion, you know, compared to previous levels.

And our projections of the types of congestion issues that we might see, you can see this slides covers projected transmission elements with at least $20 million of projected future congestion. And it also shows that some of these are affected positively or negatively by some of the transmission RTEP upgrades planned. However, significant levels are still being projected.

I would add, too, that PJM has recently completed an initial phase of a renewable integration study in PJM that looked at the installation of 41 gigawatts of wind in the PJM area in order to meet RPS standards for the PJM area. And that showed a significant amount of conditional congestion, we'll call it, that could arise if the PJM entities satisfy their RPS requirements by integrating all that wind into the PJM region.

So, we would say that we probably have some regional conditional congestion, with the provision that there's a little bit of an inference, I think, in the DOE definition that makes it sound like, well, we have conditional congestion and we have no way to handle it. We don't know what we're going to do. But, you know, we think that we can adequately anticipate with our current processes this conditional congestion and that we can put transmission upgrades or come up with other market solutions that are integrated into our planning processes in order to satisfy the needs of transmission out into the future to handle even these wind integration issues.

So, to wrap it up, PJM does experience significance west-to-east congestion patterns and congestion into our load centers, our load pockets. Some of the studies you heard referred to earlier about RPM type of analyses are analyses of the PJM load pockets, and so those are manifestations of congestion also.

I would mention that, I'd urge DOE to understand the difference between energy type of congestion and the congestion that we show in, you know, RPM type of analyses, which are indicative of capacity locational capacity congestion. And the purpose of the RPM studies is to create that locational price that drives an incentive for generation to locate in a particular area. It's only one of the considerations, however, I think as we've found, that causes generation to actually locate in a particular area. So, it's an important element and I'm not the best one to speak to the details of the RPM, but PJM has lots of evidence that RPM is working and does provide lots of generation retainment and generation installations that are a benefit to our system.

The Mid-Atlantic corridor is still a very congested area in PJM, as you've heard about today, and congestion management through the LMP markets distributes congestion very broadly to many of the loads in PJM. And so, there are granular manifestations of congestion, and it also has very broad impacts to prices to loads and generators.

PJM continues to monitor and evaluate the congestion issues, and it is an ongoing challenge to plan the transmission system and all the market solutions, you know, in unison and to achieve the installation of the transmission elements that we need to manage congestion in an ongoing fashion.

That pretty much wraps it up. Thank you.

MR. MEYER: All those presentations are an example of drinking from a fire hose. A lot of material there. Thank you very much.

I want to ask one brief question, and then we'll turn to questions from others. So far as I recall, none of you mentioned future gas prices and yet clearly the system and some of the changes that you mentioned are going to be very much affected by gas prices. So, a brief comment on that, what your expectations are there.

MR. BUECHLER: I'll take it first, David. I think I did mention that one of the principle reasons for the decline in congestion over the past couple years of gas prices, and at least our view, that one of the factors influencing congestion going forward will be the increased gas production leading to a relatively stable and lower price of natural gas. So, that's our view.

MR. HENDERSON: New England is currently very heavily dependent on natural gas: It comprises over 40 percent of our electric energy production and over 40 percent of our capacity as well. However, we do believe that with Marcellus Shale and other gas pipeline and LMG improvements that have occurred both recently and planned improvements in the natural gas system, that the prices will remain low for us as a region.

We are concerned with that heavy dependency.

And so as part of the strategic planning initiative we're looking at ways to try to deal with it, both from the gas system reliability perspective, but also in terms of aligning the markets to what degree do we want to, in some way, encourage and pay for, let's say, dual fuel capability or some other potential solutions?

There's also a lot of renewable development planned in New England. I did mention solar. The state of Massachusetts has some solar goals which are closer, as does Connecticut and the other states as part of their renewable encouragement policies developing close to load, as is the energy efficiency in the region that I made reference to.

So I think certainly there is some exposure there, but it's an issue we're aware of and trying to deal with.

MR. LIEBOLD: Traditionally, historically gas is not a big driver in PJM. However, times are changing. You've heard about the Marcellus Shale, so there is a potential for gas to be a much, you know, higher penetration into the PJM energy production than in the past.

Taken in isolation, it's very much like what's the impact to the EPA rules and the comments that were made there. It all depends. It's not so much the change in gas prices or the change in EPA rules, but it's what else happens after that, you know? And how do the markets respond, you know, to those types of fluctuations. So, you know, taken in isolation lower gas prices could decrease congestion. But then, if lots of new gas plants pop up in areas that are already congested, and coal doesn't retire in droves, then you could increase congestion.

So you know, it really does depend on what the market's response is to those types of variables.

MR. BUSBIN: Jim Busbin, Southern Company. I don't have our data in front of us, but we do expect gas prices to remain low. As I mentioned in my presentation, our concern is more so with the gas line capacity, the expansion of the gas pipeline system, and getting that to generation resources.

MR. BRADISH: I guess I'll just echo a couple things. Certainly prices are important. Probably equally if not more important are the price spreads between the different fuel options and of course, the geographic locations of those different fuel options. So, you have wind resources in one part of the region, that's difficult to transport wind, so you will build it there and you'll need to transport it. So it'll really be driven by the thoughts on those price spreads more than anything.

MS. SILVERSTEIN: I'm Alison Silverstein. I have two questions. One of them is for Chuck Liebold and the other is for all of you.

Mr. Liebold, I want to pursue an interesting turn of phrase that you used in one of your slides. You said that the top 20 congestion events account for 76 percent of PJM congestion, and I want to ask is this about events or is this about elements?

MR. LIEBOLD: It's about elements.

MS. SILVERSTEIN: Okay, so events is not like, we had 10 really hot days and those were when most of the congestion happened? It was about these particular substations and spots on the grid.

MR. LIEBOLD: Yes.

MS. SILVERSTEIN: Great, thank you. If it were Texas it would be the other way around, which was why this was an important point to understand. Thank you.

For all of you, we know that DOE doesn't want to look too far into the future or at too many conditionality with respect to congestion, but surprises happen and they happen quickly. And let me ask you if the economy were to get better and we were to have significantly hot days in your service territory next summer. If both of those things happened, your loads would increase markedly, I would guess. In that case, would you expect to see significantly higher transmission congestion? That certainly it would likely affect price but could it compromise reliability in some way?

MR. LIEBOLD: I did point out that we did have in 2011 just this past summer, you know, one of the hottest summers on record for PJM and congestion actually went down a little. However, that was because of other influences. In general, yes, hotter weather, all other things being equal, will cause congestion to be, you know, a very significant issue and probably a challenge.

MR. BRADISH: I'll just say, it's an interesting question because intuitively you think, the load goes up, congestion goes up. But it really depends on the geographic reach of the heat. We've had days where the Eastern part of PJM is burning up and we're cool in the West and the congestion is through the roof because we've got lots of supply and they all want it in the East. There's other days when the entire footprint of PJM is hot and you don't see the congestion. So it really, again, is going to be driven by those types of differences, demand differences across the grid and the resources available to the suppliers.

MR. BEUCHLER: We'll go back and forth to the tables here.

Yeah, I guess I would agree with both the comments that high load periods are not necessarily periods of highest congestion. In New York, for example, if you have high loads for whatever reason, weather could be the primary cause, in the northern part as well as southern part, well, then the generation that's in the north that would otherwise tend to want to go southeast would be used more in the north and you have less congestion. In those, of course they don't, so.

MR. BUSBIN: Alison, I'll take your question even further, I believe, because the scenario that you paint as we move down the road a few years and get into, as I mentioned in my presentation, the EPA compliance period, you couple with what you're talking about as far as changes in the economy that cause increase in loading coupled with the massive outages that we're going to see that are going to be required in retrofitting units and getting into compliance with those EPA regs, yes, reliability will be affected.

MS. SILVERSTEIN: Is there anything left to say on this, Mike? I bet you could come up with something.

MR. HENDERSON: I agree. (Laughter)

MS. SILVERSTEIN: Thank you, all those are very helpful.

MR. HENDERSON: We don't see the economy really affecting New England.

MR. MEYER: A little, do you have a comment you want to offer?

Mr. ROSEMAN: It was a question for the panel.

MR. MEYER: Okay, please, then. Go ahead.

SPEAKER: Actually, it's not unrelated to the question that Alison just put forward. The general question is, what do you think that the term of the study that DOE is about to engage in should be? All of you mentioned events that are coming up within the next couple of years. Chairman Finley in the first panel this morning said that we should be looking at places that are experiencing current, you know, present tense congestion.

But I just made a few notes as you all were talking. Mr. Busbin talked about the EPA regulations that could hit within the next couple of years. Mr. Buechler talked about the Indian Point potential retirement. Mr. Bradish talked about the wind belt resources. Mr. Henderson talked about the energy efficiency and how much forecasting they're going to do of that and how much may come online or not within the next couple of years. Mr. Liebold talked about transmission lines, the PATH line, the TrAIL line, sorry, coming online within four years from board planning until coming to fruition.

What should be the timeframe under which the assessment of congestion that DOE is undertaking now? What should that timeframe be? Should it just be between now and when the next study will be in three years or how far out? Should it just look at planned, should it just look at committed resources? Or can you go further than something that is already committed to?

MR. BUECHLER: I'll try that. I think as several of the panelists have mentioned, recommending that the DOE look at existing regional plans and other data and analyses that are available, that would tend to something like a 5 to 10 year timeframe. So, I believe it's reasonable to look at a nearer-in timeframe at least, because of all the obvious, the lesser, at least, degree of uncertainty in that timeframe.

MR. LIEBOLD: I would say that the valuable timeframe is that timeframe in which we engage in what I'll call actionable planning: The planning that is pursuant to, you know, the criteria that we have laid down that results in projected, you know, needs for resources in the relatively near term. So I would say that that is also five to ten years. And it should include the resources that we've identified that have a relatively higher commercial probability of coming to fruition.

I think the very long-range studies are good. I think that they perform a role also, like the EIPC study. I draw the analogy with the EIPC study to, it's like a Detroit concept car, whereas, you know, you'll never see it built perhaps, right? But there are lots of elements in those cars. There are lots of elements and we learn lots of things from the very long-range studies that we can being to, you know, anticipate and perhaps see and incorporate into our actionable plans.

And in order to have a good plan you need to have some range of ideas of where you might be going in the future. So, I wouldn't be so negative about the EIPC study. However in terms of this DOE congestion work, it's probably of lower significance.

MR. BRADISH: Yeah, as a transmission planner I'm right there with the two previous speakers. You can't do anything less than 5 years in this transmission world, so 5 to 10 years would be good. And you know, the other things that are happening are going to be happening within that timeframe in addition. So I think that's within, as Chuck used the term, actionable timeframe where you might be able to actually get something done.

MR. BUSBIN: Jim Busbin, Southern Company. And lastly, I'll take the easy answer here and say yes, I agree with the 5 to 10 year period.

MR. HENDERSON: I agree with John. I think if we got to go back to what is the real purpose of the study that David reminded us of in the beginning of today's meeting. And what I heard is that the focus would be, I guess, to provide a study that could then be used for the identification of national corridors. So for that end, no? Am I saying that wrong? It could inform.

MR. MEYER: Yes, but it, I've always understood the Act to say, DOE, you will do these studies. And we want to do them in a way that provides useful information to people who are interested in transmission issues.

The further step to national corridors, that comes later. But I wouldn't limit the congestion studies to simply providing a possible basis for corridors.

MR. HENDERSON: But to that point and informing that point, what I would suggest is a focus on historical or as found congestion on the particular systems, and then looking at the robustness of the particular transmission plans that are in place, and then the historical success of being able to implement those particular plans.

And so, I think that speaks more to a closer in focus, perhaps something in the five-year range or maybe even closer in as a primary focus. The longer term you look, the more kind of speculative the plans become and I think it's certainly more definitive in that shorter timeframe.

MS. JONES: I'll be quick because I know we're running out of time. The gentleman from Southern and the gentleman from AEP, I want to know if you agree or disagree with each other around this point. Southern seemed to be saying congestion is around firm transmission. AEP seemed to be saying, well that wind which is not firm should count as congestion.

So, do you agree with each other or disagree?

MR. BUSBIN: Go ahead. (Laughter)

MR. BRADISH: Well, we do operate in two very different contexts. We are fully engaged in an RTO and Southern, as Jim said, is not in an RTO. So whether we like it or not, whether we call it firm or not firm, those distinctions have much less meaning in an RTO world then they do in Jim's world. He's not living in RTO, he's living in transmission, you know, physical transmission rights. I'm living in PJM, which is all about financial.

So, the two contexts are very different. So within PJM it's all treated the same. So my point is, if that stuff is going to flow and it's going to create congestion and it's economical to build a transmission solution to relieve that congestion, you should do that.

So, it's a completely different context which we operate in. So, Jim?

MR. BUSBIN: Yeah, we feel that non firm flows are I guess speculative in nature. And so, therefore, should not be concluded in the determination of congestion.

MR. BRADISH: I don't know if that helps you or not.

MS. McNALLY: I have a question. I'm Diana McNally from Con Edison, and in general we're looking forward to seeing a study that involves a lot of analysis of data and facts. And just a question for the panel is, how does each of the regions go about forecasting future congestion and how far out can they make that forecast?

Thanks.

MR. BUECHLER: I'm from New York, as you probably know. As part of our economic planning process we look at a 10-year horizon, the same as the 10-year horizon we used for our reliability planning process. So when we do the forecast part of congestion we then combine with the 5-year historical congestion to determine the 3 highest congested elements, it's 10 years forward.

MR. BUSBIN: Jim Busbin from Southern Company.

To answer that, it's been a long time since I've been a transmission planner but we engage in regional planning processes whereby we look at a combined model to make those determinations and go out, those go out typically 10 years.

MR. HENDERSON: I don't know that New England would really call it a congestion forecast because we don't really forecast future bidding behavior and all that. However, what we do is we do a number of scenarios called economic studies consistent with Order 890. To date, those studies have looked out 10 years but we've done some special studies that actually simulated the year 2030. Those studies were conducted at the request of the six New England governors and we did some follow-up studies as well to inform the policymakers in our region of what some of the long-term visions of New England might look like and to help them then try to get to the future that they feel would be the most desirable for the region.

MR. LIEBOLD: PJM does a variety of studies. We do internal PJM market efficiency analysis pursuant to a bright line market efficiency criteria. Those studies evaluate, I believe it's four snapshot market efficiency evaluations, annual evaluations projected out into the future, and then do a cost benefit ration analysis over a 15 year time horizon. So, I'd say 15 years is our internal planning.

We do additional types of market efficiency studies interregional where we look at cross border, we do interregional studies where we look at cross border (Interruption)

MR. LIEBOLD: Hello? Oh, this one works. Time is up, I guess. (Laughter)

So, we also look at interregional studies, particularly with the Midwest ISO, but we also do, we are beginning to get into more types of congestion analysis with our New England friends also. However, the cross border congested flowgate study that we do with MISO on a periodic basis evaluates, you heard it referred to earlier, there's probably 100 or, you know, certainly dozens of jointly managed flowgates between PJM and MISO. So annually, we look at what the congestion is on those jointly managed flowgates and we'll do a joint study to see if there is benefit to alleviating that market congestion that occurs on our seams.

Those are pursuant to, also, a bright line criteria that's a little bit different from our regional criterias, and I believe that is not a specific time horizon but has to be a multi-year future time horizon that we look at for that.

MR. HENDERSON: I just want to, I'm sorry, I just wanted to correct something. I think I misspoke and I think I said Order 890 when I should have said Order 1000 before. So there is a record, I just want to make sure I'm saying the right thing here.

MR. BRADISH: The only other thing I wanted to add to this question was, keep in mind we're putting in place assets that will last 40 to 50 years. And you want to make reasonable decisions around assets that are going to be in place for 40 to 50 years, and make sure that they're used and useful during that timeframe.

So, you need to push the time out to do these types of studies, so you have to have a reasonable forward-looking. Yes, it's the future and we don't know what it's going to be, but you make some assumptions, you run some scenarios, and you make some decisions around those. But these are long-lived assets.

The only other thing I'll add, and I've got three RTOs here, is that I would love to have them all

synch up their processes so they all do them at the same time, that they do them over the same years, and look at the same futures. That would be awesome.
(Laughter)
MR. MEYER: Well, we're going to, I'm going to take up, I'm getting us off the hook now. Please give them a big round of applause, I think they did very well. The last stage of our workshop is an opportunity for members of the public who want to provide input or comments to do so. And I don't know if we have anyone registered?
(Interruption)
MR. MEYER: Ed Tatum do you want to -- yes, please.
MR. TATUM: I'm getting a little fearful of all these thing. I'm Ed Tatum with Old Dominion. Thanks so much for putting this together. Thanks, it's a lot of engaging conversation. I was sitting in the back listening and wondering if we're starting to measure the right things.
Again, you know, we had this metric and we've seen a lot of volatility. We live in PJM and the market world, so we do get a lot of volatility from gas, from various other aspects of the fuel supply.

So the question being, and Alison kind of hit on it a little bit earlier, is this concept of events. And I know in PJM every so often we do look at events of congestion. And I don't know if that might be another metric that we may wish to consider. We started off looking at the concept of total congestion and it's oh, my goodness, it's going up and down. And we have opportunities here. Now, congestion is getting better. Is that good news? No, we're in a recession. That's not good news. Congestion might go away if we lose a lot of coal fired units because of the EPA regulations. Is that a good outcome? I'm not sure it is.

Congestion is but one part of the overall LMP equation. We have LMP, equals, the energy, we have the congestion component, and now we have something new called marginal losses, and that's a very significant piece that we didn't have when we first started these studies going. We also had the reliability pricing model, that's a very important aspect of a congestion cost and I like what was said about the concept of the interconnection queue being a barrier to getting reliable and affordable capacity to load.

So the question is, are there other metrics we should be using that would be historically based? How many times were the top 20, Chuck, constrained, regardless of the various price differentials between the West and the East? And should that be something we're looking at?

And then the other question would be, should we be looking at not just the congestion component of LMP, but the overall LMP as well? Or a relationship to the LMP and congestion component?

Thank you.

MR. MEYER: Any other commenters? Seeing none, we will declare the meeting adjourned and thank you all.

(Whereupon, at 12:27 p.m., the PROCEEDINGS were adjourned.)

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CERTIFICATE OF NOTARY PUBLIC

COMMONWEALTH OF VIRGINIA

I, Carleton J. Anderson, III, notary public in and for the Commonwealth of Virginia, do hereby certify that the forgoing PROCEEDING was duly recorded and thereafter reduced to print under my direction; that said transcript is a true record of the testimony given by witnesses; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this proceeding was called; and, furthermore, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor financially or otherwise interested in the outcome of this action.

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Notary Public, in and for the Commonwealth of Virginia

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