BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the Matter of: :

PJM/MISO JOINT BOARD MEETING : Docket Number:

ON SECURITY CONSTRAINED ECONOMIC : AD05-13-000

DISPATCH :

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Doubletree Hotel O'Hare
5460 North River Road

Rosemont, Illinois

Monday, November 21, 2005

The above-entitled matter came on for pre-hearing conference, pursuant to notice, at 9:57 a.m.

BEFORE:

NORA MEAD BROWNELL
FERC Commissioner
Chair

KEN SCHISLER
Maryland PSC Chairman
Vice Chair

KEVIN WRIGHT
Illinois Commerce Commission Chairman
Vice Chair

APPEARANCES: (CONTINUED)

Paul Malone
Fred Butler
Dallas Winslow
David Lott Hardy
Agnes Yates
Thanh Luong
David Meyer
Jim Torgerson
Phil Harris
Doug Collins
Bret Kruse
Fred Kunkel
Steven Naumann
John Orr
Ed Tatum
Joseph Welch
Derek Kruk
Daniel Ebert
Earl Melton
Howard Spinner
Pat Miller
Gary Hanson
Wendell Holland

APPEARANCES: (CONTINUED)

Alan Schriber
Susan Wefald
Greg Jergeson
Jeff Davis
Ken Nicholai
Laura Chappelle
Gary Hastiner
Mark David Goss
Sam (Jimmy) Ervin
John Norris
David Sapper

C O N T E N T S

C O N T E N T S (CONTINUED)

C O N T E N T S (CONTINUED)

C O N T E N T S (CONTINUED)

P R O C E E D I N G S

(9:57 A.M.)

CHAIRMAN BROWNELL: We seem to have lost one of our Vice Chairs but that's okay. We're going to start without him because the Trans is going to leave on time today.

A couple of housekeeping details because Sarah McKinley would break my leg if I didn't do this first off. If you want a fast lunch, go out the door and turn right and there will be several options available to you. And if you don't want a fast lunch, you can go left and then we'll start without you after lunch. So, does everybody understand that? Okay.

Also, I have been asked by our sound technician to please speak into the mikes clearly. It's important for the taping, it will also be important for those on the telephone. And for those who aren't yet on the telephone, identify yourselves. But in any event, identify yourselves if you will so that everyone knows who you are and what you're representing.

I'm going to make just a couple of brief remarks because you all hear from me frequently enough, but I welcome all of you, welcome all friends. But I am thrilled to see so many new leaders at our state commissions and I hope that those of us who have been around for a thousand years will take the time to get to know our new colleagues. I'm hoping they will come visit at the FERC and I have already made arrangements to come to at least one of the states so that we can share our common goals which is to bring value to customers.

I think that is why obviously in EPAct '05 Congress did a great deal to recognize the importance of the energy sector to the economic development and social well being of our country, and directed DOE to issue a report and an annual report thereafter and directed us to convene joint boards to look at the issue of economic dispatch to understand how it's working in various parts of the country to make sure that we have a full understanding of what makes it work and perhaps what barriers continue to exist. It becomes clearer and clearer as we face a winter of high prices that we need to wring all the efficiencies that we can out of the system.

So, this morning, we are going to begin with a presentation by Thanh Luong who is on our staff. He and Bud Earle who are both here have worked on economic dispatch issues for us. He'll be followed by Dave Meyer who has come to present the long awaited DOE report. We thank you for coming, David. The report was, I think, officially issued Friday or Monday, so many of you have not had a chance to see it. There are copies outside and we'll have more opportunity to discuss that at a later date because I know many of you will have questions after you have read it.

It will then be followed by presentations from Jim Torgerson and Phil Harris, our grid managers who can explain to us how economic dispatch fits in to the overall market design. (And here is our Vice Chairman.) And then this afternoon, we'll have a panel of stakeholders who will give us their perspective and make recommendations.

Just to go over the process, the goal is that we will make recommendations to Congress. We plan to have a series of teleconferences following this. We'll have one with Dave Meyer and the DOE team to make sure that you have a full opportunity to explore that report. We'll come up, I hope, with recommendations that we can then review together. We'll reconvene with the other parts of the country. We will reconvene at the February -- meetings with the idea that that will be the most efficient way because people will already be in Washington.

But in the interim, I will hope that people will be free both with comments and there will be comments on this meeting due in 21 days, or 29, Christine? 21 days. But that obviously won't be the only opportunity.

So, we appreciate your participation and hope this is a full and lively day. Let me just remind you that this is an opportunity to explore economic dispatch. That's our charge. So, for those of you who are tempted to stand up and wax eloquent on something that is unrelated, we'll kind of have to ask you to sit down because Congress didn't ask you or us to speak on those issues at this moment in time. So, I hope that we can be disciplined.

I want to thank, in addition to Thanh and Bud Earle, I want to thank Sarah McKinley who is our logistics person, and also introduce the other staff that are here: Tugnasi Gadani; Pat Cleary who is from MISO; and my staff, Christine Schmidt, whom you have all heard a lot from; Jim Peterson; and Mary Morton. And they are sitting behind. And feel free to ask them questions about this or anything else.

And with that, I will turn it over to Ken Schisler.

VICE CHAIR SCHISLER: Thank you, Commissioner. I truly appreciate this opportunity and the tremendous -- work by not only you, Commissioner Brownell, but also your staff and other FERC staff and the DOE actually for preparing for this joint board, its work and analyzing this very fundamental component of market design.

I also want to acknowledge the leadership of Congress in creating this joint board and other joint boards to revisit the assumption that security constrained economic dispatch serves the nation well as to ensure reliability at reasonable cost in organized wholesale markets. I think it's altogether appropriate to do this, and as the proponents of wholesale competition will claim, that economic was and is the right policy choice. It should stand up to the scrutiny and reaffirm our basic understanding of it. At the same time, this joint board gives us the opportunity to honestly assess whether we are best served by this model and whether any mid-course corrections are necessary and appropriate at this time.

Today, to reiterate Commissioner Brownell's point, it is my hope that we will remain focused on the fundamental question mandated by Congress. There are numerous sub issues and subordinate issues embedded within the discussion, but Congress gave us a narrowly focused mission on a very broad topic. And so, we are going to have to be disciplined if we are going to stick to the very basic fundamental question.

So, with that, I'm excited to be a part of this effort and look forward to hearing from all of our participants today.

CHAIRMAN BROWNELL: Commissioner Wright acting as Chairman of Illinois --

VICE CHAIR WRIGHT: Well, let me clarify that. Until the Governor appoints one, I've been asked by my fellow commissioners to carry out the duties of the chairman as a sitting commissioner. So, I'm not going to use the word chairman, just commissioner.

I just want to take this time to welcome my fellow commissioners to Illinois and to Chicago and to this endeavor that we are engaged, and also to thank FERC for its engagement of the states. We have very strong opinions about being partners in these proceedings and decision making and we certainly appreciate FERC's outreach to include states in this process as well.

I really can't add any more than already has been said. The readings that I have done so far have been quite educational as we try to understand the issues that are before us and the report that will be rendered to Congress. And so, I look forward to today's endeavor and welcome you all to Chicago and to this proceeding. Thank you.

CHAIRMAN BROWNELL: Thank you. Before we turn it over to Thanh, I do want to encourage you to look on the table outside. You'll not only see copies of today's presentations but some other presentations developed by our staff as well as a list of references for those of you who do not have enough to read. There's about five pages of opportunity to be an expert on economic dispatch. So, I would encourage you to pursue those which may interest you.

And with that, Thanh, I'm going to turn it over to you, and then Dave, you can pick it up.

MR. LUONG: Good morning, Chair Brownell, Mr. Vice Chairs and board members. My name is Thanh Luong. I'm a Senior Electrical Engineer in the Reliability Division of the Federal Energy Regulatory Commission.

I would like to thank the joint board for the opportunity to present the high level overview of the concepts, practices and issues of the economic dispatch. My presentation consists of two parts. The first part is to discuss the general concept of the economic dispatch and the practice of economic dispatch in the non-RTO and the RTO structures. The second part is to provide a list of initial issues related to the economic dispatch for the joint board to consider and may address them in the final report.

Starting with the definition of economic dispatch, we adopted the definition provided in Energy Policy Act Section 1234. Economic dispatch is the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.

Most electric power system dispatch their own generation unit and their own purchased power in a way that may meet this definition. This definition reflects closer to real-time operation on the day dispatch. In order to achieve the economic dispatch on real-time, utilities have to do a lot more planning on the day-ahead to prepare for the dispatch. Sometimes we call it day-ahead planning or day-ahead unit commitment.

Starting with the day-ahead planning, all power systems operations develop generation unit dispatch for each hour for the next day based on the load forecast, based on the generating availability and the unit characteristic limitations, purchased power and operating reserves. After that, they give it to the transmission operator to perform reliability assessment. Taking into account the transmission outage, they perform a lot of load flow analysis and contingency analyses to ensure that load can be served reliably for tomorrow. That's the second part of it. And look at that, it's a sequential step from generation and then the transmission.

And the RTOs develop regional day-ahead schedules using Day Ahead Markets, sometimes they call it security constrained unit commitment. And this security constrained unit commitment is also based on the supply offers, the load forecasts, the demand bids from market participants including non-utility generation units. And this simultaneously considers both cost and reliability limits at the same time. And this produces hourly prices for the day ahead and it's just like the rest, it ensures that the day ahead commitments are feasible within the reliability limits of the power system.

With all the planning for the day ahead, one would hope that tomorrow there would not be a lot of changes. But actually, you know, the load forecast can change, the generation can be tripped off, or the transmission line can fail. So, in real time, a lot of power systems dispatch operators monitor their load, generation and interchange to balance the generation and load, maintain system frequency using automatic generation to change the generation dispatch as needed. Also maintain the operating reserve requirement.

The transmission operator also monitors flows and all voltage levels on the transmission system within the reliability limits. When needed to comply with reliability limits, that means when the transmission is constrained, most of the Eastern Interconnection are using the -- TLR procedure to manage the congestion. The -- TLR procedure is mainly curtailment flow to relieve constrain. It will allow redispatch when the TLR level will go up to level 5 and above. And if you look at that, it's a sequential process.

In the RTO, the RTOs manage the real time dispatch using the Security Constrained Economic Dispatch software. And it runs every five minutes and it considers both generation and transmission reliability limits simultaneously. It dispatches the instructions to generation and load and calculates the LMP price. One of the attributes of the Security Constrained Economic Dispatch is the LMP congestion management instead of the TLR. Using the market-based congestion management, it will minimize or eliminate the TLR process -- economic redispatch. As a last resort, the RTOs are still using TLR when they run out of dispatch options.

My second part of the presentation is the possible objectives and issues related for the joint board report. The report could first describe the current application of economic dispatch in the region and the consider the improvement to the current economic dispatch. To describe the current application, one would look at the scope, you know, the geographic, the footprint of the economic dispatch. One benefit that one could see is basically the different time zones if the footprint is big enough. Just like 6:00 a.m. in the East, still it's 5:00 a.m. in the Midwest, and so the same thing for the evening. You know, 11:00 p.m. is our peak hour in the East but it's still 10:00 p.m. in the West. It's the peak hour so that dispatch can be moving back and forth for the benefit of that.

And the resources that are included in the economic dispatch are including the generator, non-utility generation unit with the utility generation unit. The implementation of the economic dispatch, you know, the footprint of it, how big this is and the bigger the footprint actually sometimes it may increase the risk of the single point of failure. You know, what if the centralized economic dispatch is having a problem? So, the software is very important. It should be robust and it needs to have another alternative way to do it for the backup system.

Another area that can have the technical issue with that is the communication of information. On the generation, information should be given to the entity that will perform the economic dispatch. And also, the information from the entity that performs the economic dispatch also is given back to the generation operator on time so they can follow the instructions. Those information have to be accurate and have to be on time in order to do that.

Then the other one is consider the improvements of current economic dispatch practices. We have the following questions and issues: What improvements could be considered? What are the potential benefits and costs of those improvements? How would those improvements affect or enhance reliability? Are there any regulatory impediments to the identified improvements? This concludes my presentation.

CHAIRMAN BROWNELL: Thank you. We'll hold questions until after David has completed his presentation. I would remind you that all of the mikes are hot and I am asked to remind you to watch your sidebar conversations. Although it could be some interesting entertainment, it is difficult for the people on the phones. Also, I should remind myself of that.

MR. MEYER: Thank you, Madam Chairman. It's great for me to have this opportunity to come and talk to you, talk with you about the report that DOE has just released on economic dispatch. This report was mandated by the Congress in two sections of the Energy Policy Act. And the Congress told us to study current economic dispatch procedures and to identify possible improvements and analyze the potential benefits of such changes. And Thanh has already cited for you the definition of economic dispatch that's in the law. I'll give that to you again just as a base to go forward.

It's the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operation limits of generation and transmission facilities. Now, it's interesting that the people who commented on the questionnaire for us, none of them took issue with this definition and the definition seems to have held up pretty well so far. So, we're pleased about that.

We prepared a short questionnaire of six questions about economic dispatch practices and possible improvements. We circulated that to interested stakeholders through seven trade associations. And we gave people a pretty short time to respond but respond they did. We got responses from 92 separate parties.

And I'm also pleased that the responses were very diverse. We got responses from all sectors of all groups of stakeholders and so we drew heavily on these comments in preparing our report. And we also reviewed a substantial body of literature that's out there that gave attention to economic dispatch or to regulatory organizational changes that affect economic dispatch. So, that literature was also fruitful.

Turning to our findings, we found that as Thanh has already alluded, the economic benefits tend to increase as the geographic scope and electrical diversity of the area under unified dispatch increases. There are some caveats to that, and that is, bigness isn't always automatically better and people do think that at some point the system can become too complex to manage. But personally, I haven't seen too many of those limitations being identified thus far. We all recognize there must be such limits at some point but still.

Now, the retail customers benefit if the cost savings are passed through in retail rates. And also, economic dispatch can reduce fuel use and emissions as high efficiency units frequency displace lower efficiency units using the same or similar fuel. That is frequently the case; it's not uniformly or always the case, however.

In practice, economic dispatch requires balancing economic efficiency, reliability and other factors such as the ability of a given generating unit to shift output at short notice and scheduling limitations imposed by environmental laws, hydrological conditions and fuel characteristics. And as a result, economic dispatch is what the economist would call a constrained cost minimization process.

And there are two subtypes of economic dispatch: that is the unit commitment which is done on a day-ahead basis, and then unit dispatch which is done in near real time. In practice, both are security constrained but as I've explained earlier, there are a number of other kinds of constraints as well. It's not just constraint in terms of reliability concerns.

And in terms of regulation, regulatory responsibility for economic dispatch, it's dispersed among, the states have lead responsibility for economic dispatch by investor-owned utilities. FERC oversees economic dispatch by RTOs and ISOs. And then, for public power entities and cooperatives, the oversight is provided by their respective governing boards. So, I think that economic dispatch is a peculiarly appropriate subject for a joint board, and so I'm looking forward to the results of your efforts.

In terms of the extant studies that we reviewed, there were two basic types. Some of these studies were analyses of impacts associated with the proposed formation of ISOs and RTOs. And then the other category, basic category was studies of dispatch of IPPs, independent power producers. And neither type of study, however, was designed to produce the disaggregated assessment of benefits of economic dispatch that was envisioned in the sections of the Energy Policy Act. So, we tried to extract as much value as we could from those studies; but nevertheless, the studies were not written with that kind of question in mind.

The RTO studies found benefits in the range of 1 to 5 percent of total wholesale electricity costs, that is the benefits of economic dispatch. The IPP studies found benefits of 8 to over 30 percent of total variable production costs. So, those two measures may sound like there are substantial differences between them. Actually, that's probably not true because one is looking at total wholesale electricity costs and the other is looking at total variable costs.

The principal issues that we found pertinent to economic dispatch in the body of comments that we received, the non-utility generators or at least some of them assert that some vertically integrated utilities use dispatch processes to favor their own generation. And this may be that favoring of particular generation assets may result from the operating rules and practices used for economic dispatch. That is, if the rules and practices have the effect of excluding non-utility generation capacity from what's called the economic dispatch stack, that is when you put these plants into merit order, the rules and practices used may either exclude capacity from that stack altogether or it may affect the position of a particular generation resource in the stack.

And these practices or rules may include, for example, rules for determining whether non-utility generation receives long-term contracts for their output or for the use of transmission facilities, and whether non-utility generators provide sufficient operational flexibility to qualify for economic dispatch. Being able to qualify for economic dispatch means that you have to be very responsive to changing conditions and some non-utility generation is arguably doesn't provide that kind of operational flexibility.

It didn't show up in our study or in the body of comments that we received, but as we were writing the report, the question of economic dispatch versus efficient dispatch became a matter of great interest, particularly before the Congress. But I expect it's also a matter of interest at the regional level as well. The point here is that economic dispatch does not always run high efficiency gas units before it runs lower efficiency units. I would say it usually does so, at least we don't have systematic data on that yet. But that's the result that one would expect, but that is not always the case.

And whereas efficient dispatch would presumably seek to mandate that units be dispatched in efficiency order, the Department of Energy is skeptical of the merits of efficient dispatch because we think it would increase consumers' electricity costs for benefits that are at best uncertain. By comparison, we think that improvements to economic dispatch, going back to economic dispatch, staying on that path but trying to make improvements to it, that such improvements would have the potential to both reduce consumer costs and improve the efficiency of natural gas for generation.

So, in terms of possible improvements to the practice, the joint boards may wish to examine economic dispatch practices in their respective areas to determine whether non-utility generation capacity is treated appropriately. DOE urges the non-utility generation and power purchaser communities to work together to ensure that contract terms compensate non-utility generators for providing operational flexibility.

Another issue that we think has some promise is to focus on the tools used for economic dispatch; that is, the software, the data, the algorithms and the assumptions. These should be subject to systematic review and testing. And I don't think there has been that kind of systematic review done today.

And finally, the economic dispatch is very dependent on the accuracy of load forecast. And improvements in the accuracy of such forecasting will, by themselves, lead to improvements in the efficiency of economic dispatch. So, with that, I will stop for questions.

CHAIRMAN BROWNELL: All right, I'll start. And if people have questions, if you'd put your tent cards up, you know the drill from --

You suggest that a better analysis of the tools that are used be undertaken, and I hope that you would say more on that because that's clearly been an issue in some parts of the country, not all. And it's pretty clear that if your modeling is incorrect or your tools are incorrect, you can in fact manipulate the outcome which obviously impacts on who gets dispatched and who doesn't. But who should undertake that review, Dave, and how would one go about that? Is that a DOE project? I'm just not sure how the joint board would actually go about doing that.

MR. MEYER: Right, sure. Well, we do have an annual assignment in the Energy Policy Act to focus on economic dispatch in an ongoing way. And in 90 days, we didn't think we could undertake to answer all of the kinds of questions that are in the section of the Act. So, what we tried to do here was to lay out a landscape, and those are some of the issues that we will focus on going forward. But I think this cries out to be done with a lot of input and cooperation from other parties, and we'd be happy to talk about working with FERC staff or with states or the industry, of course. We'll see what feedback we get from this report and decide how best to go in terms of particular next steps and see what people feel is really important and where they see a lot of the payoff.

I think there are a lot of questions here that can only be pursued through empirical analysis, and so it does require collecting a substantial amount of data and particularly from different parts of the country would help. But we'll be happy to take input from people.

CHAIRMAN BROWNELL: Did you, I know that there is some distinction and comment on different regions, and I know you really didn't have time to drill down as much as you would have liked. But did you see any difference between complaints by the non-utility generators based on RTO markets versus non-RTO markets?

MR. MEYER: Well, again, the data that we collected was, you couldn't say that it was a statistically valid sample. But we did notice that the non-utility generators in the organized markets seemed generally pretty content with the way economic dispatch was going. There are always going to be some possibilities of technical improvements in the practice, I think, no matter who is doing it. But it did seem that they were generally content with the way that formal markets were handling the economic dispatch.

CHAIRMAN BROWNELL: Thank you. Laura?

MS. CHAPPELLE: A quick question. And thank you for this overview. You all can hear me? And I appreciate the written material, and certainly the question I'm going to ask seems to be answered here, but I just am hoping you can help flesh it out a bit. You kind of ended your overview today with the conclusion from DOE that economic dispatch, the modifications to that would be preferred over using the efficient dispatch. And if you could, can you just expand on that and tell us what you perceive the differences to be and why you think that modifications are favorably to simply using the efficient dispatch model?

MR. MEYER: Well, it's hard to, if economic dispatch is done well, then it's hard to improve on it. And going to efficient dispatch is going to sort of take you off that economic efficiency beacon. And I'm not saying that one wants necessarily always to follow the economic efficiency path, but you better have a pretty clear rationale for going off that path. And it would tend, by definition it would increase consumers' electricity costs. Whether there would be offsetting benefits that would make it worthwhile to bear those higher costs would have to be shown. So, right now, I'm just skeptical that it would appear to be an improvement.

CHAIRMAN BROWNELL: Alan?

MR. SCHRIBER: Thank you. Either Thanh or David. If I'm the utility and I'm self-scheduling because I have some inflexible generators and maybe kind of high cost, doesn't that constrain you to some degree or maybe even to a significant degree on what it is and how much you can economically dispatch? I may have a plant that may be somewhat economic in the stack because it's high cost from inflexible. How does that fit into the dispatch role?

MR. MEYER: That's where some of the art, I guess, in terms of designing these rules comes in because, for example, a given unit may be inflexible in the sense that you're talking about. It may be comparatively inefficient for an hour or so when it first starts up. And so, in some way, but it may then turn out to be more efficient later in its operation. And so, you have to balance these things in setting up the algorithm that selects the unit to be run so that everything depends, in my view at any rate, it depends on the input data. You have to have pretty good data going in into the algorithm about when that plant starts to become efficient to run and you need to average these things over a longer period of time and schedule it based on that longer term level.

MR. SCHRIBER: So, in other words, the more self-scheduling inflexible generation that's on board, the greater the possibility of deviating from what's most economic in general? Is that correct?

MR. MEYER: It depends on the quality of the information going in. If you've got good information about the plant characteristics and that's accurate, then I think the algorithm could handle that.

CHAIRMAN BROWNELL: Thanh, if you want to add?

MR. LUONG: I think it depends on the portfolio generation that you have. You know, in order to self schedule and it's inflexible, I mean, it may be inflexible in terms of the efficiency heat rate, you know, but it may be constrained by the fuel contract, by certain other constraints that you had to do. So, some utility look at it in a longer term, you know, have a weekly unit commitment or a monthly unit commitment to commit that unit. So, it depends on the portfolio that you have. And on the surface, it may be inefficient but there must be a constraint somewhere. That's the reason you become inflexible to do that.

CHAIRMAN BROWNELL: Wendell?

MR. HOLLAND: Sure. Mine is more a comment and I'd be interested in hearing the debate in the pre-distributed materials. Is it Jim Torgerson? I think his testimony kind of went straight to this point and he basically said that there seems to be some confusion about economic versus efficient dispatch. And he says that economic dispatch is in fact efficient dispatch. And the real confusion seems to be one with respect to access.

I would be real interested, and I'm not asking you a question but I am inviting him in his testimony to comment on this particular issue because it seems to be, he said something about a false red herring. So, it's more of a comment rather than a question, and Jim, I hope you take me up on that.

CHAIRMAN BROWNELL: You're the boss, he is going to take you up on it. David?

MR. SAPPER: Hi, David. You touched on findings or speculations about dis-economies of geographic scope or scale with economic dispatch. It seems to suggest things just become too complex at some point. I was wondering if that comes from kind of the cost minimization side of SCED or the reliability side in terms of things becoming too complex.

MR. MEYER: That's simply reflecting some of the input, the comments that we got from some parties. There were commenters who felt that there was a significant risk of systems becoming too large to manage effectively. The people who were running very large and complex systems didn't seem to exhibit that much concern about the problem. So, our data is simply not systematic enough to enable us to go deep into this subject. We simply acknowledge that the problem has been raised and the issue has been raised. But I don't think we have enough information to go much further.

MR. SAPPER: Okay. Does the study go into RTO configuration at all?

MR. MEYER: No.

MR. SAPPER: Issues of contiguity, I guess?

MR. MEYER: No, we did not. Again, we simply didn't have the, you know, we had essentially two bodies of material to draw on: these existing studies and then the body of commentary that we received from responses to our questionnaire. So, dealing with some of these questions more systematically is something that we can think about going forward.

MR. SAPPER: Okay, thank you.

CHAIRMAN BROWNELL: Are there any more questions from staff? Randy?

RANDY: Randy Reese Miller, staff of the Illinois Commerce Commission. To follow up on David's question, both of you gentlemen mentioned the potential benefits of expanded geographic scope of economic dispatch. But I don't believe either of you put it on what I noted down here as the To Do List for this proceeding to examine. Did I get that correct? And if you didn't put it on your To Do List for this proceeding to examine, why not?

MR. MEYER: I certainly didn't mean to exclude anything from your possible To Do List.

MR. LUONG: Yes, I think we put it in as initial list of issues that need to be addressed but it's not a complete list.

CHAIRMAN BROWNELL: I think one of the reasons Congress set up this sequence, report, joint boards and then meetings to determine what recommendations they want to make is just that. The limitations of time to which David referred clearly did not allow them to explore all of the areas that they wanted to explore or we would like them to explore. So, I think this is the opportunity to try and identify those things.

Are there any other -- yes, sorry.

MR. HADLEY: Dave Hadley from the Indiana Utility Commission. For David, Section 3 of your report talks about the need for better data compared to the type of analysis done on economic dispatch already available. And then you pledged that you were going to be looking at that for next year's report to Congress. In relation to this board's work and trying to understand costs, benefits and data, what specifically should this board be thinking about so as not to duplicate the type of work you're doing but to add to that body of work?

MR. MEYER: Well, I think the thing that we particularly want to hear from you is get a sense of what issues you want to pursue. The data question is I think about questions first and then relevant data as the next step. So, and the circumstances for your part of the country are so different from other parts of the country that it's going to be, for us at least, a very different set of questions that I think you folks would be interested in as compared to some of the other boards.

CHAIRMAN BROWNELL: And is that because there is more transparency, we have more data? Is that --

MR. MEYER: No. It is more you've got more transparency, the markets are organized. It's a question of are those market rules in some way affecting economic dispatch that we ought to try to learn more about.

CHAIRMAN BROWNELL: Okay. Sorry.

MR. HADLEY: Thank you.

MR. NICHOLAI: And this is to both of you. When you look at the actual operation of the RTOs, for example the transmission owner's agreement requires the management of the RTO to maximize transmission revenues. So, I was wondering if either of you had given any thought to whether or not there is a potential conflict between the goal of economic dispatch in the way the transmission owner's agreement requires the maximization of transmission revenues and whether that's something we might want to explore to make sure that if there is a potential conflict, that we eliminate it.

MR. LUONG: Yes, I think for the security constrained economic dispatch in the RTO, actually when it had a constraint, a missing constraint, using the SCED, Security Constrained Economic Dispatch, every five minutes is solving the most minimized, the most optimized way to solve it unlike the TLR position to do the management congestion. TLR has the tendency of more, it's starting with a contact path. You know, that's not really a true flow. And it had a tendency of, you know, over-curtailment. So, actually it's harmful to the utilization of transmission. Using the Security Constrained Economic Dispatch software every five minutes, that's the most efficient way to really do it. And it will maximize the transmission revenue utilization based on the constraint of the transmission and generation and the low forecast.

CHAIRMAN BROWNELL: Wendell?

MR. HOLLAND: Just to be specific, Dave asked the question as to issues to pursue and I would like to put in a plug that the young man from Illinois said about RTO expansion. And specifically, I would be really interested in including the RTO membership because with any acquisition, there is always that transition where acquiring companies have a chance to understand and appreciate the cultures of a new company. I would be interested to hear more stories quite frankly and to see if the integrations are working as smoothly as they seem to be working. So, RTO expansion would be an issue that I'd like you to pursue.

CHAIRMAN BROWNELL: Fred?

MR. BUTLER: Let me highlight a question that may be the other side of that same coin, and that is, the differences between the two RTOs/ISOs that are grouped together in this joint board and perhaps if there are differences or there are perhaps different approaches. We're spending a lot of time talking about integrating and rules and trying to erase seams between the two. I sometimes wonder whether there aren't some differences that we're not absorbing and maybe on this whole idea of economic versus efficient dispatch there are some. And while we're talking about this as one group, I wonder if we're also going to identify some of the differences that need to be addressed.

CHAIRMAN BROWNELL: I would hope, Jim and Phil, that to the extent that you can, you could address whatever differences you may see today and then we'll decide what more we need to pursue. And Wendell, I want to clarify your question. So, you're asking us to take a look at RTO expansion as it impacts economic dispatch? You're not asking us to look at merger --

MR. HOLLAND: Oh, absolutely not.

CHAIRMAN BROWNELL: Okay. Thank you. Fred Kunkel. Oh, and I see a camera, Fred, so at the break. Fred and I are posing for our Christmas card today.

MR. KUNKEL: Fred Kunkel, Wabash Valley Power. The description of what I heard so far was economic dispatch is implying that generators are inside the boundary such as regional transmission organizations, PJM and MISO. But also what I heard from Chairman Schriber, if I pronounced it correctly, was describing a self-supplied generation which if you're within the region, then so be it. But if you're outside and using firm point to point transmission reservations to get it into that ability to displace energy charges for your customers, then that is a different issue because now the only way the entity can save money is the availability of the transmission system which is TLR'ed or has the ability to be a constraint.

In an economic dispatch issue, it would imply in my opinion that you have the ability to displace it within the boundary of the regional transmission organization. So, there's clearly two venues here. One of them is within the PJM/MISO or RTO vision as well as an expansion viewpoint for economic dispatch. And that would embrace the entity to either join an RTO or make arrangements to have that transmission organization join the RTO.

As an LSC, you are subjective to whoever the transmission organization is. And if that transmission organization joins that RTO, then that load ability goes along with it. And this is some of the things that are on the drawing board, the differences between, say PJM and MISO, what had occurred in the last year or two with the alliance.

Anyway, I wanted to bring that up because that I think is the crux of one of the issues that you're discussing on a global, high level vision. How do you go ahead and foster people to join an RTO or some organization that can lower that cost for their customers?

CHAIRMAN BROWNELL: Thank you. And I hope perhaps the two of you will address that as well. And if not, we'll pursue it further, Fred.

I have a question from the audience, and this is for Dave Meyer or Steve Naumann. The distinction between efficient dispatch and economic dispatch is not self evident. Could you please give examples of how efficient dispatch could be less than the most economic?

MR. MEYER: Well, we have, one example is plants that have somewhat, that are not flexible to operate in that they may not reach peak efficiency until after they have been running for a period of time. And so, you have to take that into account in terms of what assumptions you make about the overall efficiency of that plant. Clearly, the warmup problem, if you will, is going to tend to lower it a little bit in the dispatch order.

If you simply order -- another issue, I guess, is more directly related to natural gas fired plants. There may be, the entity operating the unit has acquired access to fuel at a very low rate. Even though the generating unit may be somewhat less efficient because the fuel is low cost, the entity operating it can bid in at a low cost. And so, the consumer then gets the benefits. And so, but if you are dispatching solely on the basis of the efficiency of the, in terms of the heat rate involved, going over to always dispatching the most efficient units first regardless of the fuel cost involved would tend to increase consumers' costs, electricity costs.

Now, there might be offsetting benefits to somebody else or even to electricity users associated with somewhat the potential improvement in the efficiency with which gas is being used overall for the purposes of generation. So, how these two things match up is not obvious. But that's an example of how, if you dispatch simply on the basis of heat rate efficiency which is what I take efficient dispatch to be as opposed to economic operating costs overall, you see you can come out with a different pattern of dispatch.

CHAIRMAN BROWNELL: I think Steve Naumann wrote this question for himself. So, Steve, there you go.

MR. NAUMANN: I'm not sure how I got so lucky as to be volunteered. I think, first of all, it was never clear to me exactly what the definition of efficient dispatch is. But if we take it to be the lowest heat rate, I think it's an oversimplification. I think that's what David is saying.

Generators don't have, you know, don't necessarily have a single heat rate for the entire operating range. There are different heat rate points depending on where the unit is operating. So, it's a lot more complicated. If you say, if you're looking at the average heat rate over the entire range, you're going to get a different answer than if you're using a more complex economic dispatch algorithm which looks at different load levels and different heat rate points.

An example might be a simple cycle peaker which has a fairly, a brand new simple cycle peaker has a fairly good heat rate when it's operating at full load. As soon as you get all full load, the heat rate is miserable. And so, you really have to look at the dispatch over a much longer period of time.

We would take into account not only the different load points, you have to take into account as David said the maneuverability, the ability to ramp from one point to another, all because you've got an efficient dispatch at hour one. The problem is what happens at hour two? And you may end up having multiple starts and stops on units that in effect have limited amount of starts and stops and some of the other things.

So, I think, to me, it seems much more of an oversimplification to say just look at heat rate when you need to look at both the unit commitment and how to get from hour to hour plus all the other limitations that are on the generator.

CHAIRMAN BROWNELL: Thank you. Thanh? I haven't forgotten you.

MR. LUONG: Could I answer that? Yes, I think if you really look at the economic dispatch and efficiency dispatch, actually efficiency dispatch is a subset of economic dispatch. Economic dispatch taking into account of the heat rate in there is one element of the variable. And on top of that, it takes a lot of operating units, characteristics of the unit, you know, the minimum run time, the minimum up time, the stop cost, so actually it takes much more than just the heat rate. But the economic dispatch only considers the heat rate in there.

So, efficient dispatch is only a subset of the economic dispatch. That's based on engineering. We look at it that way.

CHAIRMAN BROWNELL: Thank you. And the distinguished Chairman of the Electricity Committee?

MR. ERVIN: Madam Chairman, I think we're probably, I assume, acting on the assumption that we are somewhere close to finish bothering David and Thanh, I did while wearing my -- hat to thank DOE for the extent of their outreach to state commissions. They were very good about doing that. They went the extra mile in terms of contacting us both through the DOE offices themselves and also through Allison -- I counted up to 21 state commissions that actually filed responses to this survey which given the time constraint involved I think is pretty remarkable.

And I think somebody on the state side ought to at least thank David for the extent to which he and Allison and others went the extra mile in terms of trying to explain the importance of this to us and also to make sure that we participated in it. And I want to do that publicly.

CHAIRMAN BROWNELL: And I join you in your thanks because I know this was a difficult task. We're actually lucky not only to have the Chair but the Vice Chair of the Electricity Committee here today. Laura Chappelle. So, if you have any other issues, you could build their agenda as long as we're here.

We're a little behind schedule, so I'm going to turn it over to Phil and then Jim. Steve Naumann is now going out to write some more questions for himself.

MR. HARRIS: Thank you. Thank you, Chair, for letting me be here. As a system operator with over 30 years experience, being able to come in and discuss Security Constrained Economic Dispatch is about like sic 'em to a junkyard dog. It is a pleasure to be here.

I was somewhat intrigued by the questions on Security Constrained Economic Dispatch. In my career, I've operated power systems in the West, I've operated power systems in the South. I've operated PJM five years as a tight power pool and now eight years as a market. And virtually every system I've been familiar with or dealt with from the West to the South to the North all operates with

Security Constrained Economic Dispatch. I know of none that does not.

So, what is the real question as I was asking myself and it seems to me that the real question is who is deriving the benefits to the economics. Economics is like beauty, it's in the eye of the beholder. And who is getting the benefits of the economics? Who is making the decisions on the economics of the dispatch? Who is bearing the risks of the economics of the dispatch? And also on the technologies, are technologies being employed and utilized in the right way?

One of the things about Security Constrained Economic Dispatch is that it's an evolution. It isn't a status quo concept. And I think as public policy makers, questions as to is the current practice en vogue in whatever state or region you're in, is it an impediment to the implementation of the provisions of open access under the Energy Policy Act of '92 and '05? Or is it a barrier to market entry and that would allow wholesale competition to take place? And these are the real questions around it.

Perhaps, and I did want to discuss a little bit of the history of PJM because to a large degree, PJM has been the leader and the history of economic dispatch is largely buried within the organization. And this goes back to 1925 when a study was performed with three different utilities that asked the questions if we operated together as three utilities as opposed to singularly, as individual utilities, wouldn't we be better served? For the same reasons, a common dispatch among three as opposed to operating separately. And that 1925 study showed that there were benefits of $45 million a year in 1935 dollars than if you had three utilities operating together.

Now, in order to operate together, they had to develop security constraints on how the transmission would work and determine to build certain amount of transmission to make it work and then to create algorithms and methods. And basically, every utility followed that pattern as you begin to grow and operate. And indeed, when you look at the large holding companies in this country when they were acquiring companies and growing, most of those advantages said it was because they were going to be able to operate more efficiently from having multiple companies in their holding company structure.

This stayed the same in PJM until 1956. In 1956, other companies joined the PJM pool, and by that time, some of the sophistication had increased on how do you do Security Constrained Economic Dispatch. Most of that at that time was used in analog systems where you're trying to simulate the power grid in order to solve the problem. And the problem you're solving is really just a simple linear programming problem of how do you reach that optimum point between the balance of every unit, the heat rate of the unit and the fuel cost based upon the transmission configuration. It really is a simple control problem is all you're trying to deal with.

In '56, the end of the pool codified that. They staffed up appropriately. They put more people in engineering and science into it trying to deal with that. And other entities were driving the same way. As a matter of fact, it wasn't until 1962 you might recall that we had an interconnection to the Eastern Interconnection which today is a 600,000 Megawatt interconnection.

The systems then evolved to the next step such that by the late 60's, we began to understand that digital control systems with the advent of computers could actually solve this faster than using analog simulations. PJM actually wrote the very first digital control system in the late 60's. It was used to actually make these calculations for balancing the pool.

And at that time, we had eight companies operating as if they were one over a five-state region. And that stayed in the status quo for a number of years and actually had perfect bid-based dispatch. We saw every unit, every heat rate, every cost of every unit every hour. And this was audited and the information was distributed to each state commission. So, you had perfect dispatch, perfect auditability, every unit and fuel cost and what could transpire.

It's interesting that by the 1990's, a study was done by McKinsey looking at what was the value of operating this way and the numbers were somewhere over a billion dollars a year of savings to the customer by having perfect information, perfect dispatch data, eight utilities operating as if they're one over the five states. A very good system and one that served very, very well.

As things progressed, and that study was ultimately replicated, I know that New Jersey did one. It came about with the same number, and Maryland did one also during that period of time. As it began to grow, however, and move into how do you bring in markets, then obviously you are in competition among generators and that sort of program wouldn't work. And a number of states asked us to look at how we did this differently and then we got into bid-based security constrained dispatch.

And we've had a lot of models as to how does that work. Can you bid base better than you can cost base dispatch? We ran models and models and sensitivity analyses and so forth. We have some numbers, I'll talk about a little bit later about how that came in to play.

With all of this throughout, you do get into the area that size does matter. And I've heard that mentioned several times here, that having diversity of units, oversized, optimizing through the math and the calculations, how does it work and can you optimize that dispatch. And with the wonderful world with computers and technology where these things can be solved, then you can see the numbers as they produce the results of this kind of dispatch. Certainly with the complications of constraints and the distribution system, even the transmission system in real time and knowing how you have to do that, you have to send the price signals to allow it to happen.

I think the other part of it that's meaningful as the evolution of Security Constrained Economic Dispatch grows is how do you bring in the new players. How does demand response be able to play? How do IPPs be able to get the information to be able to show that they're able to compete in a fair and equitable way as we move forward into the future? And we have the technologies, the price transparency, and the things today that we've never had before that allowed that to take place.

Some of the numbers that have been looked at as we go forward in this, certainly the forced outage rate has dropped considerably. We've seen considerable savings with innovative software. For example, because of the size, we'd be able to use multiple energy programming in this dispatch equation. This saved our customers $56 million directly in 2004. In this year with the higher gas costs and the higher gas prices, the savings have been calculated at over $85 million just from having better math in the equation of your Security Constrained Economic Dispatch.

Other studies such as September of '02, the Center for the Advancement of Energy Markets said that customers within PJM realized $3.2 billion of savings as a result of the dispatch. Synapse Energy showed that savings around the neighborhood of the prices for consumers were 2 to 13 percent lower than if this kind of market didn't exist in the dispatch where everyone could participate and share in that. When Allegheny Power moved in, it was quite telling. They were the first group to join the market after we started where they were dispatching their system separately. When they came into the dispatch equation and started following the dispatch signals from PJM, the first eight months they saved $99 million.

Recent studies by AEP have shown a nominal net benefit from '04 to '08 as $188 million for AEP. Global Energy Decisions found out with the integration of ComED, AEP and Dayton, that annual production cost savings were over $85 million. Cambridge Energy Research had $33 billion of savings over seven years. A recent study by PJM which I'll talk more about in a moment from Energy Security

Analysis said there were $500 million in savings for wholesale customers as a result of having a common dispatch over a large footprint. And certainly the IRC Council has showed the same savings coming up in different areas from doing this.

Some of the key questions that you asked are what are the benefits and costs compared to the previous system? And I think PJM is a perfect test case. In the first instance, you had eight utilities operating as one. We have a 1925 study that projected you'd save $45 million a year in 1935 dollars, the 1990 study that showed just operating at a cost based system was saving over a billion dollars a year, and then we have further studies now showing that a bid based system where everyone can participate and play in the energy picture equally is saving huge amounts of dollars even above and beyond that.

We also have understood that as you get into this kind of arrangements, it's much easier to coordinate. Back into the power pool days, I remember in 1990 we had a teletype that we coordinated with New York power pool. Every four hours, we'd send 300 bits of data back and forth over the teletype that had to be rekeyed. Today, we have data links that tie in New York and PJM. We have data links that tie in MISO and PJM over the world's largest interface which has 71,000 Megawatt interface.

And the advantages of both of us using bid based security constrained dispatch is you're seeing the price convergence comes down between the MISO and the PJM border. We have 11,000 Megawatt interface with the South and agreements that work out between Progress and Duke so we can compare and see what's happening at that particular interface, and a 7,000 Megawatt interface with TVA where we're sharing data and developing programs and systems with TVA, so in short we're seeing what's happening with each other's system with the dispatch.

So, the technology is allowing these synergies to grow and develop because you have the large regions and you have the capability to do that. Some of the other savings that came out as part of the ESAR report, and I brought a considerable copies back here, but I think they're quite telling because it all ties back into what you can do with the right use of technologies, the right price transparency. Some of the findings, for example, is just because you have a region-wide energy price, that the savings are 78 cents a Megawatt or would have been 78 cents a Megawatt or higher than if you were working all of them under the same sort of dispatch.

Some of the other advantages coming about is because you have an entity and this isn't so much about structure as about having an entity that enables this kind of activity to take place that the pricing conventions and price transparency allow all the players to come in for whether you're wind or you're bowel mass, solar or whatever, you have a way to participate in the dispatch equation openly and transparently as you move into the future and then certainly innovative rights to use the transmission system.

PJM's expanding forward market has no bias. And how do you know that? Because we run the price signals. The price signals are posted every five minutes with perfect price transparency. You know the day-ahead market and the day ahead prices are converging to the daily prices. This is a huge benefit when you're trying to plan what you do in an economic dispatch because you plan the unit commit the day ahead, then you have to commit on the hour.

So, eliminating the bias between the day-ahead market and the daily market is a huge considerable savings as opposed to trying to do it internally. And the systems that do it internally, you don't have the price transparency to even know are you eliminating a bias between what's happening in the bilateral market or not. You don't have the information nor have the capability of doing that.

Other things that were found in the study is that hedging with FTRs works out and they found that the FTRs are an effective hedging mechanism within PJM. Another interesting factor comes into it and I think this is important with the high natural gas prices and the things we're seeing today is that you have a large, more optimized portfolio of generation assets and the use of those under more appropriate dispatch.

For example, we're 165,000 Megawatt system within PJM, 28 percent of our capacity is nuclear, 42 percent is coal, 4 percent is hydro, 7 percent is oil, 1 percent is green and other sorts of power and 28 percent gas. But if you look at the actual dispatch that has taken place through the summer, 56 percent energy comes from coal, 32 percent comes from nuclear. That's 88 percent of the energy provided comes from coal and nuclear. And many times it's coal that is setting the price, it isn't gas. 7 percent came from gas, 3 percent came from wind, 1 percent came from solar, bowel mass and other new green type technologies, and 3 percent from hydroelectric sources. So, even though you have a generation diversity of one sort, you can see the energy has actually been provided by those that are willing to bid and can do it and that gives you a much more efficient operation over a very large footprint which is one of the advantages of having geography and size.

The quantification of that according to the studies says that that yields aggregate savings to electric consumers on the order of $1 to $2 a Megawatt hour which translates in our region from $700 million to $1.4 billion a year savings to have been able to operate the system this way with bid based security constrained dispatch. Other savings were mentioned to it. I think particularly getting into the fact is the huge savings in heat rate, and these are all calculatable and quantifiable numbers, but the heat rate of the system dropped from 9,000 to 7,300 BTU per Kilowatt hour. Why is that? It's because you're able to optimize the units and get them to a better heat rate range and you're displacing those that have a poor heat rate, they move out.

Then you say, well, is that a bad thing, because what's happened to these other units? Well, what we saw happening is that the power then of these other units has nearly tripled flowing outside of the system. So, the other units were able to bid and to sell bilaterally outside the PJM system, so it becomes a win-win-win-win all the way around for all the players into the market place.

Certainly the integration of demand side has been a lot higher. If you look at the state of the market reports, you can see considerable savings at 100,000 Megawatt load a day, we can see price reductions as much as $260 a Megawatt hour when you're at a peak heat day. If you look at the operations throughout the summer with the heat that we had over and over again, you'll see how moderate the process where you see the influence of demand side and you see the influence of generation diversity in spades.

Some other questions come in, too. How does the power flow? We first anticipated that power would flow from West to East. And what you're finding with the right kind of dispatch and abilities to respond to processing those many times, the power was flowing from East to West based upon the time of day and the time of use. Again, economic dispatch, price signals and the line the companies are participating to respond to those signals appropriately will give you a much more efficient utilization of those resources than you are absent having that kind of a dispatch.

I think the other note in this thing that they talk about is this is a transition. It is a change. We're going through capabilities with technology we have never had before. And the digital control technologies and the capabilities of processors to solve this control problem are absolutely huge. We're now with our new control center actually looking at running the state estimator for the entire Eastern Interconnection because you can do that and solve it in minutes today with the power of technology which gives you a lot more information because you look at more innovative uses of wind and solar and bowel mass and other capabilities just doing the dispatch. You need that kind of technology to enable them to get the price signals to participate so you can optimize the dispatch equation.

And you also increase the reliability of the system when you can do that and provide the right signals. I think it's really telling to me, this one anecdote that I think is quite telling though. If you remember in 1994, we all got faced with the ice storm that came through. It started West and things were shut down. I know I talked to Kentucky several times because we had trouble getting oil trucks through Kentucky into the Mid Atlantic region. At that time, we shed 500 Megawatts of load over a three-and-a-half-hour period but we had a 48,000 Megawatt peak, we had 15,000 Megawatts of generation on forced outage with only 60,000 Megawatt capability. Now start doing the math. There just wasn't enough generation that we could command the control in order to come online.

In May of '99, we had temperatures that we didn't expect to see that early for five or six years out. We're sitting there with a system then at 75,000 Megawatts that had 5,000 Megawatts on a forced outage. We had 15,000 Megawatts out on planned outage. I mean, we were looking at a massive shortfall. But we did the security constrained economic dispatch. We had many buyers and sellers, had over a hundred different companies bidding, selling and trading into the market place. The prices never got above $200 and all the load was met for many active participants being able to see the day ahead and respond to that with price and be able to participate in the dispatch equation. So, we didn't shed load.

I would tell you that it's a much more reliable system. Same set of circumstances that we had to shed load in '94, in May of '99 we didn't have to because you had the right kind of dispatch equation. It's a more reliable system.

Other factors that are kind of hard to talk about that is because you get into this kind of security constrained dispatch, you get into the ancillary services, how do you regulate spending the reserve, et cetera. And our regulation market is 50 to 100 percent better than it was when we were trying to do it under a command and control basis for providing the price signals in the dispatch equation and allowing companies to respond to those over time.

I was listening to the discussion on economics versus efficience and it's hard for me to understand what the question is. It's almost like a distinction without a difference. If you truly are looking at how you have a security constrained dispatch as you have open price transparency, if you're meeting the public policy needs of the Energy Policy Act to enable competition, you have many buyers and sellers and traders who can participate and make judgments on their own is how you can go forth. You're able to bring in the wind technologies. You're able to spur the economic demand programs into that real time equation. Now we're making progress. But it is an evolutionary progress and one that will move forward step by step as we move to the future.

Now, I'd be happy to answer any questions.

CHAIRMAN BROWNELL: Thank you. I think we'll hold the questions until we hear from Jim, and then I'm sure there will be lots of questions.

MR. TORGERSON: Thank you, Chair Brownell and Vice Chairs and all those who are joint board members. Thanks for the opportunity of coming here.

I'm going to hit on a couple of topics. One is a discussion of the security constrained economic dispatch, then also on the benefits of it and the responses to the questions that were laid out to us. I also was asked to talk about briefly on the white paper in the inter-RTO council was this came from the CEOs of all the ISOs/RTOs released.

Let me give you a little of my background. I do not have 30 years operating power plants. My background is merely in finance and strategic planning. And when you look at the security constrained economic dispatch, it is very complex. There are mathematical algorithms that run all this. And on our staff, we have a number of people with PhDs in mathematics and power system designs and electrical engineering. They have gone through and worked with vendors to put these complex algorithms in place to solve this system.

I do know though how value gets created, and that's what we look at when we're doing the security constrained economic dispatch. And many of you can relate when you look at why mergers among utilities are successful. One of the big benefits they always point to is by broadening the area they're going to dispatch over, that is where significant savings come from, from economic dispatch over a broader area. RTOs have expanded that area. We're doing the economic dispatch over a very broad area now that encompasses in our case 1,500 generators whereas in the past you would have a utility or a control area just doing the ones that they had access to.

But the security constrained economic dispatch really is the system operator's dispatch to generation resources that they have to meet the load in a most reliable and economic matter. And it takes into account the constraints on the system. I mean, that's very basic and that's what it does. It's not a new concept. Whenever the transmission system gets constrained which it does, there is a need to ration capacity and to do it in a reliable manner. And that's how this works.

The security constrained economic dispatch is performed by an RTO and also by non-RTO utilities because it is the most reliable and economic way to manage the system. So, both do it whether you're in an RTO or not.

The concept of a security constrained dispatch requires the system operator to account for the system balance and frequency, to coordinate the power flows recognizing that there are operational security limits, that there are possible contingencies and there's transmission congestion. We use our state estimator and real time contingency analyzer as a feed into our, what we call unit dispatch system which then determines every five minutes what generators get utilized. So, we marry what was used previously for reliability directly into the dispatch of the system.

And the concept of economic dispatch requires the system operator to select generation resources to dispatch in some merit order based primarily on the incremental cost of dispatching each unit at each level of output and taking into account the security of the system. And this is to suggest that economic dispatch and reliability really can't be separated. The way we're operating the system, they are integrated entirely today.

And when the question came about an economic dispatch versus an efficient dispatch and David Meyer mentioned it and so did some others, Steve Naumann, but economic dispatch, when we do it, it takes into account everything, the bids and offers that people put in. How much, all their costs, all of the production costs, and that includes what does it cost to ramp those units? What does it cost to start and stop those units? What are their other physical characteristics? What constraints are on the system? So, when you look at it all in total, the total production cost, that's where you get an economic dispatch and it should be, by definition, efficient based on all the constraints that are looked at within the system.

And as I said, over a large area such as those of RTOs, it provides some very inherent benefits. We internalize all of the loop flows across a larger area. And it means more flows on the transmission system are managed by dispatch rather than by that less efficient use using TLRs which was what everyone used in the past. So, the optimization of dispatch across a wider region does lead to a more economic use of resources. And the regional approach also leads to more efficient planning investment. You then, by generating these LMP prices, you have a better idea how to plan the system and how to plan for investment.

So, some of the questions that were raised, what are the benefits and the costs of security constrained economic dispatch compared to the previous systems? Well, preliminary indications estimate that, and this was a study that ICF did just recently, as a matter of fact it was just released a couple of weeks ago for ours, and they looked at one day on July 7th, 2005. And this was a follow up to a study that DOE had done and it was one of the same individuals, Jimmy Glockfeld had even done it for us. He said, and they looked at one day, and keep in mind this is a day, that the savings from an economic dispatch were between $600,000 and a million per day. So, that would translate into $220,000 to $360,000 if you annualize those numbers.

We all recognize that one day you can't really extrapolate over an entire year. So, we've asked ICF to go back and then look at the six-month period we've been operating, take all the data from our operations and then come up with an analysis of those six months on an actual basis of what we actually did as the Midwest ISO versus what it was before when the market wasn't operational. So, we also did a simulation of the pre-Midwest ISO security constrained economic dispatch to post when there wasn't really an economic dispatch before we started up. And we modeled it and we saw a benefit that ranged from $59 million to $154 million per month.

Now, the differences were you had to make assumptions about how efficient the bilateral market was before the Midwest ISO had started up. And we assumed a 90 percent efficiency in that bilateral market, and that would give a benefit of the $159 million. If the bilateral market were perfectly efficient, it dropped it down to $54 million. We know that it wasn't perfectly efficient.

Also, there was a question on TLRs and, you know, are we maximizing transmission owner revenues? Well, what we found is that prior systems relying on TLRs was inefficient because we'd call TLRs and it led to about a 12 percent under-utilization of the capacity on those constrained flow gates after the TLR was put into effect. With the economic dispatch, we get much closer, right to the edge of how much transmission capacity can actually be utilized.

The other questions, what lessons did you learn in implementing the security constrained economic dispatch? Well, implementing a regional dispatch in place of local dispatch as Phil mentioned, it changes the preexisting dispatch patterns. It clearly changed the dispatch based on comments we've received about how we are actually dispatching generators from the days before the market started to today. And it also introduced transparent pricing, and this has led to reduced congestion in formerly high congested areas. We look at what happens in Wisconsin where before we have been able to put more imports into Wisconsin from remote sources than were being done in the past. And that came from people in Wisconsin.

So, how does the operation of security constrained economic dispatch relate to the operation of regional market? Keep in mind that the LMP prices that come out are the result of, they're not the cause of regional dispatch, they're a result of doing the security constrained economic dispatch. And transparency in the regional markets has led to a more economic dispatch.

Prior to regional economic dispatch, the region didn't have transparent prices. People would learn what the price was by calling each other. And that was how the bilateral market grew up. People would call back and forth, find out who had a price they liked, and then either buy or sell. And in that, how many people did you talk to in that 15 minutes or 30 minutes before the hour in order to do your transaction? There was nothing posted.

So, what effect has security constrained economic dispatch have on the reliability of the electric system in your region? Well, the Midwest ISO process is based as I said on advanced state estimator modeling, contingency analysis and continued reliability monitoring. This is totally integrated. We're actually looking at 180,000 data points every few seconds that are integrated into our state estimator. And it covers a very broad region, not just the Midwest ISO, but we go into PJM, a little into Ontario, cover the entire map region, TVA, Southwest Power Pool.

So, we cover an entire region because we need to know where the flows are going to be coming from, not just the flows within the Midwest ISO. And that aids in reliability. Our operators even have told us that actions that would have taken an hour before because of a TLR, now they can resolve in five to ten minutes from constraints on the system. So, we see a significant improvement in reliability as a result of economic dispatch.

And what effect has economic dispatch had on the cost of electric energy in your region after adjusting for inputs? Well, I mentioned two of the studies we had already done. In an analysis we did which was ordered by the Commission prior to starting our market, we identified $128 million in net benefits strictly from purchased power, cost savings and increases in our system sales revenue. Added to that would be savings and cost to sort of loaded market prices net of market implementation costs and this should be because of the transparent pricing driving down the overall price. That was estimated at a net benefit of $586 million and these were per year.

In individual state and utility studies, we did one in Wisconsin that identified after congestion, market implementation cost $51 million a year. We did another analysis for Kentucky that identified $46 million per year based on comprehensive analysis of all cost revenue and costs including the security constrained economic dispatch. We did an analysis for Aquila and their Missouri operating areas and we identified that it would reduce production and purchased power costs by $6 million a year and then lower congestion costs an additional $6 million a year. And these were all recent analyses that we have done for different states.

Now, having said that, last week we introduced a new paper that talked about the value to RTOs and ISOs, the value that they create for the grid and for electric consumers. And I want to touch base on that just a little bit. In the US, we have seven ISOs and RTOs that serve about two-thirds of the US population and coordinate about two-thirds of the generation in the nation. And these seven US based RTOs were the ones that put together this paper, and they maintained the reliability of the grid. And I just want to lay out some of the major themes that are in this paper. It's about a 50-page paper, but I think it's important to look at the themes there.

We all use sophisticated tools and information technologies to manage a very complex system that covers more than 272,000 miles of high voltage transmission lines and 585,000 Megawatts of generation. One of the most important things we do do is coordinate closely on an electronic and human basis the information exchange between these regions. We have working agreements, joint operating agreements.

Phil and I have one that was probably, it is the model that most of these have been based on where we share information and data in real time. And it goes a long way to help eliminate problems on the system. And we know what's going on in each other's area in real time. I mean, to illustrate how much information we get, a couple of our RTOs manage about as much information on a daily basis as Visa, the credit card processor. So, I mean, it's a huge amount of information that gets handled on a daily basis.

Now, much of the value comes from better use of power plants. Again, the security constrained economic dispatch, that is what we talk about in the paper. And there is a couple of things I will mention. Some of the savings, the heat rates in Ercott improved by about 40 percent, and that saved customers according to their analysis over $10 billion over a six-year period. New England has nox emissions down by 32 percent. There is a GED study I think Phil mentioned that had $15.1 billion in savings. And the Northeast has saved $7.30 a Megawatt hour from competition over seven years. So, SPP has identified

$1.2 billion to be saved over ten years from their market operations.

So, it's not just limited to those of us who are running markets today. People are estimating these for their future. And we also believe it's lowering customer energy cost by billions a year. Again, we highlighted a few of those already and then you have the studies that Phil mentioned. It also gives independent power producers greater access to the grid, increasing competition among the generators and lower cost imports.

And the other thing that we do is regional planning. And these investments often will lower the delivered energy cost as well as eliminating millions of dollars of congestion. I know Path 15 in California reduced congestion by 40 percent. And Ercott has seen two billion in transmission facilities with another 2.8 billion in development right now. PJM has done 550 million since '99 and Midwest ISO has identified 2.9 billion in transmission upgrades that need to be done by 2009.

The bottom line I think here is that the RTOs do provide significant benefits. And the only thing we looked at are our costs. What does it really cost for an RTO? Well, on average, it's 44 cents per Megawatt hour. And when you translate that to a residential customer, your average residential customer across the US, it's somewhere between

$3 and $5 per year for the cost of an RTO. So, that is what it costs to run an RTO when you get down to the individual residential consumer.

And with that, I think I'll stop. I probably spent enough time talking about this, so I'll be happy to team up with Phil and we'll answer the questions.

CHAIRMAN BROWNELL: Great, thank you. I'm sure it's just a question of who wants to go first. Ms. Chappelle?

MS. CHAPPELLE: I don't necessarily want to go first. This might be more pertinent to Jim, but Phil, jump in if you can shed any light and I'm sure you both have heard this issue. But one of the biggest complaints that I hear back in Michigan is that since the advent of MISO, we are dispatching allegedly uneconomic plants. We're dispatching the peakers, the high cost natural gas plants at a time when if the utilities were dispatching themselves, they never would dispatch these plants. And because that is being done, it's driving up allegedly the rates.

And so, I have a two-pronged question. Jim, you've heard this issue for some time and we thought maybe it was a bit of growing pains as MISO was unfolding, and it seems to be continuing. So, can you talk a little bit about that, whether or not in fact it is happening? And if so, can you also touch on how these bids come in? I think, Phil, you touched on this. Apparently, you feel that the bids are coming in to give you sufficient information regarding the actual economics of the plant, but can you tell us a little bit if you actually can make that judgment on the bids coming in?

MR. TORGERSON: Well, I think early on when we first started up, and keep in mind the Midwest ISO started its market in centralized dispatch April 1st, so I think our people, our operators were probably a little conservative the first couple of months. I mean, they were -- plus we had cost-based bidding in the first two months, and so I think our people were a little conservative, making certain that they had sufficient generation online.

I would say that though today, we've gotten much more efficient at the generation dispatch. And some of the things that people have to keep in mind is we dispatch based on the offers that come in. If people will offer in, they offer in their units and they offer in the characteristics they offer on are there startup costs, how much does it cost to start that unit, how much ramp time do you have for those units? And one of the things that we see is ramp time is very important, like in the morning.

Even today we're seeing a ramp and this means a change in about a two to three-hour period of about 10,000 Megawatts from where it was to where it has to go in the morning. Then we see another, it can be as much as 10,000 to 15,000 Megawatts, and then another 8 to 10 in the afternoon again in the winter, the days like now. So, we have to have enough units on that can keep up with the amount of load that's being required and the generation that's being required.

So, at times if we have offers that can only ramp a smaller amount, and keep in mind people are putting in their own offers and you heard a question about flexibility. Well, if we don't have the same flexibility on ramping a coal unit that let's say they used in the past, then we have to call on other units to do it because they're putting in their offers. We can't change their offers. We can't change the characteristics they're putting into the system.

So, you look at all the production costs and then we determine which one based on the offers we have and the constraints within the system, and that's another big thing you have to keep in mind when we're looking at when we dispatch certain units. What constraints are on the system at any point in time? Because this is a security constrained unit commitment in unit dispatch. So, we factor all those in and then the algorithms determine which units will run.

So, I'm actually fairly confident we're doing a considerably better job and we're doing it based on the economics and in the bid patterns that people put in. So, you know, those are all the variables you have to look at when you say we may be dispatching more peakers than were done in the past.

MR. HARRIS: I think the question on is it more efficient is a very good one and I think PJM is a perfect test case. Again, we had perfect knowledge, perfect economic cost-based dispatch every heat rate, every unit. And we had a huge, had a whole department just dispatching a hydroelectric system. We had the Saska and the River Valley. We got pump storage. You got environmental constraints. You've got to worry about running river. You've got to worry about the temperature of the water, all these different factors in order to handle the hydroelectric system of the Saska and River Valley. So, we had a whole department just calculating all that to make sure we didn't bust any of those environment constraints on the hydroelectric side.

All the models that we ran said that bid based would be better. But even at that, we operated a year at a cost base just to get people used to the bidding behavior. The studies that are coming now are showing that, yes, it is working better when people are making their own economic decisions about ramp up, start times, you know, no load costs, all these things that you have to factor in on their own commercial interest that the bid based system is much better because it transfers the risk.

If they make an error, they don't run. If they make an error, then whoever owns that plant has the burden; not society, not the public. So, it's their risk judgment that they have to balance when you're in a bid based system.

CHAIRMAN BROWNELL: Wendell? Steve after Wendell.

MR. HOLLAND: Phil and Jim, thank you for your comments regarding economic versus efficient dispatch. I truly appreciate that. And I liked both of your papers quite frankly and I think I understand your savings analyses and how RTOs create value and especially as it relates to nox reductions because a number of retrofitting cost is saved.

But my question is to Phil and it's something that Jim actually brought up. And this makes it real simple, Phil, in your paper you talk about how overall PJM operations cost each household in the region about $3.50 a year, and Jim said between $3 and $5. Could you just elaborate on that? Could you comment on it? I think I understand it but could you just elaborate on it please? Because I think that really simplifies this issue enormously.

MR. HARRIS: Yes. It was just a simple

calculation. Our cost, our budget for example next year is 36 cents a Megawatt hour, and if you take the cost of PJM and average it out across the 700 -- hours of power that goes to the retail, it comes out calculated at $3.50 a year per residential customer.

Now, I think other things, again, let me preach on this just a minute, but size really matters. In the entire world, you got 3,600 Gigawatts of generation capacity. Okay, the Eastern Interconnection is 600. You know, you're one-sixth of the world in Eastern Interconnection. Within the Eastern Interconnection between MISO and PJM, we're nearly half. We got nearly 300 Gigawatts between the two of us.

So, you've got two entities operating an extraordinarily large market. The value proposition of that is where you're getting these huge numbers. It's a tremendous value to society by getting those kind of economies that you're dealing with. I think even the transmission expansion numbers, many of you have seen these calculations, we're looking to expand the transmission system. We can make a $4 billion investment and if that investment was translated immediately to the retail customer being one-tenth of a Kilowatt hour.

So, you're getting economies to sale that can drive value that you can't get in smaller type enterprises.

And that's where these savings come down.

MR. HOLLAND: Okay, thank you.

CHAIRMAN BROWNELL: Steve?

MR. NAUMANN: I just wanted to make a quick comment in response to the question Commissioner Chappelle asked. It's based on the experience of when ComEd got integrated into PJM. One of the things that you find is once you go into a competitive system, the reliability criteria whether they're good, bad or whichever they are, have to be met exactly.

And the comment that Jim Torgerson made about dealing with the ramping, it was not uncommon when utilities were independent control areas. They have operating reserve requirements. Well, when you're ramping up in the morning and units are coming on, they don't always come on exactly when you want them to come on because things aren't perfect. The control area might go into their operating reserve.

When you have a competitive system when other people are providing that reserve, you've got to compensate that. And that's one of the reasons that the peakers, that we found at least upon our integration initially, that there was more use of peakers because PJM said these are the operating reserve requirements, we're going to meet them. And so, it is a different regime.

Now, one can argue that the requirements are wrong or should be modified. But so long as you have them, the RTOs are meeting them. And I think what you're seeing there to some extent is the cost of reliability. And so, I just wanted to add that because sometimes it's missed.

MS. CHAPPELLE: Very helpful, thank you.

CHAIRMAN BROWNELL: Chairman Davis?

MR. DAVIS: Jim, I've got two --

CHAIRMAN BROWNELL: Lean in to that mike please.

MR. DAVIS: Jim, I've got two questions. The first question is, you know, in your savings analysis, do you take into account uplift charges?

MR. TORGERSON: The uplifts are a, they are a component of the overall because uplifts typically are transfers from one party to another within the overall region. That's what they really are. You're paying one person, one group one load who's paying somebody else. So, they do get factored in.

MR. DAVIS: Okay. So, you're saying that those are included. Okay.

MR. TORGERSON: Yes.

MR. DAVIS: And then, my next question is with regard to your savings analysis for Aquila. I mean, we've got them in a rate case right now, so I have their numbers laid out in front of me. I guess there is no other way for me to ask this than, you know, I've got your spreadsheet where it's got a little more depth about what the actual analysis was. But you know, if I just calculated these numbers right, you know, it's an estimated savings of $41.5 million a year. Just tell me how much that share is Missouri's portion and how much I can just yank out of their revenue requirement.

MR. TORGERSON: That part I don't know. I do know that --

MR. DAVIS: Well, you can file that with this later.

MR. TORGERSON: Okay.

MR. DAVIS: But I just want to know. I mean, are these numbers reliable?

MR. TORGERSON: The numbers that we've generated for these economic analyses are, yes, they're reliable. But you have to look at the assumptions that were made just like any analysis that's being done. And the assumptions that will drive these analyses, and we believe we took, you know, appropriate assumptions when we developed it, and we looked at each one and, yes, that's why like the ICF study, I want them to look at the six months of actual data we now have, or actually seven months now, and compare that to before when there wasn't a market operating.

So, to answer your question, yes, I think you can rely on it but you also have to look at what assumptions are made and people can challenge those assumptions and that's what going to drive it.

MR. DAVIS: I'm sure I'll have the opportunity to hear more about this later. Thank you.

CHAIRMAN BROWNELL: Maybe ICF should come visit. Chairman Hardy?

MR. HARDY: I listened to both you gentlemen very carefully and I appreciate your information. If my ears serve me well, only Mr. Torgerson used the word net when talking about some of his studies. And Mr. Harris, I don't believe the way you presented your information you ever used the word net.

Net is really of concern to me because when I look at what you're proposing, which sounds wonderful, I have some difficulty in saying if this is projected to save millions, billions, whatever, I need the meaning of context, and to me, that context is net. And when you present your numbers, if you would give me a net number on something you're going to realize in savings over five years, that would be much more useful than simply a projected savings. Or have I misunderstood your position?

MR. HARRIS: No, I just don't think it may have been characterized appropriately. What most of the analyses are, it's analysis of you go back and actually calculate if the entity had operated without being part of the large market, what their cost would have been. Okay, then you calculate what it actually was being part of the market, and the delta is the savings your seeing. Those are the efficiencies. Operating singularly and by yourself or operating as part of a market. And that's what you're gaining almost throughout the studies. And the numbers are real and meaningful and calculatable.

MR. HARDY: So, I'm to understand --

MR. HARRIS: Same thing with the efficiencies on heat rate. What's the heat rate prior and what's the heat rate once you're in to a large market and operating in that way.

MR. HARDY: So, you build into that calculation a net number which is the cost of the operation of PJM, for example?

MR. HARRIS: Absolutely.

MR. HARDY: So, your numbers are not gross, they are net?

MR. HARRIS: It depends on what you're analyzing. What we are analyzing for most of the numbers to try to show the value of security constrained economic dispatch, what did it cost you to operate by yourself. You calculate that, you run those numbers. Okay. Then what did it cost to operate as part of the pool including the pool cost and you get the delta and that's where you're getting the savings.

MR. HARDY: Okay. Do you do it the same way, Jim?

MR. TORGERSON: Well, Chairman Hardy, what we do is we look at, let's say we're looking at production costs, the production cost before, the production cost after, what savings were there. Then we subtract all of our costs to actually operate the market from the Midwest ISO perspective. And in some cases, we look at, we've done it with just the cost to operate the market, but then we looked at the total cost to the Midwest ISO which would include all the activities we do around reliability which are about half of our costs and we subtracted all those to come up with a true net number just to net out if the Midwest ISO, all its costs were applied to these savings, to come up with a net number.

So, we do it two different ways: one based on just the market and then the total cost to the Midwest ISO.

MR. HARDY: Thank you.

CHAIRMAN BROWNELL: Okay. We have Susan Wefald. Susan, I'm sorry, I didn't see you --

MS. WEFALD: Thank you, that's all right. Back in 2004, the Ernest Orlando Lawrence Berkeley National Laboratory did a study on their environmental energy technologies division and they did it on the potential impacts of a competitive wholesale market in the Midwest.

And all of us looked at that study at that time and we're interested to see where our utilities would come out in that as far as economic dispatch when the market was implemented.

And at that time, they showed several figures and maps and one of them showed that, for example, that there were going to be winners and losers. You know, some companies' plants would be dispatched more and some would be dispatched less. For example, it said the uplift change in control area generation ranges from roughly 1,000 Megawatt increase in the Detroit Edison Company area to a more than 1,000 Megawatt decrease in the First Energy area. And those were the two biggest changes in the Midwest ISO region.

Do we have any more accurate data since the market started and is that the study that you're talking about that you want to have done in that next six months that will actually show us what changes have occurred? And will we still be able to get, will we as Commissioners be able to get that data on a company by company basis or is that considered privileged once the market went into effect?

MR. TORGERSON: The data, we have the data on how we dispatched every unit since we started. So, we know how each one was done. The study I was talking about was taking what we did over the six-month period, compare to what it would have been like with the companies dispatching themselves which was prior to the market startup, doing that comparison to see are we actually adding value. And that's really what we're looking at.

To answer your other question on, you know, can you get access to that data, I'm certain you can. We have to look at, to make certain there isn't confidential information and then we have obviously a process to go through if it is. But the information, the studies, we're more than happy to make available.

MS. WEFALD: Because it looks to me as if, from this analysis that was done earlier, that there should be some companies in our region who are feeling good about economic dispatch because they're running their plants more. And there are some companies who are feeling bad about economic dispatch because they're running their plants less. And so, it has to affect their bottom line as to how efficient their own company is as far as making profits.

And I'm sure that that's part of the reason that there's some, why they wanted the whole discussion about economic dispatch because those decisions are no longer being made by themselves, they're being made by an outside entity. And so, they're concerned about the effect this has on their bottom line. So, it would help me as a regulator to know what effect this is having on the companies I regulate and how it's affecting my customers, you know, versus the big numbers that we get from you about this is the economic impact for our whole region are interesting, but on a control area by control area basis, they're probably different.

And that's what I need to see is in my own control areas, how is it impacting my customers in price.

MR. TORGERSON: Certainly, and I think the overall benefits, you'll still see benefits because keep in mind, take any particular utility, if they were running their plants before, they're generating unit and they're not today, it's because they found cheaper energy to move into that area. So, it's an economic decision that says the customer should be better off because they're not running that plant, because we found energy that could be dispatched to that load at a lower cost to them.

And then, you have to, and I don't know what all the particular states are but many times the cost of energies goes to a fuel charge. And did the fuel charge go down as a result or should it because the dispatch was more efficient, people were buying outside and not necessarily running their own plants. And that's one of the things we found, that, you know, the plants, we're running many more coal plants today than that ran in the past at higher levels because they weren't being able to be dispatched in their own control area necessarily.

So, when you run those coal plants, yes, you may be exporting the power within the Midwest ISO from one area to another, but then that other area is benefitting because they're getting lower cost power and the other one should be getting a benefit because now they're selling elsewhere and those revenues should be coming back into that utility in that state. And then it's up to the Commission how they deal with those off system sales or those sales.

MS. WEFALD: May I ask one more question?

CHAIRMAN BROWNELL: Sure.

MS. WEFALD: When I look at our fuel cost adjustments though, because I announce those each month to the public, I see one company where their fuel costs have stayed relatively consistent from before to the present. But I see two companies whose fuel cost adjustments have gone up considerably substantially since, in this last summer. And so, you know, that concerns me. When I hear you say, well, you should see those cost efficiencies reflected through your fuel cost adjustments, on two companies, I'm not seeing them.

MR. TORGERSON: Well, the other thing to keep in mind is what's happened to the fuel costs themselves. If they're using gas, gas prices are up dramatically as I think most everybody knows. And coal prices are up, too. So, you've got to look at all that, and I was trying to equate it to if you adjusted the fuel cost input, the fuel itself, gas or coal, keep that equal, then look at the dispatch and the efficiency that we gained from that, that you should see something, you should see some savings.

Now, whether it's, well, it should be, if we're doing the economic dispatching on overall savings, you should see it.

MS. WEFALD: Thank you.

MR. TORGERSON: And we'll be happy to get you data on whatever you need.

MS. WEFALD: All right. Thank you.

CHAIRMAN BROWNELL: Chairman Schisler, Chairman Nicholai, David Sapper. Jimmy, you've been up and down, maybe you're --

VICE CHAIR SCHISLER: Mr. Harris, I'm going to ask you this question because you mentioned it in your oral comments here today. But I would encourage other commenters to this joint board to mention it perhaps in their written comments and it is about the effects of bid based security constrained economic dispatch within an RTO in the long-term fuel diversity of generating units in the RTO.

To give my question some context, recognizing that the right amount and types of fuel diversity are going to differ from region to region based on the natural resources and fuel availability, but that some degree of fuel diversity serves as a physical hedge against price spikes and serves as part of a component of our national energy security, we probably all could agree and I believe you inferred it in your comment that there is a social good element in fuel diversity.

As it relates to security constrained economic dispatch, when you throw in a number of variables that are inherent, spot and futures prices, the geographic location both domestically and internationally of energy sources, the lumpiness of investment decisions in new generating stations and a new one for me discussed, Mr. Naumann discussed the variability of heat rate across the operating range of the unit, does bid based security constrained economic dispatch serve the fuel diversity needs? Or how can be sure that it serves those needs or at least that it doesn't bias investment decisions toward certain fuel types?

The second part of that question and I can repeat the crux of the question, if security constrained economic dispatch is neutral as to fuel diversity but yet we see a social value in having some level of fuel diversity, is there a need for some exogenous regulatory action to ensure that we maintain fuel diversity over the long term?

MR. HARRIS: Let me answer it twofold. First of all, as an operator of a market, we're agnostic as to fuel type. The market is the market, a generator is a generator, electricity is electricity. And we should be neutral whether it's a neutral plant or a home generator ultimately. Electricity is electricity and that's how the market would work.

What you're seeing in practice is quite telling. As I mentioned, the actual supply of energy this year, we had 56 percent of energy so far supplied by coal, 32 percent nuclear, but the others are quite telling. Only 7 percent was gas. Another 7 percent was made up of 3 percent wind, 1 percent from bowel mass and other and 3 percent hydro. And so, you're seeing a greater significant component coming from the green side, if you will, and the capabilities and the demand side that also factors into that.

So, what you're seeing happening through the very hot summer is that you're getting the diversity because everyone sees a price and they can play and participate in that particular market place. I think that number is quite telling.

On the side of the question as to what do you have in the long run, that's why we have planning. And as you know, the State of Maryland was the lead with PJM in 1994, requiring us to have a long-term planning protocol. And it's under the long-term planning protocol that we take into account the fuel diversity, the base load capability, et cetera, over the long haul, transmission as the alternative, et cetera. So, it's under the planning process where that becomes a question for reliability of the power grid.

And the actual dispatch, you have to be agnostic as to fuel type. It's what people bid for the price and that's how you select the stack or who runs.

VICE CHAIR SCHISLER: Thank you.

MR. NICHOLAI: Thanks. And Jim, this is for you. And this is just to help my comfort level on this issue I brought up earlier. In an integrated company, FERC has rather elaborate rules about keeping the generation side away from the transmission side because of concerns about the kind of influence of decisions. Now you're in a position where you have a fiduciary duty to the transmission owners by the transmission owner's agreement under which you operate, but at the same time, now you're also operating the generation units.

Why shouldn't we be worried that there needs to be reform to whom your fiduciary obligation is to make sure that we really are going to get the most efficient economic dispatch of generation?

MR. TORGERSON: That's a good question. I think what happens by definition, and I can point to the examples on TLRs where we will maximize the use of the transmission system in order to dispatch most efficiently. And the part on the transmission owner's agreement that says we have to maximize transmission owner revenue, utilizing -- and I think the rest of it says something to the effect utilizing the transmission system as currently configured, so I mean, we have to look at the configuration of the system and then maximize that use which is what we would do because you want to eliminate constraints. You want to redispatch around those constraints. And when we looked at what happened in Wisconsin, we had inefficiencies related to TLR the utilization of the system to the extent of about 11 to 12 percent when you use the TLR.

So, I don't find them inconsistent but it's probably good to look at and think about it. Are we doing something that could put a conflict to those two requirements? I mean, we're going to do it as an economic dispatch. I don't think we are. I think we are probably doing it right and we're maximizing both. But it's probably worth thinking about.

CHAIRMAN BROWNELL: David? Oh, I'm sorry, Alan.

MR. SCHRIBER: That's all right. Go ahead.

CHAIRMAN BROWNELL: No, no. Chairmen go first, sorry. It's not a perfect world.

MR. SCHRIBER: I'm also cursed with the title of economist. If big is better, I'm just curious to how the pursuit of the joint and common market it between the two.

MR. HARRIS: I think the most telling thing is you got price convergence and that's what you wanted to eliminate. You're eliminating the pancake rates and you're seeing price convergence at the border between PJM and MISO. And I think that tells you the concept is working, it's coming to fruition and achievements are there.

The other thing that's working out is that we have identified there is a filing recently made at FERC that identified the things we can do to make more efficient operations between us. Some things aren't worth pursuing because they're not economic, not good enough business case form. Some things are. But for the most part, the most telling thing is the price convergence you're seeing at the border and that tells you you've got a very large, very efficient market place working.

MR. TORGERSON: I think, you know, when I look at it, I think things are working rather well between the two of us. The joint and common market, there are a lot of activities that we can add to, I mean, getting on the same time frame for FTRs which we will be doing. You know, we run a market that allows people more flexibility. Sometimes I think that's good, sometimes I think it may not be. But you know, there are some differences that we're looking at jointly, you know, what direction should we be heading to make certain that the markets, the two markets are as close together as they can be.

Then the other question goes, well, if they're, you know, that close, why don't you just merge the two? Why don't we just combine PJM and Midwest ISO and do one big dispatch? Well, we looked at that and our people did an analysis of it and the costs were so large and I'm not sure the technology could do it yet. It's getting closer but the costs would have exceeded the benefits on doing that and that's what we put in the report to FERC when we looked at one dispatch over the entire PJM/MISO region.

But all the other things, to allow price convergence, to make sure data is being shared, those are all being pursued rather aggressively right now. And I think we have extremely good information flow between the two entities. And we know what's going on in PJM and just like they know what's going on in the Midwest ISO. And if something pops up that we don't know about, they get on the phone and they talk to each other constantly. We have some people that are just identified on our desk that that is their job, to make certain they're communicating with PJM.

MR. SCHRIBER: When you said the cost, you mean the cost of joint dispatch would exceed the benefits?

MR. TORGERSON: The incremental cost of putting in a single dispatch is actually taking, eliminating what we have and then putting in a single dispatch over the entire PJM/Midwest ISO region. The costs at least were identified as being more than the benefits we'd derive from that because we have an economic dispatch for the two and we can communicate that now.

MR. HARRIS: Yes, the problem isn't stacking up the generating units, you can do that for the whole Eastern Interconnection. The problem is analyzing all the security constraints.

MR. TORGERSON: The contingencies --

MR. HARRIS: And the contingencies around that. But between the two of us, we're looking at probably close to 150,000 contingencies that you're analyzing every ten seconds. And so you do that for your entire transmission system, it becomes a pretty massive data problem.

CHAIRMAN BROWNELL: How then are you doing a state estimator for the entire Eastern Interconnect? I'm sorry.

MR. HARRIS: We used a hierarchical state estimator. It hasn't been done yet but we've got a hierarchical practice into it. So you can take what the distance, what has the most meaningful to it and you build it down into what would impact PJM.

CHAIRMAN BROWNELL: Okay. We're going to have a couple more questions, Chairman Jergeson, and then as my chairman said, if you've got really, really, really insightful questions that are short and get short answers, we're going to you, Dave, and to people over here. Okay.

MR. JERGESON: My question is for Mr. Harris. And it's prompted by just one of the very recent comments that you made that you're seeing price convergence at the border. Price convergence anywhere, if we did take into account all of the studies and about all of the efficiencies, we would assume lots of people are paying less and there wasn't any discussion in all of those studies about somebody paying more. But by definition, price convergence means somebody is paying more, and for those people who are fortunate enough to be served with low cost power somehow is part of what's going on here is that they are going to lose that economic advantage in the scenario that's developing with this whole program.

MR. HARRIS: No, what we've seen empirically is that they actually are going to be saving more than they would be absent in part of the market place. So, while it's low now, it will be lower because they're part of the market place. The same system, the same thing we saw with Allegheny. Now, dispatching over, you're able to get more economic advantage to optimize units and actually reduce the costs further than where you're already even though it is low compared to the relative region.

The price convergence is that when you run a separate market in MISO and then you run a separate market in PJM, to the degree that those markets are getting to be common and shared, then the price differential between what the price is in PJM and the price is in MISO should come together and start converging. And we're seeing very small differences between the spot price of MISO and the spot price of PJM.

MR. JERGESON: In Eastern Montana and parts of North Dakota, our customers are served by a utility that the price of power is $20 a Megawatt compared to higher costs elsewhere in the MISO region. What can we do to assure our constituents and customers that somehow the price they pay isn't going to converge to that higher level that's apparent throughout the region?

MR. HARRIS: Well, I don't want to speak for Jim but you can demonstrate quite readily as if they operated by themselves what that price is and then what if they operated again being part of a large system what the delta is in the price. So, that can be demonstrated. It's a calculation that can be made.

MR. TORGERSON: They're not necessarily paying the LMP price for every transaction that occurs. I mean, the LMP price is usually just paid on the imbalance or on a very small amount of the transactions that happen. And in your state, I mean, you still have vertically integrated utilities, and you have, as state commissioners, you can determine, you know, what gets passed through to customers from your costs and from your generation, from the generation that they do. They're offering it into the market and we're dispatching it at $20. If they are offering it at $20, that's always something you've got to make sure that, you know, look at what they're really offering, and then their generators are going to run. They're going to have the power there and some of it is going to be exported.

So, you'll have all that data and information on what is actually being done. And then, as regulators, you know, you will look at all this information to determine what is appropriate in your state.

CHAIRMAN BROWNELL: I think you both better go see the chairman in Montana. Dave?

MR. SAPPER: I can't help but follow up on Chairman Schriber's question about joint and common market and the point about we're seeing price convergence. It seems to me you could set up a simple textbook example where there are two applecart salespersons and either they were prohibited somehow from selling and each was on one side of the street. If they were prohibited in some way or to some extent from crossing the street or customers were prohibited in some way from crossing the street, I think you could still see a price convergence though apples are still the same price at both side of the street. But that doesn't necessarily say that that price reflects a marginal cost of selling those apples.

So, to me, price convergence isn't enough and it's bringing that absolute price level down through competition that really matters. So, I was wondering to what extent there is competition across the seams. And maybe a specific question, Jim, you mentioned higher imports in Wisconsin, if you know, were those coming from generators, was that electricity coming from generators in PJM or just through PJM or was it coming from the West?

I guess that's two questions. But the most important is how much dispatch across the seams do you think is being driven by competitive forces versus reliability needs?

MR. TORGERSON: Well, I think at the seams you're going to have competitive forces because we see our net schedule interchange fluctuate based on what the prices are in either PJM or in the Midwest ISO. I mean, there are people who may be selling power on an hourly basis and they will look and see where the prices are. I look at what, you know, the hub prices are. And when I look at the hubs at ComEd, Northern Illinois and AEP, Dayton Power Light compared to, let's say our Synergy hub or our Illinois hubs, the prices early on, there is a bigger spread. And today, it's down to pennies, I mean, cents. It's not, you're not seeing the spread that we were before.

Where the flows are going in like into Wisconsin, I'd be guessing at it right now because I haven't analyzed it. But my guess would be, and that's all it is, is that you're seeing more flow coming in from Manitoba. You're probably seeing flows come in from the Western map region, and then maybe even from ComEd. So, I would guess it's not isolated to just one area.

CHAIRMAN BROWNELL: I think, because I have a question from the audience, I think we're going to ask you to come back for a rerun after lunch, because I want to keep us on schedule to the extent that we can. So, gentlemen, if you wouldn't mind waiting, we'll make sure that you're first up.

A couple of housekeeping drills. Once again, the cheap $9 fast lunch is out the door and to your right. The commissioners, we'd like to do a team photo with the commissioners and I don't know where we want to do that team photo. Against the wall, okay. And we will, it is now 12:15, we will start at 1:15.

(Lunch break from 12:15 p.m. to 1:12 p.m.)

MS. SCHISLER: I have a question for PJM and MISO so, in terms of their presentations we've seen a lot of presentations on historical benefits and since this region really involves primarily two large dispatch areas, my question is where does PJM and MISO see the greatest possible benefits for improvements to the market systems that they operate today?

I did not see any, well, PJM had a short paragraph that addressed that but in generalities that I think with this group and this board needs are some very specifics that, that we can address in terms of how to improve what we've got today.

Thank you.

MR. TORGERSON: On our behalf, I think there's two areas that we need to improve on. One is transmission planning. We need long term transmission plans and we need to put the procedures in. We put the marketing efficiencies as part of that equation and we're working on that but I think that's an area we need to improve.

And the other is continue working on the ability for demand side to participate in the dispatch equation. There's some wonderful technologies on demand side. The opportunities are huge. The capabilities are there with the technology and, and the sooner we can get demand side to fully participate in the economics of the dispatch, the better we're going to be and it will really balance out the supply side devices.

So I think pursuing long run transmission planning and working harder with the demand side program so they can participate in the economics are two big improvement areas.

MS. HARRIS: For us, there's several thinks we're doing. One we characterize as, overall as operational excellence to make certain that we're going everything as best we can which would include the dispatch and fine-tuning all those things from when we started up.

So, we're not in the same position that PJM is, having been running things for a long period of time. So we have some more fine-tuning and just operational expertise that has to be improved upon.

Secondly, then we need to be looking at what kind of capacity market mechanism reserves, you know, have to be done. And we've had many discussions with the State Commissioners in the Midwest about that and where we go from, next in that regard.

And then thirdly and I have to say, you know, we need to be looking at what do customers want out of the market and out of, what products, services do they really thing they need or want that an RTO could be providing in the future and I don't have any specific ideas about that today.

But those are things, working with the customers, what are they going to need for the future and how can we work with them on providing that?

And we may not be the right entity to provide it, but at least we can provide the form for it.

MS. BROWNELL: Thank you. Yes?

MR. HARVEY: John Harvey from the Iowa Utilities Board. And a little bit different direction but I think it's also something that has been addressed as kind of a throw in and not that it isn't important but not that we haven't talked a lot about it and that's the issue of reliability.

And I'm particularly interested if, if either Phil or Jim have an opinion on what the running of a market does to improve reliability if, if you could, let's say that PJM rates itself as getting a grade of A on reliability, disaggregate the system or disaggregate PJM, disaggregate from a market perspective only, continue to run a day one type reliability operation but disaggregate the market effect and tell me then what you think the grade would be just doing the reliability operation.

And then if you want to, give me the grade for if I didn't even do the reliability.

MR. HARRIS: Well, I'll speak to that first. I will tell you, because I ran PJM for five years as a tight power pool before we had markets. And we are more reliable with markets than we were without markets.

And I can give you one anecdote this morning that showed that and I can tell you over and over again we're more reliable, the regulation market is better with markets than we were without markets.

Voltage collapse is the single biggest threat to the Eastern Inter-connection. We have better knowledge, understanding on working with reactors than we ever did as a tight power pool. So just empirically in experience I can tell you we're better and more reliable with markets than we were without markets.

As far as part two of your question, it is a really interesting question and I'll dance on it just a little bit. But the United States is the only country in the world now that's combined the markets with a grid operator.

And if you look at Europe, you look at Nordpool, you look at New Zealand, Australia, you actually are running the markets separate up to the day ahead market. And then the market operators, actually the independent transmission company that's operating the real time hourly market and it's working quite well.

So I would say if you look at this as mission to study that we're in a transition that's going to take a generation, we're probably only ten years into it, I don't think the current structure is necessary to the status quo.

You know, we may evolve and change and develop to have better structures.

When you start looking at the markets you start looking how to develop the derivatives and the risk instruments on markets, that really is not an RTO expertise. That's people that trade and sell in markets expertise. You look at the clearing functions that need to take place that aren't taking place today.

So I, I don't know where that's ultimately going to settle. But it probably won't be exactly like we're shaped today. But I think you'll always have a reliable grid because either the RTO will do it or an independent transmission company that can operate can operate the -- market and do something separate with the day ahead in the futures markets.

MR. TORGERSON: I think when I looked NERC did a little analysis and they had ranked the Midwest ISO and I think it was six categories that we were best in class in everyone from, with reliability.

But I will tell you that having even said that that I know having, now that we're running the security constraint economic dispatch, we're better and it's more reliable than it was before.

So if you put that at an A, I would probably have to say, you know, we're better so we probably couldn't have been better than a B before.

MS. BROWNELL: Yes?

MR. GOSS: Phil, in your written comments that dated, well dated today, you say "Regional grid operators must constantly examine the market structure to identify and remove barriers to optimal skid usage. For example, those barriers could involve retail, wholesale, institutional or regulatory barriers, etcetera."

And I'd like for Jim to weigh in too. You have a room full here of State regulators and Federal regulators, what regulatory barriers do you think need to be addressed?

I would really be interested to hear specifics.

MR. HARRIS: I think the first one we have to look at is how do you get rate relief for transmission expansion. You know, certain states have passed model legislation that allows the rates to be passed through currently to retail customers.

And for PJM, we can spend $4 billion in transmission construction and if it's passed through currently to the retail customers, you're talking one mil per kilowatt hour. And some states are passing legislation enforcing that.

So I think for transmission it's approved and an RTO rubic have no way to pass through those rates currently is essential for rate relief.

I think the second question you need to address is cost allocation. It is an integrated machine. It's a huge network. And just because you build a transmission line from West Virginia to New Jersey virtually everyone benefits and no one can solve the cost allocation problem.

I mean we can calculate it but what percent should Kentucky pick up or Wisconsin because the line's going from West Virginia to New Jersey. And I think that should be taken on head on, cost allocation is the issue.

And I think the third one is how do we get, we truly get in demand side functionals and I really think that the in-state will be demand that can participate in the economics or real time dispatch.

But each state has different rules in retail, different rules how demand would work, net metering rules. You know, how to really concentrate in that area so that we can really get the consumer participating in the economic value of the dispatch equation.

And it almost has to be state by state but to the degree we get commonality in moving that forward and get a healthy, robust demand programs moving, we'll be much better served quicker and it solves a host of other issues when you get that into play.

MR. TORGERSON: I wouldn't characterize in so much as regulatory barriers but as areas where we need to be working with the State's and the Federal regulators on the capacity mechanisms, whatever we end up doing and coming to some consensus on what we want in place for determining what capacity and what reserves are needed in the Midwest.

Secondly then would be also on our, the cost and benefits of transmission expansion, same thing Phil mentioned. How are we going to agree on that within the OMS, with, you know, that can be actually put into place so we do have some effective cost sharing across the region.

And do we, you know, break it down into sub-regions or across the entire Midwest, so however we end up doing that, those are probably the two biggest areas that we need to work on.

And I wouldn't consider them regulatory barriers because we have had very fruitful discussions, we just haven't resolved it yet. So we've got a ways to go.

MS. BROWNELL: I have a question from the audience for you, Jim, and it's related I think to your comment that reliability and economic dispatch are basically inextricably intertwined.

The question is that the number of frequency excursions since MISO started the market seem to be significant, is that the impact of having 28 balancing authorities as opposed to I think one in PJM and if so, what can we do about that?

That certainly has been a topic of discussion since well before the market opened.

MR. TORGERSON: Well I think they're two different things but the frequency excursions, I know it was something that NERC had looked at, did a lot of analysis and study on and determined that there really wasn't any big impact simply from the Midwest ISO starting up that really had nothing to do with it.

And there were a couple of frequency excursions that were observed. But, then we have the bigger issue of running 27 control areas and how do we manage within that, which we're doing.

But I think we see it could be done much more effectively and efficiently with fewer. And we have an obligation to provide a report to the Commission a year from the time we started the market which we already have a team who's digging into that right now.

And we will be making recommendations, suggestions, based on our experience and observation of having to run those 27 different control areas which does create some issues, particularly related to, you look at the NERC standards for which the control areas have to operate too and running inside of a centralized dispatch, it may not make sense to have those same requirements on a particular control area today when they're not doing the dispatch anymore.

So there are a number of things I think we need to tackle and I think it would make things more efficient and probably would help on the reliability side too by looking at fewer control areas.

MS. BROWNELL: And candidly as people talk a lot about costs, when you look at what happened just at ERCOP, when they had that consolidation, the savings that emerged from them, I would think this is something that State Commissions really probably want to look at in addition to the reliability impact.

MR. TORGERSON: Right.

MS. BROWNELL: I couldn't resist. I know it's about, not about economic dispatch and the team behind me is going to give me the club in a minute.

David?

MR. HADLEY: Thank you, Madam Chair, this is David Hadley from the Indiana Commission. Partially for the, the two presenters but more specifically a question for all of us to consider with the board.

And we've heard a lot of numbers and a lot of studies indicating benefits. And yet with the Department of Energy's analysis, they were saying that the very narrow window of benefits that were defined in Section 1234 of the Energy Policy Act, after reviewing 25 different studies, failed to reach what they thought the Act was asking for specifically.

And so perhaps if, I think the words was the studies asked questions that are different from those itemized in the Act and they need to be more analytical models developed so that they can more appropriately answer the question, and that's what I asked David Meyer about earlier, that they intend to address in a year from now.

Perhaps, as much as anything, narrowing the questions from all of the State regulators to a lot of others who are saying credibility or not credibility in some of these studies, believability or not, if you could just help focus some key questions with the Department of Energy, with the RTO's and with the members of this Board, what needs to be asked and what needs to be answered independently so that the benefits, as asked by Congress, can be clearly articulated.

And I, I just found it interesting to see so many studies and yet reducing to a real specific answer, we need more studies. So maybe identifying what that should be would be very helpful.

MS. BROWNELL: Thank you. A comment from, okay. With that, gentlemen, you are excused. Thank you for doing such a wonderful job. Again, if there are more questions for these presenters, I hope that you will feel free to ask them.

MR. HARRIS: Okay. Thank you.

MS. BROWNELL: Next. Perhaps next -- Board should be about cost allocation. One of my favorite topics.

Okay. Right now we're going to hear from the stakeholders, who were also asked some very specific questions about economic dispatch. And even though I deviated, no one else can, so let's remember the topic at hand.

And have, are we starting from this side? Okay. Doug, you're up.

MR. COLLINS: Okay. Thank you. First of all I would like to thank you for allowing me to speak on behalf of the Midwest ISO Vertically Integrated Transmission Owners.

Getting the economic dispatch correct is very important to us and to our customers. I'm going to dispense with a lot of my prepared remarks because we brought out a lot of the issues this morning. So if my presentation seems a little disconnected, more than usual, it's because I'm trying to pick up some points from this morning and elaborate on them.

This morning we heard Jim talk about the start up of day two market and how the Midwest ISO was conservative and that resulted in generating units being run at lower levels and additional peakers being brought on. He said that that is, has been at least somewhat corrected.

In my opinion, it's still the case although probably at a lesser level. The way the system is operated today appears to be more conservative, more so than what's needed for what I believe is a reasonable level of reliability.

There was a question asked whether benefits had been, had been realized in the MISO footprint and certainly a true economic dispatch implemented MISO footprint-wide holds great promise.

I would say we're a ways away from that but there have been benefits realized. The question is not what benefits have been realized but what is the potential and how do we get there.

I got to qualify my remarks somewhat because I, as I try to quantify what benefits there might be, what struck me was we really don't have a good baseline to compare after market to pre-market.

Jim talked about it this morning. We started the market and immediately had the, one of the hottest summers we've had in quite some time. Gas prices went through the ceiling and then coal prices, because of the derailment also increased. So to compare what the cost is today compared to what it was before is a very difficult thing to do.

We have learned some lessons. We've learned that generating units have very unique characteristics. And those characteristics are difficult to incorporate into the structured offered format. Jim talked about their running economic dispatch but it was based upon bid prices.

Because of the unique characteristics, because of the newness of the market, it seems like every time the transmission owners or the load serving entities within MISO talk about the apparent uneconomic dispatch. The answer we get is our algorithm gives you an economic dispatch, it's your bidding which is causing the problem.

I guess the statement I would like to make is it is a market problem. It is not a load serving entity problem. It is not a MISO Staff issue. It is something we have to work together in order to solve.

MISO must take the lead so that we can get that solved and reduce the problem and the increased costs that we're seeing over what we could realize.

We knew that there were going to be transitional pains. Part of that is caused by, you know, MISO rules to dispatch are not necessarily clear and not necessarily interpreted the same way by our, all parties. We need to make sure that those rules are clearly understood by everyone.

Appropriate training is definitely another lesson learned. You know, if we were going to do it over, I think we'd probably do much more training, make sure that everybody understood the rules on how to bid before we went into the market.

Possible improvements, we heard a lot this morning about economic versus efficient dispatch. As was said, I don't see that there's a whole lot of difference between the two. But I think the one thing that I would state is that where's, we may be doing an economic dispatch, you've got to look at it and say it's an economic dispatch over what time frame, based on what market rules.

Minor changes in market rules could have large impacts on what that dispatch looks like. For instance, there's a volatility in LMP pricing each five minutes and that causes excessive swings in generation, base points between economic min and economic max.

If you could smooth that out, then the asset owners would be more comfortable in putting in different RAMP rates which, in return, would make the economic dispatch look different.

There's questions about how MISO treats jointly owned units. And as you get at least in the western part of MISO, those units are jointly owned by not only market participants but also by people outside the market. We need to clarify what those rules are. There is a solution that's been proposed and hopefully we can move towards that.

There was a question around how does economic dispatch affect markets, spot, day ahead and bilaterals. You know, in my opinion the market or the economic dispatch operated by MISO is, is the day ahead and the spot market.

In talking to, you know, the people that run our, our merchant, what they have told me is that the bilateral has shrunk considerably. They're still doing some longer term transactions, but the people willing to be the other side of that partnership is shrinking quickly.

And then finally, how do non-participants affect economic dispatch? MISO has to be able to handle thousand megawatt swings every 15 minutes. I think this is part of the cause of what's, why they had so many peaking units running.

If you look at the RAMP rates of units and having to handle those, that magnitude of swing and it's, and it's driven primarily by people just outside the market looking at the different, differential and going from one market to the other depending on where the price is better each 15 minutes.

A potential solution, if you get an agreement with the non-participant parties, is a economic dispatch scheme which has been implemented between Manitoba Hydro coordinating member and MISO.

They worked out a real time dynamic dispatch scheme to facilitate non-market entity dispatch for market concerns. What this does is it allows MISO the flexibility of dispatch some non-participant generation in a somewhat comparable fashion to what they do with the market generation.

And with that, that concludes my, my remarks.

MS. BROWNELL: Thank you. Bret? We're going to save our question until afterwards, is that okay with everybody?

MR. KRUSE: I'd like to echo Mr. Collins remarks as far as my gratefulness and the gratefulness of my company, Calpine and the other independent power producers and PJM and MISO to have the opportunity to talk with you guys this afternoon.

My view on economic dispatch is slightly different than the view that Mr. Torgerson and Mr. Harris purported earlier in as much as I think my company's position on economic dispatch in non-RTO, non-ISO areas is fairly clear on the record.

With that said, let me explain why we appreciate and like the set up that both MISO and PJM have.

There's two key components that both of them share. This independent and they're transparent. Those are the two key things from an independent participant that we expect in a market that helps make it work right, it helps us have confidence that the market's done the most economical way with no favorability to any of the other participants

. Those are key in what makes the economic dispatch decisions work right.

We also believe that the LMP pricing strategy allows for the most optimal use of transmission. The old TLR process certainly did not. And I think that shows, if you look at the non-coordinated areas, consistently that still rely on the old TLR process, it's just not the most economic, efficient way to manage congestion.

The second part of the discussion we were asked to talk about is improvements. There's been a lot of discussion or at least some discussion this morning about multiple control areas, ancillary services and a little bit more telling about grid and flexibility.

Now this is an important distinction between PJM and MISO. The PJM gen stack, if you will, is slightly different, it is a little more situated as to where they have more flexible plants to move around. MISO doesn't quite have that opportunity. Part of this is driven by the fact it's a lot more heavily on the solid fuel type plants.

The other piece of this is they've got a lot less of what I'll call a dispatchable range on a given day. It makes it hard to handle those megawatt swings that Mr. Collins was referring to.

What this creates and how this affects economic dispatch means they have to run more out of merit units to make up for the inflexible needs that they have to manage the grid system. This is inherently uneconomic.

Why is it like this? Well part of this is due to bidding behaviors that people have and how they bring their units in. There was some discussion earlier, I believe about how you try to associate the value from the high end of the spectrum where many plants, particularly gas fire plants, for example, are much more efficient generators to the lower end where they're lesser efficient.

There's ways to do that and there's ways to price that. Not all of that in MISO currently is being appreciated by all of the member participants.

There's some data that I requested from MISO last week that they provided me that will show you lots of times on a given day, from the day ahead perspective to the real time perspective, what they'll see is a collapse of anywhere up to 50 percent of their dispatch full range.

And this affects them several ways. One thing, they have to run their peakers. I think there's only 17 combined cycle plants in all my cell which is a lower number than you'll see percentage-wise in the other RTO's. Not a lot of what I'll call intermediate plants.

That means they have to fire peakers to give them that extra flexibility. In fact, when there's some discussion, I believe the Commissioner from Michigan brought up about the running of the peakers, I think my analysts that were looking at the market going in figured they probably ran a little bit less than we thought they would.

So the fact that they were running more peakers really didn't, didn't surprise us a whole lot. They, if you're used to understanding how grid operations work, they needed that additional flexibility.

So that's an important thing to understand and it's important to understand how the bidding behaviors goes into that. What you have to have is a wide enough range, a physically wide enough range with each generation aspect such that the MISO dispatcher can deploy those plants through those ranges.

If you make say 100 megawatts of a 500 megawatt plant available for RAMPing day ahead, then when it gets struck, because that will help make it more, more advantageous from a cost standpoint.

Then when you take it in an intra day and you take five percent off the top end, because you're messing with your reserves, and I'll talk a little bit more about how a simple reserve market would fix that, and you pull 30 percent off the bottom, which in some of the cases is what they did, what that does for you is two things.

One, it keeps you out of that lower end range, where your plant managers don't want to operate in the first place because even though they can legally do it by their environmental permits and they can operationally do it, it's less efficient and quite frankly, they don't like to run there.

But what that does to MISO is it changes the day ahead plan as they go into real time. If you've ever looked at studies of how control rooms work, whether they're plant control rooms or grid control rooms, if you have a better day ahead plan and the operators that have to put that plan into process believe in it and are comfortable with it, they're going to work more effectively and more efficiently, which by definition brings lower costs to your rate payers.

So it's important that the day ahead plans mirrors as closely as possible to the real time plan such that the real time plan, when they're implementing it is merely a delta a things like lines tripping and generators tripping off line and other mechanical and electrical issues that you simply can't get around.

But they have to be confident in their day ahead plan. That will help bring down costs. So there's, let me talk just a little bit more about the bidding behavior.

It's important and I know MISO is trying to push some rules through or they're really starting look through them, up through their reliability sub-committee, they start locking people in day ahead with only certain exceptions for mechanical failures. It's very important that we do that.

I don't think, I'm not going to try to put myself in the minds of these people that, that do collapse these ranges. What I will say is there's a discernable affect on reliability that also translates back into economics. That, in my estimation and my staff's estimation is one of the key drivers of what's driving up their uplift costs, the revenue sufficiency guarantee or RSG's for those people that, that follow MISO. So it's important that that point's made.

It's, it's interesting that, to hear Mr. Harris and Mr. Torgerson talk about improvements. I would have to agree, slightly, in as much as what Mr. Harris says about demand side management is certainly the forefront of the future for, for a lot of reasons.

And you can certainly pick up on the fact that PJM's been doing this a lot longer than MISO has, so you would expect to see a much more mature organization.

With MISO, I think Mr. Torgerson kind of stretched a little bit about what we can do as far as consolidating the balancing areas. There's a misnomer out there that PJM really operates this single balance area.

That's, if you dig down to the technical aspects of it, quite frankly that's not true.

If you compare it to traditional control areas, they way they've been in the many decades leading up to now, what they really do is have more of a shared area control area, they're regulation figure or their ability to maintain the grids stably and they have a centralized reserve market.

So these things bring out natural reliability efficiencies and natural economic deficiencies such that these, the inflexible plants, if you will, they don't have to provide any kind of discernable to dynamic power services anymore.

They don't have to have a cold plant, for instance, providing regulation all the time. The plant can run at a 100 percent like it's designed to do. The intermediate plants can pick up most of that regulation range. They RAMP faster anyway. Why not have a plant that can give you 20 megawatts of range in five minutes instead of one that can give you two or three.

It just, it makes better sense economically and it makes good sense from a reliability standpoint. These, these are key aspects that PJM provides that MISO has not provided yet.

Now I can tell you, because I'm on this panel that Mr. Torgerson talked about that's looking at ancillary service markets, we're starting to get there. Part of that's people getting past their paradigm of what is probably not the best phrase of controlled air consolidation and starting to really dig down to the aspects of what's really going to change, from a balance in area to balance in area perspective, what's really going to change.

And it's not that much. It's better for reliability and it's better for economics. And it does affect economic dispatch. Once you have everything being run more centrally, whether you're talking reserves or regulation because they go hand-in-hand, you're going to drive your costs down and you're going to improve reliability.

There's no secret that everyone of the other formal markets and Calpine Merchant Services, my subsidiaries of Calpine is involved in every market in North America. It's no secret that they all went to this. It's been successful for all of them.

Every study I've ever seen that talked about it before or after has always shown it's more economical. So this is a natural staff for MISO to take that will be better in return with economic dispatch. You're optimizing not only your energy and your location aspect of it where you're trying to optimize the transmission system, but now you're bringing these other dynamic factors in if you need to run the grid and optimizing around that whole spectrum.

So you're going to give yourself a better economic output. You're going to have a more true economic dispatch.

How does this affect the markets as they are today? I can tell you if you sat through a lot of ERCOT meetings like I do, you'll see exactly what happens if you don't have a good, solid day ahead market. ERCOT really doesn't have that right now. They run into a lot of problems because of that.

They're kind of in some ways MISO, they're, they do, they've kind of got a single control area but they kind of don't because they use a little thing called portfolio dispatch that creates a whole lot of other problems. So it's not necessarily the optimal design.

So if you want to see something that's good about what currently exists today in MISO and PJM, that's the relationship between day ahead market and real time LMP and real time dispatch, that the two go hand in hand for optimal design.

The last thing I'd like to bring up is non-participants and what affect they have on the markets. I think the, if you have non-participants inside of a geographical area of the market, the thing that they don't provide or the problems they cause are pretty apparent.

I will let go something that Mr. Collins just said about opportunities and I think this is key. He mentioned the Manitoba situation. There was a similar situation that PJM had with Wiley Ridge that they cut a re-dispatch agreement with MISO before MISO came into their day two market.

That was good for both parties. It saved PJM a lot of cost. I'll look a that and say that's a textbook example of where the two RTO's could reach out to other people whether they're in the MRO area, TBA, these other type areas and say if we had some re-dispatch rights with this generator than that would help alleviate strain in our system. Let's find a way to make it work economically for both of us.

I think that's a tremendous opportunity they have, particularly for some of these areas that aren't going to be in a formal market anytime soon.

That concludes my remarks.

MS. BROWNELL: Thank you. Fred?

MR. KUNKEL: Good afternoon. Fred Kunkel, Wabash Valley Power. Thank you for the opportunity to allow us to, allow me to voice my opinion on economic dispatch.

My predecessors here, Bret and Doug did a fine job of taking away all my, my wind. And I thank them for it because I don't have to speak as long.

But one of the things that I would want to bring to the forum here is the PJM/MISO market, right now, we don't have a combined market. Going forward with this, the advent of having spending reserve available in MISO and as well as in PJM, somewhere along the line a pilot program, if you want to call it that in my opinion, whereby this is a real rude and crude issue but getting to allow MISO and PJM to experiment on this seam exchange for economic power.

This is something, you know, years ago and I'm dating myself near a power pool, but where we did do economic dispatch and share the savings between that, if, if nothing in the beginning, to learn how these things would occur between the pools or the RTO's rather and learn how to grow into a larger vista.

The other thing that I would like very much to, to expand on, Bret's issue that he brought was the bid in process.

I, I am a supporter of once you put your bid in the day ahead, you're locked into it for the, for the next day. That, that causes less fluctuation in your, in your market.

The third thing that I would like also to be addressed down the road is the fact that MISO and PJM both have operating periods different for those entities that share load serving entity responsibility, such as Wabash

Valley, we operate in eight control areas. Seven of them are in MISO and one in AEP which forces Wabash Valley to be part to PJM.

And we have different characteristics for operations and we have different bidding characteristics. So they are inherently differences between those companies that share both RTO's.

Somewhere along the line I would, I would think that it would be a logical convergence that you get into a single bath for allocation of the time period, January, February, March, whatever you, the RTO's choose and try to converge to that as a goal.

That would be very helpful in bridging this issue of bidding in process. I thank you very much.

MS. BROWNELL: Steve?

MR. NAUMANN: Thank you Commissioner Brownell and all the State Commissioners for asking me to appear. I'm here on behalf of Exelon which has a number of operating units, ComEd in Chicago, PICO in the Philadelphia area, Exelon Generation which owns Generation throughout the country and Exelon Energy which is a retail provider.

I would be remissed if I didn't welcome you to the Chicago area as Mr. Wright did and mention I believe O'Hare Airport is the only airport with a dinosaur in it. So for those who get a chance to go to terminal one, you, I think it's a brachiosaurus, and it violates the TSA rules and it goes from the secure area, it's tail goes in the unsecured area. And I'm sure someone will do something.

I, on economic dispatch, to me this is deja vu. If you go back to integrated utilities, how they operated, that security constraint economic dispatch was how those systems were operated.

There was congestion in the integrated utilities. There was out of merit dispatch due to transmission constraints and it was internalized but it wasn't visible. So a lot of the things that, that we're seeing when we go to a market is simply that you're seeing it now instead of it being buried in the entire cost of service.

But still the cost of dispatch were minimized as much as possible and the costs were paid by the captive customers and the system worked pretty well.

Then we got restructuring and now we have independent generators and we have customers seeking access. And, and that's where we ran into this issue of how to substitute in a deregulated market or an unintegrated market what we had before.

I think we found that LMP is the best substitute. I don't think the question is whether the security constraint economic dispatch is good. I mean, it's hard to argue with bringing cost down and bringing efficiency up.

The question is how do you do it especially in areas that you don't have the organized, organized markets. It's not just a matter of saying I want to do economic dispatch. There's a whole what I would call infrastructure that PJM brought to the table and MISO has developed to apply and that is, that is the market mechanism that is mechanisms to compensate the generators that are not owned by the, by the operators or don't have captive customers.

It's the congestion management infrastructure and to echo something that's been said, it's the rules, it's the rules, it's the rules, it's the rules.

All of that stuff, all of those things are needed to do security constrained economic dispatch.

Benefits. I can tell you Exelon is very pleased with ComEd's integration into PJM. We think it has brought more efficient operations. There are things that ComEd is no longer doing. We're no longer a control area operator and that makes me happy.

Years ago, years ago there was a saying in the industry and pardon my political incorrectness, real utilities or control area operators, now I'm not sure I want to be a control area operator. We're not the transmission provider. We're not the, we don't run the oasis. These are a lot of things we're not doing.

And, in fact, the job that I used to have doesn't exist anymore. So to some extent I'm a casualty of this.

We're also pleased with the start up of the MISO market. We do own a, in effect a merchant nuclear plant in MISO and it makes the ability to sell that into the market much easier.

Obviously security constraint economic dispatch we think you get the most economic generation, considering transmission and other reliability constraints. Better use of the transmission system.

Another thing that, that is inherent and I don't think it's been talked about are the transactional costs under the old system. To actually do a transaction for a few pennies, it, you needed people to put something in Oasis, make a transmission reservation, confirm it, do a tag, do all these little things that had to be done and, and for half a dollar or 25 cents, I don't know what the cut off was, it wasn't worth it.

Internalizing all of that through the PJM LMP system, you don't have to do those things so it happens naturally, just like it used to.

So those were, I don't know if you would call it administrative barriers to, that you do away with when you go through a market and security constraint economic dispatch.

Congestion management is much better than it was in the old physical rights days. That's for several reasons. One, the larger amount of generators that will respond to the price signals and the greater geographic areas that you're dealing with.

That means you're, you have more, in a control system point of view, you have more things to control than you did before.

NERC TLR, I think everybody said this, it's not the best way to do it. It's command and control and it doesn't take in to account economics. But there's another thing and, and people have eluded to this, it takes time.

TLR occurs after there is a problem. Security constraint economic dispatch anticipates the problem through the State estimator and the dispatch system.

It takes time to affect the TLR and I've said this in other forums, I believe that security constraint economic dispatch improves the reliability of the system. Just look at TLR as an example. Operators should be worrying about what will come next. They should not be spending time on unwinding transactions that have already caused a problem when they could have avoided that in the first place.

That is a major reliability benefit of security constraint economic dispatch over a large area.

Improvements. There, there are a couple of, couple of area I'd just like to touch on. One is, for lack of better word, seams issues and the other is reliability rules. And it, to some extent, I am going to get down into the weeds because you end up having to get down into the details on the improvements.

First I want to say the joint operating agreement between PJM and MISO is a template, I think, for the seams that are between PJM/MISO and other areas that don't have economic dispatch.

There's a lot of experience there. The two RTO's have done a lot and they've come up with innovative solutions.

One thing that we would suggest that they should look at for improvement, you've heard about the price convergence, but right now they're aggregate RTO to RTO proxy prices. We think that moving to more interface points, provided that's done in a coordinated basis and provide their rules to avoid game playing will improve the economic dispatch.

I would note that, that PJM has had to react in the past to this game playing on the multiple interface points and I'm sure that's, that memory of that has to be taken into account. But we think that more work on that can get you more granularity.

Somebody mentioned different, the differences in the algorithms and Commissioner Brownell, I think this morning you asked David Meyer about who should the, the algorithms are, so to speak.

These are subtle and it seems that there, we should try to move to one standard. I know that's hard when you have history there and going, it's not, not that easy to go in and make a patch. But the subtle differences can cause subtle changes.

The other piece I wanted to talk about is reliability rules. As I mentioned earlier, these, these do have costs. One of the things that we found and I think PJM has found, PJM is driven is as an example the NERC TLR rules.

Right now, the fact that PJM and MISO re-dispatch automatically, before a system gets overloaded is very nice, thank you, but once there's a problem all the good deeds they did don't get any credit. They, they're at time zero so to speak and now the PJM and MISO systems get hit just like the third parties who haven't yet re-dispatched.

That, that creates a real equity problem and a real disincentive for economic dispatch on the part of others.

Now PJM has been and MISO have been driving this at NERC to try to find a solution. I understand in June the operating committee approved the concept of essentially giving credit for prior re-dispatch but there's a long way to go to put this into effect.

So an example of the interaction of where a reliability rule can impact the costs. And if there were, you know, in our opinion that is one place where if we could get some quick action, I think you would get some better dispatch because then you would get the third parties who aren't subject to re-dispatch would be carrying the burden of these TLR's rather than the people who have done well and done the right thing having to shoulder burden that they shouldn't have to.

Another thing is the, the multiple sets of rules that the RTO's are under. I think Bret mentioned in PJM that it is one balancing area but right now there are slightly different operating reserve requirements in different parts of PJM.

Well, hopefully January 1st with Reliability First Corporation, we're going to take care of most of that. Having one set and that will help in a single reserve market. That won't get going to all of MISO.

But things like that having common reliability rules will help. First of all, you'll get a review of why those rules should, what they are, making sure that they are the best rules and eliminating the differences so that you get more efficient operations.

So I think that's, that's what I have for now. And again, thank you very much for inviting us to speak.

MS. BROWNELL: John?

MR. ORR: Hi. I'm John Orr, I'm with Constellation Energy. We do a little bit of everything across this region here. We are a generator, a load serving entity on some transmission and do a lot of power marketing to both retail and wholesale customers.

Thanks to all of you for allowing me to speak today and I'm very happy to be here to share some thoughts about economic dispatch.

What I'm going to do here is try to kind of bring up, come up a level. A lot of things have been said already today and I think to try to put some perspective on just generally what's this economic dispatch's value to all of you in this room and what's the value to the customers here and that's the, in this region, and that's the context I'd like you to take my comments in.

And so lets start off with saying, look, MISO and PJM both should be, you know, applauded frankly for establishing operating some of the most reasonably and workable security constraint economic dispatch models in the country. There's no question about that.

They're at different stages in their evolution but both of them are on the right track, they're brining benefits to consumers and they should be noted for that.

The second thing, and you've heard this is as an undercurrent, I don't think some, anyone said it explicitly, maybe Phil or Jim did, is that the reason this is good is because it brings, and especially in the LMP form that we see it in here in this region is because it brings price transparency to the marketplace.

And what that allows people to do, whether you're a load or a generator or a transmission owner, all right, what you can do is you choose now, on an economic basis, how to deploy your assets and manage the risks for your constituency, whether that be a generator, load, etcetera.

All right, that's what you're getting. You're getting price transparency in a, in a real time information. And then you can manage risk forward off of that information.

The last thing here in the general sense is that we should encourage PJM and MISO to continue down this path and continue evolving until they are both, become the widest area possible of deployed economic resources if you will.

I think you want to continue development. You don't want to say we've got it good enough right now. And that's kind of been an undercurrent of things, but that's how I would generally characterize the message that I want to send you.

Now, to get into the specific questions that were asked of this panel, you know, the first question really dealt with what are the qualitative and quantitative benefits? Well I just told you the big qualitative one. It's transparency and the ability to manage risk around that and just make asset deployment decisions, if you will.

The, but as for quantitative benefits, I don't think any one of the individuals sitting here, we could all say, well we got this out of it, you know, he got that out of it. The truth of the matter is is that Phil and Jim really are the experts on that. They see the big picture. They've given you reports. Matter of fact, I haven't seen a report that says this was a really bad idea in any way, shape or form.

All the, all the reports that were done prior to say MISO implementation said it was a good idea. And MISO itself is confirming that. And they're back of the envelope presented in the October advisory committee was a confirmation of that, just, like I said it was a back of the envelope they presented to everybody.

The last thing is that, or on that subject too is that, you know, I think from a lessons learned perspective here is that, you know, you've got large geographic scope, that's a good thing when you're looking at security constraint economic dispatch.

Some of the measures that you could see of whether this is successful is the amount of trading liquidity you have and how many participants do you have in this market that are actively trading. Are there forward markets being made off the prices and operations that are being generated by these models?

And in both of these markets the answer is yes, there's a lot of those things. We have a lot of liquidity, particularly in PJM, financial liquidity around say PJM West Hub. You see it already developing in the MISO as well, just six months into its operation.

So if you look at number of participants and a matter of liquidity, this is really good. And this goes back to my point about why do you really want to do this. The more of that you see, the more chances loads and those who regulate them have a chance of protecting themselves and managing risks.

That's what this is all about. It's about getting the best price for the risk profile that you select for your customers.

I mean we have a, and when I say risk profile, one of those measures is reliability, like Steve's talking about. What, what level service do you want and how much does it cost? You want the best deal for that. That's what this is all about, security constraint economic dispatch is a big piece of that. It is the foundation upon which people can act.

I know that's like a broken record, but I really want to get that point across. So it's just a tool in the toolbox is what I'd say.

Let's talk about some improvements. You know, I said they need to continue to evolve here. What are those areas? You know, remember the gull here is low cost to consumers overall for the reliability that we desire for them all and here are some things and we've heard these before, and I won't go into detail. But MISO, in particular, needs to continue to work to develop bid basing ancillary services markets.

And that doesn't mean we have to do them all tomorrow, but we certainly should start with some of the easy things, some of the things Bret was talking about and start moving forward.

That means things like regulation and reserves should be first on the list and start bringing those more into an economically, an economic deployment mechanism rather than a command and control mechanism split up among control areas or balancing authorities I believe is the technical term today.

The second thing I would suggest, and you ought to think about this because it's part of the continuum of overall costs to consumers is to make economic dispatch work, you want a level playing field among all the participants.

And this goes to one of the issues that almost seems not in, in the zone of economic dispatch but capacity markets. You want everybody to have a similar profile and the enter the energy markets where security constraint economic dispatch takes place.

This means that you don't want some people having a capacity payment and some people not. In other words, some people having their fixed costs governed and some people not. That's not a good program. Everybody needs to be thrown into the same bucket in some way so that you, you get the right economic mix.

The, kind of going hand in hand with that, I'd say is that you have to be careful about excessive mitigation. It sounds really good to get involved in capping prices and trying to keep a lid on things but the more you do that, the more you create problems.

And some of the things that people have already talked about here, about people having to change their bids from what would be their true cost of serving someone to accommodate some type of incentive created by mitigation schemes.

And so I would caution you and be careful to say is that we need to make sure that excessive mitigation doesn't occur as we're employing the skid process here.

And last, this has already been a mention also too is that MISO and PJM should continue to work to manage seams issues around this. Those are the areas of improvement, I think, that we should see.

You know, the third question asked to this panel was how does economic dispatch affect the markets, spot, day ahead, bilaterals and I'll tell you, I think this goes back to my point about why are we doing this and it is the transparency that, that this device gives you gives people a lot of confidence in the market.

And what I mean by that is it lets people know that the pricing is efficient and it lets them have a benchmark for which they can compare what they're actions have yielded. It's just that simple. It's confidence. That's what you get from having a good economic dispatch in the marketplace.

And finally, the last question was what affect do non-market or do non-participants have on economic dispatch? And I wasn't sure what to take the context of this question, so the context that I'm going to lend to is this is for people choosing not to participate in RTO administered bid based markets, is the context that I'm going to assign to this question.

And that is what I think they're doing is they are reducing the RTO's choices about how to best serve load. If they choose not to participate they are, to some degree, affecting reliability and tying the hand of the RTO.

And then part two of that and this is important for their customers and for those of you who regulate people who are choosing not to do this is they can never really be sure that their customers are getting the best deals because if they take themselves out of this marketplace, and they're not participating in security constraint economic dispatch where they're getting the benefits that we see that Jim and Phil talked about ascribing to their marketplaces, how do, how do they ever know that they're getting the best deal for their consumers?

How can we ever really be sure if they don't participate?

And, and really that's what I'd like to leave you with is. This is a good, security constraint economic dispatch is a good thing. PJM and MISO should be complimented for that and we should keep moving forward to create more transparency through just about anything that could be priced as a megawatt hour type service as an energy price mechanism.

Thanks again for your time.

MS. BROWNELL: Thank you. Ed?

MR. TATUM: Commissioner, thank you very much. Appreciate the opportunity to be here and I've really enjoyed this morning and this afternoon, the different perspectives that have been brought.

I, I'm hearing some very consistent themes and I suspect others might be as well. I'm Ed Tatum, I'm with Old Dominion Electric Cooperative, we're an electric cooperative. We've been experiencing the PJM experience since day one and the Del Marva Peninsula and now with the integration of Dominion Virginia Power, into PJM as well as AEP in Alagany, we now have our entire load within PJM.

So, we've been there for a while. It's, it's been a very interesting, enlightening experience.

What I've been hearing today as we talk about something that the electric utility industry has been doing for many, many years and this is security constraint economic dispatch.

And I liked what Phil Harris said about the evolution of this is changing. And our industry is dramatically changing as well as so it's appropriate that this changes.

I was listening to the comments earlier with Steve, listened to Doug, listened to John, Fred, I'll listen to you as well and the things that I was hearing, the things that I was hearing --

MS. BROWNELL: You better. He's tough if you don't.

MR. TATUM: Oh, I know. And he's got a camera.

The things that I'm hearing though really are indicative of how our market has changed and how our industry has changed and we apply these changes to this old friend, if you will.

And so we're transitioning, we're evolving. There's a tremendous amount of details. We talked about how the market rules will affect a security constraint economic dispatch.

We talked about more granularity. We talked about how reliability comes through. What's I'm hearing is there's a lot of exogenous variables that affect a security constraint economic dispatch. We talked about the rules, we talked about the fleet.

The aspect that I wish to bring to this is another piece and that's the underlying transmission grid that enables the economic dispatch to take place.

And again, as Phil was talking this morning about the evolution of PJM, these three utilities got together and they planned the resources and the transmission to make that economic dispatch happen. And so I don't want to lose sight of this one other piece.

We changed our paradigm significantly and when we're, previously we were on a integrated resource planning type of environment where we'd actually trade some generation for transmission and make decisions based on cost.

And I understand that as we are in a market environment, we hope that the market will enable us to indeed get back to cost. But I love the comment earlier of, with regards to the MISO response that we're, we're not bidding right.

Well, yeah, you're bidding right. You're bidding what the market will bear. I submit to you that we're still evolving and our infrastructure is not allowing the transportation to take place. But we're changing.

Separation of generation to a competitive market while transmission remains a regulated monopoly requires development of new standards to reflect that new relationship and that still needs to fully evolve.

We were integrated in inter-related grid and the economies of skill are certainly something that you're looking for in a security constraint economic dispatch, but you need to be able to get there from here.

Lower voltage local facilities that are operated under the same protocol as network pull facilities can result in significant congestion. And we've seen that, transmission congestion. That directly does affect dispatch decisions and affects competitiveness.

And Steve was talking about common reliability rules. I think those are indeed crux and are good opportunities to take a look at that.

As we apply new rules and new paradigms to old environments, we do have significant change.

Possible improvements to the current economic dispatch practices, both within an RTO or outside, it comes back to the need to have a better underlying transmission grid upon which to apply this dispatch.

Even with an RTO in place to address the mechanism for all generation to bid into the market, if you, if you don't have the adequate transmission, you still will not be able to get that generation to dispatch and displace others.

Some potential solutions I'd like to offer up. For those that are not in an RTO or are still trying to figure out how they're going to do, they perhaps consider phased implementation of, of this economic dispatch and start with the bulk network facilities. Start with integrated grid, the high voltage facilities that was designed under different standards that local radial systems.

Develop consistent reliability and economic criteria that must be satisfied prior to lower voltage, local facilities being turned over to operation by the RTO.

I have a list here of, of how you might acquire that. Let's see, you evaluate the facilities under the criteria. You take a look at their functionality, how they may help or hinder overall operations.

You take a look at the short and long term impact of facilities on congestion. And include in the dispatch only those that pass the criteria and reject those that don't.

Another potential suggestion I bring forward, given that we are in a new environment is to implement a collaborative and inclusive transmission planning process for local transmission owners and all their wholesale customers.

Again, this is an opportunity that we think could be more evolved and applied in our little neck of the woods and we think it might be helpful in other areas and that way all stakeholders of the transmission grid would have an opportunity to be involved in the planning of that grid.

I might take a different position than my friend John with regards to market monitoring. We think that the market monitor, they wish to focus a little bit more attention with regards to the potential exercise of market power on a transmission grid itself.

The dynamics and the inter-relationship and interaction that you see of bidding behavior and congestion and the impact the transmission construction can have on the relief of that congestion are serious issues.

There are opportunities there that, that there could be gaining. I can't say that there was, but it's something to be thoughtful about.

The, Mr. Harris made the comment about cost of new transmission investments being recovered and a little bit of surety there. We suggest that the, a number of ways to handle that might be implementation of formulary rates as a ways to, and again an ability to recover new investment in a timely manner.

We strongly support moving forward with the State and Federal partnerships for inter-state facilities. Gatherings like this are particularly exciting. I think there are a lot of opportunities to come from this.

And we'd like to suggest that we, that there be a recognition that regional transmission should have regional rates applied to it and we think that this will spur a lot of new investment.

The affect of security constraint economic dispatch in the market, it has the potential for tremendous benefit if applied to the facilities capable of supporting a competitive marketplace.

But it has the potential for tremendous harm, in local areas to certain constituents if applied without sufficient infrastructure. We've well documented this in another case that I'll leave silent for today.

And with regards to the last question, with regards to non-participants. I would hope that as we evolve, and I want to be very clear with this, Old Dominion is an active participant in PJM, we feel we are a member of that RTO and that as PJM goes so does, so does Old Dominion.

It's to our benefit that PJM be successful, we are much better off in a competitive marketplace wit open access than we are in balkanized regions. But one thing as far as non-participants, I think it's a function of continuing to evolve.

It's a function of continuing to design the market rules such that folks who do not wish to play are able to see that it's irrationally economic not to do so.

I thank you for your time. I hope I stayed on topic, Commissioner.

MS. BROWNELL: Um-hum. Thank you for that silence on that certain topic.

MR. TATUM: Yes, ma'am.

MR. KRUK: Good afternoon, everybody. My name is Derek Kruk and I work for Citgo Petroleum Corporation. And I will say that my comments will generally reflect similar point of view, in particular an industrial consumer point of view.

My first advice to all the generators is keep those bid prices down really low, it helps us as a consumer. And I think it also helps the Commissioners from all the states here do their job as well.

One of my opening statements here is we really believe in free markets. And when we see markets are really free, we say let's make them freer. And I, it's amazing what a lot of competition can really do in terms of increasing efficiencies and that benefits everybody.

But in terms of this economic dispatch and some of our reflections on what that does to an industrial customer, I'll talk about some positive, positives first.

One of them is price transparency. It, it's wonderful when you can just get online and go to PJM.com and find out what power's costing, costing you this hour and you can act accordingly. We think that's really a great benefit for a consumer.

Also from a retail basis we've seen some really imaginative product offerings that hereto forward just not available and that really helps us, makes life, you know, more confusing and potentially more risky but it can really add value for your operation.

We have a few questions on PJM/MISO and the impacts that economic dispatch may have and one of them is, is producer of market power. We, we got concern where somebody can, really has a constrained area that could really raise their bid prices and produce some really high returns that you wouldn't necessarily see in a free marketplace.

We, we'd like to see that continued to be, to be monitored. Because we know there's a lot of smart people on, for these electric generators that are trying to optimize all this and getting whatever the market can bear. And the consume is not necessarily that sophisticated.

Also, another question we have is, is this seams issue between PJM and MISO, it appears to be working itself out. If it, if it doesn't, it just doesn't seem right to have a free market and have, you look over the fence and the price is significantly different, it just doesn't, it could never sell to an industrial customer.

Some suggestions for improvements. First of all, we'd like to see more states in this, in this process in the open market. We just, I know that it's not going to benefit everybody but overall I think it adds efficience.

And also what I think would be very important is that industrial customers, or for that matter, small commercial or even residential customers have an opportunity to participate in this market on a demand response point of view. So instead of a generator bidding in a price, we would bid on a price to shed load, I think that would really, really help keep everybody honest and have a lot of different types of competitors in this market to truly make these, this market a free one.

Thank you for having me here this afternoon.

MS. BROWNELL: Thank you. And last but not least, Mr. Welch.

MR. WELCH: Well first I want to thank Ed for, I thought I was going to be the only person here to talk about anything to do with transmission. So, with that, I thank you, Ed.

Good afternoon. My name is Joseph Welch. I'm the president and chief executive officer of International Transmission Company.

As the only truly independent transmission company, International Transmission is not a market participant, does not materially benefit from the energy market and is uniquely qualified to comment on the benefits that can be realized by a truly competitive marketplace.

Our perspective is unique, not only because of our independent status but also because of our history. From 1969 until 2001, the Michigan Electric Coordinated System provided many of the functions of and in some cases more functions than our provided by RTO's today.

The two major Michigan utilities which operated the Michigan Electric Power Coordinated System performed joint economic dispatch generation, jointly planned transmission capacity expansions, but more importantly built the transmission system to eliminate all internal congestion for their generation to be economically dispatched.

Although the joint economic dispatch in Michigan ended, much progress has been made in the drive towards energy markets. There's a greater price transparency and an increasing number of market participants are bidding into the market.

Unfortunately, markets are hampered by the shortcomings of the transmission system.

In today's world of energy markets, the transmission system is being used for a purpose for which it was not designed and the result is visible in the price differentials within energy markets.

If we could start over again, from scratch, and create an environment that was conducive to economic dispatch based energy markets, all transmission facilities would be placed into independent ownership and large regional transmission organizations would take a proactive role in the planning and oversight of regionally based, economically motivated transmission expansion projects.

As long as ownership of the transmission grid remains in the hands of the generation owners, protected by its congestion, the benefits of economic dispatch will not be a reality for end users.

As long as the intra-market price differences exist, there is more work to be done. True competition cannot exist until the constraints that cause these price differentials are eliminated.

International Transmission is not a market participant but is interested in the efficient use of the transmission system. We're deeply concerned that economic dispatch and the consequent pricing of a congestion is a dangerous remedy from a reliability standpoint.

Uneconomic re-dispatch to relieve congestion can create the situation where physical needs of the system are overlooked because there is a re-dispatch remedy for congestion.

Economic solutions cannot and will not fix physical limitations of the grid. The best way to ensure the cost of delivered energy is lower is to fix the physical limitations, expand the system and eliminate the constraints that are causing the congestion in the first place.

Transmission infrastructure investment yields benefits of an economic nature, has increased capacity, reduces congestion rents associated with the periods of heavy demand and are crucial in sustaining system reliability.

If the transmission resources are inadequate, it is not only rolling the dice with the Nation's electric infrastructure from a reliability standpoint, but it is unrealistic to expect that the forces of competition will deliver the lasting benefits to consumers.

International Transmission believes strongly that the competition in the electric industry, it's progressive steps toward lower prices, better reliability, more opportunity for alternative price producers.

If the policy makers want to bring the benefits of economic dispatch to end users, the benefits of alternative supply to end users, they must create a regulatory environment that enables real competition to take place.

The success of the electricity market hinges crucially on the ability of low cost energy to be delivered and this is why a robust transmission grid is crucial and the market based approach is to succeed.

In 2003, the Midwest Transmission, Midwest ISO Transmission Expansion Plan had claimed $1.84 billion in infrastructure investment through 2007 will yield $304 million to $1.6 billion in reduced annual marginal cost of wholesale energy.

These investments will not take place unless there's a process that attracts investment dollars and returns them in a predictable and formulate manner.

The FERC had the vision and International Transmission has responded by substantially upgrading the quality of southeastern Michigan's transmission system in our two and half years as an independent transmission company.

Customers in our footprint have seen the benefit of added capacity as we have set a new all time peak demand this summer and we have all benefitted from a more reliable system.

Our studies show that for the first 120 million of capital that we invested on the behalf of our customers, they have received benefits of approximately $100 million annually.

While we're proud of what we've done, we know that there are many issues unresolved. When asked how they faired since the start of the Midwest ISO energy market, a large industrial customer in our zone recently lamented the transmission constraints were causing higher than usual congestion costs and there is no certainty as to how long the contemplated fixes will be instituted. Who pays during the interim? The customer.

In conclusion, International Transmission supports competition and feels that economic dispatch is a good way to allow economically superior producers to supply the market. The first steps have been taken but the job is far from finished.

It's not sufficient to think that the pretense of competitive markets is enough to ensure the competition is alive and well.

If we are truly ready to go down the path of competition, we cannot expect to see the benefits by going halfway. We cannot have the constraints of the transmission system disallow economic generation resources from coming to the market, denying end use customers that economic benefit.

Thank you very much.

MS. BROWNELL: Thank you, Joe. Questions? Okay.

MR. SCHRIBER: Well, for one I'm really happy to see that our panelists didn't wade into the swamp of economic versus efficiency in terms of dispatch.

And from that point I would advocate, we talk about optimum dispatch so that we, we don't have to get involved with that.

Out of curiosity, ancillary services are obviously a critical component of what goes on here. And in terms of dispatch, would it make any sense, and I'm just sort of thinking out loud, would it make any sense to have a, sort of a segmented market for ancillary services, aside from those which would otherwise be dispatched?

In other words, could you just have a market for and dispatch ancillary services as sort of boutique offering, if you will? Aside from, from that which you are otherwise dispatching?

MR. KRUSE: I'll take a stab at that. I think yes and no. If you look at, for instance, PJM and I'll use that because I think our, my company's belief, and those of our clients that we serve and those, most IPP's and power marketers is that PJM probably has the best model for a variety of reasons.

If you look at what they do, there's two components there. One, they do offer those services segmented. In other words, they have a regulation market, they have a reserves market, so forth and so on. So there is some of that segmenting.

But what's important is the way they dispatch those services in real time and they do that hour by hour is integrated such that the algorithm that they use looks for the lowest cost determinant for all the little components that go into it such that if you may have a strong regulation provider with a wide range that would normally be a very good provider of regulation if the congestion cost locally, for whatever reason that particular day or hour are high, that's going to figure into the component that maybe in the overall, the big picture, if you will, it's not the lowest cost provider.

So it will then go to another alternative. So it's important and this is one of the things I tell my colleagues on the ancillary service task force in MISO, it's important to use an integrated system.

If they were to use something like the Sprego system that PJM uses, it already takes all those components in there so it's a very good model to work off of, if not copy for a variety of reasons because it does all of those things.

So, yes, you've got defined markets but they all are interactive. And that's really the best way to look at it because that will end up bringing up the lowest cost for the product.

MS. BROWNELL: You asked the show stopper there. Susan?

MS. WEFALD: My question is for Bret Kruse of Calpine and if anyone else cares to comment on it, that's fine too. You mentioned about, you said between the day ahead and the real time market, you said there's a collapse of 50 percent between generation that's made available in the day ahead and then in the real time market.

Would you please comment on that more and the implications you think that that has on security, economic dispatch?

MR. KRUSE: What that is is you're talking about a deployable range. It is flexibility that that particular generator is providing the overseeing system operators to move it through that range based on the economic profile that they submitted as part of their bid, their bid curve, if you will.

It's very important that they pretty closely reflect what they've provided day ahead that they were chosen for under that financial contract when they take that into real time.

The other RTO's and part of what I do, well actually I work for Calpine Merchant Services, which is a spinoff between Calpine and Bear Stearns, part of what we look at all the time is we want, we want to take our clients as close in to margin as we can.

We want to give every physical limitation the right price. For instance peaking turbines, there was some discussion earlier about how they worked the best at the highest end, they're most efficient. That's true.

But there's, for a price, we'll RAMP them down. We use our peakers in MISO, for instance, all the time, move them around on AGC, even though it costs more to move them down, we put the right price on them, we want to be able to give MISO that flexibility. That's inherently good for the market and it's fundamentally a economic good bidding policy. Not everybody does that.

In part because some of the individual BA's have to carry their own reserves. There's some duplicity, if you will, between the reserves that MISO carries and the BA's, that is inherently inefficient. That's something they're working to get past, that ancillary markets will help get us there.

The other piece of that is plant managers, and I can tell you from my own experience, you don't like running at lower ends. It's less efficient. It causes a lot of other problems, even though it may be legal by your environmental permits, those people tend to be conservative in nature.

And it's, without, this is one of the great things, price transparency gives you is real clear economic signals on it, what's it really worth to go that far down. You're not going to violate anything, your machine's not working as good. Maybe it's going to increase your maintenance costs a little bit, but let's get down to the real choices and put some prices to that.

It's the same argument that demand response is looking for right now. At what price will I start curtailing load. And those, that transparency that John and many of the others touched on it are really what drives RTO markets to make them better than non-RTO markets.

So, so it's important that you understand that what you physically can, are capable of doing, that you develop the right curve, based on economics and you take that curve in every day, into the market day ahead and make it available.

At the end of the day there are physical changes, you lose a pump or something else happens that can make you change your profile in intra-day, that you can't get around that. But it's important that you take everything in, as best you can, economically day in and you don't change that going into real time.

I hate to put myself in the mind of others, but I can't get away from it in this example. There are sometimes that people would want to change, for a variety of reasons that are centered around the fact that they still have to maintain their, their NERC criteria, their CPS I and CPS II scores, as a result of their BA.

That's one of the other things that go into a wider footprint of control, if you will, would help.

So there's, there's a couple of aspects that play into that but it's important that that's not only bad economics when you consider economic dispatch, but it's inherently bad for reliability and that's something MISO can fix.

It's interesting that PJM's rules don't allow you do to that and in PJM it's a little bit more mature market so it works a little more efficiently.

MS. BROWNELL: Anyone else who'd like to comment on that? Ken?

MR. NICHOLAS: Thank you. Doug, I heard you talking about, and I want to make sure I was understanding. I think I heard you talking about inefficiencies that you think are actually being created by the, by the market.

You mentioned that the, I think the system was being operated more conservatively then the needed and that the unique operating characteristics were not, you weren't able to capture those int eh way this is operating.

Are these, are these minor issues that just need to be tweaked or are they serious enough that we're not getting the benefits from the market that we expected because of the nature of this inflexibility?

MR. COLLINS: I'll start the answer and if I don't do a sufficient job, Fred will finish it.

But, you know, they are, they are tweaks. They are keeping us from fully realizing the full benefits. Doesn't mean there are no benefits but they certainly are keeping us from getting the benefits.

They likely are the cause of the, of the high uplift charges that we see. And I think that, you know, as I talk about the unique characteristics and learning how to put those into bids, talk about the volatility in LMP's, it's probably related to market rules and those rules can be adjusted.

I think that, you know, the main message is the market participant has some ability to change the way they bid but we don't necessarily have the data available to know what a certain change will do.

And that's why I stated earlier that, that it really has to be in cooperation with MISO. We've got to work jointly in order to get the dispatch correct and get the rules correct.

MS. BROWNELL: Chairman Hardy, oh, I'm sorry. And then Winslow, sorry.

MR. HARDY: Gee whiz. Okay. Also for Mr. Collins. I thought I heard you making a progression to a conclusion that you did not express and I'm curious if you have a feeling. I thought you were going to say, at least to date, probably the start up costs and all the related costs of establishing the MISO probably have not paid back more than the start up costs, at least as of today. Perhaps it will in the future.

And I'm just curious if, if I heard your progression correctly and, and you're more politic than perhaps I am and you didn't want to say that?

MR. COLLINS: With four of my regulators in here, I'm not sure I would want to say that. But I, you know, I think it's really difficult to tell. You know, like I said, we, we don't really have a good baseline to compare it to.

You know, hot summer, high gas prices, high coal prices. There's no way of knowing exactly what the dispatch would have been, particularly with the oddball year that we've had.

I think we are, my opinion is, you know, we're significantly under the benefits that we could see. But I don't really have a good base line to compare it to to say are we, have we seen enough benefits to offset the costs that have been incurred.

In the one, in the one fashion you're talking about capital costs and another you're talking O&M so it's even harder to, to determine.

But I don't, I don't have a good answer for you.

MR. HARDY: Just that you're thinking, just that you're thinking about it, I appreciate.

MR. HARRIS: Thank you.

MR. WINSLOW: I was at my first -- meeting this last, just recently and there I believe unanimously the Commissioner, sort of got on board with respect to economic dispatch and everything I've heard today has been almost uniformly positive, not obviously uniformly positive.

And most of it's been in the area of operations, in terms of improved operations. I was happy to hear from

Mr. Tatum and Mr. Welch about some of the constraints on the system and might happen to improve that because as a person who lives on the Del Mar Peninsula, that's a great concern of ours.

And how economic dispatch and the capital side of the house actually may, may not or may fit together and what we can do to improve those constraints because that obviously leads to higher costs, as pointed out to the consumer.

So I don't want to hear from Mr. Tatum. If Mr. Welch, you neither, please, sir, although I, because I think I know what you would say. But some of the other gentlemen here, can you give me some insight into what we might do as part of this economic dispatch at this course to improve or make more robust the transmission system, either bulk as well as local? Anybody want to volunteer? John?

MR. ORR: I'll take a try here. I think, I think the key message here is that having good economic dispatch, and that means as extensive as possible, and this was kind of my point, helps you make a, the decision and it's what you want to know, whether making the investment decisions these gentlemen were talking about are proper or not.

It starts, it sends you the price signal. That's the reason it's good. That's the connection here. It's the better you do economic dispatch the better decision making you can make about whether it's worth spending the money to build that line or not.

It's that straightforward.

MR. WINSLOW: Would you then be supporting what Mr. Harris suggested, which are the transmission costs pass through ideas or the formulary idea of Mr. Tatum and also, I guess the, I guess the cost allocation is a term I heard as well?

Those, some of those regulatory things would be of assistance along with the market signals you get from the, from the market or not?

Could somebody who's accustomed to us regulators might answer that question.

MR. NAUMANN: As a transmission owner, and maybe I, as a transmission owner --

MR. ORR: It's my third day.

MR. NAUMANN: Let me try to answer, answer a couple of things. Pass through is always good from, from the transmission owner's point of view. There is this Federal, State dichotomy that I do think that the State regulators here need to work with FERC on because it's not as easy as just waving your hands and say pass it through, there are local political issues.

Obviously, as a transmission owner, I'd love to get the rates passed through immediately on the State but they were, in Illinois for example, there was a policy decision made by the State Legislature to have a rate freeze for X amount of time.

And so we need to live with that until, for another year and, what is it? Year and a month and X number of days.

And so it's, that's a State by State issue that's pretty difficult.

I don't think you need formulated rates. I think that's a decision that the owner has that option of having it but I don't think forcing, forcing someone on that. There are down sides of formulated rates.

You don't know what it means if your O&M costs happen to go up, those get passed through. If your O&M costs get, go down, goes get passed through. It has to be tied in with, and I noticed that FERC just put out a no-par on some of these incentives.

So, yes, we think there needs to be working together to deal with those issues.

But the bottom line for expansion of the system is the regional planning process. That's really where the, where the rubber hits the road.

PJM has had that regional expansion process for awhile. As Phil mentioned, they're in the process of trying to change it. I think that's, that's where you have to look for the lines.

But I don't think economic dispatch in itself creates the congestion. As I said earlier, at the beginning of my remarks, that congestion was always there in the individual utilities. It wasn't as visible.

Now what you're doing is seeing vices and if, if that gets people more interested or more excited about it then, then in fact it has accomplished one of the goals and it say, you know, there really is congestion here, it might be worth looking at and eliminating it.

MR. WINSLOW: Thank you very much.

MS. BROWNELL: Joe?

MR. WELCH: I've got a little bit of different take on this. And I'd like to start off by talking about the difference between involvement and commitment.

Our, we only are in the transmission business, so we're definitely committed and it's not just a part of our business like it is with vertically integrated utilities.

Let me start from the top. There clearly is a problem with split jurisdictions. State and Federal mandates you always hear, every time you start to talk about a transmission expansion, especially for something like the State of Michigan, which is a peninsula state, surrounded by water but to the south, about trying to get more throughput or import capability into the state, most of the constraints now lie outside the state.

And the common answer is, I'm not going to ask my customers to pay for that upgrade to service Michigan. So there's a problem there and that's a big problem.

The second thing is is that I totally disagree with the, the concept that formula rates should be a pick'em. In fact I will tell you that unless everyone is under formula rates, we're creating a disincentive to not build transmission.

One of the things that comes through in the formula rates and you have to go through all of the calculations though is, but the biggest one is is that all of the revenues that we collect for point to point service are flowed back to customers in the form of a revenue credit every year.

If you don't have a formula rate, you keep that money. Let me give you the math on this. We're a small system and, for investment-wise, about $500 million. We get that big FERC enhanced ROE that everyone thinks that we make a lot of money with.

That enhanced ROE is worth about $4 million annually to us. Our point to point revenue, that if we were able to freeze our rates and not flow it back to customers in the form of lower rates, is $22 million.

I'll take the other deal, freeze my rates. When

I freeze my rates, I also then start to earn higher returns year after year as I continue to not invest in the system because my rate base is declining with my depreciation and as a matter of fact, the lack of formula rates is causing for lack of investment in the system. And it's causing, this is mine, not yours.

The last thing, and this is big, is the allocation of benefits. If we can't get the transmission grid expanded and realize now that it is truly regional, the markets that everyone's talking about here cover multiple, multiple states. Hundreds of thousands of megawatts.

We had a situation in Michigan, where internal to the state, joining another utility in the state, it was identified that early on, a year ago, that we were starting to experience a transmission congestion problem.

Now understand that there's a deficiency of total generation in southeastern Michigan. So anytime there's a constraint on that transmission system, it actually could result in load shedding having to take place.

We identified it. We started to work it through the process. The adjoining utility did not want to upgrade their portion of the system because they didn't want to raise the rates to their customers. They just purely didn't want to do it.

The amount of the investment that they had to make was under $100, I'm not even going to tell you how far under $100, but it was pathetically low, considering the investment that he made.

It increased the throughput in Michigan by 1,000 megawatts on our day of system peak, we consumed 700 of that 1,000 megawatts that day. Had that system not been there, had it not been for the Michigan Public Service Commission helping us get that done, we would have had to curtail load in southeast Michigan.

So let me summarize. The Federal State jurisdiction split, we've got to get this fixed. We can't have us versus them.

Allocation of costs, we've got to get this straightened out. We've got to come out to the point where people who get benefits pay for it and transmission upgrades absolutely uniform.

Third, formula rates. Last thing, we built a project in Michigan called the Jewel Spokane line, $10 million investment reduced congestion costs by 63 million annually in Michigan.

So you say, well that's a great deal. The real, the other problem is or the other part of the coin is is had $93 million worth of benefits for the region. So others benefitted from it too. No one was asked to pay.

We have to get this worked out.

MS. BROWNELL: Thank you. Ken?

MR. NICHOLAS: I'll refrain.

MS. BROWNELL: Oops. Sorry, Fred.

MR. BUTLER: No, I just put the card up because I was, I've been quiet most of the day because, as coming from the State that's the J in PJM, I'm kind of used to some of this discussion. We've had it a lot. I'm comfortable with a lot of what's going on.

But we just got into a subject that causes me a little heartburn and that's the whole idea of transmission. When we talk about economic dispatch and we heard the comment earlier today that we're dispatching a whole lot of coal, a whole lot more coal, that's coming from farther and farther away from the State that I represent.

And Dallas, you and I are the east enders in this whole discussion. And in order to get that economic dispatch to us, there needs to be increased transmission. And some, under some formulas, we're the ones that are going to have to pay for that. We're the only ones that are going to have to pay for a lot of that transmission because we are the "beneficiaries."

Well we're the beneficiaries because of the economic dispatch that's causing it to be dispatched from the other end of the, of the region. And I'd ask the panel to comment on how they think there's equity in that or whether there's a way around that.

We all want to get to the same goal, we all want to have the best value for our shareholders, for our customers or your shareholders. But at the same time, to put the onus for construction on one set of states of one region because economics says the best dispatch comes from the other end of the, of the system causes me and some of the people that I have to report to and be responsible to some problems.

MR. WELCH: Let me take a quick stab at that. The first thing that we do on our system is we don't build a project unless the net economic benefits are there for the customer.

Our goal is to get the lowest cost power to the customers in the most economical fashion and if it's not cost justified, why do it?

We've got a large industrial base in Michigan and all we can possibly do is further drive them out of Michigan and everywhere else.

The cost allocation benefits that you're looking at, I've never seen one piece of transmission, ever in my life, unless it's D.C., ever be, have, ever could ever pass the straight faced test to be directly assigned.

Right now, today, I could tell you that even though Michigan's a peninsula state, we support a lot of transactions that actually wind up in your state. We have, MISO has told me now that they now understand what lube flow is after years of me beating my gums on it.

Because we experience about 1,000 megawatts daily and overload one of our nodes with just lube flow, that's unscheduled flow through our system every day to the tune of about 1,000 megawatts.

Really, if you want to get to the bottom line and cut to the chase, a postage stamp rate across the region is where this always ends. When you get to the allocation of benefits, the transmission's going to get built, and if you run the math out long enough and you keep running the algorithm, it goes to a postage stamp rate for everybody inside of there.

Everybody pays the same delivery cost. The most economic generation gets dispatched. That is the final and the answer. We'll probably spend 20 years getting there.

MS. BROWNELL: Then we better buy candles.

MR. BUTLER: Well, hopefully not.

MR. NAUMANN: I, I want to, I'd like to try to answer the question as best I can. I think some of us have to be very careful in what we say because there, there is a proceeding right now, at FERC involving this issue and so I'd appreciate someone raising the red flag if we go a little too far.

I think what you raised, Commissioner, is a ver difficult issue and one we've been trying to grapple with. But let me try to answer that from the view of Exelon which has two load serving companies, PICO in the east and ComEd in the west.

And if we look at your example, for instance, and the, let's just take this theoretical project PJM has, maybe it's not theoretical, this project Mountaineer, $4 billion investment from the coal fields of Ohio and Kentucky, how do I go to Commissioner Wright and say the ComEd Illinois customers should pick up 16 percent of that line that's going, that set of lines or whatever it is, that's going, that's being built explicitly to transport coal from Ohio and Kentucky to the east.

That's the problem I have and that's the one we're struggling with. On the other hand, I do agree it's hard to say that an AC line benefits for over its, its full length of time one particular set of customers.

I think the way, PJM has a method now, as you know, and I think what you're asking is, in that particular case, why should New Jersey and I think Pennsylvania in that respect and Delaware, I guess everybody to the east of Ohio and Kentucky pick up those lines.

I think the way that needs to be done is I think we need to get the states in a sense that they can and the customers in the same room and try to work out something that's fair. Because it's, it's not only going to be the cost allocation, it's going to be the sighting.

And while your concern about rightfully so, picking up the costs, I think Chairman Schriber might be concerned about sighting a line where the primary justification for the line, in the case of this project Mountaineer is to deliver, deliver power to the east.

And then his, I don't want to put words in your mouth, Chairman, but, you know, are his constituents going to have to pay for that cost or what, in return for the environmental detriment or whatever you want to call it, what are they getting?

And I think the only way to solve that, I don't think just saying we're going to go to a postage stamp rate is going to solve that. I think you got to get the states, the load serving entities and the planners in the room just like you have today and say, on this project, how are we going to deal with it?

Let's talk about the need, let's talk about the, the overall, all the benefits which are net of some of the, the environmental or whatever you want to call them and try to deal with that.

I think it's just, and hopefully I didn't cross the line on the other issue.

MS. BROWNELL: I, Steve, you're wonderfully cognizant of the limitations we have. But we will put the transcript into any dockets that are open before us if we think they're impacted.

But no, you, you didn't.

MR. NAUMANN: Okay.

MS. BROWNELL: Karen obviously has you by a little leash back there.

MR. NAUMANN: Okay.

MS. BROWNELL: Yes. Jimmy?

MR. ERVIN: And this is more of comment than a question but I, the issue that we've been discussing that Fred brought up for the last few minutes is one that has interested me for some time and I think without beating the horse too much, it might behoove a lot of us to follow what's been done down in the SPP area because I think they have tried to grapple fairly hard with some of these difficult allocation questions.

I don't, and I think they ultimately concluded, as best I understood what they did, that while fine tuning probably wasn't proper that some kind of rough justice could probably be worked out using essentially the kind of process that Steve was describing.

And I know that Sandy Hachstetter over here, she'd want to talk to you at length about how they did that.

But I just offer that up as a suggestion around the problem that, that is a very real one that you all have been talking about because there are equity issues arising out of this kind of thing that different people can look at and feel pretty strongly about differently.

But there are ways, perhaps to work them out too, as long as you don't require excessively fine calibrations.

MR. TATUM: If I may respond to that. I share that sentiment and I'd like to echo's Steve's, Steve's comments. All we've talked about today, with regards to economic dispatch, we've said well this affects it, this affects it, this, it's a whole system here and regardless of how we've tried to unbundle it and piece it out, it still has to be integrated and worked together.

And so, I mean, if we looked at the whole system impacts, and there's going to be a generation, there's going to be new generation constructed, there's going to be folks that adverse environmental impacts there's with a positive economic benefit and sit in a room and if we have some basic truths that we do believe that a regional pool is a good way to go, if we do believe that a competitive market's a good way to go, if we believe we need transmission, set those up and then come up with some, some compromise and well thought out positions taking into account not just a single issue but the whole, more holistic situation.

MS. BROWNELL: Questions? Everybody's tired. A lot of economic dispatch. I'm, I'm going to take a, we're not going to break because I think people have planes to get plus I know no one will come back.

And I want to be sure that we have a little plan here for going forward. I'm --

MR. ERVIN: Madam Chairman, I think as long as you tell us to come back, we'll come back.

MS. BROWNELL: Some of you are better behaved than others.

MER. ERVIN: I was going to say some of us are more beautiful than others.

MS. BROWNELL: I am, I'm going to just describe what I see happening next. In summary, and this was a terrific panel, you really gave wonderful, wonderful recommendations.

I think we've come away with a better sense of what economic dispatch is, what it can do, it does bring transparency, it does bring clearer economic signals, but that in fact there are a number of things we can do, particularly in the newer markets.

But even in PJM, like getting that common algorithm to do, to make it better and improve it. And I, I started to list them but I have so many we would be here until midnight if I listed them.

So what we will plan on is this. December 12th, I remind you the comments are due for this conference. Bret, for example, it would be great if you and Doug kind of expanded on the specifics of the market rules that you think need to be changed. The more specific we are in comments the easier this report is going to be to write.

You, as joint board members, if you would be good enough to have your recommendations is, because this is really, as Congress directed, recommendations from you and the joint boards to us for the report, we will publish those and have some teleconference on what we agree, what we don't agree on as we try and put together a report.

Bud Earle who is on our staff will be in charge of amassing all those recommendations.

As I mentioned earlier, we can also have a teleconference with DOE if, as you read the report, which has a lot of really interesting information, most of which got discussed today but not all of which did.

We can also, I think, fine tune our thoughts on the further studies that they recommend and we, perhaps, would like to see.

February 3rd we'll send out the consolidated list of recommendations for discussion at a meeting at Naruk, because we think that's the most convenient, we can have fewer or more teleconferences as you want before that.

If you want to designate staff to be your stand in, it would be good to know who those are and just have some consistency because when we get a different person on the project we find it a little difficult to get the project done.

If in fact we need further meetings after that, we can certainly do that, but I know the Chairman's desire, and I think he expressed this at the meeting at Naruk is to get this to Congress as soon as possible.

It strikes me that if we all, for example, identify the need for more and better information from DOE, perhaps Congress would like us not to wait a year but maybe to take the next step sooner rather than later.

So to my --

MR. BUTLER: Madam Chair?

MS. BROWNELL: Yes.

MR. BUTLER: Can you just go over those dates again?

MS. BROWNELL: Yes.

MR. BUTLER: December 12th?

MS. BROWNELL: Yes. And we'll, we'll send out a note to everybody as well. December 12th the comments are due from today's conference. January 6th you should have your recommendations in to Bud Earle, Bud will stand up and give his e-mail address.

We'll consolidate those and send them out February 3rd for discussion at the Naruk meeting in February. If anybody has preferences, I think we'll probably try and coordinate it with the other joint boards so that we don't take up all of Naruk's time.

Jimmy?

MR. ERVIN: And one other thing I would point out and we discussed this at the south joint board meeting in Palm Springs is that, for your planning purposes, Madam Chairman, we are already obligated on Wednesday and Thursday to a DOE Naruk electricity delivery conference.

And so one thing that we have suggested to the Chairman in Palm Springs was to the extent that you wanted to have any of these joint board meetings in connection with winter meetings that you look at either Sunday or maybe Monday morning --

MS. BROWNELL: Okay.

MR. ERVIN: -- as a possibility and obviously if you'll just get your staff to get with me we can --

MS. BROWNELL: Okay.

MR. ERVIN: -- coordinate that so that we can make the maximum use of the time that's available.

MS. BROWNELL: And we will try and do that as soon as possible so that people can make travel arrangements.

Kevin?

MR. WRIGHT: Well I found this to be quite extraordinary and I particularly appreciate the stakeholder panel that was assembled and gave us some very frank and forthright views.

I always appreciate hearing from the CEO's of the RTO's but I appreciate even more hearing from those that are actually out there day in and day out living under this type of framework that we have.

So I specifically kudos to the stakeholder panel in improving my knowledge and hopefully the contribution that I can make to this process very informative. Thank you.

MS. BROWNELL: Ken?

MR. SCHISLER: Ditto. Have a safe trip.

MS. BROWNELL: Thank you again and, oh, yes?

MR. JERGESON: Well, I don't know how much time you planned on discussing this. I too, appreciated the stakeholder panel but other than some nuances in their presentation, there didn't seem to be a lot of major differences between any of those panelists or the presentation that we had from the leadership of the two RTO's this morning.

But we have the interesting question about the affects of the non-participants. And when I think of non-participants I'm not sure what exactly the definition of that is, but I did not have or we did not have today anybody, like for example, from WAPA. We didn't have anybody from non-jurisdictional entities like Basin Electric who are skeptics about the RTO notion in particular and, and what place and what role they may play in that.

And I'm wondering if we can really, as any kind of a group, actually offer a balanced analysis of this whole notion, without having had some of those key providers of a variety of utility services to a number of customers throughout the regions without their participation in the discussion.

And I don't know whether they were invited and declined to come and participate on a panel here or what happened.

But, but I think there's a huge body of folks out there with very key interests on behalf of their own consumers who were not represented today. And, and that gives me some pause to wonder about what I can participate as a Commissioner from my state in some sort of a final product as a recommendation to either FERC or to, to the Congress on this subject.

MS. BROWNELL: I think that is a fair statement. Candidly we, with recommendations from many people, invited people who were participating and had direct experience with the economic dispatch.

But why don't we take your comments, which I take seriously, and see if we can set up something with a non-jurisdictionals. We'll work with their associations and some of the members to see what we can do to answer that question. I appreciate that.

Yes, Jimmy?

MR. ERVIN: And again, I was a little bit confused about the definition of non-participants too, but if you are referring to people who are on the periphery of these bodies but are affected by it there are some of us that can help you line up folks --

MS. BROWNELL: Okay.

MR. ERVIN: Because there are all kinds of opinions on the periphery of these bodies as to how effective or not effective they are that I won't bore you with today.

MS. BROWNELL: Okay. Good. I would also remind everybody and if you would be good enough to use your platforms in your states that public comments are welcome and will be included.

But we'll see if we can set up, you know, albeit a focus group, perhaps, but I think include the RTO's so that there can be a dialogue back and forth, or anybody else who wants to participate.

Thank you, good reminder. And I didn't mean to rush this to a close, I just could see people looking longingly at the door. So I'm glad you stepped in.

MR. NAUMANN: Commissioner Brownell, they want to see the dinosaur.

MS. BROWNELL: They do indeed, but I don't want to get in trouble with TSA because I'm on airplanes five days a week. So take a picture. Fred, take a picture of that dinosaur, would you?

MR. KUNKEL: I will.

MS. BROWNELL: Okay. Thank you.

(Whereupon at 3:15 p.m. the conference was adjourned.)