U.S. Department of Energy
Pre-Congestion Study Regional Workshops for the 2009 National Electric Congestion Study

Oklahoma City, OK

June 18, 2008

1:00 p.m.-4:30 p.m.

Transcript

David Meyer: Well, good afternoon, ladies and gentlemen, welcome to DOE's second workshop in relation to our upcoming 2009 congestion study. Before we get into the substance of the workshop, I'd like to turn the microphone over to Bob Anthony, Commissioner Bob Anthony from Oklahoma, who is our gracious host here today. He has some remarks.

Bob Anthony: Thank you very much. Welcome to Oklahoma. We're glad the sun is shining, it's a great day, and we appreciate especially this important workshop being held here in Oklahoma City. It's book-ended against the Annual Meeting of the Mid-America Regulatory Conference, our annual meeting of the 15-state organization just concluded, and, you know, Benjamin Disraeli once said that listening to an author speak about his works is like listening to a mother talk about her children. Well, anyway, I just finished this conference, and I'll try not to go down that line.

But we are very excited about the energy and the regulatory topics that we were able to discuss. I think many of the people are jointly concerned of electric and transmission issues. My colleague, Joyce Davidson, is here to participate throughout the afternoon, and we look forward to sharing and learning as time goes on.

The conference we just had mentioned a few things that pertain to transmission. I might just throw them out as things get -- could be of interest. Sometimes they ask, "Well, how do you -- where would you site wind energy? Would you have it right on the best location?" and the answer is, "Well, no, not really, because there are some other economics, like the economics of transmission. If there's not a transmission line nearby then you've got to figure those economics into it.

Some of our speakers talked about the upcoming -- importance of carbon sequestration and said that that might --having a suitable facility to do that sequestration might become one of the factors you would consider when trying to site generation of electricity, and we caught some of the issues involved in energy, water and excess that we think the Department of Energy and others are pursuing in a formal way, organizationally and otherwise -- and water availability as a consideration in energy.

So I guess what I'm saying is maybe things are getting a little more complicated. So I know you think you've got a tough job here today, but there are lots of things to keep in mind.

Welcome to Oklahoma, welcome to this place where we love to talk about energy issues of all kinds. Thank you very much.

Kevin Kolevar: Thank you, Bob. I wanted to say a brief welcome, as well. I'm Kevin Kolevar, the Assistant Secretary for Electricity Delivery and Energy Reliability at the Department. This second technical conference is part of the Department's ongoing work to apply the statute from the 2005 Energy Policy Act. We appreciate the participation of our -- all the folks in the audience, all those that are joining us on the webcast, certainly, and our distinguished panelists, as well, thank you very much for coming. We value greatly the information we receive out of here. The data, the comments that we get from meetings such as this are crucial to our work to put together an objective, unbiased report that speaks as, really, the preeminent document regarding the nation's -- the status of the nation's electricity congestion.

So thank you, everybody, for joining us today. I look forward to hearing from our panelists and others.

David Meyer: I'm David Meyer from the Department of Energy, and I'm going to start us off with a brief overview of the reasons we're doing the congestion study and how we're planning to approach it.

But before I get into that, I want to introduce some other folks up here. One, Warren Belmar from DOE's Office of General Counsel. He and his staff are very important to our effort. And I have two other people here that I want to introduce to you -- Peggy Welsh of Energetics. She has helped us to arrange these workshops and is very helpful to us in a number of ways, a long-time colleague of many state regulators. Also, we have Joe Eto from Lawrence Berkeley Laboratory. Joe and some of his colleagues are going to be providing some very important technical assistance to us in doing the congestion study.

So, Peggy, when we get to the panel discussion is there an easy way for this podium to go away so that we can see each other across here?

Peggy Welsh: I'll check on that.

David Meyer: Okay. The Energy Policy Act of 2005 directs DOE to conduct a congestion study every three years, and the first one was for August 2006, and so now we are in the process of preparing for the upcoming one in 2009, and so we are doing six of these workshops, and this is the second, but I want to emphasize to you that although our purpose in hosting these workshops is to gather information and data that we need for the congestion study. I'm not under any illusion that I'm going to walk out of this meeting with a briefcase full of good stuff. This is really our attempt to reach out and communicate to people the kinds of information we are looking for so that we can get a better view, and the folks who are on the webcast, can get a sense of what it is -- what information and data we are looking for, and there will be plenty of opportunities over the next several months for you to make that available electronically, and I am also aware that some of the -- there are studies going on that are relevant but are not completed yet, and so even that material might not become available until September or something like that, and that's fine now. But at least if we know of things that we should be looking for, watching for, and once we get kind of the titles or the topics entered into the record then we can chase these things down and take them into account as we go forward.

Now, in addition to these workshops we are more than willing to meet with anyone who wants to meet with us in our offices in Washington or at meetings of this kind and at each of these workshops, we are taking every opportunity to meet on a bilateral basis with interested state officials who want to talk with us about congestion matters.

Now, I know that there is a close linkage in most of your minds about -- between congestion, the congestion study and national corridors, but it's -- and I want to emphasize the Act requires the DOE to do the congestion studies on a fixed schedule, but the Act does not -- it authorizes, with respect to corridors, it authorizes to designated corridors, but it does not require that we do so, and it does not set any particular schedule. And so while there is a linkage, of sorts, between the congestion study and national corridors, our efforts now are focused entirely on the upcoming 2009 congestion study.

Just one additional remark about the information that we are seeking with respect to congestion, I think most people recognize conceptually what we are talking about with respect to transmission congestion; that is, that congestion arises when the transmission network or particular lines on the network are not able to accommodate all of the desired or scheduled transactions.

But what's more important is to try to understand with greater precision what the character or the magnitude of the significance from a broader perspective of that congestion, and so it's going to vary from one area to another, one situation to another, what the real significance of that congestion is. And so we welcome your views on that.

And in some parts of the country, there is a particular problem of particular concern about, sort of, disparities between the technical availability, the physical availability of transmission, and some of that transmission capacity may not be available because it's tied up in some contractual mode, and so if, from time to time, we hear from people who say, "Well, I know that, in some sense, that transmission capacity is available, but every time I want to move energy from one location to another, I can't find available wire."

So we're interested in whatever linkages you can illuminate between those two kinds of situations and know where that problem occurs and how it's -- some of the ways in which it might be dealt with.

This study, unlike the 2006 study, this study will focus only on recent or current congestion, but in the 2006 study, we relied -- we worked -- well, let me back up a notch; that is, in doing this study, it's important to do it in two parallel efforts -- one, for the Eastern interconnection and one for the Western interconnection, and for the Western interconnection we worked with a group under the auspices of WECC, the Western Electricity Coordinating Council, and we will do so again for the upcoming work.

And then internally in the East, in the East we last time around the -- we relied on a consulting firm to collect some of this material for us, and help us both in terms of analysis, and we are in the process of engaging a contractor, again, to help us with that work for the Eastern interconnection.

So today we will hear from two panels -- the first panel will be the folks at my right. In the interests of time, I will not introduce them by name to you now. We will ask each of the panelists to talk briefly, five minutes or so, from their -- about congestion from their particular perspective, and then after the panelists have made their opening statements, then we will go into some more particular kinds of questions with I or others here from the panel will raise.

We invite all persons here and all other folks who are interested in these workshops to send us your material in written form at whatever length you wish, and send it to us electronically, if possible, and the discussion here is important but it's just not possible to go into the level of detail that this subject really warrants. So that's why I'm particularly interested in obtaining your written statements. And you can provide those written statements at the website shown.

In the 2006 study, we identified various areas of the country that were of particular concern with respect to transmission congestion problems or issues. And so we invite the panelists and others to tell us what's been happening in your neighborhood in the period since 2005 with respect to transmission congestion or, if you want to go back further in time and find some longer-term trends that you think are of interest, that's the sort of input that we are really looking for.

And, finally, if there are new areas of concern that have appeared more recently that 2005, we'd like to hear about that.

So far as schedule is concerned, we will be reviewing and synthesizing the information that we get through the end of the year. In the early part of 2009, that's when we will start developing a report outline and by April and May we will be in the process of drafting a report, and then in June and July, we will be involved in an internal clearing process. It's clearing not for publication.

So I'm going to stop there, and we'll go on now to the panelists. I will not play favorites here, I'm just going to go down the row and ask starting with Lauren Azar, ask you for your comments. Thank you.

Lauren Azar: Thank you very much. It's an absolute pleasure to be here. I am especially delighted because since the last DOE Congestion Report came out in '06, much has changed in Wisconsin. Before I get to my comments, I just want to note that these are my personal comments as a commissioner, and our commission will actually be taking action on more fully vetted written comments later, and we'll be submitting them via the website.

Historically, Wisconsin has had transmission congestion. We experienced a dramatic increase in congestion as a result of the federal policies opening the grid for wholesale trade in the late 1990s. Two sides of Wisconsin abut the Great Lakes, which greatly limits our ability for interstate ties. Currently, MISO considers the area known as the Wisconsin Upper Michigan System, or WUMS, a narrowly constrained area.

Despite the NCA designation Wisconsin has and continues to address congestion, and the state has done so without federal intervention.

The following material briefly summarizes three major issues with respect to congestion. I'll be looking at reliability-oriented congestion, economic, and then, lastly, renewable corridors.

With regards to reliability concerns, I'll talk just briefly about some historical trends we've seen in Wisconsin and what we are doing now.

Several events occurred in 1997 that highlighted growing indications of the Western interface into WUMS. All of Wisconsin's new plants were offline, which, not surprisingly, dramatically increased our import from out of state, ultimately overloading our interstate ties and prompting TLRs.

Let me tell you, that was a wakeup call. Facing reliability issues and the potential for capacity shortages, Wisconsin jumped into action. Two primary initiatives began at that point in time. One was to develop a plan for bolstering both our transmission grid as well as generation infrastructure.

And the second was to incentivize the state's vertically integrated utilities to create a stand-alone transmission company. These initiatives prompted the creation of ATC, the American Transmission Company, which was the first stand-alone transmission company in the nation as well as the building of the Arrowhead-Weston transmission line, which was a 220-mile line -- it is -- 345 kV, from the center of Wisconsin up into Minnesota. That line, I'm proud to say, went online in February, and we are already seeing some pretty dramatic differences in the LMPs.

In 1997, back when we heard the call for the need for improvement, the WUMS area, at best, could import 1,000 megawatts. Today, with operation of the Arrowhead-Weston line in conjunction with numerous other infrastructure improvements, our import capability from out of state has increased to 2,900 megawatts -- that's a threefold increase.

According to ATC, Wisconsin's southern flow gate, can now import in excess of 2,400 megawatts and the Western Slope nearly 1,100. In short, Wisconsin's model of a stand-alone transmission company whose sold purpose is to ensure reliable and economic transmission service has, indeed, been a success.

Now, as far as where we are today and where we're moving to in the future with regards to liability or in congestion, that we have had tremendous successes since 1997. We're not stopping there.

So when I evaluate where problems remain, we evaluate the number of constrained hours. Based on this metric, ATC has identified the top 10 constrained elements in Wisconsin all of which, all of which, will be addressed by projects to be completed by 2010.

Indeed, based, in part, on these improvements, the independent market monitor has opined that Wisconsin could lose its MCA status in the 2010 to 2012 timeframe. This material highlights that Wisconsin, by itself, has addressed the liability-oriented congestion affecting the states. Moreover, can solve EHB lines affect large areas; Wisconsin's actions have strongly benefited other states in the MISO region.

Now turning to congestion through economic metrics. Specifically, it's demonstrated through the differentials in LMPs. Sub areas of the MISO footprint in which there is a continuing difference between LMPs can be an indication of the need for new generation of transmission improvements.

The most recent ATC data depicted the 2007 annual LMPs show that inside ATCs we have a differential of about 6 percent when compared to the average MISO. So we have a 6-percent higher average LMPs than the best of the MISO footprint, which tells me we still have some issues to address and, indeed, we are addressing them.

Specifically, commission and ATC embarked on an access initiative during 2004 and 2006 and examined where the construction of additional transmission lines could reduce the delivered cost of energy to Wisconsin consumers by reducing congestion on the system. The access initiative led ATC to file an application for the Paddock-Rockdale line, which is 35 miles long and ties us into Illinois.

The primary purpose of this project is not reliability but economics. Paddock-Rockdale is the first economically based project approved by the State of Wisconsin. I think we approved it about four weeks ago, and it is also one of the first of its kind in the MISO footprint commercial operations expected for 2010.

It is noteworthy that the Paddock-Rockdale project will be completed around the same time that MISO's special expanded cost congestion hedge pricing expires in Wisconsin. Right now we have special dispensation because we're a congestion project; that special dispensation expires in 2010 when this line comes online. That's no accident; and it's just another example as to how Wisconsin has been taking care of its own business without federal intervention.

Now just very briefly with regards to reliability as it relates to -- I'm sorry -- congestion as it relates to wind resources and other renewables. The State of Wisconsin, I think everybody has seen the lengthy and wonderful comments from Missouri, which I am assuming will be discussed a bit later. We concur with the comments put forth by the Missouri Public Service Commission; namely, that the large overlay EHB projects must have demonstrable benefits to the state's customers, which far exceed the costs.

There are numerous studies examining the potential for delivering wind resources to Eastern load centers from the plains and the upper Midwest. These studies are ongoing and have not yet reached conclusions. The studies the MISO is conducting will not even be done until after 2009, and that's when the analysis is connected on the schedule.

We would ask that the DOE not rush to judgment on declaring any national interest electricity transmission corridors in the Midwest as the Missouri comments highlight, from a 2006 DOE study, no NIETC areas were specified for the Midwest, and the only congestion concerns appeared in -- as far as future potential issues relating to the Dakotas and Minnesota area and Oklahoma and Kansas. Wisconsin concurs as well.

Present studies assume a national renewable portfolio standard, which is not yet lost. Like the Missouri Commission, the Wisconsin -- this one does not make sense, so pardon me for this. We do not concur -- we do not believe that it is time for the DOE to specify areas as qualifying for an NIETC designation for a transmission, and that's, as the Missouri Commission notes, might be needed at an unspecified time in the future when nationwide requirements for renewables, indeed, are set. Thank you.

David Meyer: Sandy Hochstetter, please. Would you -- I have to ask each of you, for the benefit of the people on the webcast, whenever you speak, introduce yourselves. It sounds a little awkward, at times, for us to always be introducing each other to each other, but it is very helpful to the people on the webcast.

Sandy Hochstetter: Well, thank you, David. My name is Sandy Hochstetter, and I have the privilege of representing the Arkansas Electric Cooperative Corporation. We are a generation and transmission cooperative. We have about 3,000 megawatts of generation, and we serve all the counties in Arkansas, about 30 percent of the residential customers and a sizable number of commercial industrial customers.

I'm just going to take the opportunity to address three quick topics within my five minutes. One would be the sources of transmission congestion evidence that DOE can look to for its next congestion study. The second is real-world issues caused by congestion in this region, and the third would be some of our policy suggestions resulting from this congestion.

First of all, I think it's worth noting that both the SPP RTO and the SPP Entergy IPT regions are significantly transmission-constrained. For reliability and supply delivery assurances to provide options for new base loads and intermediate generation, for access to renewables, particularly on the Western side of the region and for more economic generation opportunities.

The indicators of this transmission congestion can be found in several places. One, the congestion costs and corresponding charges that are being established by SPP's new energy imbalance market, which have not been insignificant from our standpoint. Secondly, the number of TLRs called in this region. There has been SPP congestion in 56 percent of the five-minute intervals over an 11-month period, and 75 percent of the congestion has occurred on 10 out of 200 flowgates.

When evaluating wholesale generation opportunities, which is something that we do on a regular basis, there are transmission constraints a majority of the time, thereby limiting what options we have to pursue for our members.

The ability to access wind generation and bring it into Arkansas is almost non-existent. There is a huge interconnection queue problem for new generation proposals. There are 31,142 megawatts generation in the queue, with 76 percent of that being wind. Currently, wind generation cannot be delivered from the Western portion of SPP.

Now, available information to document these transmission congestion issues can be found in the historical LMP information provided by the EIS congestion cost data, SPP's state-of-the-market reports, the monthly congestion resolution reports that the independent market monitor has been required to provide the FERCs, and within the context of transmission planning reports, what's required for new generation, the construction release that's need for specific flowgates that are causing the congestion, and the plan versus constructed transmission.

And one point worth noting is that the N-1 reliability studies do not necessarily reveal all of the congestion. There is a current unfortunate problem with respect to some interpretation of Note B, which is one of their planning protocols that would allow a significant amount of interruption of firm load between two points in one of those transmission constructions. This, quite frankly, is a reliability time bomb within the context of Northwest Arkansas's load and needs to be fixed with transmission construction very quickly. We have members in that part of the state that will have to wait for a few years before transmission to be built to relieve that particular issue.

For transmission-dependent electric cooperatives, here are some real-world issues caused by transmission congestion in this region. The first is reliability concerns -- not building it fast enough or robust enough to accommodate potential demand peak. There is insufficient transmission to be able to confidently plan for our new baseload needs. Every time that we do an RFP or do any sort of internal analysis on new baseload generation options, time and time again we come up with transmission constraints that rule out a number of opportunities.

There is insufficient transmission to accommodate in the existing or future potential renewable portfolio standards, although we don't have any in place right now. The importation of wind is not there. There is insufficient transmission to be able to seriously pursue wholesale market purchase options that could be more economic than self-dispatch our existing generation.

Now, here is a short list of some policy suggestions tied to transmission congestion. First off, we think that there is an equity and an economic relationship between the congestion costs paid by the load due to the congestion and the construction of needed new transmission. There needs to be some sort of a clear linkage, if not a legal linkage, between the obligation to pay high congestion costs and the right or the obligation to either build yourself or have transmission built to relieve that congestion.

Without some form of linkage, the congestion costs are just punitive and don't actually produce anything constructive. We need timely identification in construction, a grid upgrade. Economic projects absolutely have to be identified, proved and built more quickly before they become reliability issues, and equitable cost allocation methodologies I think are key, which the SPP regional executive has done a really good job of, but we think that that needs to continue, and that's a part of any of this raw plan. Thank you very much.

David Meyer: Thank you, Sandy. Now, next we have Susan Wefald. You're on, Susan.

Susan Wefald: Thank you. I'm Commissioner Susan Wefald of the North Dakota Public Service Commission, and I'm very pleased to have this chance to share thoughts with the Department of Energy at this workshop. I would like to thank the Department for arranging this meeting to provide input on the 2009 Congestion Study on Electric Transmission Congestion. My thoughts represent those of the North Dakota Public Service Commission.

In 2005, North Dakota had an export limit around its south and east borders (commonly referred to as NDEX) of about 1950 MW, which if exceeded, can cause system instability. Although, in 2008, North Dakota still has an export of about 1950 MW, a great deal of activity has taken place in the state since 2005 that has had an effect on transmission congestion.

First, there has been a significant increase in wind generation. Back in 2005, there were only about 80 MW of installed wind capacity in North Dakota. Now we have about 716 MW of wind capacity here either in service or under construction, plus, another – plus another 807.5 MW that has either been site permitted or in some stage of the siting process. There are also plans for 1200 MW of additional projects in North Dakota that are not yet in the permitting stage.

Next, let us look at transmission investment in North Dakota and our upper Midwest region. The CapX 2020 plan to install several major transmission lines in Minnesota is moving forward and making progress. Our Commission has received a letter of intent to construct a new CapX 345 kV line from Fargo, North Dakota, to Monticello, Minnesota, which is expected to increase the North Dakota Export Limit by approximately 350 MW of additional exports.

There is certainly less certainty regarding transmission upgrades necessary for interconnecting new wind resources and the proposed Big Stone II generating unit in eastern South Dakota into the Western Minnesota transmission grid. This generating project has been approved by the South Dakota Public Utilities Commission and is presently pending before the North Dakota Utilities Commission. An application for a Certificate of Need required for the needed transmission is pending before the Minnesota Public Utilities Commission where an ALJ has recommended denial. If constructed, the Big Stone II project and related transmission additions are expected to increase the NDEX limit by as much as 500 MW of additional export capability.

On June 6, the North Dakota Public Service Commission approved the siting of all but 4 miles of a 61 mile 230 kV transmission line in eastern North Dakota, which will provide transmission for approximately 350 MW of proposed wind capacity near Valley City, North Dakota. A hearing is scheduled in July regarding the remaining 4 miles of the route.

There are also two 230 kV transmission lines proposed in western North Dakota where load growth in the oil fields of the Williston Basin is driving a need for additional transmission.

This spring, Minnesota Power announced its intention to purchase a 250 kV direct current line that extends from the wind-rich plains of central North Dakota to eastern Minnesota. As a result of this proposed sale of the DC line to Minnesota Power, Minnkota Power Cooperative announced its plan to build a new 345 kV line from Center, North Dakota, to eastern North Dakota. This is very welcome news, and this proposed new power line should help the transmission constraint between North Dakota and areas to the East.

Last December, the North Dakota Public Service Commission participated in a technical conference at the FERC on Interconnection Queue Practices. We reported to the FERC that wind developers are ready to invest now in North Dakota, but the inability to interconnect is hindering investment. The MISO Interconnection Queue is overwhelmed with wind interconnection requests in the upper Great Plains region. Today, Minnesota wind interconnection requests total around 26,000 MW, South Dakota requests total 11,683 MW and North Dakota requests total around 8,000 MW. We noted to the FERC and we note to you now that the main problem is that there is not enough regional load or transmission export capability to accommodate interconnection requests.

This is an immediate concern. Studies indicate North Dakota leads the nation in the potential for wind energy development. We have an exceptional wind resource and developers want to build wind projects in North Dakota and they cannot move forward because of transmission constraints between the Dakotas and Minnesota.

In comments dated July 6, 2007, from the Organization of MISO States to the Department regarding its draft National Interest Electric Transmission Corridor designations, the North Dakota Public Service Commission and the South Dakota Public Utilities Commission joined in a footnote requesting that the conditional congestion area identified in the Department's 2006 congestion study between the Dakotas and Minnesota be designated a NIETC.

It is still our hope that the Department will recognize the critical contribution the Dakotas can make towards resolving our national energy crisis with an NIETC designation in 2009. This designation would assure investors that needed transmission investment across state boundaries is a priority, not only to the region, but to the nation as well.

(inaudible) the workshop today but I had to put that comment in.

David Meyer: Thank you, Commissioner Wefald. Next we have Tom Sloan from the State of Kansas.

Tom Sloan: I'm Representative Tom Sloan from the State of Kansas, and since there are no other Kansans here, either legislators, PUC members, or from the governor's office, I speak for everyone. (Laughter) Please don't tell them what I said. We have all of the issues that have been raised so far and some of those things that Mike's going to raise after me, we identify with. We have localized congestion that leads to the dispatch of uneconomic generation. But we don't have the traditional congestion over hundreds of miles as you would have on the East Coast or the West Coast, but what we have is the economic opportunities that are not being maximized or realized because we don't have the transmission to move generation via fossil, nuclear or renewable from our state into the region much less to load centers in Eastern and Western parts of the country.

So we, too, would look for a NIETC corridor designation within the Great Plains areas so that we would be able to provide the generation necessary to serve load centers outside of our region and notwithstanding the fight we had between the governor and our legislature this session, the Plains states still are an area where you can generally site generation, and it is easier to site a transmission in the Plains than it is in the more highly populated area. We are looking for corridor designations, if you will, in Kansas and the region to be part of the solution to problems that don't exist in our area. We have capacity potential; we don't have generation capacity, but limited transmission capacity/capability.

To that end, the state of Kansas has done a couple of things led by the legislature. We've created a Kansas Electric Transmission Authority, and that is an organization that can identify transmission projects that need to be built, and yet no one wants to respond to an RFP or step up and build them, we can build them ourselves, we have another state agency, the Kansas Development Finance Authority that has statutory approval to help finance projects or a 30-year time period so that, again, the state can be looking at projects of a more elegant nature that have benefits, but which traditionally utilities are not going to be able to cover their investment or earn on that investment in a traditional short period of time. We try to make ourselves friendly towards independent transmission companies in order to encourage them to come in. And we have ITC Great Plains have established a presence in Kansas and identify some projects they want to build.

We have also tried to address both the traditional and non-traditional congestion issues by passing statutes that allow utilities to upgrade existing transmission lines on existing rights of way without regulatory approval. Kansas City Power and Light did a project approximately 30 miles in length and by the time they worked out cost recovery and such for the SPP, they had that 30 miles reconductored in five months that relieved major additional congestion, if you will, a major success in transmission construction.

Kansas policy-makers view the cost recovery problem from a different perspective. We look at congestion in two ways. The traditional way of where utilities use economic dispatch generation resources but, again, from the perspective of those in the middle of the country, that we have the economic projects, the unrealized opportunities to generate and to deliver if we're to address the intra-state and inter-RTO problems about how we coordinate plans, how do we coordinate the movement of power and construction of transmission lines.

Finally, I would also encourage -- in the context that we experienced twice in the last four or five years, we have had major weather impacts on our system -- ice storms, tornadoes, things of that nature, that have taken out large segments of the North/South transmission lines within Kansas and between Oklahoma and Kansas. One of those, I think, both situations, the only way we didn't have a more major crisis, it was all those municipal peaking units that came online and partially mitigated the grid interruptions. We need a more robust transmission system. We need it, too, in terms of, again, at least for the state of Kansas and, I think, for some of the others in the region, economic development and energy security.

David Meyer: Thank you, Tom. Our next speaker is Mike Proctor.

Mike Proctor: Thank you. Mike Proctor from the Missouri Public Service Commission and I am here, in the next five minutes, anyway, speaking on behalf of that commission. (inaudible) that is why I have to say the Missouri Commission has a mandate, and it's a jurisdictional mandate. It's set up in terms of the state law that established that commission, and they have an obligation to ensure the charges that are paid by Missouri rate payers are just and reasonable, okay? From the outset, then, and I think this is important, because I think it's true of every state commission, that if they're going to get rate increases for transmission upgrades that provide insufficient benefits to those rate payers, they're not going to return those to be just and reasonable. In fact, they have a legal obligation not to return those to be just and reasonable.

Having said that, and that's the background from which the state commission comes. Having said that, the Missouri Commission has been very active in Midwest ISO and the Southwest Power Pool working on cost allocation, working on beneficiary (inaudible) approach to how to allocate cost, and so the Missouri Commission doesn't stick a (inaudible) it has been very active in both of those RTOs.

Let me give you a real brief description (inaudible) few more details in the paper about transmission providers in the state of Missouri. There are essentially three transmission providers in the state -- the Midwest ISO on the eastern side of the state is a transmission provider, the Southwest Power Pool on the west side of the state is essentially a transmission provider, and in the middle of the state we have the Associated Electric Cooperative, and those are the three large transmission providers. There are a lot more transmission owners, but those are the people that determine -- that operate the transmission systems.

(inaudible) congestion related to the eastern part of our state, (inaudible) is the utility there, is relatively low, and that's because (inaudible) put in significant upgrades in 2005 to 2007 period of time that increased the import capability into their service territory by 1,300 megawatts. Those upgrades were running -- we just get the system right now, and I understand (inaudible) and there's not a lot of congestion on the MISO side in terms of (inaudible).

On the western side, SPP. (inaudible) and I think this was mentioned before -- 75 percent of congestion comes from 10 flowgates within SPP. Looking at Missouri specific, and (inaudible) information for DOE in terms of what they need to be looking at, and Sandy has already mentioned that information (inaudible) SPP website particularly (inaudible) to the market monitor reports, which are just excellent in terms of where the congestion is.

In terms of Missouri utilities, the Missouri utilities are paying (inaudible) SPP efforts. (inaudible) since we're on the eastern side of SPP and the congestion in SPP must be from east to west. I mean, that's the implication that I get from it. One of those utilities is primarily a seller into the SPP market, and probably would like to see higher prices (inaudible). The other one is a buyer, and probably wouldn't like to see higher prices. So we don't see any major congestion. There is congestion, and it needs to be looked at, but no major congestion within the SPP side.

(inaudible) is more difficult. I can't go to a website, I can't download the information, I can't get LMPs because they don't operate in that environment. The best that I can do is (inaudible) and that can be really dangerous doing that to see if there's a congestion problem there. But I will give you some facts that might be helpful.

Direct connection between SPP and MISO, there are three arms -- 720 kVA on those three arms, that's a direct connection. SPP to ACI, 112 lines over (inaudible). MISO to AECI, 63 lines with over 15,000 (inaudible).

In the little bit of time I've got left, what I want to mention is about the DOE current wind integration study that's going to be completed in June 2009. I don't know how that fits into this congestion study, but it's driven by these wind resources that may be needed at an unspecified future date. Now, I understand base cases is based upon current needs or current standards that are out there, but when there's one to 20 percent RPS standard there is no federal RPS standard at this time. This is looking to the future. I strongly support this study. I think it's needed. I think we need to look very hard at (inaudible) like a federal transmission backbone in the Eastern interconnection. I think it's important. We're going to get information out of this study about operational issues. When you put those large amounts of wind in, whether the operation (inaudible) we need to know that. We need to be ready to deal with those and, unlike Susan, one of the major concerns that I have, even in SPP right now, we can build 345 kV lines to export probably a moderate amount of wind. But is that the best long-term plan? And I think we -- in states, we need to look at whether to assess long term plans not just what's best in the short run. And so I don't think, right now, is the correct time to say until we get this study done, until we start reaching some conclusions about that, to start (inaudible) too much about it. What needs to be done with respect to the large 765 VHV overlay.

We don't expect the DOE (inaudible) suggestion. If you do find it, we would just simply request that either immediately inform us of that, and we have a lot of transmission expertise within the state, and we'd like to sit down and better understand what the problems are that you found and see if we can help you develop some solutions for those.

That's my comments, thank you.

David Meyer: My thanks to the panel, and a lot of great material, I think, was put on the table here for us, and I encourage all of you to -- if it's not called that explicitly in your statements, pointed us -- I know Mike mentioned the website as a resource, and that's certainly an obvious place for us to look, but there are bound to be other places that aren't quite so obvious, so I'd welcome your help on that.

Let's go on to the discussion phase here. Kevin, do you have anything you want to raise at this point? Okay.

One topic that -- the Midwesterners have long been the leaders in, I think, in saying that there is no clear knife-edge difference between the economic downside of congestion and the reliability downside; that these things really begin to shade, or they overlap to a considerable extent, and I wanted to get your views on that. Is that a subject that we should focus on and probe more deeply into in this 2009 study?

Sure -- Mike?

Mike Proctor: (inaudible) a lot of times, our own efforts do impact economics, okay, there's no question about that. We understand that, and when (inaudible) added millions and millions of dollars of upgrades, over the 2005-2007 period, we didn't ask the question, and this need for reliability and the need for economics, the Missouri Commission didn't ask that question. We knew it was needed, so we weren't making that distinction.

However, it's important, the decision is important in terms of what (inaudible) particular parts of (inaudible). Reliability conditions drive the reliability of (inaudible). It's not economics that drives us. We don't sit back as a state commission and say "We need to see the economics of that." You know, it's violating enough standards, we don't think it needs to suggest the economics of it. We (inaudible) let's just say from that perspective, there is a really distinct separation between those two. When you get into economic (inaudible) one of the things, one of the great dangers that you're going to step into, and I saw particularly the (inaudible) working on the metrics (inaudible). Different states valued different metrics, okay, and it just (inaudible) that we're, like Missouri, that we're still (inaudible). We value the (inaudible) production cost, because that's what (inaudible).

So one of the issues you're going to run into if you start going too far again in that is what leverage should we use in (inaudible) as we use those particular metrics. Thanks.

Unidentified Participant: I would also like to comment on that. As an example, the CapX 2020 plan that I mentioned earlier that involved several major transmission lines in Minnesota -- that project has been proposed as a reliability project. It's very much needed to meet those NERC requirements. But, as I mentioned earlier, it does increase the North Dakota export limit by approximately 300 megawatts of additional export capacity. So it does have impact on both, once it’s built.

I would also like to comment that when MISO addressed cost allocation issues and spent years, literally, on those issues, there was a distinction made in cost allocation between reliability projects and projects based on economic need. And there was such a strong feeling that there needed to be -- that those needed to be addressed separately, that I think there is strong feeling in the Midwest about some separation between those two issues.

David Meyer: Lauren Azar from Wisconsin.

Lauren Azar: When I think about it from a regulator's perspective, I think about it in terms of proof in applications, and when one makes a proof for a reliability project, it's very different from a proof from an economic project. So in that regard, they are quite different and, in fact, in -- you know, reliability congestion results in lights going off, whereas economic congestion results in higher LMPs. And in our most recent docket in which we were dealing with a project that was primarily economically based, the commission noted that the demonstration needed to obtain the permit was actually higher for an economic project because we couldn't see the physical, you know, there was not a physical manifestation necessarily for the needs of the project. Instead, we had to rely on economic models, which, I think, some of us are still scratching our heads about. And so we indicated that we needed to have a lot of comfort in the modeling results for economic projects.

So, that being said, I think from the application process, they are distinct, and there is no question. However, I also -- when I visualize it in my mind's eye, I visualize it as a Venn Diagram, with two circles, and there is overlap and, depending on the project, the overlap can be greater or less. So I think it's a good question, but ultimately when the rubber meets the road, and we're having to approve them, they are different.

Unidentified Participant: Lauren makes a good point that sometimes your position depends upon what hat you're wearing in the moment, and my position on some of these issues as a former state regulator was and is slightly different than some of the perspectives I hold today as a member of the Electric Cooperative Organization, and that's because I am now on the side of the fence having planned for new generation that may take 10 years to build, or five years, depending upon whether it's nuclear or coal, natural gas, or renewables, and what transmission options you have today determine what your new baseload options are, and what you will commit to as an organization and a board, and that they multi your past. So whatever transmission congestion exists today that may be great reliability, that's one thing, but there is a huge, what I would consider, reliability type of congestion that has as much to do with how you're meeting the needs for your future baseload plants, the customers that are going to need that over the next 10 years for baseload reliability purposes.

So it's a very fuzzy intersection between the two. It may be economic today but five, 10 years from now, it could be very much so a reliability issue that not only constrains you in terms of where you get your power from and what options you have but also how much it's going to cost your customers. So I think we need to start looking out, long term, particularly when you have a litigious environment these days in terms of planning and building new baseload generation plants and not knowing what sort of carbon constraints you're going to be facing in the future from a legislative standpoint.

We are on a many, many, many year path for getting some of these plants that are open. We've got to have enough of a robust transmission system today to give ourselves Plan As, Plan Bs, and Cs for baseload options to be able to keep the lights on, and that's very much a reliability issue.

Tom Sloan: Tom Sloan -- (inaudible) a robustness and reliability that we touched upon with weather-related crises that we had. There is, obviously, an economic component. We can develop the western part of Oklahoma and into Nebraska, the Dakotas, (inaudible) state aid for schools and other functions that government provides in economically centered in the true sense. But just as commissioners risk both simplifying when proposals will be brought to them, legislators have to try and create the situation that drives the development. (inaudible) over-simplification I can tell from the looks on my co-panelist's faces. But the thrust of what I'm trying to get at is (inaudible), particularly those who are involved in, like, the (inaudible) transmission authority working with the SPP, are trying to find the incentives that look to change the economics of proposed lines or allow cost recovery over a different timeframe or some manner facilitate the development for both the economic development but also the reliability robustness issue that I raised.

And so, again, bringing that back to the Department of Energy, if I would encourage a broader definition, a broader approach as possible to defining congestion, it's lost opportunity, it's lost opportunities in terms of did we have to put on more expensive generation to overcome the traditional congestion is lost opportunities in terms of having the regional energy solutions to one or more states' energy shortfalls.

David Meyer: Okay. Well, thank you, that was very helpful. I want to go a little further on the distinction raised on the economic project. That is one of the things that we, in our work here, we need to come up with metrics for congestion and different parts of congestion impacts are obviously going to involve different kinds of metrics.

So if you're talking about the need for a line from an economics perspective, and you mentioned either LMP differentials in those kinds of markets and then in less formally organized markets, you can look at differences in collection cost.

Those two don't strike me as being incompatible. You use each of them where appropriate, and I don't know how the results would compare, but if there are any -- do you see any particular difficulty in simply applying the one in one area where appropriate, and the other in another area.

Unidentified Participant: What do you mean: one in one area and one in another area?

David Meyer: Well, in areas that do have formally organized markets we use the LMP, and then in the other areas we would use differences in production --

Unidentified Participant: Transmission loading.

David Meyer: Well, no, in the cost of delivering electricity to consumers, you would have one production mode if the transmission line were in place and another, for the most part, if the line were not in place.

Unidentified Participant: Let me kind of respond to that because I'm not sure exactly how you would apply this. The first metric, I'm very familiar with, and that data is available, the LMP data is available. Actually, a lot more than the LMP data is available. The people who have used the shadow prices on congested (inaudible) dates and accumulated, there have been all kinds of things to rank congestion within an area, and that's very important.

It sounds like the other thing that you're doing is something very similar to what Southwest Power Pool is doing in terms of economic metrics that they're using to determine the benefits from doing an upgrade. And the way they get hold of that is through a modeling procedure, and they look at the change in production cost by zones. And you could do it any way you want to define it; you just have to define it ahead of time.

If we put in this upgrade, what is the savings in production cost by various zones from doing that upgrade? Certainly, that's something that's worth looking at. Now, whether that gives you a good indication of the benefits that you are likely to get from a project versus the cost of building the upgrade. I mean, that's the way we look at it. I'm not sure how that fits into DOE's metrics when they're attempting to look for congestion, but it's certainly a very valid approach to looking at cost and benefits for upgrades.

Unidentified Participant: I would just like to comment that the last time you came to the states for suggestions on how to do a congestion study and what information should be used, the Organization of MISO states strongly encouraged the Department of Energy to not recreate the work that is being done by MISO. Congestion studies are being done on a regular basis. The participants in those markets have an opportunity to participate in how those congestion studies are done and to offer input into those congestion studies, and so the people in our area understand those quite well -- or as well as anyone can -- a congestion study, all right?

And so rather than to have the Department of Energy go out and create a totally new approach for what is a congestion study, we really prefer that you continue to use the metrics that are presently in place.

David Meyer: Well, I didn't mean that we would go off on a separate track of our own. I think we want very much to build on the work that others have been done -- that others have done and not try to do things again and perhaps even less well.

But the point I was trying to understand better was are there major inconsistencies that we would have to take account of if we're sort of using available materials from one region and another region and are there going to be mismatches or uncertainties of how well they fit that we're just going to have to find -- to probe a little bit to understand do these things really tell the same story or are there some differences here that we have to understand better.

Unidentified Participant: It's one of the questions -- I wanted to ask if there's a question addressing seams (ph) issues, like between RTO and non-RTO regions and had to figure out what type of congestion exists there is what, you know, what bucket to label it, put it into --

David Meyer: Yes.

Unidentified Participant: -- and a perfect example is the fact that we have a significant amount of congestion between SPP and Entergy. I'm sure that there are many seams, issues, like that across the country where there are difficulties, and, you know, unfortunately for us that seems -- cuts down the middle of the state of Arkansas, and it's like and apples and oranges thing, and we really need that fixed not only for immediate reliability issues, current reliability issues but new baseload needs, you know, requests for transmission in RFPs where you get wonderful offers, perhaps, on the other side of the seam, but there is congestion at the interface. And that really is something I think DOE ought to target is the congestion at these interfaces on the seams.

David Meyer: Would you go so far as to say that -- let me put it a different way -- that is, within an organization like SPP or MISO, you have now in place a mechanism that can identify congestion, illuminate it and make it reasonably well understood and bring solutions to bear.

The implication, then, is the congestion problems arising from less well-organized ties across regions that we're going to see a disproportion of problems right along those seam lines.

Unidentified Participant: And that's a huge issue not only today, but it's going to become an even bigger issue when we start talking about wind integration or being able to plan very large, new baseload units to serve multiple load-serving entities in multiple states, which may be on opposite sides of a seam, as the (inaudible) nuclear plant or large coal plants if any ones every get certificated in the future, but things that are going to serve multiple load-serving entities -- a lot of those are going to be along seams, so -- and I don't know what the answer is in terms of how to get that data. You may have to approach individuals on a separate, one-on-one basis, or talk to some of the load-serving entities in these regions that are struggling with being in the middle of such a seam and suffering from that congestion problem at the interfaces, and then maybe collectively we can get some information that will be helpful to you.

David Meyer: Okay.

Unidentified Participant: I have one more comment.

David Meyer: Sure.

Unidentified Participant: And I think this is where it should fit in, all right?

David Meyer: All right.

Unidentified Participant: My staff member, Jerry Reen said, "Now, you be sure to mention this," all right, so I am. There has been a tendency to judge the amount of transmission congestion in a region based on the number of transmission living where these events that are initiated. However, it's important to realize that utilities in our MAPP region have managed the -- not the credit export constraint with operating agreements in a way that has minimized the number of transmission loading release needing to be initiated.

And so I'm not sure what the best measure of congestion and its impact should be, but it's my hope that people will look beyond the number of transmission loading release TLRs initiated to try and determine a more accurate measure of congestion and the impacts that could not have been mitigated operationally.

David Meyer: My way of thinking about that is to say that where you see TLRs, obviously, there are transmission problems, but it doesn't work the other way; that is, if you don't see the TLR it doesn't mean that there isn't congestion there. There may well be, it's just that people have essentially learned how to work around this problem; how to go to the second best or third best solution --

Unidentified Participant: Right.

David Meyer: -- without going through the TLR process.

Unidentified Participant: Thank you.

David Meyer: Let me ask the other panelists, since we are drawing close to the end of this panel, if there are points you particularly wanted to bring out in the discussion -- make them now while -- this is now the opportunity.

Lauren Azar: In addition to sitting on the Public Service Commission of Wisconsin, I also sit on the Board of Directors of OMS, and one of the points that one of the OMS (inaudible) groups mentioned was that they would urge DOE to continue this dialog even beyond the technical conferences so that we have an ongoing dialog on congestion issues and not just a one-time thing in relation to the studies.

David Meyer: We are interested in finding ways to do that. Let me turn to my colleagues here to see if they have questions they want to bring up. Let me turn to my -- to Joe Eto, who helps me a little on the technical issues.

Let me ask you one other point -- when we -- some of the -- on this RFP that we've got out for the Eastern interconnection -- one of the respondents told us that the available data, particularly in areas of the country that did not have RTOs or ISOs, the available data is not going to be that good, and we will have trouble really understanding the story about congestion, and this entity was arguing to us that the only way you're going to be able to understand this is through some modeling, and that is, you will use the model to understand it and try to replicate the 2007 data, the historical data that you can collect, but it's -- the use of the model in a sort of retrospective way to try to figure out what congestion was occurring on the -- in those parts of the country.

And I wanted to ask you -- how does that sound? Would results of that kind -- would they strike you as useful or would you be interested in those results? Is this a line of endeavor that you think would be of value for us to pursue, or should we just make the best we can from the data from those areas given the gaps and the fact that it's less than -- the kind of more transparent story that we can see from this formally organized markets?

Unidentified Participant: Just so I understand -- when you're speaking about the 2007 data in these areas, is that TLR-related data?

David Meyer: No, no, I'm talking about the LMP data, flow-related data, you know, the enormous reservoir of material that comes through those -- that is available through those centrally organized entities.

Unidentified Participant: Modeling always involves a number of assumptions, and so therefore when one starts talking to me about, "Well, we need to 'model' this data," I always -- now, as a commissioner, I always think "I wonder what assumptions they are going to put in? Are they assumptions that I would agree with or assumptions I would disagree with?"

So when you say, "Will modeling be helpful?" It all depends on the modeler and the assumptions that are used, and you need to be able to have people be able to understand, up front, what those assumptions are and -- because some people start to see that there are biases instead of "scientific assumptions."

So -- it's so important, then, to get confidence in the assumptions being made in the modeling before you take all the time to go forward with the model, or you're going to end up with something that people disregard no matter how much money was spent on the modeling.

Unidentified Participant: Just real briefly -- I -- I tend to be involved -- I'm not a commissioner -- I tend to be involved a lot more in the modeling side, and we do something called "benchmarking," and with any model that we work with so that we do have confidence that the model is giving us accurate information.

I do not know what data would be available -- the other data that would be available. I know it's not going to be nearly as transparent in that if you run the model, and it's benchmarked and it's steady with the areas -- I know these Eastern -- total Eastern interconnection models are -- that sounds crazy to us, but those kinds of models are being run all the time, and if they are benchmarked against what the RTOs were doing in 2007, then that should give you some confidence to interpret the areas where you don't have RTOs, and there are other metrics that you can use, too, to benchmark it.

You know, are you matching the amount of coal generation, gas generation, those types of things that are occurring within those areas? So if those things are benchmarked, then the LMP data, the pricing data that you get out of it will provide you, I think, some real insights into congestion.

And I just wanted to add, and everybody might not agree with this, but from a reliability standpoint, I feel fairly certain that with the RTOs and with Order 890, those upgrades are going to get made; they are going to be fixed; they are going to happen. And, like I said, everybody may not agree with that. It could be a timing issue at times, and then they have to use some kind of operational directive to carry you through because it takes some time to get the upgrades in.

But DOE's focus, I think, is on the economic side of it, the economic upgrade, and that's my -- I don't know how you can do it without doing the modeling, but that's --

David Meyer: I wouldn't go quite that far to say that our focus is primarily on the economics. I think we are sufficiently concerned about reliability problems in various parts of the country nowadays that those issues are certainly very important to us, but we try and look at these transmission issues from a lot of different perspectives, and we want to be sure we understand that the full implications here, whatever they may be.

I agree with what Mike was talking about in terms of modeling and benchmarking and use of the RRTO ISO data and models as a way of approaching the problem, but I would raise another political issue as well -- regardless of who the next president is, there will be a lot more discussion about national RPS and the movement of energy, particularly into the South or other areas, and it may not RRTO ISO. So I think that the department will be well served trying to develop the modeling necessary to figure out how you address constraints and movement of power before you are ordered to come up with something. And so I think that your question is extremely timely, and the process should start.

Okay. Any final comments? We are slightly ahead of schedule, but we would break here, and the next panel will begin at precisely 2:45, and we will adhere to that time because this is being webcast, and we've got an audience out there that will appreciate that. So thank you very much.

[20 minutes of silence during break]

David Meyer: We're going to resume the workshop now and go into the second panel discussion. This second panel will be a somewhat more technical-oriented panel; that is, where the first panel was primarily senior state officials of one kind or another who were addressing things more from a policy perspective, this second panel will be primarily folks from utility-related companies who can talk about transmission congestion from their perspective.

And so, again, we will follow the pattern of short statements from the five panelists, and then we'll go on to some more specific questions and discussion amongst the panelists.

So I am going to ask Jay Caspary to lead off. And, Jay, please introduce -- again, let me ask all of the panelists, each time we speak, please identify yourself. I realize it may seem a little awkward for us to always be introducing ourselves to each other, but this is of considerable help to the people who are listening on the webcast; that they know who is speaking at all times.

So, with that, Jay, please.

Jay Caspary: Thank you, David. This is Jay Caspary; I'm Director of Engineering at Southwest Power Pool. I am here to provide some comments from SPP's perspective. I also want to interject some comments from the ISO/RTO Council Planning Committee's perspective, too, since I am chair of that group.

I think, before I start, I guess, these are my comments, and I'm sure SPP will file formal comments that will work their way through our working groups, and it will start at the transmission working group soon. We look forward to this dialog and moving this ball forward.

I think we can learn a lot from the past, but I think we also have to look toward the future to optimize good expansion and balance -- the reliability and economic needs of customers in the carbon-constrained future that we all see.

The future is bright in terms of major transmission expansion projects, and I speak for economic reasons let alone reliability reasons.

I think there are some real exciting things going on right now with SPP in terms of cost recovery and cost allocation, and there's a lot of credit that needs to be given to the regional state committee in that regard, and the cost allocation working group that Mike Proctor chairs.

I think you're going to see postage-stamp cost recovery for economic transmission projects, a balanced portfolio of 345 kV projects in SPP that will be proposed and probably filed at court this fall, which will probably be $300 million, $500 million worth of projects that provide economic benefits that we can justify that are more than the cost to the individual members of SPP.

I think there are several things we need to look at that have changed since 2005. FERC Order 890 obviously happened; and that the joint coordinated system plan is in process. We've got the EIS markets and TLRs in the Southwest Power Pool. We've also got congestion management processes in our JOAs that are being implemented -- the joint (inaudible) agreements.

Significant transmission expansion improvements are in process today. FERC Order 890 helped improve transparency and the collaboration and planning at all levels. The joint coordinated system plan that's being completed by MISO, SPP, TVA, and PJM, which also incorporates Entergy, MAPP, AECI and others due to the strong relationships that we have is a monumental effort right now, and I think the DOE needs to look to that effort and to leverage that effort in their study, going forward.

It's exciting that ISO New England and the New York ISO have joined that process formally, and we've also seen support expressed by Duke Carolinas as well as the Ontario Independent Electric System operator. So we're starting to get a significant contribution and support from a majority of these for interconnection.

The sponsors are proposing to present scenarios that would be studied under the Southeast Inter-Regional planning process that would directly complement the scenarios we are creating as part of the JCSP. So even though the Southeast may not be at the table, we're going to create scenarios that will look one-on-one with results coming out of the JCSP. You see that's exciting.

The JCSP is looking at a base case as well as a 20 percent national RPS. Frankly, the 20 percent national RPS scares me. It's very aggressive. It shows numbers of (inaudible) development in SPP that are unthinkable. I would propose that the DOE fund an effective 10 percent national RPS scenario to complement the base scenario that exists today, which is based on existing RPSs that are in place, and the 20 percent scenario that's being framed.

I think we need something in the middle that's a real case that we could use for models and the data from that process and probably do it relatively and extensively.

One thing that we need to know about is the Eastern Reliability Assessment Group is moving forward to create really good models. That process has been in place for a year, year and a half now, and we're seeing the benefits of that to everybody whether they're in organized markets or not.

With respect to the EIS market and TLRs in SPP, we've seen a lot more, and I think our large increase in TLRs in our market, the energy and balance service market have provided price transparency and much more efficient operations of our system. The increases in TLRs in SPP represent a more effective use of the transmission system to provide lower-cost wholesale energy to buyers. It doesn't necessarily mean that we're in trouble or that the system is more congested. We're just pushing the system harder.

TLRs don't necessarily mean that we even cut schedules in SPP, so don't jump to conclusions about schedules or service being cut because of that.

We have congestion management process in our joint operating agreements that are working well. There is always room for improvements in those, but if you look at flowgates, and I know you're trying to look not prospectively but in the past, please be careful to make sure you understand the data and the anomalies in the system that may be driving those flowgate results and those TLRs.

I think we have congestion and (inaudible) in our system today that are a product of the design and are intentional because people just really don't want to address legacy issues that are problematic between certain providers.

Some of the biggest opportunities for improving the grid efficiencies are cross seams where there is no interconnectivity today. You can see that if you look at the LMPs in ERCOT, for example, and compare that to SPP, but there is no flowgate there, because there is no transmission there.

So be careful how you look at it. And I think we also need to look at flowgates that don't exist today between interconnections, even, and I know this is real broad and pretty aggressive, but with SPP's expansion into Nebraska, we'll have five DC ties to the West. We'll also have two DC ties into ERCOT. All seven of those DC ties basically are approaching their useful life, and it's time to look at what are the opportunities to upgrade those or to maybe change how we interconnect the systems long term.

I've got some other comments, but I'll wait and hear what others have to say. Thank you.

David Meyer: Thank you, Jay. I'm going to just go down the table here. So -- Jennifer Curran.

Jennifer Curran: Great. This is Jennifer Curran with the Midwest ISO. I appreciate the Department of Energy offering us the opportunity to make these brief verbal comments, and we will also be following up with written comments.

In terms of historical information, which is certainly one of the inputs to this study, the Annual Midwest ISO Transmission Expansion Plan contains a detailed historical flowgate analysis. It provides data both on average use of the flowgates and shows that the -- while the number of flowgates have increased, the number of hours that their flowgates are (inaudible) is decreasing, which reflects, in large part, a more efficient use of the system through the market set but also, to some degree, transmission pollutions that have been implemented.

It also contains those top constraint flowgates, the historical patterns we have seen on them, and the transmission solutions that have been identified, to date, that would -- are believed to address, at least in some degree, that congestion.

The average length of time to build transmission in the Midwest ISO -- to get it approved and built is seven years, so there is a lot of projects identified where we have not yet seen the results.

Commissioner Azar from Wisconsin referred to two projects, which addressed two of our top 10 constraints -- the Arrowhead-Weston line, which was recently energized. We have seen a significant drop off in bound hours on that flowgate, I believe down to zero, and those results will be in the next expansion planning report. And then we have projects like the Arrowhead-Weston project, which we believes it drives constraints but, again, won't be built, as she mentioned, until 2010. So we do have some time before we will see those results interchanging congestion pattern.

It is also worth noting that there are a number of constraints, which affects, as a MISO market, which are not in the Midwest ISO footprint. So the notion of addressing seams and continuing to refine our congestion management practices and looking for those solutions, which do cross borders, is really the next frontier of analysis that needs to be done. As I think I mentioned, we've addressed, at least in some part, a lot of the ones within the footprints, so now the question becomes making the overall system more efficient.

The 2008 Midwest ISO transmission expansion plan will be available in draft form later this summer and in final form in October. It will update the data through the third market year, so we go April to April in that data. So there will be data available through April '08 on those flowgates and showing the historical patterns.

The independent market monitor of the Midwest ISO also publishes information about constraints, and we will make that available, as well. The most recent report is not published, will be published soon.

Finally, another study that is ongoing at the moment is specifically focused on narrowly constrained area within the Midwest ISO footprint, and this is where we begin to take our analysis beyond the reliability considerations for the constrained areas and look more at the economics. That study is going on in a couple of phases. It is expected to complete this year.

The first phase is taking a more robust look at previously identified transmission projects and trying to determine the impact on existing congestion. And the second part of the analysis is to identify what additional transmission may be needed and whether the benefits of that transmission outweigh the cost of solving those constraints. As I think was mentioned earlier, we do believe that at least one of those narrowly constrained areas may have been fully addressed, but we have two others that we're also taking a look at.

I'd like to echo Jay's comment both as an independent entity and as a member of the ISO/RTO Council with respect to the joint coordinated system plan, which is scheduled, I believe, to be completed in December of '08. That methodology looks at where the energy wants to flow and can provide some insight into where our transmission would be most beneficial now and in the future. It identifies transmission corridors -- I have to say corridors with a little "c" rather than a big "C" -- that provide that opportunity. And the impact of '07, if you look at the projection of where congestion will be in the future, it was, in many cases, not in some of the locations we see today. So those are issues we're looking to address as well.

We would encourage the DOE to use that method in conjunction with the historical data to identify transmission expansion that would mitigate both current and future congestion. Thank you.

David Meyer: Thank you. Next we have Dan Klempel. Dan, please go ahead.

Dan Klempel: My name is Dan Klempel. I am with Basin Electric Power Cooperative. We would like to thank the Department of Energy for this opportunity to share some of our thoughts on transmission congestion issues. Basin Electric is a wholesale power supplier to rural electric cooperatives located in the Midwest and in both the West and the Eastern interconnections. Naturally, our generation and transmission facilities also reside in both interconnections, so we use asynchronous back-to-back DC facilities to balance loads with resources on both sides.

With headquarters in Bismarck, North Dakota, we find ourselves in the heart of some of the nation's most desirable wind patterns for potential renewable energy development as well as electric energy production from more traditional sources.

Lignite coal has been a reliable resource for electricity production in North Dakota for decades. Recently, the U.S. Geological Survey reported a large deposit of recoverable oil in the Bakken Formation beneath North Dakota and Montana. The 2006 National Electric Transmission Congestion Study labeled the Dakotas/Minnesota region as a conditional constraint area due to the potential for wind development as well as development of additional lignite fuel generation.

The discovery of the oil potential of the Bakken Formation is now driving rapid growth in electric pumping load in North Dakota. Basin Electric is expanding our high voltage transmission network in order to supply this demand. Over the next few years, we will be adding over 250 miles of high-voltage transmission with about twice as many additional miles being recorded shortly thereafter if oil and gas develop, as some have indicated.

In the Eastern interconnection, our transmission facilities are part of a joint transmission system known as the integrated system, or IS. The IS partners are Basin Electric, the Western Area Power Administration Upper Great Plains Region and Heartland Consumer Power District, a group of municipal utilities. These integrated transmission facilities provide most of the backbone transmission network within the Dakotas.

Because of the proximity of the IS to the Midwest ISO market, we have many generation resource developers requesting to connect to the IS so they can deliver electricity into MISO. In addition, renewable resource mandates have significantly expanded the demand for wind energy. The IS has requests for about 15,000 megawatts of generation. We have about 3,000 megawatts of load primarily wind wishing to connect to it. Unfortunately, these requests do not include any commitment to long-term use of the IS and therefore it is not possible to finance the construction of facilities for their benefit.

The proverbial elephant in the room, the question of who will pay, must be addressed because analysis of congestion, however useful it may be, does not finance construction. Basin Electric has been a supporter of regional postage-stamp pricing for transmission. A little over a year ago, a group of transmission providers in our region from Iowa, Minnesota, Nebraska, and the Dakotas offered a proposal for a regional transmission tariff that would allow a user to pay a combined system-wide average rate and reserve long-term network service throughout the region. The goal was to enable financing of regional expansion. However, the template established within the LMP markets; that is, the template of license plate pricing, proved to be an overwhelming hurdle for such a regional pricing template to overcome at that time.

Something needs to change. The LMP markets provide pricing signals that tell where congestion is occurring, but those signals are not causing transmission construction. In the 2006 report, it was mentioned that the CapX 2020 group is developing significant transmission within Minnesota, but it needs to be noted that this investment is for reliability and not in response to price signals.

Our IS partner, the Western Area Power Administration, manages the electric energy produced by the dams along the Missouri River in Montana, North Dakota, and South Dakota. The river has been experiencing a drought for several years significantly reducing the production of hydro energy. Due to the reduced energy, Western has had to purchase replacement power to meet its commitments. Increasingly, the ability to import such purchases is being limited by congestion on facilities remote from the IS.

The NERC Interchange Distribution Calculator uses transaction tags to determine the impact that transactions have on a facility and to assign relief responsibility to alleviate the congestion. The LMP markets, however, do not take transactions within their footprint so they provide to NERC what they determine their impact to be.

The ability of LMP markets to adjust their economic dispatch rapidly allows them to operate very close to the flow limit on transmission facilities. However, it also causes a tension with take transactions that are not nearly as dynamic.

In addition, the non-LMP parties do not have independent knowledge of the closed cost by the LMP dispatch and thus cannot determine the equity of relief responsibility assigned by NERC. The IS partners have been investigating options to alleviate this tension. One option is to use generation re-dispatch between the IS and MISO to achieve the assigned responsibility on pre-defined flowgates. But we are concerned that the dynamics of the LMP market and the unpredictability of transmission outages will overwhelm predetermination of appropriate generation pairs for re-dispatch.

A second option is to include the IS loads in generators in the MISO LMP dispatch calculation. This option, however, inserts additional variables into the uncertainty that comes with the generation and transmission development required to meet the load growth we are currently experiencing. These variables include independently determined and administered financial rights that are much less understood than the physical transmission that our rural members have built and paid for, and generation dispatch rules significantly different from the cost-based production our consumers are familiar with.

In conclusion, I would like to say that although we can and are addressing the need to serve customers within the integrated system, we have been observers only of the transmission being constructed as a result of the LMP markets and their price signals and can only say that in that role we are still awaiting proof-of-concept. Thank you.

David Meyer: Thank you, Dan. And next we have Gary Pieper.

Greg Pieper: Greg Pieper from Xcel Energy. First of all, Xcel Energy thanks the Department of Energy for their invitation on the panel as part of their comment-gathering for their report.

Xcel Energy is an investor-owned utility that I was going to say in unique, but Basin also serves on both interconnections as well. We have three operating companies -- two on the Eastern interconnection and one on the West. We participate in two regional markets, the Midwest ISO and the Southwest Power Pool and a bilateral market in the West.

Xcel Energy is -- believes in the robust transmission buildout to connect resources to load and is working jointly with a number of neighboring utilities to develop plans and to construct facilities. Examples of this are the CapX projects, which we talked earlier on the commission panel in the Minnesota system and several projects in Colorado as part of the Senate Bill 100 and the High Plains Express, both transmission system and participating in some of the SPP developments for bulk transmission as well.

As an operator, from my perspective, the comment earlier is about the transmission system - is it reliability- or is it market-driven? And from my point of view, or economics driven, it's all of that. It's a vehicle to be able to import, export energy and provide for ancillary services. The deployment of those reserves is critical to be able to have sufficient transmission. Without that, you don't have reliability.

So however the system gets built and for what purposes, it will be utilized under various conditions, and in many cases the idea that the system is intact is really not true because many days there are outages for maintenance, construction, and we're operating with less than the system that sometimes shows up in planning studies. So development of the system is critical.

Moving forward in this, the discussion that we have had around the modeling issue, I'd like to talk a little bit about that -- when Commissioner Wefald was talking about dealing with congestion that doesn't show up on the system, one example that I am aware of is in the North Dakota, Minnesota in conjunction with the Manitoba Hydro Province, there are a number of areas where we had some interdependencies with the transmission system capabilities, and they are, when you study the systems, those interdependencies are not static, they are more dynamically linked in angular stability, voltage stability, and those are technical studies that require assessments on the congestion, and through joint studies operating limits, we have been able to develop safe operating conditions that get applied in the dispatch that never really show up in TLR unless they actually get threatened. So we actually operate to avoid those in many cases, including the regional markets.

So I think there are some examples of areas to go look and to see where are examples of that that we are deliberately avoiding congestion and are recording it in some ways.

What I've seen, you know, the differences that have occurred primarily on the NSP system have been the introduction of the MISO market has changed the directional flows prior to the market. The flows were very west to east frequently. Today, however, the flows can change daily from east to west, west to east, and because the market is a lot more dynamic than previously the bilateral market. So that's an example of how the system uses have changed in a very short period of time.

Otherwise, we -- those are really the only prepared comments I have at this time.

David Meyer: Thank you. That was very helpful. Our fifth panelist is Manny Rahman from AEP.

Manny Rahman: Thank you, David. My name is Manny Rahman, I am from American Electric Power. All my professional years I have been in the transmission and have worked with illustrious leaders in AEP and still working with a lot of people who have vision. AEP is number one in the mileage of transmission line. We have built over 2,000 miles of 765 kV line, which illustrates that we have been working on transmission on a progressive way so that we can transfer of our power from generation to, really, what that load is.

I will take this opportunity, when David mentioned earlier that instead of going to 2005, I can go to the past. So maybe I'll make my point by going a little further back in history and use that to make my point on the transmission.

When our forefathers in the power industry started this kind of industry, the generation was located where the load was. So in Manhattan had generation, and they had load. And as the system started to grow, I was looking at AEP history in the early 19th century, early 20th century; they built a transmission line from Canton, the city of Canton, to Windsor, several miles away to bring the generation closer to where the load was. And, in a way, 138kV transmission system on the AEP was started at that point.

As the system grew, the loads have been increasing, and the generation has started to get away from the load centers, and we are talking about in future our renewable generation, which will be more of the wind and most of those wind will be located where the wind is not where the load is. And essentially the transmission system should be typically free of congestions. I mean, the generation and load should not worry about where we are, each connected to each other. That's the theory. There will always be congestions, so that will be impossible to have attained no congestions. But generation should still be allowed to come where it comes from and each load center should meet that generation available to them as needed, and that will make the system really a system, which is for future.

We did talk about that there is a lot of generation coming in North Dakota. The Commissioners mentioned about several thousands of megawatt. We also know the panhandle of Oklahoma and Texas will have tons of generation coming in there, and that generation will not be just absolved by local load. So they need to build a transmission system, which is free from any problems as much as possible. I mean, free is not a completely achievable thing, but we should be going towards that.

So essentially the Department of Energy should be coming out with a vision of what the transmission should look like.

Let me give you a simple example of what AEP's system has. We have 765 kV line. We do have 345 in the voltage, also. Each of those voltages, they've been going back to 69 voltages. They have their place on the system. We want to build transmission system in such a way that the underlying voltage, like 69 or 138, or even 345 kV should be ready to serve the local load. They shouldn't be burdened by the transmission or farther from one point to another point. The system should be built that will carry that power and allow the underlying voltage system to carry the power to the local load, in a sense.

Just think of when President Eisenhower was looking into building the interstate system -- that did not remove the building of the local roads, the local roads that were still needed, but we need a vision, which will allow us to build 765 kV, 500 kV, and DC or anything else, which is needed in there.

Just an example of if we built a 765 kV line that's built of six bundled conductor. And if we built a 345 kV line there, too, I mean, we can transmit power several hundred miles on 765 kV, so essentially what 765 kV would look like is a system of (inaudible) which is just a few dozens of miles away from each other, and that will allow us to reduce the system losses on the U.S., and system loss is very important in future also because that will allow us to curtail the carbon footprint on the nation, and if we properly design our transmission network, which can carry power from one end to the other end, and do it in a way that we can reduce transmission losses -- each line shall have losses, but we can reduce the losses in a way that we can reduce the number of power plants we need to build.

We can also design our system on a transmission basis that we don't have to build too many transmission lines. A 345 kV line equal into a 765, it will be about three double-sectored 345 kV line that will require much more footprint. So, essentially, we can reduce our footprint on transmission system and build less number of transmission lines. We need to build a lot for the future, and that will allow us to properly put the system in a proper way. Thank you. I'll have a few more points, but I'll mention that later.

David Meyer: I want to thank all of the panelists for some very interesting perspectives here. Let me respond on a couple of points.

This congestion study is going to focus on 2007 data. We may, if time permits, we may look in the same way at 2006 data and possibly 2008 data, but I don't want to give the impression that we are not interested in forward-looking projections. We realize that most of you spend most of your time on forward-looking analyses for very good reason.

So we are very interested in that material, and if you want to point us toward some of the things that you think are most important, we will appreciate that. We may not address those subjects specifically in this congestion study, but nonetheless I want to make clear that we do have a continuing interest in projections for various other work -- kinds of work that my office does.

And further extension on that is that we are very interested in the joint coordinated system plan that Jay mentioned. We think that kind of interconnection-wide analysis is extremely important, going forward, and it's going to become more important, and my personal view is that it would be a mistake for DOE to undertake to do those kinds of studies. They need to be done by people who are very familiar, on a working day-to-day basis, with the transmission system in their part of the country, and they need to come together in coordinated groups of the kind that Jay has been participating in.

But my point here is that we need to -- personally, my view, is that we need to move beyond just doing these studies to serve particular interests, and they need to be thought of increasingly as studies that have immense value from a public policy perspective, because they -- we're looking at alternative futures for this system, and we need to be looking at alternative futures and understanding them better so that the people that have to make important policy decisions can do so in a well-informed way.

So that's my sense of where we need to go. Now, how we are going to get there, I welcome suggestions from others about how best to do that, but I think it is time to kind of stake out a sense of where we think the effort needs to go to.

I want to now turn back to some of the questions that were raised, particularly, I wanted to focus on Greg Peiper's point about there is a lot of congestion out there that is being dealt with in other ways other than TLRs, and so it may not be quite as visible as it might seem, you know, if you just look at the TLR practices.

So I wanted to ask the panelists more generally; that is, how should we, in this study, identify congestion that is out there that doesn't show up quite so readily because people have found various ways to deal with it and have kind of “routinized” their approach so it's not being handled as a special case, but it's handled in a more systematic way, but nonetheless the congestion is still here, they've just found a way to work around it in some fashion. So, please, if you folks can tell us where to look for that kind of information.

Jay Caspary: Let me start, if you don't mind. I'm Jay Caspary of SPP. With regard to 2006 or 2008 flowgates and looking at that data, just be careful with it. I know there's -- within SPP, I know there's three major auto transformers that failed in that period that resulted in some temporary flowgates and significant congestion in TLRs, and that's a product of history, and I think it's indicative of the age of the infrastructure that we're starting to manage, and I think we need to start looking at inventory policies and things like that so we don't have these 18-month waits for a transformer to be replaced.

So be careful with the data. I think if you look at the JCSP study, for example, and I know it's looking out in the future, but there are some really great visualization tools that will show you where the congestion points are on the system for whatever scenario you want to determine or evaluate. You can do that. It's hard to get some time-synchronized data from one market to a non-market to another market, but it's out there. You just have to manipulate it and play with hit and maybe even create some of it, but we -- I know SPP would be willing to help you with that as well as the ISO RTO Council would like to help you with that. So there's no silver bullet.

Jennifer Curran: This is Jennifer Curran with the Midwest ISO. I would just echo Jay's thought to the extent that it's not in the Joint Coordinated System Plan, I think, ultimately, it may be a question of modeling. It seems like your alternative is anecdotal discussions saying, you know, where -- these are the things Greg sees in his day-to-day, and then having similar conversations around the country. The methodology incorporated in JCSP does highlight, as Jay mentioned, in a -- you know, it's a matter of getting the crash point in time, but does highlight where the power is wanting to flow and those congestion issues and, I think, provide some good insight.

David Meyer: Do others have comments on this point? Yes, good.

Greg Pieper: This is Greg Pieper. The only other additional comments I have, I think, is what we heard earlier, even on the Commission panel so that the congestion does seem to happen around markets seams, so I think that's another place, which you are aware of.

The only other observation I have is that occasionally, kind of like Manny was talking about, is that bulk systems can cause issues on underlying systems. Now, maybe not congestion but it clearly impacts reliability at times where you end up operating underlying systems' radial because you can't handle the flows in the event that you have an outage of a bulk system. So there are some impacts, as well, in that area.

David Meyer: I noticed that most of you have referred frequently to flowgates and not to more generic pathways or paths. And yet if you're doing a national-level study, as we are, and you're trying to identify major problems in moving electricity efficiently and reliably from generation sources or major clusters of generation sources to major load centers, if we don't abstract somewhat the problem simply becomes enormous.

So my question to you is -- would you -- in doing the work that you do, do you not find a need to take a flowgate and say, "Yes, this flowgate affects a combination of several other lines," but do you then -- are you able to think of the effective lines as a group of lines that flow to a load center and are more or less operating as a single path? Or is -- this is the way that the West has approached it, and they, as you know, have a catalog of 60-odd paths that they routinely handle as a monitor.

Now, in the East, I know the East is a more networked system and does not rely on long lines to the extent that they do in the West, but nonetheless from an analytic point of view, I see some potential benefit in trying to abstract to pathways, but I want to get your reactions to that approach. If you don't find it necessary to do that, I'm unsure why. I'd like to hear why that mode of analysis is not necessary for your particular purposes.

Unidentified Participant: Within the MAPP region there has been forever a subcommittee known as the Design Review Subcommittee that looks at the transmission upgrade plans of the MAPP members, and rules on whether they are adequate or not. It looks at their uploads -- other facilities are impacted on other people's systems, and you have to get the approval of that group for whatever project you have in order to basically get accreditation for your power pool, for the reserve sharing pool, and, you know, we've seen where we ourselves make upgrades to facilities that we don't own that are hundreds of miles away in order to put in a project and relieve constraint that isn't ours at all.

So I think maybe we function more like the Western interconnection in doing that. It's just the nature of the system that we've had within the MAPP region.

Unidentified Participant: I want to ask the rest of you, when you think about either solving congestion problems or simply understanding how this system works, do you focus on flowgates? How often do you have to -- is it useful to think about a path in the sense that the West thinks about a numbered path that it may include as many as five or six major transmission lines that operate as a sort of cluster, and if what happens on one of those lines in the cluster has very significant effect for the other lines in the cluster, and that's one of the reasons that I find it useful to organize their analysis along these paths and -- as opposed to just looking at the specific constraint, the flowgate portion?

Manny Rahman: It's Manny Rahman. The main difference between the system in Midwest is that it's quite a bit integrated type of a system. It's not one line or one path, which carries power, and then if you lose that, it (inaudible) results into a majority of that going into some other path, which is predetermined. The responses on transmission system in the Midwest and Eastern part of the country are much different than those in the Western part. The response is, generally, if you lose a line or have a problem on one path, it will distribute into many, many different ways, and that makes the system much more integrated and, in a way, is not as prone to problem as in the West.

This doesn't mean that different paths cannot be defined. You can still pick a majority okay half a dozen or a dozen path, which is more responsive and define your flowgate that way. But it would be a little bit harder to do that in the Eastern part of the system, in my opinion.

Greg Pieper: This is Greg Pieper. Part of the differences between the East and West interconnection is somewhat related to how tariff are implemented. In the Eastern interconnection, most tariff service today is granted through a distribution calculator, and the impacts of the system are looked at under that for firm transmission service.

In the West, they still rely more on contract path. So they deal with what are the impacts on significant pathways that are essentially identified from the WECC. And the same goes true for how they deal with when there is congestion on the Eastern interconnection, it's through a distribution calculator, the transmission line loading relief process is basically a distribution calculated to determine what are the impacts.

In the West, they rely on -- I think it's called their UEFA system, which I can't remember what that -- what the acronym stands for, but they identify a path owner, and that path owner then can take multiple different choices about how to relieve that constraint. You could re-dispatch, you could deal with transmission service. So it's kind of wrapped into how the tariff gets implemented in both the Eastern and the Western interconnect, and it's also how they deal with the flow path.

We do have some flow paths kind of what we were talking about earlier, where we have these angular and voltage stability limits that we still use yet for looking at participation and ownership, but in the Eastern, it's primarily on the distribution calculator approach.

I'm not sure if that gets to the answer you're looking for.

Jay Caspary: David, this is Jay Caspary of SPP. I can't comment too much on what goes on in the West, but I guess in the East interconnection, we focus on flowgates, so basically manage congestion on the grid, and we allocate rights on flowgates to different entities from some historical usage, and we've got to be really careful, I think, on how we use that, going forward, in terms of a national congestion study. But it's good information. It tells us where we have constraints today based on whatever conditions are out there today.

But we continue to look at, I think, interfaces, and try to get rid of some flowgates if we can, but it seems like the more we study it, the more engineers will find another constraint, okay? And some people may not want a constraint to be a constraint, okay, in the NERC IDC because that may curtail transactions that they have ways to operate around or -- okay? So I think you ought to be careful about the data and how you use it. I don't think you're going to see flowgates go away in the Eastern interconnection. To me they're more of an operating contractual agreements type mechanism than a future congestion measure.

David Meyer: So help me here understand -- you're saying that flowgates you use as a way to manage the system you have, and you focus your management effort on -- around what happens in relation to the flowgates. And that when you're thinking about system additions, and you're thinking about links, possibly long links, from Point A to Point B, and how do you -- walk me through the analysis, then, that gets you to saying, "Yes, this system needs a major link between Point A and Point B, and it may be widely separated from a flowgate that maybe isn't a matter of great concern," right?

Jay Caspary: Sure.

David Meyer: But just walk through the kind of step-by-step, then, how that analysis works.

Jay Caspary: We look at -- this is Jay again with SPP -- we look at flowgates to help us start the analysis, but that's not what we're trying to solve, all right? We're looking more at, I guess, what are the best solutions from an interface or to perform whatever objectives we decide, whether it's wind deliveries or more economic dispatch or whatever. And to us, reliability and economics really get gray really quick, okay?

If you look at the JCSP, we're coming up with some scenarios that will have 765 kV robust grids, and basically 800 kV HVDC line to interconnect systems that are significant flowgates today, whether it's ISO New England, New York, TJM on the Eastern seaboard, or even down into the Southern Company system, for example, so that we can bypass all the flowgates and all the constraints between the source of the power and where we're trying to get it, okay, to manage around it.

So there's no easy fix here, I'm sorry. But there are various ways, I think, to use that data to try to figure out how we go forward or for how we plan the system to manage congestion.

Okay? I don't know if I answered your question.

David Meyer: Let me ask the rest of the panel to go -- to take on the same issue; that is, I take the point that flowgates are a point of focus for dealing with the grid as it is and maintaining reliable operations, but how do you then go to -- in terms of relieving congestion, what's the analytic process that you use to -- that leads you to say we ought to build a new line between Point A and Point B to relieve congestion and possibly to relieve congestion on some very different flowgates. But I'm just trying to understand how different organizations deal with this question and is there a kind of common mode, or are there some important differences that we need to know more about?

Jennifer Curran: This is Jennifer Curran of the Midwest ISO, and I'm sure this will show up in our written comments, because this isn't my exact area of expertise, but what I can say is I think we are moving from -- well, I don't want to say moving -- I think we're in kind of a combination place right now. Some of it is, I think, just as Jay mentioned, that to some degree your development of transmission solutions and your specific flowgate analysis are disconnected. There is an iterative -- the flowgate points you in the direction you need to go, but it's an iterative analysis of the impact.

Having said that, I think one of the benefits of new methodologies that we've been looking at, where we look at the economic energy flow, do tend to abstract it somewhat. They tend to -- by looking at the copper sheet approach, it shows where the energy wants to go, and it then, by definition, identifies some of those paths. So maybe it narrows the focus a little bit more but, again, I don't think it's specifically tied to flowgates at that point. It's attracted a little bit higher level.

Greg Pieper: This is Greg Pieper. I'm not a planner, but my understanding is that I think, if I understood Jay and Jennifer correctly, it does start -- you know, you focus based on flowgates is a good place to start, but even when you look at the NERC planning standards, and you look at the transmission planning standards, they are very deterministic about how you go about looking whether or not your plan is robust, and you look at elements out of service and what are the impact of the other for either voltage or thermal overload excursions.

So at that point you kind of shift in the process to looking at the system, and it is a very large system that you look at. It isn't isolated. I think that's one of the things that's changed in the planning process is that it keeps continuing to grow at a larger geographic area to see what are some of the impacts. In that sense, I think it is a little bit more holistic than it was in the past.

Manny Rahman: This is Manny Rahman from AEP again. Jennifer mentioned about deterministic; that it is -- you look at what-if kind of a scenario, in a way. And then flowgate essentially started with and defines your problems. This is where you have a problem, and you want to solve it. But it does go beyond that -- that once you have looked into and find out what the problem you're trying to solve, you look into what the system losses would be; where the other generations are coming in that (inaudible) already. You may have some other benefits, which you built into the solution, which you plan to do.

So, in a way, you try to solve what your past problem is. You know that problem is coming up or it is already there, but in a solution process you look into what else is coming in that area, and you integrate that into part of the solution so that you do get into an area where the solution is not just solving one problem but is attacking some other potential problems in that area.

And that's where the difference also gets into in that Midwestern part of the system. It's very, very fully integrated, and once you try to do one thing, it definitely helps or could hurt other pieces. We are building a line, 765 kV line, with some joint venture, and that vertical line will end up solving 18 different problems, which was in that area. Not all of them were local problems; some of them were farther away, flowgate-type problems.

But, in a way, it will be hard to say that we start with this problem, and this is the process, you go into and end up with that solution. So that will be very, very hard to define exactly. You have a process, but it definitely -- each process divulge from what the previous one was. So you have to look into individually each one. I don't know if that answers your question, maybe it makes it even more complicated than it what sounds like. And it is complicated.

David Meyer: Yes, no matter what. Are there caveats that you would suggest to us that we should keep in mind or think about? Bear in mind that we are -- this is going to be (inaudible) focused on primarily, entirely on historical current congestion, but we don't want to mislead ourselves or others into just assuming that the future is going to be like the past, and so if there are significant things that -- significant reasons that you see that we should identify here and, you know, put up front, we'd like to hear about it.

Manny Rahman: I think one -- this is Manny Rahman again -- one thing, which changed from when the study was done last time, 2005, the renewables are big in picture. So that definitely will say that the future does not look like exactly what the past is. We definitely need to make sure that that kind of a scenario -- Jay mentioned about 20-percent scenario -- it may not be that way in the next few years. It probably will be much less than that, but at least thinking in that part of it that wind is coming, renewables are coming, and they are part of our lives. That change is not -- that change hasn't happened in the past, but that change thinking process has happened from 2005 to 2008. So that is a history, but that history does not have traces right now. We have to define that traces what it will look like in future. But we definitely need to include that thinking process in our future thinking. Jay?

Jay Caspary: This is Jay Caspary. I agree with Manny on that. In SPP, you know, we've got an approved expansion fund that's $2.2 billion of projects over 10 years. Those that are going to address many of the flowgates that you're going to see historically -- they're going to go away. We've got plans in place to deal with that, and I think all the RTOs and transmission providers can give you data on flowgates are being addressed, and I would encourage you to ask for that.

With regard to renewables, in the last 18 months, SPP has seen probably a 200 percent increase in wind farms in our generation interconnection. I believe Sandy said something about 32 gigawatts, or 31 gigawatts. Well, it's more like 40 right now in our queue, and about 35 of that is wind.

So, obviously, there is an interest in significant wind development beyond RPSs that are mandated by law. There are agreements to build wind in the states of Kansas as well as Oklahoma that aren't legislated, but they're agreements. And we see significant development by the TOs to build those plants; to get those plants online and delivered to the local loads.

So you've got to be really careful about using historical data in going forward. That's all I've got to say -- because there's significant expansion that's going on. There are significant changes to the topology, the generation mix, and everything, going forward. I'd be happy to help you, if I could, but I don't know how you deal with that.

Manny Rahman: This is Manny again. I just want to emphasize what Jay just said -- that there is a lot of flowgates because of those winds and other generation coming up. There will be new flowgates, also, because this generation will be there. They will create some new problems, which was not there. So if you purely look at historical numbers or historical data, we will be misleading ourselves and, again, in a way, we can look at historical, and we know those generations are coming. They are already on the books on different RTOs. AEP is part of three RTOs -- PJM, SPP, and ERCOT. And we know each one of them has a huge list of what those generations are coming out, and that generation list is available to everybody. So that DOE should look into that and make sure that they are considered, and then we define our future based on that.

Jay Caspary: One other comment -- Jay Caspary again -- if you look at our Oklahoma Electric Power Transmission Task Force Study that we published in March, basically we developed a 765 grid to collect winds and deliver it to loads in SPP and beyond. It essentially eliminated all flowgates in SPP. I mean, there are some load-related flowgates we still have to fix, but anything dealing with transfers between controllers basically goes away.

And so I think -- again, I think you need to be cautious about using flowgate data and extrapolating that.

David Meyer: I noticed that none of you have mentioned smart grid as a gain changer, as a significant break from -- possible break or something that you would expect to break from a historical task. One friend of mine was telling me that he sees enormous challenges just trying to model the transition to a smart grid; that you're going to be putting some important new widgets in the system; that is, if a lot of the major new components that are being added to the system are going to be smarter in an electronic sense, you have to take that into account in the modeling -- that there will be capabilities associated with those pieces of equipment that weren't there before. And it isn't just that the hardware is going to change and require some additional kinds of assumptions, but you're going to see different behavior on the part of whether it's the homeowner or operators that have some of that equipment.

And so his point was that just the modeling itself is going to become more challenging, and -- just throw that out through their reactions to see whether it is -- does this strike you as a realistic concern? Or is it so far in the mist that we really don't need to worry about it for a few years or what?

Greg Pieper: This is Greg Pieper. Unfortunately, I'm not as connected with the smart grid approaches. I know many companies, including Xcel Energy, has a prototype effort, a smart grid city that they are working on. In our case, we're working on Boulder, Colorado. And much of the approach that I am aware of is, one, is to give customers choice. To me, it's unclear yet whether or not -- how people are going to react to economic signals. You know, are you going to do your laundry at 10:00 rather than doing it at 5? I don't know that.

But I do know that, from an operating point of view, when I have control of a DSM product out there, then, to me, that is really where you actually can impact how the system gets utilized, and the NSP system right now does about 10 percent of the load is under DSM. And I can tell you that on a day where it becomes critical, it really feels good to be able to exercise that when you need that.

And so, in this case, much of the load is being controlled by -- it's a product called "Save a Switch," which cycles air conditioners, which is a good part of that load, and that, for the most part, is fairly innocent to the customers, but it really helps the grid perform better and be able to get through areas where you have issues not only on generation resources but also, you know, it definitely changes the transmission usage as well.

Smart grid, as I understand, and then, again, I guess I’m not a good source, is one is the data-gathering about equipment. It doesn't necessarily change its performance. Now you know more about that transformer, that breaker, does it need maintenance? So I don't see that impacting the using of the grid, but maybe a better use of maintenance dollars to go out and repair and do something in advance.

But, beyond that, I know there are proposals to move forward with smart grid. One of my concerns is the -- whether or not people are going to start substituting one product for another, and the one that has me concerned is the plug-in hybrids. I think they're a great idea. They're being advertised as both a load and a resource. I believe they'll be a load before they're a resource, and they could really impact our metropolitan areas if you have a concentration of a load like that and, in fact, it could become an economic incentive for people to move away from our current vehicle choices.

So I don't know -- to me it's speculative. Is it worth our pursuing? I think that the potential is great, but I can't tell you when it's going to happen.

David Meyer: Okay. We have five minutes left, and so I want to ask the panel: Are there any points that you sort of said to yourself earlier and those things you particularly wanted to be sure you got into the dialog? So if there are any such things that you haven't mentioned yet, now is your chance.

Unidentified Participant: I'll start real quick. I appreciate the opportunity to be here and look forward to giving more formal comments. I think we need to recognize that doing nothing has a cost, and that cost may not be readily apparent to the customers or policymakers, but every day we delay a decision or delay building out the grid, it just will compound the significance of us not having a robust grid down the road, especially in terms of all the uncertainty we have.

I think we've done ourselves a disservice in undervaluing transmission for many decades. I think now is the chance to really build it like we need to build it for the future. I would look to DOE or maybe somebody else at FERC or NERC to help us deal with seams agreements and cost allocations. We've got to get that to move forward to deal with these seams between transmission providers or between ITOs and RTOs even. That's one of the key principles in FERC Order 890 is cost of these seams between transmission providers as fair and simple as possible. We can study it to death and never agree on the answer and never do anything and cost our customers billions of dollars, over time. We can't afford to do that. Thanks.

David Meyer: Any other comments?

Manny Rahman: I'll just add one more to that -- I suggest that DOE does the review of the previous study (inaudible) what mitigation has taken place as a result so that will help to come up with a new study in that sense. I just want to go back to what Jay had earlier said, that discussion on what impact JCSP and other (inaudible) plants will have on congestion. That should be included.

David Meyer: Well, I want to thank -- give my personal thanks to the panelists for some very insightful commentary. The next stage of the workshop is going to be -- we're going to give an opportunity to folks in the audience who want to make short statements to us. We have two such parties who have identified themselves, but those of you who haven't signed up, now is your chance, also. Please, if you do wish to make comments, please indicate to Peggy that you would like some time.

I am personally going to have to bow out here and run to the airport quickly. I have a meeting in Wilmington, Delaware, that I need to be at tomorrow, but I'm going to turn things over now to my colleague, Warren, here, and he will handle the microphone from here. So thank you all.

Warren Belmar: Thank you, David. If the panelists don't mind staying a few more minutes, we're getting close to the end and maybe some of the questions might pique some comments that you care to make as well.

Okay, our first commenter is Richard Walker. Is he here? Why don't you introduce yourself, Mr. Walker, and please take your time.

Richard Walker: Good afternoon. I'm Richard Walker, President of Sustainable Energy Strategy. My company provides consulting services to developers of renewable energy projects, utilities, industrial customers, and large landowners. One of my primary clients is the Wind Coalition, which is a regional affiliate of the American Wind Energy Association, or AWEA.

The Wind Coalition generally covers the ERCOT and SPP regions of the United States, and I am here to provide input on behalf of both the Wind Coalition and AWEA.

The Wind Coalition's members include many of the largest wind developers active in Texas, Oklahoma, Kansas, New Mexico, Missouri, and Arkansas. It also includes many of the major component suppliers such as turbine manufacturers or tower manufacturers, plus a handful of environmental and consumer groups.

AWEA is a national trade association representing the broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States.

I, myself, have been active in the wind energy field since 1994 and, under my supervision, the first utility scale wind project was constructed in this part of the country in 1995 near Fort Davis, Texas, as part of a DOE program called the Wind Turbine Verification Program.

Since that time, wind generation has expanded rapidly in these regions. There are approximately 4,942 megawatts in operation in ERCOT as of March 31 of this year; 1,710 megawatts operating in the SPP region; four 1,872 megawatts, if you include that, in the state of Missouri. This is only a small fraction of the amount of clean, renewable energy that wind resources in ERCOT and the Southwest Power Pool can provide to our nation.

Jay and Manny kind of set this up. They pretty much nailed it right on -- they were talking about the amount of renewable potential out there in this region. There's actually 40,000 megawatts of wind energy projects either in operation or in the SPP queue right now. As of a couple of weeks ago, we went over 40,000.

So AWEA and the Wind Coalition believe that due to issues such as high and volatile fuel prices, climate change and air quality concerns, water conservation needs and threats to national security from high reliance on imported fuels, our nation's vast resources of wind in the middle of the country can and should be tapped.

There is an international interest in doing so and reducing our dependent on foreign sources of energy, shifting supply to renewable energy and bringing development to rural economies.

The Department of Energy recently released a report showing that 20 percent of our electricity could come from wind energy by the year 2030. It's achievable. According to this same report, the benefits would be enormous. Those benefits include electric sector greenhouse gas emissions would be reduced by 25 percent. The amount of natural gas required to generate electricity would be cut by 50 percent, and United States gas consumption by 11 percent lower overall. This helps limit our reliance on energy imports and reduces consumer energy cost.

Because water is not required to operate wind farms, water consumption could be reduced by 4 trillion gallons, according to that same report, and approximately 500,000 new jobs would be created.

The SPP is moving forward on two new policies regarding the allocation of costs for transmission additions or upgrades, which the wind industry is very excited about in support of those. The first of these would provide for base studying of a balanced portfolio of economically justified transmission projects.

We, in the Wind Coalition, are hopeful that such a portfolio of economic projects will include major transmission backbone projects such as that envisioned in SPP's Kansas Panhandle Sub-Regional Transmission Study, also known as the X Plan, or the EHV Overlay, which Jay has alluded to, each of which could facilitate the movement of a significant amount of energy from the wind-rich Western parts of the SPP states to areas of our nation further to the East, which, typically, have higher demands for electricity but lower wind speeds.

The second policy moving through the SPP committee structure was approved just this past Monday by the SPP's regional state committee. This would allow base studying of transmission upgrades necessary to the integration of wind projects selected by SPP members as designated network resources. This policy would place cost allocation, a transmission for wind projects, on a much more comparable level to that which is currently applicable to fossil fuels or nuclear-generating plants. And, again, AWEA and the Wind Coalition are very supportive of this new policy.

While these polices are very positive steps forward, there is much more that can be done to facilitate our nation's effective use of the enormous wind resource, or wind energy potential, of America's heartland. We believe there is a national interest in building transmission to access our nation's wind resources; resources that our nation is blessed with. Our nation's highest quality wind resources are often distant from population centers, which speaks directly to the importance of transmission in developing our nation's wind resources.

The Wind Coalition and AWEA also believe that now is the time to move forward with national transmission corridors that can help our nation effectively integrate large amounts of renewable energy into our resource mix to efficiently use the existing fossil and nuclear units, nuclear generation that we have, into dramatically reduce the amount of emissions attributable to electricity production.

We heard from MISO earlier -- it would take seven years, on average, to build transmission. So when we start talking thing like EHV, we're really talking 10 or more years. So we need to start now.

The EHV overlay being considered by the SPP would be a critical component to national transmission corridors, but the really good projects like this, moving forward, we need our nation's RTOs and ISOs to agree on principles of cost allocation and seams agreements. We've heard it here from several different people.

Seams agreements are basically defined how all these adjoining reliability regions will work together on planning operation and cost allocation. To accomplish these goals in a timely manner, the Wind Coalition and AWEA believe the direction from the Department of Energy, FERC, the president, and our U.S. Congress will be vital. A national energy policy emphasizing a transition to renewable fuels and the construction of national transmission corridors needs to be enacted.

One policy that should be available to DOE is the ability to designate national interest electric transmission corridors. Section 1221 of the Energy Policy Act of 2005 provides for designation on the basis of fuel diversity and energy security. We believe, therefore, that DOE has the authority to designate such corridors, assessing resource areas, accessing resources area that are not currently served by transmission. We believe that DOE's last congestion study and the currently planned congestion study are fatally flawed in this regard. They only evaluate congestion on lines that exist now, not the lack of transmission infrastructure to areas not currently served and not this potential influx of wind generation from our heartland that would be served to meet a national RPS. So that makes no sense not to consider those things.

We encourage the congestion study to correct this mistake. I hope the department finds our comments on the need for such policy as useful. Thank you for your time, and I'd be glad to answer any questions you have.

Warren Belmar: We're going to break from tradition and talk with you afterward. I'd like to show you some of the decision that we issued on the first two designations. You'll find that some of the points you've made have been resolved. But if you want us to go back and change it when there's (inaudible) something different, I'll be glad to consider that.

We have one other speaker (inaudible). Michael Sidiropolous -- is he here? Sir, why don't you take the time you asked for?

Michael Sidiropolous: I was going to be a speaker. I don't have anything written up, but I just wanted to make a sort of statement.

Warren Belmar: Please.

Michael Sidiropolous: I am with RES Americas, Renewal Energy Systems. We are developer of wind power projects.

Unidentified Participant: King Mountain and others.

Michael Sidiropolous: And what I'd like to say is that I'd like to see the study an emphasis on conditional congestion, which, as I understand it, is the congestion resulting from the inability to integrate new generation. Mr. (inaudible) presentation gave me another idea that I think if we are to meet the federal RPS objectives, which are very challenging, we need to go into a super grid type of super highway, 765 kV perhaps, system that will be extended throughout the country, and I cannot see that being funded by anyone other than maybe the federal government with cost recovery through usage.

That's my suggestion. Thank you.

Warren Belmar: Thank you. Many of the things we've heard today are interesting proposed solutions to a problem, which may or may not be adopted today, tomorrow, or the next day. Our purpose of conducting the congestion study, as you know, is to identify the regions that are suffering congestions and constraints, and then leave it to you into the various states and perhaps if they can't work it out, the Federal Energy Regulatory Commission tracked on the applications that might be filed. So we appreciate not only your identifying the issues that directly relate to congestion and constraints but also to many of the resolutions or solutions to the problems that do flow from that and putting those on the table is always very helpful.

Is there anyone else who would care to make a comment? Did any of the comments intrigue any of our panelists to want to say anything further?

Well, having heard from everyone, I think we'll be able to finish our session today a little bit earlier than planned, and on behalf of the Department of Energy, I'd like to thank all of you for being here, for all of the contributions you've made, to date, and, most importantly, for the written detailed materials that I hope all of you will be filing with us as we proceed in trying to complete this next study on schedule by August of 2009. Thank you very much. This session is adjourned.