Spring 2009 Technical Workshop in Support of U.S. Department of Energy 2009 Congestion Study

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Transcript

David Meyer: Welcome to Day Two of our program. And I want to welcome the people that are listening in on the webcast. We're delighted to have all of you here. The discussion yesterday, I thought, was very helpful, very, a lot of insight there and a lot of interesting material, and so we were very pleased with the results that we got yesterday.

For this panel, we are going to turn to the East and talk about some of the current planning efforts that are underway at various levels across the Eastern Interconnection. It presents a different set of problems--somewhat different, at any rate, compared to the West. But that's part of what makes this particular meeting, I think, very interesting, is just to be able to compare and contrast here and see what the similarities are and what the differences are.

I'm going to turn now to our panelists, and many of you know John Lawhorn. John is the Director of Transmission Planning at the Midwest ISO. He led this recent project that many of you know about called the Joint Coordinated System Plan. It was certainly a path-breaking effort in the Eastern Interconnection to do this kind of analysis at the interconnection level. So, John, would you tell us more, please?

John Lawhorn: Thank you, David. It's a pleasure to be here today to talk about congestion identification and mitigation and the way that we do transmission planning in the Midwest ISO. The whole transmission planning process kind of brings to mind a joke that I'd like to share with you. "How do you tell the difference between an extroverted engineer and an introverted engineer? The extroverted engineer is the one looking at the other guy's shoes."

Basically, why that strikes me as the planning process is that we need to get our eyes off the floor and look further out--look further out both from a temporal standpoint, time horizon, as well as a geographic horizon standpoint. And the planning process that I'm going to be discussing addresses both those issues. It also will illustrate how we can determine the congestion corridors within the East for any time frame and any year. And I'll also, I'll tie this to the long-term planning processes such as the JCSP and how they fit into the near-term and short-term planning processes that face us all.

The Midwest ISO uses a seven-step planning process, and it is value-based planning driven. And by value-based planning, I mean that we look at the hourly chronological values, we look at every hour of the year and capture the energy value in the process, and use that energy value as part of the overall planning process. Within the Midwest ISO, we have both, we have separate but intertwined economic planning processes and reliability processes. And that's illustrated here in this step process chart.

We had some discussion yesterday--I found it very interesting--from the West, and they identified some of the issues that are up here as our key issues. Our Step Number One here is that where is the generation that you're using to site the transmission? As we go to these longer-term studies, the generation isn't out there. You've got the short-term queue, which is good for three to five years, generally, that you can use for the generation, but as you move out to 15 or 20 years, the generation isn't there. And the transmission isn't there. It's the chicken-and-egg problem. If you have one, you can solve the other more easily. But when you're missing both, you have to make an assumption. And that's what the first step of this process is--to perform a multi-future or scenario regional resource forecast.

So for this step, what we would do is we would do a capacity expansion on each region within the Eastern Interconnection out for 20 years using the reliability criteria for that given region. Once we have that information, which is essentially a least-cost resource plan based on the information available--which is done through an open stakeholder process to derive what the assumptions are for each of the variables and what the scope of the study is--you take that information and you site it within the transmission and the economic study models.

The third step is, once you actually have that--and for the JCSP, that was about a five-month process, to go through the open stakeholder process, determine what the variables were and what the uncertainties around those variables were--do the regional expansion plan and site. It took about five months.

Once you have all of that information in the models, you can actually start the transmission development process, the design process for that scenario, which is our Step Three here. That is where we went through that particular step in the JCSP, and it took us, from start to finish of actual analytical work, about a year.

It's important, though, that that gives you information for a scenario, but we live in a complex world where there's many different scenarios that could come about. So you really need to study a very wide range so that you make sure that you capture the scope and breadth of what can happen. So that means that we need to run multiple scenarios. But ultimately, we're only going to build a single system. So you have to do some robustness testing on those scenarios to determine a core set of facilities that best meet the needs and then build from those as you go forward. And we do that through portfolio analysis to help us with that aspect.

And we move on to Steps Five and Six, where we consolidate those plans and then take them back to the reliability process, and then that once again informs part of the transmission design we have. And it's an iterative process to come up with an economic and reliable plan.

And the seventh step there is perhaps the most difficult, and especially within the Eastern Interconnection, and that's the cost allocation--getting the right rules around who's going to pay for it. Because there are many developers out there that would love to build transmission, but they want to be able to get the appropriate cost recovery. So the cost allocation is a hugely important function, and that is being worked on at many different levels.

From a timing of the planning process perspective, the short term is really dominated by the queue. And within the Midwest ISO, we have a fairly significant queue, which I'll talk about a little bit later. Then, as we move to the three- to seven-year-out time frame, we get to what we call targeted studies. These are studies that are to meet specific time horizons.

An example of this would be the Regional Generation Outlet Study, Phase I and II, which is called RGOS here. That particular study is intended to develop or define the transmission required to meet the renewable energy standards within the Midwest ISO. Every state within the Midwest ISO, except for Indiana, has a renewable standard, and they have specific time lines in them. So long-term studies are great, but we have to devise the solution that actually gets the renewable energy to the states in the time frame that they have put in their legislation.

And then from the longer-term perspective, we have the MISO Transmission Expansion Plan and the Joint Coordinated System Plan processes. They serve that longer-term need. From a policy perspective, the cost sharing and recovery is hugely important, and the initiatives underway are the UMTDI, which is the Upper Midwest Transmission Development Initiative, that's got the governors of many of the Midwestern states involved. It's got the Cost Allocation and Resource Planning Group within the Midwest ISO. And federal policy--we've got FERC involved in cost allocation issues. So there's a significant amount of activity on this forefront, and that's good, because it's a very thorny issue.

For the internal versus external, the queue, our targeted studies and the MISO Transmission Expansion Plan tend to be focused on the internal Midwest ISO. Additionally, the MISO Transmission Expansion Plan also looks outside of our borders, because, let's face it--RTO borders are arbitrary. They can change. The laws of physics go beyond those borders, so you need to look within your border, but you, importantly, have to look outside your border. This is really one of the main messages I'd like to leave with people today is that inter-regional planning on the Eastern Interconnection is a must. The RTOs by themselves are too small to do realistic, credible planning of this magnitude.

So the Jointed Coordinated System Plan was a multi-RTO planning effort that looked at the Eastern Interconnection, predominantly most of it. We didn't really look at the Florida area. And the JCSP that I'm going to use for the next few slides to illustrate some of these concepts.

As I mentioned, we did a multi-RTO capacity expansion. This is the consolidation of all those individual expansions. The RTO-by-RTO regional expansions are all contained in the JCSP Study Report, which can be found at the jcspstudy.org website.

As you can see, as we move to, we really looked at two main scenarios with JCSP. The first was that middle one there, which is the Eastern Interconnection Reference Scenario. That was basically targeted to meet the existing state mandates or renewable portfolio standards, because there are standards in some states, or mandates in others, throughout the Eastern Interconnection. That essentially means, or requires, a 5% wind energy solution. And we assume that all of those standards would be met with wind, even though they do have components of solar and biomass and the like. But this was a study that we were performing with the Department of Energy. They were looking at wind, and so we used the assumption that the renewables would all be met with wind energy.

The big bar on the right there is the 20% federal standard for the Eastern Interconnection. So you can see that those big green areas there under the reference case--that's 57,000 megawatts of new wind being required--and for the 20% case, that's 229,000 megawatts of wind. Those numbers would change depending on where it's sited, but based on the open stakeholder process that we use and the assumption set used, this is the information that we came out with, and this is what we studied. If you want to study something else, we can certainly do that. So based on that capacity expansion, this is where the resources were sited.

So capacity expansion models are generic. They don't tie the unit that comes out of there, the capacity, to any one specific bus, so this is a separate process that we went through. We created rules by which we took all of that generation--and in this case, 400-and-some-odd, 409,000 megawatts--and we sited it at the bus level in our Eastern Interconnection planning models. So that took us to the point where we could actually do the transmission design work.

This is perhaps the most germane slide to this meeting in that this shows the transmission congestion corridors for the year 2024. And that was the year that we were studying for the Joint Coordinated System Plan. This essentially represents an unconstrained run of the Eastern Interconnection, and it's a comparison against the existing system. So it's a constrained run versus an unconstrained run. And we take the difference.

So what this shows is that this is an indication of where the energy wants to flow in an unconstrained system, and by analogy, it also shows the congestion paths. So those that are red, those paths that are the most red, are going to be the most constrained in 2024 under the scenario that we performed and the assumption set. If you have other scenarios, other assumption sets, you'll get a different set of constraints, but this is indicative of what can be done to identify the congestion. So this was prior to putting in the transmission overlay, and this is the resulting congestion flow after the transmission overlay is put in for the 20% case.

So we're not turning this entire diagram from the reds and yellows and greens to blue, but we are making significant inroads in the mitigation of congestion through the transmission overlay.

This is just a slide to show the indicative of the amount of savings, the magnitude of the savings, that is the difference between that constrained and unconstrained case--$35 million that year.

The end goal of the JCSP was to look at, "What is the transmission needed under the 5% scenario and 20%?" So from our reference case perspective, this is the transmission that was designed to address that 5% wind energy requirement by 2024, and this is the 20% transmission overlay. And those transmission lines are indicative, they're following pretty much the paths identified on that previous chart that showed the congestion corridors. So these major DC lines--those are the big black lines, those are all direct current, 800 kV--they're kind of indicative of the transmission congestion corridors. This particular overlay was about 15,000 miles of new high-voltage line; 50% is AC, 50% is DC.

Now that we've really looked out over the long term, the reason we did that was to help us define the space of the analysis. I look at the transmission planning process as a fairly big jigsaw puzzle, and by starting with the longer-term studies first, the most regional, that is essentially helping us to define that outside edge so that we know where we need to hook into as we develop these shorter-term and mid-term projects. It helps us understand where we're looking, and it gets our eyes off the ground and toward a larger horizon.

So given that we now have a longer-term framework with a space defined, let's step back and look at the shorter term and midterm and see how they fit into that process. So within the Midwest ISO, our queue changes all the time, but as of February, just a month ago, there was about 76,000 megawatts of generation in the queue, of which 61,000 gigawatts is wind. That's a lot of wind. It's a lot of, and we only need essentially 22,000 megawatts of that 61,000 to meet the existing state mandates.

So quite a bit of challenge there. The wind in the Midwest ISO tends to be located--the highest-quality wind--tends to be located in the western side of our footprint, toward the, in the North and South Dakota, even to the west side of North and South Dakota, but very high-quality wind from Minnesota, Iowa, and North and South Dakota into Montana.

Those areas tend to be very sparsely populated. This is an illustration of the queue locations relative to where the load is in the Midwest ISO. The red areas there are kind of load zones, and the black dots are the queue locations. And you can see that they're pretty much, the wind is not located all that near to the load centers.

Which brings us to the Regional Generation Outlet Study, which is the one I mentioned earlier, which is intended to be a bridge between the longer-term Joint Coordinated System Planning work and the queue planning process. And so for this process, we took kind of a page out of the Texas CREZ process, one to define zones that we could use for the transmission development. So we picked on the order of 21 zones in multiple states and did indicative transmission planning on that, because as you move to those western zones in that red area, there's some very high-quality wind there. The better the wind quality, the fewer wind turbines needed to meet our portfolio standards.

But it comes at a price, because there isn't transmission out there. You get higher-quality wind, you need fewer machines, but you need to build the transmission. So it is a combined solution of transmission in conjunction with generation locations. So we went through some indicative planning processes with our stakeholders to identify what the total cost for each one of these bubbles would be to give the policymakers some extra information to help them make up their minds where to study.

The policymakers in this case are the governors of these states. They're involved in determining where the, which zones to look at, and we got some information back from them yesterday, I believe, or in the last two days, at least. And they have given us two separate scenarios they would like analyzed. So it's a combination of these zones and certain megawatts from each zone, and we will go ahead and develop JCSP-like transmission systems for each one of those scenarios so that we can help inform that debate as to what's the transmission needed to meet this specific need of 22,000 megawatts across those states.

As we tie the different planning processes together, I wanted to put them on this reference case map. Because there is a core set of transmission that we think that we're heading toward. You can, certainly building 15,000 miles of transmission is a huge undertaking. But there's a certain subset of that that is coming out in the majority of these plans, and this reference case, those two DC lines there that go from Illinois to the East Coast, are tending to be fairly, show up in most of our analyses. So for putting on, using the reference case here as our backdrop and seeing how the other process overlay on it, we see that the queue development is continuing and is continuing with smaller, near-term upgrades. We're doing what we can in those areas to hook up generators and get that energy out to the market.

But you can only do so much without major transmission being developed. The next step is to continue those upgrades until the Regional Generation Outlet Study aggregate plans better inform the broader solution for the area. And that solution needs to ultimately be consistent with an inter-regional plan with a longer-term view, which is what the JCSP gives us context around.

So it's a, our process is to look at the long-term, multi-region, multi-RTO analysis to use to framework the study process, and then that helps us to make sure that our short-term and our long-term activity is consistent with a broader vision so that we don't waste cost, waste valuable corridor assets, don't undersize lines. This is all a, this has to fit together in a coordinated process.

And so from a takeaway perspective, the transmission congestion can be established and determined for any year, both the magnitude and the direction. And multi-region and multiple RTO planning is a must, and a single RTO is too small to carry this out. Thank you.

David Meyer: Well, thank you, John. I think you got our discussion off to a great start. We're going to turn next to John Buechler from the New York ISO. John is the Executive Regulatory Policy Advisor for the New York Independent System Operator. And before then, John had a 30-year career at the Long Island Lighting Company, where he served in various managerial positions, but with a strong emphasis on Corporate and Strategic Planning and work in the Office of Engineering. John?

John Buechler: Thank you, David. Good morning, ladies and gentlemen. First of all, I'd like to say thank you to David and the DOE for this invitation to appear here and talk about inter-regional planning in the Northeast. And I do have a lot of material to cover here, so I'll get right to it.

Sort of an outline of what I intend to speak about. I'm going to start off talking very briefly about general planning principles that are used in ISO and non-ISO regions, focused on the New York ISO's Comprehensive System Planning Process--note the word "system," not transmission only; then talk about inter-regional planning under the Northeast ISO RTO coordination planning protocol; and finally, other planning initiatives in the region, in New York State, and future directions to address congestion issues in New York in particular.

One of the gentlemen from the West--I think the last panel--spoke about different levels or layers of planning. And in fact, we agree with that, and certainly that is a common element, we believe, of planning, again, in all regions.

First of all, regional planning starts within our individual footprints, and this is very consistent with what John just spoke about a moment ago. There's inter-regional planning under coordination agreements with our neighbors. Normally, they're close-in neighbors at the first instance, coordinated inter-regional planning as required by NERC and its regional entities. And in New York State, we're lucky enough to have the New York State Reliability Council, which is also in that equation. And then there's broader coordination, at least across all ISO and RTO regions, to share information on issues of common interest through the IRC Planning Committee.

The IRC Planning Committee several years ago undertook to put a white paper together comparing the planning processes in place at all of our members--at that point in time, anyway, which was a few years ago now. In that process, also developed or identified principles of planning that are common in all ISO regions and to some extent common in non-ISO regions, and they are there, so I'm not going to have to repeat them all. You can all see that, and I think you appreciate the fact that ISO regions in particular have open and transparent stakeholder processes and are run by an independent board generally approving the output of the planning processes in our regions.

Moving over to the New York ISO's Comprehensive System Planning Process, as in other ISO regions, the New York ISO is the transmission service provider for the New York control area. We administer both a Comprehensive System Planning Process, and then, as John mentioned, in the shorter term, interconnection process for all transmission interconnections in New York.

To put ISO in perspective--this is the only really background slide I've got--New York ISO is positioned in the Northeast geographically. We're surrounded by four other control areas. Three of those are ISO/RTO operated, and one is, and the fourth is Hydro-Quebec.

We need to put the New York ISO's planning process in the context of our overall market-based philosophy, and that does lead to a somewhat different process than you've heard described here by probably all the other speakers that you've heard so far. The NYISO and its stakeholders are strong believers in the power of markets, and that philosophy is evident in both our market design and rules as well as our planning procedures. This has been a philosophy that's been supported, and it is supported, by our stakeholders and by our state regulator. And we believe that evidence of the success of that philosophy is that the combination of the NYISO markets, or locational pricing signals for energy and capacity throughout our planning process, has provided benefits and has resulted in resources being added where they're most needed from the standpoint of both congestion as well as reliability.

And I'll move over to the pictures here. Since the beginning of the NYISO in late 1999, there has been--a piece of this slide did not come out here, interesting--oh, there we go. There's a significant amount of generation added. Again, remember we're talking about a 34,000-megawatt system. And the majority of those resources--these are generation now--have been added in the southeast portion of the state, where both the prices are the highest and the impact on reliability is the greatest. The dotted line through there is what's referred to as our Central-East Interface, which is often limiting, and I'll show you some figures, congestion figures, shortly on that.

We've also had, over the last several years, two large merchant transmission facilities interconnected to the New York and the Long Island area--the Cross Sound Cable to southern Connecticut, and the Neptune Cable to the PJM service territory.

See, the Comprehensive System Planning Process has been developed through our national stakeholder process on a voluntary basis initially. New York ISO, prior to Order 890, had not been under any directive from FERC to develop a planning process, but we voluntarily engaged our stakeholders in the beginning of 2003, roughly, and developed that and filed it with FERC, which was approved in December of 2004. FERC, in particular, in that Order, found that the NYISO planning process--and this was a reliability-based process initially--a properly balanced consideration of what to base the regulator solutions and also was, of course, a substantial improvement over traditional planning processes that have depended upon TO-developed regulated solutions.

What does that all mean? And again, I'll go to the graph here. The NYISO's reliability planning process is unique, as I mentioned before, in this way. It is a truly all-source process. It begins with the NYISO performing a reliability, security, and adequacy analysis of the bulk power system in New York State and identifying criteria violations, which we term reliability needs. The base assumption for this analysis is a very conservative model which does project, obviously, low growth added to the future, it does project known demand management programs and known resource additions, both generation and transmission. But there's a high hurdle capacity to be included in that base case. Consequently, we always identify needs.

At this point, the NYISO publishes the results, if you will, and in fact they're developed through a stakeholder process in the first place. But when that process is complete, we publish our reliability needs in our office, and we solicit not only a formal contract solicitation process, but we solicit market-based responses--we solicit responses to those needs. And that results in a parallel process where there are developers on a market basis, and they may and do submit proposed solutions, and they may be and have been generation demand response and merchant transmission. And the parallel process is New York transmission orders are taken on the obligation to provide regulated backstop solutions. And notably, those solutions are not limited to transmission, and in fact, those solutions that we have received, as in both categories, have included all resources.

The NYISO takes in all these responses, evaluates all the proposed solutions, and gives an explicit preference to market-based solutions. That is, if market-based solutions submitted are sufficient to meet the identified needs, we do not go into the transmission owners and direct them to move forward with a regulated backstop solution. This plan is, again, run through our stakeholder, the governance process approved by our Board.

In the lower right-hand corner, if in fact either during the annual cycle of the planning process or midstream, it becomes clear that there's an unanticipated immediate need to threaten reliability, we have a process included where the NYISO works with the transmission owners and the Public Service Commission to identify what's called a gap solution.

After the issuance of Order 890, the NYISO engaged the stakeholders and focused principally on some of the newer elements in Order 890. The first was a more formalized and detailed local planning process as input into the NYISO's planning process. The second major focus was on developing an economic planning process, a looking-forward economic planning process, which we did not have in place up until that point. We also developed specific cost allocation request recovery procedures for both reliability and economic projects. And a compliance filing was made and conditionally approved by the Commission last fall.

Moving on to the economic planning, people mentioned acronyms yesterday. Well, we created another one here. The economic planning process is called the Congestion Assessment and Resource Integration Study Phase--CARIS. It's a two-phase process. The first phase, in accordance with Order 890, is a study phase where we look both at historic congestion and forecasted congestion, utilizing the most recently approved reliability plan as the base for the 10-year study period. The NYISO then works with the stakeholders to identify the most congested elements based on that combination of historic plus projected analysis. And the NYISO then develops solutions in this study phase which are to include, again, all three types of resources, and performs a cost-benefit analysis, providing that information to our stakeholders and to the public as an indication of what types of projects, congestion-reduction projects, might be cost effective.

The second phase, taking that information into account, any developer of a proposed transmission project--that could be a merchant developer, it could be a transmission owner--who desires to have this project considered for cost recovery under the NYISO tariff will submit that project to the NYISO planning process for analysis. The initial phase looks at the statewide production cost benefit. If the project passes that phase, then we go on to looking at a beneficiary determination and cost allocation, which is based upon LNP load savings by zone.

That analysis, again, will be conducted in a public fashion. The report of that analysis will go through our stakeholder process. It will be approved by our Board.

Two more steps. Following, assuming approval there, a simple majority of at least 80% of the identified beneficiaries must vote in favor of the project in order for it to receive cost recovery under the NYISO tariff. Then, of course, the developer still is obligated to file with FERC for approval of project costs and file with the PSC and local and state agencies for licensing and permitting and so forth.

Since 2003, the NYISO has developed a process for reporting historic congestion. We developed, with our stakeholders, specific metrics to be used for the analysis and reporting of historic congestion. The primary metric developed is bid production costs, on a statewide basis, believed to be the primary metric because it measures the societal benefits of every project. We also report unhedged congestion generated payments and unhedged load payments. Each metric is reported daily, in fact hourly, by zone and then rolled up into monthly summaries and annual summaries, and all of that is posted on our website and has been for the past five years.

I thought I would give a couple of examples of congestion from our 2007 report to compare with the data provided by OATI yesterday. I think maybe many of you are aware of this, but the general pattern of power flow in New York is from north to south and from west to east, being large resources, hydro resources--at least large for New York, anyway--up on the St. Lawrence River in the north and over at Niagara Falls in the extreme west and also on the lake, a significant nuclear power complex as well. And more than half of the demand in the state is located in the southeast portion, principally in New York City and Long Island area.

This is a five-year comparison of cumulative congestion based upon the statewide bid production cost impact methodology. And you will see that while there have been some increases in the past five years, you're looking at a total of, in 2007 being the blue line, the very top line--the dark blue line, that is--of about $125 million.

I need to define that. The way this metric is calculated is we take our day-ahead market and we have a simulation model. We take that actual market results. We, in the model, remove all transmission congestion, set transmission and transfer line limits up to 9999, if you will, and rerun that same model. The difference between those two is what you see here on a cumulative basis.

So by definition, this is certainly the maximum amount of congestion relief that you could ever achieve from any individual project, and any individual project would of course achieve less than that total shown there. No one's suggesting that that would be an economic thing to do, to remove all congestion, but that's the methodology being used to report it and to get a good idea of what the maximum possible benefit might be.

This is just an example of all the metrics and an example of the annual roll-up by zone.

And then finally, I wanted to focus on this slide for a moment. We also rank--again, daily, weekly, monthly, and annually; this is the annual for 2007--those elements of the system which are responsible for the greatest amount of congestion. This, again, is on a dollar basis, bid production cost basis. If you look here, you've got Central East Voltage Constraint, Leeds-Pleasant Valley and Dunwodie to Shore Road that make up, made up in 2007, 87% of all the congestion in the state of New York.

If you were to look at the tables presented by OATI yesterday, you will see these same three elements in, I believe, their top five or six, maybe not in exactly the same order. Of also interest, we have found that over the five years that we've been performing this analysis, that these three elements have always been in the top 10 as well. So I think there's a message there at least that says that even though the approach taken by OATI was significantly different than the approach taken in the calculation here, they seem to be pointing to the same elements, which, I guess, gives us some comfort, anyway.

Moving over to planning in the Northeast, back in 2004--I don't know why the date was coincidentally the same date as FERC approved our internal planning process, it just turned out that way--New York ISO got together with ISO New England and PJM and determined that there would be value in developing an inter-regional coordination process for planning across our entire regions. We in fact put that together. The agreement was signed in December 2004. Our Canadian neighbors, the IESO, HQ, and New Brunswick, are also participating on a limited basis. They're not signatories because of concerns about jurisdiction--or non-jurisdiction.

The agreement has formed an ISO/RTO Coordinating Committee, the JIPC, and a regional stakeholder committee, the IPSAC, and Mike Henderson can tell you what those acronyms stand for if you really care about it. And importantly, I think that FERC found that this protocol satisfies Order 890's inter-regional planning principle based on the Order 890 compliance filing last year.

The objectives of the protocol are to provide for, again, enhanced coordination planning throughout the Northeast and address so-called planning-related seams issues, and support, and supplement but not, importantly, not replace or supersede the individual ISOs' regional planning efforts. Again, those kind of layers of planning I talked about at the outset.

To give you some idea of the region covered, it's the highlighted region here. Everything that's not in the--I guess it's sort of dark beige--to the west that John just talked about. This region encompasses about 230,000 to 240,000 gigawatts of load served by about 400 gigawatts of generation, a population of over 100 million people, representing nearly 30% of the US population and two-thirds of the Canadian population within this footprint.

So what are the other elements of the protocol? There are a number of technical procedures on kind of the basics of coordination of exchange of information, coordination of interconnection requests and transmission service requests, and importantly, the development periodically of a Northeast Coordinated System Plan. There is, in the agreement itself, what I call a placeholder and cost allocation indication, indicating that cost allocation--initially, at least--is obviously subject to the requirements of each of our federal tariffs, and a dispute resolution mechanism, which we've never had to use.

The most recent NCSP was just actually finalized earlier this month, and it is posted on all of the ISO websites, actually. I just give the link to New York there. That, again, with the layering of planning, began with a very brief recap of all of our most recent existing individual plans; importantly, reported on inter-regional planning studies that have been conducted over the course of the past year; and also had significant discussion on a number of key elements that we've been talking about here for the last two days, and certainly many other places. The impacts of wind and renewable resource studies in the combined region, potential--well, not potential, I mean actual--environmental issues and prospective regulations; and demand-side resource plans, again, across the region.

These are mostly, and I'm certainly not going to go into detail--I have no time here today--are the types of analyses, the analyses, that have been done over the past year and are reported in more detail in the planning document itself. Perhaps more importantly, these are the highlights of some of the next steps that are also identified here. New York and New England, in particular, are going to explore further the replacement or upgrading of an existing tie in northern New York to Vermont. And that also has implications for loss of source as well as renewable resource development in that area of New York. And also explore the possibility of an additional tie towards the south.

PJM and New York, as part of this process, will be doing a focused analysis of the southeastern New York and northeastern--southeastern New York, northeastern, right--I don't know why that is, but they are. Yes, you have the PJM system including both reliability as well as market efficiency analysis. And then the ISOs, the two ISOs have agreed, have noted with stakeholders, in response to stakeholder requests, that we intend to begin discussions with the joint stakeholder group on inter-regional cost allocation following the identification of potential projects from the studies listed above.

Other planning issues. I don't need to go through in any detail with this group. The NERC ERO structure. Again, as I mentioned, in New York, we also have to, the NYISO also has, by agreement, to observe the requirements and reliability rules of the New York State Reliability Council as well.

Ditto here, just to show that NYISO is an active member of the planning committees of both NERC and the NPCC.

New York State planning initiatives. Outside of the New York ISO's specific processes that I talked about earlier, a year ago, the Governor of the State of New York established a State Energy Planning Board, charging them with the development of a State Energy Plan by mid this year. That, the New York ISO has been working with the state agencies, specifically on the development of their models and assumptions and for the electric analysis. We are in fact performing the reliability analysis for this plan.

The New York State Public Service Commission has three significant proceedings. And they have other significant ones, too, but these three particularly impact the ISO. One dealing with long-term planning--in fact, the initial phases were intimately related to the NYISO's planning process. Energy efficiency portfolio proceedings and renewable portfolio standards, kind of a relook at those programs with respect to the goals in New York State. I've highlighted New York's wind integration studies. New York performed, I believe, one of the earlier, at least, wind integration studies back in 2003, at which point we looked at a maximum penetration of wind of about 3,000 megawatts. And we have significantly more than that in the queue right now, about three times that amount, so we've re-upped this study, which is looking at operational as well as congestion analysis, and it's scheduled to be completed within about a month.

The New York Transmission Owners recently kicked off an aggressive and comprehensive transmission assessment, looking at the long-term, i.e., up to 20 years, transmission system needs for the state, looking at things from a physical condition assessment of facilities to transmission security and reliability analyses as well, as part of that study, and the New York ISO is participating in that as well.

And then finally, New York City, through one of its agencies, actually commissioned a study to look at transmission, principally focused on transmission alternatives to deliver additional power New York City. And while that study is not yet public, the initial results are indicating a significantly lower level of congestion than I'd say some of those people commissioning that study had believed might be in place before they did that. And this is a 10- to 15-year outlook as well.

The last couple of slides. I mentioned wind and, in terms of future challenges for congestion, if you will, in New York, wind power development is primarily in New York in the northern and western regions. That's where the wind resources are the greatest if you don't count offshore, and we'll come back to offshore in a moment. We currently have from there, we knew about a year ago, 1,275 megawatts, and I haven't checked in the past couple of days, so it could even be higher, actually in service and interconnected right now. We expect another 1,000 megawatts in this coming year. In fact, our last interconnection class year process, all of the projects in that class year were wind projects. And we have another 6,500 megawatts in the interconnection queue, so if you add all those up, you're at about 8,500 or more megawatts--remember, on a 34,000-megawatt system.

Geographical location, all of the--those are counties, actually--but all the counties shaded in green, the numbers in there, if you can read them or not, but show the locations of all the existing and the proposed wind projects. And one last comment on offshore. They're all like 600 megawatts proposed in the Long Island area down to the southeast. Notably, the Long Island Power Authority and Con Edison, just two days ago or maybe three days ago, announced they're moving forward with their partnership to develop a significant, potentially significant amount of offshore wind off the Atlantic, off the Rockaways, so towards New York City off the Queens area there, the light beige to the left of Long Island, of 300 megawatts, potentially expandable to 700 or even 1,400 megawatts.

And this is the last slide, which I don't think I need to talk much about, because we've talked about all these things, I think, yesterday and today. So thank you very much. I look forward to your questions.

David Meyer: Well, thank you, John. We will hear next from Ron Carlsen from the Southern Company. Ron is the Interconnection, Delivery Service, and Regional Transmission Planning Manager for Southern Company Transmission. He joined the Southern Company in 1999 and has worked in Transmission Planning since that time. During his career, he has also worked on Wholesale Marketing, System Planning, Generation Development, and Energy Trading. So, Ron, please come to the podium.

Ron Carlsen: You'll have to bear with my voice. I guess, maybe, as Bob Smith referred to his being a pharmacist, apparently, I need one, so that's what I plan on doing this afternoon is going, visiting somebody like that.

But I'm going to go over some of the activities in the Southeast and some of the specifics that Southern Company's doing as far as planning inter-regionally and regionally. Planning activities, such as the Southeastern Regional Transmission Planning Process and also the Southeast Inter-Regional Planning Process. I'll talk a little bit about the 2006 DOE Congestion Study and also touch on current and future coordination activities. And I'm going to have a little, a couple of slides about the Clean Energy programs that Southern Company's currently working on.

The Southeast Regional Transmission Planning Process is kind of depicted by that shaded area, kind of blue and orange. The sponsors of that process are Georgia Transmission Company, Municipal Electric Authority of Georgia, South Mississippi Electric Power Association, PowerSouth Electric Cooperative, Dalton Utilities, and Southern Company. So you see a mix of not only jurisdictional but non-jurisdictional utilities supporting this process.

Coordinated annual planning efforts to develop a transmission expansion plan for the region, in coordination with the stakeholders. Several meetings to coordinate activities, review assumptions, coordinate the transmission planning alternatives that we're looking at, and determine a final plan. Analysis also takes place as stakeholders submitted economic studies.

More specifically about the transmission planning process within the Southeastern region, it's kind of an ongoing process. There's really never no end to it. We take the load forecasts from our load-serving entities within the region and also incorporate their generation resources options as well as their demand-side alternatives that they're looking at, and we fold that into external models, such as MMWG or ERAG models or the SERC LTSG model, and then we develop a transmission plan. Once that plan is developed, we then again get a consultant on load-serving entities to ensure that if they have new load or resource assumption changes, so we continue to evolve that process. There's really no end to it. Even though we do report a Transmission Expansion Plan once a year, we're continually refining that plan.

Additionally, talking about the Southeastern Regional Transmission Planning Process, I want to give you a few highlights about what happened in 2008. Again, we developed a 10-year Transmission Expansion plan for the region, and one of the cornerstones of that plan was approximately 250 miles of 500-kV lines were identified and were a part of that plan. That's for reliability purposes. That's not economic projects. Those are actually planned and budgeted in the process right now.

Also a part of that plan is the completion of the stakeholder--well, not a part of that plan--but also in addition to the transmission expansion plan, we completed five stakeholder economic study requests. And those were the Mobile to Atlanta 1,000-megawatt request, Alabama to Florida for 1,000 megawatts, Entergy to Alabama for 1,000, Georgia ITS, which is basically the state of Georgia, for 1,000 megawatts, going to Santee Cooper in SCEG. And also 2,000 megawatts coming in from Entergy into Georgia ITS, which is basically the state of Georgia again.

Here's kind of a picture of the southern control area, but basically it represents the region itself. And I wanted to kind of dive in a little bit about the 500 kVs, because I think that's important to mention. Even though I'm only going to touch on the 500-kV projects, obviously, there's a lot of underlying 230 and 115 enhancements and upgrades and new lines that are part of this 10-year expansion as well.

Specifically--and I don't have a pointer to point to it--but you'll see on the bottom right-hand part of the screen, Plant Vogtle. There's a nuclear expansion plan for Plant Vogtle, and as part of that plan, there's a new 500 line leaving Plant Vogtle up to a substation which is to the northwest, right above Augusta. It's going to be called Thompson, I think.

And right there is where Thompson is. That line's approximately, I'd say 50 to 55 miles in length, that line. I'm sorry about that, John. But that line's planned for about the 2016 or '17 time frame. Of course, it will be coordinated with the developer of the nuclear plants, the nuclear expansion at Plant Vogtle.

In addition to that, before that line is actually built, there's a line planned and actually in the process right now of being built between Warthen, which is that substation right there at Sinclair Dam, or right up above the dam, going up to Thompson, and also has a 500-230 substation being built. That line, again, is about 40 miles in length.

In addition to that line, a few years out in the future, there's a line being proposed, a line in the plan between Thompson and what we call Middle Fork, which will be a new 500-230 kV substation. That line is approximately 90 miles in length, and there is also a line between what we call Wallace Dam and a Rockville substation, which will be new, and another 500 line between Rockville all the way up to what we call East Walton. That line's about 60 to 70 miles in length as well. This line for about the 2014 time frame.

All these projects are in that, except for the line between Warthen and Thompson, which is in 2010. All those lines are for, let's say, between '14 and '17 as far as in-service dates.

Additionally, regarding the region itself, I thought I'd show a few of the transfer capabilities that we're currently seeing for summer of 2009. As far as the region is considered, the region, which is the blue area, has pretty strong imports from neighboring regions. As far as imports from Florida, capabilities there for 1,000, can be as high as 1,500 megawatts year to year. So then the VACAR region, import capability of 1,000. That interface rides up to 1,500, as much as 1,500 to 2,000 megawatts, depending on the year. And TVA, 2,400, and imports from Entergy, up to close to 2,000 megawatts. And again, outbounds, a similar type of amount except for going to Florida, which there's a 3,600-megawatt capability going south.

So from those numbers, you can see there's substantial ties between the southern control area and our neighbors.

Now, next I want to touch on the Southeastern Inter-Regional Participation Process. And this is kind of a broader region than I first talked about. The sponsors of this process are the same as was in the Southeastern region, but with the addition of Duke Energy Carolinas, Progress Energy Carolinas, Entergy, TVA, E. ON U.S., Santee Cooper, South Carolina Electric and Gas, and Southern Company once again.

Supplements, the sponsors' regional planning process, this is essentially an overlay of the regional planning process with more inter-regional activities to take place. And specifically what we're looking at doing here is analysis of stakeholders' submitted economic studies.

For the Southeastern region, I showed you basically the same kind of slide, but now we have this northern part of it which talks about the inter-regional assessments taking place related to the expansion plans. Inter-regional issues are sometimes identified. And those, once they are identified, are coordinated through reliability coordination agreements that we have between areas. And so it's the same kind of message you've been hearing from other presenters earlier today and also from yesterday.

And that gets folded back into the region's plan. So it's, again, kind of an evolving process, but you have the, I guess the outlet when you go up and make sure everything's simultaneous from an inter-regional standpoint and see how it affects your neighbors, and look for optimal solutions when possible.

Some of the highlights from the 2008 and 2009 SIRPP activities, specifically we're looking at requested economic studies of SPP to Southern for 5,000 megawatts. And that's essentially looking at a sensitivity of bringing wind generation from SPP into the Southeastern Inter-Regional Planning Process kind of footprint. PJM Classic to Southern for 2,000 megawatts. Southern to PJM Classic for 3,000 megawatts. PJM West/MISO to Southern for 2,000, and also again, Entergy to the Georgia ITS for 2,000 megawatts.

So you can see from the variety of requests that we're looking at, we're looking at a pretty broad range of study types and pretty broad range of sources, and not only just things coming into the Inter-Regional Planning Process, but actually transfers going out to neighboring regions.

Next I want to touch on some of the findings or some of the observations that were identified in the 2006 DOE Congestion Study. Specifically, I wanted, as they relate to the Southeast part of the United States, one of the things that was identified was a conditional congestion area associated with Southeast nuclear expansion. And in particular, since that, I guess, that identification, joint studies have been conducted between transmission providers in the Southeast, not only to look at their particular resources and how they impact the transmission system, but also look how the nuclear expansion throughout the Southeast impacts each other.

As part of those studies, enhancements were identified to support nuclear expansion, and those transmission expansions are actually being budgeted and planned, as referenced in one of my previous slides, that Vogtle-Thompson line.

SERC also did, started in 2008, I think recently completed a long-term reliability assessment, and that was related to nuclear expansion in the Southeast, looking at the transfer capabilities that might be in existence after the nuclear plants come online. So there was an additional study that was done recently on top of the joint studies that were conducted amongst the TOs.

Additionally, the 2006 DOE Congestion Study talked about Southern-Florida interface limits. In particular, since study was that done and really during, I guess, during the process of the '06 study, studies were being conducted between the southern Southeastern region and also the Florida utilities, and studies were conducted to expand the interface above the 3,600 megawatts. Several alternatives for doing that were identified. And a recent study has provided a means to expand the interface up to 5,100 megawatts.

Additionally, there has been transmission service offerings made to customers who are looking at the economics of providing service between the two areas, but a viable request or a viable commitment has not yet been confirmed.

Current and future coordination activities, specifically in regard to that, one of the things I wanted to leave with you all, is the bottom-up process. There's a lot of ways you can look at transmission planning. You can look at it from maybe the generation -out, but we prefer to look at it from the bottom-up process and maybe ask all of you to kind of consider that as a viable option going forward, because what it does is it brings the load-serving entities load growth and resource decisions that they're making over time. You know, they're doing that economic analysis to see where they're going to go for that next resource or replacement of existing resource. So we feel like that brings, let's say, more real batting to the process as far as their future direction for where they're going for resources.

Additionally, as far as another aspect we fold into our process is the transmission service obligations that exist. So we take the load-serving entities, load growth, like I said, transmission service obligation, and we develop a transmission expansion model that will satisfy both of those long-term needs. Then we coordinate, and during, we coordinate that with neighbor transmission owners in the planning process to identify optimal solutions. And that's through reliability coordination agreements, that's through regional planning processes such as the Southeastern region, and it's also through relationships that are built through some of these inter-regional planning processes that we've been talking about for the last couple of days.

And additionally, there's NERC and SERC reliability assessments that take place on an annual basis to make sure that all those plans are simultaneously feasible and we're making the best, I guess, we're developing the best solutions for the system and the customers that use it.

And finally, a couple of slides just about Southern Company's clean energy programs I'd like to leave you with. Specifically, Southern has well established demand side programs. We're looking at expanding that and building supporting infrastructure in relationship to that. Specifically, we installed our 1 millionth SmartMeter in February of this year, and we're looking at putting in 4.4 million by 2012. We're also pursuing a balanced portfolio of renewable and low-carbon options -- with regard to that, we have a substantial amount of existing hydro and pump storage, so that's going to definitely play into that particular solution that we're looking at. Additionally, we are ramping up our efforts as far as trying to integrate, looking for biomass solutions, specifically there. We got recent Public Service Commission approval for a conversion of an existing coal unit in South Georgia to biomass. The unit will be converted by 2012, and have the capability of approximately 96 megawatts once the conversion process is completed.

We are also looking at re-powering some of the other existing units that are out on the system to biomass at several other sites. And not up there, there has been, on the slide itself, there has been a lot of activity from the landfill gas side, too, as well. There are a lot of developers looking at developing that resource to supplement some of the Clean Energy programs out there as well.

In addition, there are solar activities that solar companies are looking at as well. We have solar PV demonstration projects in both Georgia and Alabama, solar augmented steam cycle study with EPRI. We also have demand-side solar water heating that we're looking at as well.

Then regard to wind, we are also looking at offshore wind and wind imports to be evaluated for competitors, so we're looking at that as well. Existing transmission capabilities for modest levels of imports today, especially during the off-peak hours, and that is kind of represented by the slide that I showed earlier. If you think about, I guess, the wind duration and the wind availability and relationship, what I showed earlier was kind of a summer peak in a 3:00 or 4:00 hour TTCs are out there for the Southeastern region and, of course, we would have quite a bit more of transfer capability in off-peak hours when the wind will be coming in.

Additionally, one of the Clean Energy programs we're moving forward with is, of course, the nuclear expansion at Plant Vogtle for Vogtle 3 and 4, which is 2016 and 2017 timeframe, which recently had some regulatory approval in Georgia as well. So that's going well down the path.

Additionally, I was actually asked about yesterday is for the proposed projects we're looking at is an IGCC plant, which is Integrated Coal Gasification, which has a 50% carbon capture rate, and that's being developed in Mississippi, and that's a pretty sizable unit, about 600 megawatts delivered.

Additionally, what I want to leave you with is Transmission Expansion plan is planned to accommodate the output of all of these resources without congestion. So as below seven entities point at these for future resources, we're folding those into our transmission plans, and we're developing a plan that budgets and builds transmission infrastructures to support those resources in the future.

Here is kind of a busy slide, but I think it kind of -- I like it, so I got it from some of the Clean Energy program guys. Plus, I didn't have to make it, so that's even better. But what it does is it paints the picture for you of all the different Clean Energy programs that Southern Company is looking at within the footprint, both completed, in progress, and under development. There's a lot of work being done out there, and there will continue to be a lot of work done in the future.

That's all I have.

David Meyer: Thank you, Ron, and we especially appreciate your -- yeah. We especially appreciate your fortitude being here when your voice isn't all that you would like it to be.

Our next speaker is David Till from the Tennessee Valley Authority. He is the Transmission Planning Manager for TVA, and he has served 29 years in various transmission planning and operations and maintenance roles but also with particular attention to nuclear engineering issues. David.

David Till: Thank you, David, and thank you, DOE, for allowing me to participate in this panel. I just wanted to give you a brief reintroduction to TVA and then make a few comments. You see TVA's interconnections. You see, also, that -- TVA and the Central Public Power Partners, which we formed in response to FERC 890 is the purple area on this particular slide, and it's very central to the Eastern Interconnection.

Our partners in this are Big Rivers, East Kentucky, and AECI. We formed the central region and as Ron has referred to the Southeastern Region we perform coordinated planning, regional planning within this area.

We made the decision early to not limit the number of economic studies that we would do for our stakeholders until those studies got in the way of our reliability studies, and that hasn't occurred yet. However, we find that the stakeholders' interests are best served by screening studies when they are only concerned with the region, and if we need to do an inter-regional study, then we participate in the Southeastern Inter-Regional Planning Process, have also participated in the Joint Coordinated System Plan Wind study. We have committed to our stakeholders that we'll perform detailed studies within the agreements that we have with our larger inter-regional neighbors.

In addition to the Southeastern Inter-Regional Planning Process, which Ron has just explained, and a Joint Coordinated System Plan Study that John Lawhorn explained earlier, we are doing EHV overlay studies with our neighbors. The purpose and methodology of the SIRPP and the JCPS are much different, as you had explained to you, the results from each of those studies are that we know more about the larger Eastern Interconnection than we knew before those studies.

My conclusion from those studies is that we have a great group of planners in the Eastern Interconnection, and they will jump in and study anything that we want them to study. They will do it without an agenda, they will look at the assumptions that they are given. Most times, they will look at those assumptions and say, "Well, those aren't exactly the assumptions that I would have made had I been doing this alone, but the reasonable assumptions, let's jump in and study these."

The studies themselves, and the information that's gained about the Eastern Interconnection is incomplete, though, when these studies are finished. Let me go back to my operations and maintenance days for a moment, if you'll allow me to. We focus and we, as a larger company, focus on this, with a larger industry focus on this, although it's more emphasized in the operations and maintenance world. We focus on safety, we focus on reliability, we focus on competitive cost and, in today's environment, we focus on compliance. And everything that we do is performed under the over-arching umbrella of those four considerations.

And as history has occurred, we've done what we knew to do under that umbrella, and then we've added to it as we needed to in order to get better as companies, as an industry. So -- these studies really haven't performed their function until they're placed in the hands of leaders and then the study results filter through the minds of leaders, and those leaders act on them and Eastern Interconnection, or individual company and the Eastern Interconnection, improve as a result of that process.

I want to report to you that I believe these studies have each had good impact. The third bullet on this page, the EHV Overlay Joint Studies that we're doing today result from the JCSP, they result from some of the SIRPP, and TVA is looking both internally and with neighbors at which pieces of the EHV Overlay we can start to build. I trust that's occurring in other companies also.

For us to go forward, that leadership, those leaders within our interconnection need to get together and form a joint plan that results from these studies. I think we're headed in that direction, I think that this is an exciting time for the Eastern Interconnection and the industry, and I am very optimistic about where we're going.

That, I think, is all I can add to what these fine gentlemen have said. Thank you.

David Meyer: Well, thank you, David. I want, first, to see if the panelists have questions or rejoinders that they want to make to the -- in reaction to each other's presentations. So I'll see if people have additional comments they want to offer.

John Buechler: This is John Buechler. This may require a warm-up. Sorry about that -- I guess just an observation I have, and I made a few comments when I gave the presentation, I've heard a lot of commonality here even as between the East and the West, the anecdotal comments are always at the East and the West are the difference. But at least in terms of process, I have heard significant support from this panel and from others and from the West and the East for, I guess, what David and Ron called a "bottom-up" process. We support that as well in New York for the reasons that they have stated as well. I heard that yesterday from a gentleman from the West as well. So that's at least a common thread that I've observed throughout this meeting so far.

David Meyer: Any other -- let me then pose a question to the panel. As you know, this Administration -- and I have to emphasize I'm speaking for myself, I'm not an official spokesman on behalf of the Administration, but it's -- I think it's reasonable to say that this Administration has a very strong commitment to renewables development to reducing carbon emissions, to using the electricity sector as in production from the electricity sector as a way of displacing petroleum fuels from the transportation sector. And to achieve those broad objectives, I think there is a strong recognition that we need robust transmission networks in all interconnections.

And so with those kinds of things in mind, then I want to ask the panelists -- suppose someone -- one of our major leaders, whether the Secretary of Energy or the President or somebody said -- asked you, "How quickly can you folks in the Eastern Interconnection come up with an interconnection-wide transmission expansion plan? How long would it take and what kinds of caveats would you want to add to the plan?"

And I recognize, for the first time around, you might want to call it an "interim" plan. Now, just give me your thoughts on how long it would take to get at least an interim product and what caveats would you attach?

John Lawhorn: This is John Lawhorn, and I guess I'll start with that question. That is a very important question, and it's very difficult to answer. If you've got the organization in place to conduct those types of analyses, they can be done within six to nine months. It would take a lot of work, but it certainly could be doable within that timeframe, leveraging off the existing studies and the existing knowledge base.

The key there is getting the study group in place, and that's a paramount need is getting it established. The actual work process can be done fairly expeditiously. I think the joint coordinated system and planning process showed that we can do that type of analysis over a large region and provide results. It's getting the -- additionally getting the assumption sets, getting the different scenarios that are important to the Administration to look at. That is really what's going to drive the transmission overlay, is the assumption set -- what are we going to study and can we get some help in defining what that is?

John Buechler: I hope we get more than the 60 days that someone referred to yesterday to come up with this plan. I would agree with John that, you know, such an undertaking is significant even leveraging off existing work that's been done that we talked about here today, I think a year would be aggressive, frankly. But I'd like to go back to some other comments that were made during the course of this meeting, and that is I think, David, you posed a question, you know, we just got a directive to come up with a plan. I think someone mentioned yesterday, you know, we need to know what our objectives are.

There are a lot of good planners, excellent planners with years of experience throughout the country, and they can do -- as someone said today, they can plan anything but you need to know what the objective is, so I think that's a role of government and of Congress and the legislature and so forth, is to provide that direction because we can study anything, and I'm not sure that an un-focused study is something that's of any particular use to anyone for decision-making purposes.

Certainly, as John mentioned earlier and others have mentioned, we obviously need to get the assumptions together but, you know, that would be common to doing any kind of transmission or planning analysis. You certainly need to do that, and then you certainly need to address a multitude of scenarios to make sure you have, I guess, what's commonly termed as a robust plan, which would provide a reasonable basis for a policy decision and determinations that had to move forward.

Ron Carlsen: This is Ron Carlsen with Southern Company. As far as, I guess, David's question -- I would ask you to consider that we do have an Eastern Interconnect Transmission Expansion Plan. You know, I had a slide -- just kind of dovetailing on what John just said to me, New York ISO, is we do have a bottom-up process. Our load-serving entities and transmission customers are making decisions based on economics every day. They're submitting long-term service requests, they're going out and doing RFPs, request for proposals, for future resources, they're looking at self-developing resources, they're looking at, you know, the potential of legislation that will require renewables.

And as you can see from the slide that I had, you know, within the Southern control area, as far as Clean Energy programs, you know, there are other Clean Energy programs out there besides wind. There's considerations I've seen from some of the draft legislation talking about some of that RPS could be met through demand-side programs. If you're meeting part of that through demand-side programs, do you need 20% wind, or whatever percentage is mandated.

And if you have, let's say, biomass opportunities within your control area, if you have landfill gas opportunities within your control area, if you have limited wind within your control area, you know, whether it be offshore or what have you, like the Southern control area has, there is all, you know, that say go into that 20% renewable portfolio standard requirement if that's what it is.

So -- you know, it’s as John just mentioned, I guess both Johns just mentioned, there needs to be a lot of consideration into what needs to be studied. If the question is what would it take to come up with an Eastern Interconnect Transmission Expansion Plan, I’d say that's what we have today based on our load-serving entities of input for future resource and loads.

If you're asking, you know, what other scenarios do you want to study and how much time that would take, I agree with, I guess, John and John again. You know, you need to allot an appropriate amount of time to study whatever scenarios are being requested.

Thank you.

David Till: David Till with TVA. I think that we have the leadership in place to get an organization to have an interconnection-wide plan and perform studies within the six to nine months that's been mentioned. I think that we need the disclaimer that we can come up with a plan, but the stakeholders are so diverse that we need to satisfy them. The state agendas versus the federal agenda, the local resources versus distant resources, there are so many aspects to this that we need to keep in mind the limitations of engineering and we need to have the disclaimer that the plan that we come up with needs to be fully vetted so that we don't stick a beta max plan in front of the faces of people that want a VHS product. So -- thank you.

David Meyer: I am going to turn next to Joe Eto for some questions, because Joe has to catch a plane in a few minutes, and I want to give him an opportunity before he has to leave. Turn the mike on, please.

Joe Eto: Hello? This is Joe Eto. I have just a few clarifying questions for a couple of the panelists. Yesterday, Steve Herling talked about some of the most congested lines -- or the amount of congestion within the PJM footprint and how four lines would essentially eliminate 80% to 90% of that congestion.

John, I thought, John Buechler, I thought it was very heartening that your own internal work using different types of metrics were coming up with the same types of lines or areas that the OATI had found in terms of historic congestion -- that just a few of those lines represent, I think you said, 87% of the congestion according to your metric. Can you tell me if there are plans in place to address that congestion, and at what point would they either eliminate or change or how much relief in that congestion would those plans have?

John Buechler: We've had several proposals that would address some of those facilities, at least Pleasant Valley, in particular, as part of our West -- several reliability planning cycles. Since, as I think I mentioned earlier, we've had those proposals were submitted by transmission owners since we had not had to move to a backstop type of process, we have not needed to evoke those for reliability.

Our economic planning process, I think I probably failed to mention in the schedule, we are just beginning that process, it will be kicking off in June of this year, by the metrics or by the methodology that I mentioned in terms of selecting the elements or the areas to be studied. We will most likely be picking off elements. Again, we'll be looking at projections as well, but I would suspect that the three that were on the top of the list here today are going to be good candidates for that analysis. So that's where we are right now. That's the best answer I can give you.

Joe Eto: Do you expect those lines to persist in terms of your ranking and the magnitude or significance of the congestion that they represent within your footprint?

John Buechler: Given, in particular, the increased amounts of wind that we are experiencing, not just may be experiencing, and the locations of that, as I mentioned, the SBS.

Joe Eto: Thank you. I have another clarifying question for you, Ron, and also David. It's a matter of terminology -- both of you describe connecting economic studies in response to stakeholder requests and, at least, Ron, in your case I've reviewed some of those studies, and they focus on the economic cost of the transmission upgrades associated with – you know, allowing that amount of import capability to take place.

Do either of your sets of studies also look at production cost impacts as a result of that construction within the region?

Ron Carlsen: This is Ron Carlsen, again, with Southern Company. The studies, as it relates to the Southeastern process in the South, that's the Regional Planning Process in the Southeast Inter-Regional Planning Process do not look at production costs. Early on, we talked through those types of issues, and we found that the stakeholders, they're the ones with the market dollars, they're the ones out there procuring resources, and they're the load-serving entities, they're the power marketers, they're the generation developers. They have the knowledge to do that type of analysis, so that's -- so we limit ourselves to the transmission side so we can give the -- let's say the transmission threshold as far as pricing related to transmission upgrades so that they can make their decision.

The bulk process is -- you know, they'll take the transmission information and put it in whatever kind of models, and they can then make their economic decisions -- not based on our, I guess, production cost assumptions but based on what their knowledge of the market is.

Joe Eto: Is that also true for TVA studies then, David?

David Till: That's true for TVA right now. We have not conducted any that took that into consideration. However, one of the difficulties in justifying projects is the lack of sophistication that we all experience in gathering benefits from a project, and, too often, we see a project that everybody that looks at it thinks this is a no-brainer, this should be done, and yet we can't get onto paper the benefits that justify it. So we're constantly looking for more sophistication in capturing the benefits, and this is one of the areas that we've talked about but we don't -- we haven't really captured enough to do anything with it.

Joe Eto: All right, thank you.

Alison Silverstein: This is Alison Silverstein. Joe Eto is too modest to mention it, but Lawrence Berkeley Laboratories and The Search Project have done some excellent work on benefits identification for the California Energy Commission, and you might want to talk to him offline about getting some of that.

David Till: We spoke last night, and he mentioned that. I've noted that.

Alison Silverstein: A question about the broad process within the Eastern Interconnection -- I gather that some of JCSP is going to be going on, and I want to ask -- I want to get sort of confirmation on the record of whether that's going to happen and whether all the players i the East are committed to participate. Starting with you, John, is this going to happen?

John Lawhorn: Yes, it will happen. The players are talking at the CEO level working out scope and -- are trying to work out scope. So in some form or fashion, this has to happen through the introduction of the Reid and Bingaman bills, you look, both of those bills have the provision for an Eastern Interconnection planner. If it's not some of JCSP, then it's going to be some other entity. So there's a lot of movement toward getting the original participants of the JCSP back together to formulate that process.

Alison Silverstein: Thank you. Following up on Joe's question to Ron and David -- I just want to understand who is looking at that Order 890, and then looking at what you all are doing in the South. Who is doing the planning? And does the entity doing the planning meet the FERC requirements for an independent analytical entity?

Ron Carlsen: We do the planning as far as the TOs that sponsor the -- both planning processes that relates to Southern Company do the planning associated with 890 requirements.

Alison Silverstein: Okay, and what's in the queues in the South in terms of generation, in terms of magnitude, megawatts, technologies, and who is asking for stuff? How big are the lines?

Ron Carlsen: All of the -- I guess the information you're referring to related to Southern Company, you know, speaking on behalf of any of the other TOs, you know, it's publicly available through our OASIS site, so you can go see it there.

Right now I'd say there is probably a very modest amount of transmission from our generation interconnection is being requested, and from what I recall, most of it is probably CT or CC type based resources, gas-fired resources. A lot of the -- there is a growing number of requests that we've gotten over the last year or two looking at the development of the biomass type resources and also the landfill gas resources. So we are seeing those -- you know, as far as a percentage-wise pickup where maybe five years ago they were somewhat nonexistent, but over the last couple of years, they're probably making up maybe 25% to 50% of the requests that we're getting.

But, again, due to -- I guess – the market, the economy and all that -- generation interconnection requests are somewhat down.

Alison Silverstein: Thank you. David, in TVA area?

David Till: The interconnection requests are almost exclusively for new TVA generation to meet new TVA load or designated network resources to meet TVA load. We have had some increase recently in transmission service request activity, and within the economic studies that give somebody the information they need to know whether it would be a good business decision to transmit across this, we have only had a handful of requests for that information.

Alison Silverstein: And do you expect your recent renewable RFP to change that outcome?

David Till: Am I allowed to say I don't know because I do not know.

Alison Silverstein: Yes. Okay.

Ron Carlsen: One follow-up that I would say is -- your first question regards 890, and the Regional Planning Process, both regionally and inter-regional, I think has afforded the generation developers and the stakeholders for the region a venue outside of, let's say, tariff generation, interconnection requests, and also transmission service requests to get answers. So that might also play into what we're seeing as far as lower numbers. They're getting that type of information through those regional planning processes instead of going directly to the interconnection queue or transmission service queue.

So I would think, you know, maybe long-term, as those processes begin to mature, maybe in some of the requests that we see in our queues for being more real than just speculative requests just to see what the impacts of our interconnecting generator or asking for a particular type of transmission service.

Alison Silverstein: Thank you. Two more questions, if I may. One of them goes back to Joe's question about what constitutes your economic study, and I want to look to go back to a point that was made by some of the WECC commenters that we have studies of transmission in the Western resources, but we don't have plans.

It sounds like you have studies but only TVA has a plan, and Southern has a plan, because if you're not going economic impact analyses how do all those other stakeholders, or TOs, say "Here is my plan." I mean, who says, "This is what we're going to do?" or makes the leap from having enough information to make a decision about transmission commitments?

Ron Carlsen: Just stop me if I'm going offtrack, because I want to make sure I answer your question, but that's the whole intent behind the 890 process that we have. And 890, you know, did not turn on something that was not already there. It just, I guess, made it more visible. Those reliability coordination agreements have been in place way back before I was probably even thought of by my parents. So there's been a lot of interaction over the years, there will continue to be a lot of interaction.

All those plans, as far as what Southern is doing is developing their expansion plan, which, you know, there's no congestion associated with that, and that's making sure -- that was the only thing, you know, we talked about how the RTOs and ISOs, you know, shared some of the congestion points they had up there, but inside the Southern control area, inside the Southeastern region, we've been planning to ensure that all resources are available to be delivered to load -- all firm resources as are being designated by the load-serving entities that are pointing at those resources.

Then we also make sure that all the firm commitments are available – you know, 8760. So our plans are to eliminate the congestion within the region. Now, as it relates to my plan to TVA's plan or the other processes, we have those reliability coordination agreements and our activities at SERC and our activities through the inter-regional planning process that brings all that up to more the macro level, layer by layer, to make sure that what we're doing doesn't necessarily negatively impact what David and TVA are doing, or the VACAR companies.

So as we identify, let's say, if a solution that Southern has causes a prime on TVA, we identify that, and we coordinate back and forth, and we develop an optimal solution. Then we keep taking that up a layer until the -- let's say, the Southeastern Regional Planning Process has the best plan for that inter-regional period. If that happens through SERC, that also happens through NERC, you know, as far as ERAG and MMWG process, so all of that, there is not -- you know, a lot of people talk about this disconnect, you know, there's a fence there, and we're not doing it -- that fence is -- is it nonexistent?

I mean, there is a lot of activities that take place back and forth, and now we have these big venues for economic studies to be done on a regional level, and an inter-regional level, and even at the inter-regional level, which you was a pretty expansive footprint. There's coordination activities happen in the Southeast in a recent planning process -- PJM, MISO, SPP -- well, we're getting the input from them as far as what resources are being used for these transfers. In the event that a transmission enhance is needed, where there's coordination that's going to take place to make sure the most optimal solution is identified through those economic studies.

But, yet, again, they're economic studies, so they're speculative. They're not the decisions that the load-serving entities are making within the inter-regional area and the regional area based on their economic needs.

Alison Silverstein: David, did you want to add something?

David Till: Yes, this is David Till. I'm somewhat excited to tell you that our answer is changing on that. Through the stakeholder input that we've had, so far, through, really, I should say the stakeholder interaction. TVA announces what our preliminary expansion plan would be and together we determine what the final expansion plan is going to be.

Now, I want to emphasize a word that Ron used as the process matures. We haven't had a great deal of stakeholder input to say, "Well, we'd like to see this change into this or that or the other," but we're open to it. And a big part of 890 is not just the economic planning but opening up our historical reliability planning -- and I hate to use those terms because reliability planning has economics in it, of course. But we're excited about the interaction with the stakeholders to jointly determine that we've got the best plan to go forward with within our footprint.

Beyond that, we're looking at the benefits that we could gain from partnering with peer utilities and putting some of the JCSP lines in place. I don't know how that will turn out, we're on the front end of that. I don't want to mislead you in any way with this statement, but in looking only at the TVA system between 500kV and 765kV AC, we don't have a need for 765 in our system unless the larger look says it's the best thing to do. And we're initiating that larger look.

So my answer is that has changed somewhat -- the answer to your question -- and it's still in a state of change.

Alison Silverstein: Thank you. This is Alison with one last -- I don't know if this is a question or a test of what I'm hearing you all say -- one of the common comments that DOE has received to the 2006 Study and people who are fretting about the 2009 Congestion Study is not all congestion is a problem that needs to be solved. And although our friends in PJM have observed that where you see economic congestion it is often a precursor to future reliability problems, and that sounds like kind of what you were saying in New York, John.

My question -- it sounds like Southern, in particular, is driven by a different philosophy, which is if there is -- there is not, by God, going to be firm congestion -- congestion for firm flows in Southern. You are going to go out and build in advance of that to prevent that.

So -- whereas everybody else says some congestion isn't worth fixing, you all are saying if it's firm, and if we've got loads that wants it, and it's in network resources, we are going to build to prevent congestion in advance of a problem. Is that correct?

Ron Carlsen: That is correct.

Alison Silverstein: Okay, thank you.

David Meyer: Questions from the floor?

Jagjit Singh: Jagjit Singh with OATI. I have a question in terms of short-term plan, which is the generation that's in the queue versus a long-term plan, and it seems like, at least in the Midwest ISO case, John mentioned that there is a large amount of generation in the queue that needs to be addressed in the short-term, three- to five-year time period.

So my question is twofold, actually -- one, how does this long-term plan you have changes the amount of generation in your footprint? And the other is looking at the current economic conditions, you probably are not going to see the kind of load growth that you may have assumed a while ago. So does -- the real question is how do you take the short-term plan and merge it for the long term to gain the benefit over the long term period? And the other one is, if you solve the short-term problem, are you really solving the long-term problem as well because of the size of generation in the queue?

John Lawhorn: This is John Lawhorn, Midwest ISO. That was the crux of my presentation -- was to be able to understand what the long-term issues are so that you can define the space that you have to work with so that when you develop the short-term transmission, which are mainly upgrade-driven because -- especially for the wind-related queue, there is an existing transmission in many of those areas. So you're doing system upgrades to hook up as many of those megawatts as you possibly can.

You have to build transmission. I mean, that's the solution, you have to build transmission that meets that goal, and that transmission needs to be considered and thoughtful within the broader scope of what needs to be done on the longer-term solution.

So -- issues that we have to identify up front are, you know, we have this debate, 345 or 765. Most of the transmission in the Midwest ISO is 345kV, and the next incremental -- the least-cost incremental transmission line is always going to be a 345kV line for that particular project. But when you look at the sum total of 22,000 megawatts of capacity being needed, 765 could very well be the best overall solution, and it provides that steppingstone to the even larger 20-year out solution -- the transmission overlay.

It also saves valuable transmission corridor, and that's something that the East and the West are very concerned of, is that if you build 345 lines, you're going to need five of those for the same footprint that you would for 765kV line.

So -- you need to consider your short-term needs in conjunction with the long-term aspects and make that overall plan meet both of the objectives. Now, the Midwest ISO, we don't have -- we don't own transmission, we operate transmission, but we don't own it, and we can't compel, at this point in time, say that you'll go out and build it. So we're providing information to our stakeholders, to the transmission owners, to the transmission developers with what we think are some of the best solutions. That, in conjunction with the cost allocation initiatives are going on will provide, I think, the suitable framework for that transmission to get built.

David Meyer: I see we still have questions from the floor, but I have to tell you that we are on a fixed schedule here because of the webcast, and so we need to close this panel and then reassemble here in 15 minutes for the windup. But please join me in congratulating the panelists for a great discussion.

[applause]

During this last session, I'm going to say a few words about the Congestion Study, the upcoming Congestion Study, and then respond to any questions that you have. Can we have the next slide, please. Oh, I'm sorry, I'll take care of that.

[laughter]

Once again, the law that we're operating under here, the Energy Policy Act of 2005, directs DOE to conduct a national congestion study every three years, and then after receiving public comments on the study, and digesting other information that may become available that's pertinent, is the Secretary may designate National Interest Electric Transmission Corridors, but he is not required to do so, and we did designate two corridors in October 2007, but as yet no decisions have been made about possible future corridors, and we -- essentially, we simply are not at that stage here. We are doing a congestion study, and that is the focus of the discussion today.

Our process involved six public workshops in many cities across the country. We have also received quite a number of extensive public comments. All of those comments have been posted on our website where you may review them, if you wish. The results of this workshop will be posted on the website as well, and we expect to publish the final report in August of 2009.

The 2006 Study relied on a three-level classification of congestion areas. We feel this classification system worked pretty well for us. At the moment, we see no reason not to use it again, so brainstorms may happen but, still, we expect to use this approach again; that is, in 2006 we identified “critical congestion areas” and what we called "congestion areas of concern," and then, finally, “conditional areas” where congestion would result if generation were developed on a large scale without associated transmission capacity.

So the 2009 Study will review -- we'll go back and take a look at those areas that we designated in -- or identified in 2006, and we'll, in effect, try to bring people up -- bring the reader up to date on what has happened in those areas that is especially relevant to the question of transmission congestion. We may, in the course of our review, identify some of these areas may drop off the list, in effect, and other new areas may come onto the list.

So the scope of the reviews that we anticipate for these areas are -- the scope is broad. We will be looking at load-side developments in terms of load growth or in terms of efficiency and demand response programs that have been put in place or are planned to be put in place. We will look at generation or at least on the load side in terms of distributed generation. We will take into account the status of major transmission projects, and we will look at the findings from transmission planning studies that are pertinent to the particular areas.

And, finally, we will take into account generation plans; that is, announced plans and cancellations, retirements, and state and federal policies that might affect generation development decisions.

So the likely content for the 2009 Study -- and I don't mean that we would necessarily follow the sequence of things presented here, but we would take all of these things into account in one way or another; that is, in terms of the "critical areas and the "areas of concern," we have noted many positive actions of one sort of another that will tend to alleviate transmission congestion problems. I would say, however, that in many of these areas, little new transmission has been added although much transmission is now planned or in -- some of it approved but not yet built or projects are in the process being discussed.

For the "conditional areas," obviously, the concern now today is most intense with respect to renewables, but the question is also relevant for new nuclear projects, and we are very pleased that insofar as we know in those areas where new nuclear plants are being considered, there is very active attention to transmission requirements. The continuing cancellation of coal plants is a concern that we will need to take into account as we look at these areas.

I want to emphasize that the Congestion Study is not seen as a planning process; that is, planning is going on through some of the different institutions and organizations that have been talked about today, and that's exactly what should be happening. We will comment or refer to those processes as needed, but certainly the congestion study is not intended, in any way, to modify or interfere with those efforts.

Also, the Recovery Act just passed includes some requirements to DOE concerning material that we are to address in the new study; that is, it directs us to consider transmission obstacles to the development of renewables and obstacles to the development of the transmission. And it even has a reference in there about requiring us to look at, consider, study, litigation in particular various cases across the country. The question is, is litigation surfacing as a significant impediment to the development of needed transmission projects.

So -- in terms of differences between the 2006 Study and the 2009 Study, the historic analyses, East and West, I think are quite similar in that in both cases, 2006 and 2009, we will take a close look at historical data with respect to congestion. It is somewhat more tightly focused, I think, in this time around; that is, we have made a more serious effort to -- at least in some parts of the country -- to develop and apply transmission metrics in a very systematic way.

The prospective part of the work -- there are some differences in that in the 2006 Study, certainly for the East, we employed a consultant, CRA International, that prepared interconnection-wide projections for us for the years 2008 and 2011, and this time -- for this 2009 Study, we elected not to undertake our own projections but to give more specific attention to the projections prepared by others at the RTO level and the ISO level or the state level or even the corporate level. So that's one significant difference, but I don't -- arguably, it may not affect the overall results, in a sense.

For the West, we are relying considerably on projections work being done by TEPPC, and we look forward to the value that that work will add to the discussion.

So -- in conclusion, the 2009 Study will be based on an extensive and public consultative process. It will draw on a wide variety of information. The factors affecting congestion in the three classes -- areas -- will be reviewed. We may find new areas of concern to focus on.

So, with that, I think I'll stop and see what questions you folks may have about the Study -- particular questions that come to mind.

Mike Henderson: Thank you, Mike Henderson, ISO New England. As part of this process and considerations, could you discuss the effect of Canadian resources and how you think they could affect this overall process? As you may be aware, just in the Eastern provinces alone, they're looking at over 13,000 megawatts of hydro and considerable wind development as well.

David Meyer: Sure. Well, in the -- I have to be honest, in terms of the historical analysis, we have not sought to deal with historical congestion in Canada. But certainly for any of the forecasting work that, looking ahead, we think it's very important to take Canadian plans and expectations into account in terms of -- well, it goes back to the fundamentals that these systems are international systems, they are planned as if the border did not exist, and they are operated as if the border did not exist.

So -- certainly, for the work that TEPPC has done. I'm pleased that the Canadian provinces in the West have been active participants in that work, and when we draw on existing projections prepared by, say, the New York ISO or ISO New England, our standing assumption is that the Canadian input there is taken into account so that we think that is an essential part of the analysis.

Yes, Steve?

Steve Naumann: Steve Naumann, Exelon. Just a comment -- I know this is a difficult job for DOE and the people putting the report together, but I guess I'd like to raise a note of caution -- maybe that's not the right word -- the existing studies that you would be looking at are, by their very nature, very limited and considered a rather limited number of scenarios. And it would be unfortunate if large-scale recommendations were made without recognizing that fact. The JCSP was a great leap forward in trying to put something together, but it did consider very, very few scenarios.

And the second part is, none of these actually looked at what I would call the delivered cost economics when you take into account the cost of building the transmission lines and understand that you have higher quality wind out of the Dakotas but if you look at lines that are less long and lesser quality wind, you could end up with the same result for a lower delivered cost -- not try to prejudge the study but just try to say there really is a limited amount of work out there.

David Meyer: Yes, yes, absolutely. You've touched on a point that I alluded to before, but I'll expand on it a little bit; that is, we recognize that there is a lot of important forward-looking analysis to be done in both interconnection. We need to do a broad range of scenarios and identify that core set of transmission facilities that are needed or will be needed under a wide range of possible futures, and we recognize that the congestion study isn't the vehicle to try to deal with those kinds of challenges. Those things need to be dealt with through other vehicles and that's why we are talking with people in both interconnections about establishing and supporting interconnection-wide planning entities, interconnection-wide planning efforts, and we want that work to go forward, and we aren't expecting that the congestion study can carry that kind of load.

It can be supportive, it can contribute, it can underscore the importance of that other work to be done, but it's not a substitute for it in its own right.

Any other questions?

Brad Nickell: Brad Nickell with WECC -- a question, David -- are there things in -- as you guys get prepared to put the 2009 study together, are there things that we can start thinking about now as far as preparation of materials that will help you expedite that process?

David Meyer: Yes, Alison has a comment she wants to make here, so I will give her the floor.

Alison Silverstein: Yes, thank you. This is actually a question for all of you -- one of the things last time when we were putting together all of the material on individual areas of concern and critical congestion areas -- we pulled together a lot of information from a lot of different sources, and many of you, when writing back to the department, were complaining you didn't like this source or you didn't like that source, and yet you all hadn't been a whole lot of help in terms of providing the material on which we were basing those calls on the data.

Therefore, let me ask you this question -- if the Department were to come back to each of the areas of concern in the critical congestion areas that were identified in the 2006 Study and say here is a shopping list of specific data that we need just before to doublecheck. We already have collected exhaustive materials and numbers that, of course, don't match because, God forbid, you all do consistent analyses from study to study or source to source, but if there is a -- the question is this -- is there a responsibility party for each of these areas that could stand up and say in our judgment, here are the best numbers to use for each of these things like incremental energy efficiency since 2006, incremental demand response; what is the new -- not the transmission that you wish was online, but the transmission that actually came online in the last three years and so on and so forth, and provide very specific references and cites to each of those -- to back up each of those numbers. Is that a role that you all would be willing play and by you all, I mean very generically, because, John, I think -- you're nodding, so that means New York is in. Is the ISO -- Diane, is the DPS going to trust the ISO to submit that material?

Diane Barney: We talk with them on a regular basis.

Alison Silverstein: Good answer. Okay, is there someone here from -- can you guys in WECC help me find someone in California? Do I go to the CEC or do we go to the PUC or to the ISO? Who does that job? Southern California -- who can do this, I guess, Rob, are you our contact for -- here you are -- are you our contact for the SWAT area?

Rob Kondziolka: Correct.

Alison Silverstein: And is there anyone other than SWAT who is going to get their nose out of joint if you all are the designated spokespeople and data wranglers? People behind you are saying, "Yeah, make it his fault," okay?

Seattle/Portland? Someone from -- who would we use for that BPA?

Unidentified Participant: [inaudible]

Alison Silverstein: Okay, I've already got your report, but I'll be getting your card to go with that. Okay, we're on a roll -- David's happy, I'm happy, you're happy -- she's really happy, she's doing a lot of the research.

David Meyer: Mike is volunteering something here.

Mike Henderson: I am the contact there.

Alison Silverstein: Okay, so you're the area of concern? Okay. I think that's everybody.

Doug Larson: Can I ask a question then? We had some concerns in the West last time when the analysis the West gave to DOE. It didn't seem to have much effect on the designation of NIETCs, and we're wondering maybe you could put out a draft, which would show how you're interpreting the data that's being provided, and then people could respond to that saying, "We think you got us wrong?" Dave?

David Meyer: Well, you're getting into the corridor of designation part of the process, and at this point I can say we don't know whether there will be additional national corridors.

Doug Larson: Yeah, I was referring to that example, but I'm just wondering in this iteration are we trying to figure out what happened in each of these areas that were previously identified as critical or conditional, et cetera. Would you put that out in draft form?

David Meyer: We will put the Congestion Study out for comment, and we will -- I'm sure we will get a lot of comment, and we will take those comments into account. We will consider them carefully, and what happens thereafter is, at this point, I can't tell you. But we will look forward to comments that we get on the Congestion Study.

Alison Silverstein: I just want to make sure I didn't forget any of the areas. There were six, and I think we got six volunteers, right?

David Meyer: Well, I think we put people on notice that we may be calling them.

Alison Silverstein: We will hunt them down, I just want to get it on the record.

David Meyer: Yes, Rob.

Rob Kondziolka: Good morning, David -- Rob Kondziolka, Salt River Project. Two items -- Alison -- in fact, initially, I can be a contact for the entire West Connect footprint, which would include the Colorado Coordinated and Planning Group and also the Sierra Sub-Regional Planning Group, and so -- and then I'll make certain that the folks who should be included on there are included in any correspondence.

Dave, I want to thank you for your last comment. If you recall, at the initial regional workshop that was held -- I think it was last June or July in San Francisco, one of the requests I had was to have the opportunity to review a draft report and to write comments, realizing by the time you get to that stage, you've got a critical mass already in place on the report. But I do think it is incredibly worthwhile to allow a proof to make certain that even though we may not agree with specific recommendations and conclusions, but we can make sure that it's absolutely certain factual, and that there is no misinterpretations of data and give that opportunity to give you that feedback -- so thank you.

David Meyer: Any last questions? Seeing none, we will declare a victory here and wish you all a safe and happy trip home.

[applause]