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

Rosemont, Illinois
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10:00 a.m.–5:00 p.m. EDT

Transcript

Joe Eto: So my name is Joe Eto, I'm a staff scientist at the Lawrence Berkeley National Laboratory, and I am supporting the Department of Energy in the conduct of assets of the 2009 Congestion Study. On behalf of the Department, I'd like to welcome everyone to the Spring 2009 Technical Workshop in support of the 2009 Congestion Study.

I'm just going to do a few logistic and housekeeping things before we get started, and then I'll introduce David Meyer.

I think one thing I want to make people aware of is that we are broadcasting this over the Web, and so we're going to ask that folks who have questions -- and there will be questions-and-answers after each of the panel sessions -- come to these microphones that are in the center of the room and identify yourself by name so that as the workshop is transcribed and for the folks that are listening on the Web, we know who you are and where your comments are coming from. And I will probably -- the moderators, through each of the panels, will be reminding folks to identify themselves before speaking. So I'd just appreciate that.

As I've mentioned, the workshop will be transcribed, it will be posted on the DOE website, along with all the other materials supporting the 2009 Congestion Study. I believe all the presentations are currently posted on that website as well as the draft reports for the first two panel sessions, which I'll talk more about as I moderate those sessions.

One thing I want folks to be aware of that's not on the published agenda is I want to thank the Western Electric Coordinating Council, PJM Interconnection, Midwest Independent System Operator, and Southwest Power Pool for sponsoring a hosted reception that will take place at 5:00 after the workshop concludes this afternoon. So be sure to catch that. That will be in the atrium, which is down by the stairs where the escalators are -- excuse me -- the elevators are. I hope you'll join us for that for some more informal discussion after the formal session event today.

So those are all the formal remarks I want to make. I wanted to now introduce David Meyer, who is a senior policy advisor for the Department of Energy's Office of Electricity Delivery and Energy Reliability. He is the one who has been leading the 2009 Congestion Study, and he'll make some opening remarks for us.

David Meyer: Thank you, Joe. It's a pleasure to be here to welcome all of you here in this hall and to welcome all of the people on the webcast. We are delighted at the careful attention that you folks are giving to the Congestion Study. I see a lot of familiar faces here and a lot of very talented and expert people. So I appreciate your support.

I want to start off by reviewing for you the responsibilities that the Department has with respect to transmission -- responsibilities that were given to us in the Energy Policy Act of 2005. It directs the Department to conduct a national transmission congestion study every three years. We published the first one in August 2006, and so we are planning to publish this one in August of 2009.

The Act authorizes but does not require the Secretary to designate National Interest Electric Transmission corridors. We designated two corridors in October of '07, and the -- I'll be candid with you that the Administration, so far as I know, has not made up its mind what use, if any, it may make of this tool. It realizes that there are a lot of tools in the toolbox, this is one of them, but they will work through these issues, over time.

The process that we have used with respect to the 2009 Study, we had six public workshops across the country in various cities. Many of you have participated in those workshops. We have also opened a website and encouraged people to provide public comment to the website. Any such comments that we receive are automatically put up there, and we see a total of 38, so far. I expect we'll get some more. And then there's today's workshop -- all leading into the publication of the final report in August.

Within a short period of time, we are going to gather all of the inputs that we have received, start figuring out what we think they mean, what the storyline is, and start preparing the draft final report.

The purposes of this workshop -- Joe will give you more information, but both East and West, we have supported efforts to examine historical flow data for -- particularly for the year 2007, congestion at various levels have been identified on particular lines or paths, but I am sure you understand very well how, from our perspective, all we see is the data. You folks have much more intimate understanding of how the system works and why the system is producing a data pattern that shows up like this.

So it's discussion with you, how to properly understand and interpret this data. That, we think, is one of the most important parts of this discussion.

We will seek comments here and any subsequent comments that you want to make before we prepare the final version of the study, but I encourage you both to get your comments into us quickly because we can't keep the window open indefinitely. At a certain point, we are going to simply have to close the window and commence to prepare the report.

So -- if you have additional comments that you want to submit, please provide them to us at this Web address http://www.congestion09.anl.gov/, and if you have questions that you want to put to me directly, then please -- you can get in touch with me at the points shown here.

So, with that, I will turn things back to Joe, and we'll move on with the program.

Sure, if people have questions, please ask them. It may be a question that would be better answered later, but if there are questions that you would like to raise now, please, let's -- seeing none, we will move ahead with the program.

Joe Eto: Thank you, David. May I ask the panelists for the first session to come to the podium, please.

Okay, this is Joe Eto again, and I am going to be moderating this first panel. This first panel is going to review a study of Historic Congestion in the Western Interconnection. I think, as David mentioned, there is a strong effort in the 2009 Study to base the study findings on empirically observable information about congestion, and so we have -- I mean, I think congestion means a lot of things to a lot of people can measure it different ways. These first two panels are going to be looking at that issue from what the historical data tell us and, in contrast, to future studies, which will be the subject of the latter panels, in which assumptions can be debated. What's observed on the ground is, in some sense, irrefutable in that regard.

So this first panel is focused now on the question of historic congestion in the West. This falls on a long tradition that folks within the West have been pursuing in measuring and assessing congestion. The panel was very proud to field and help co-sponsor the expansion of that data collection this year. It has led to the publication of a draft report, which is posted on the DOE website for the 2009 Congestion Study. It is posted specifically as a draft report because we are still seeking comments on it, and there is contact information both for the Study authors that will be presenting in this panel as well as myself, a senior client on the job.

Again, it's very important that we make sure that the historical record is solid upon which the DOE writes the 2009 Congestion Study and this, of course, is an integral piece of solidifying that basis for the Western part of the U.S.

The way this panel will work is we've invited four speakers to talk on different aspects of the study. I'll have them run through each of their presentations, and then we'll have Q&A directed at the very end.

There is some background noise I'm hearing. Hey, Dean, you're not on yet, so if you can put yourself on mute, that will be great.

So in this first panel, we've put together an integrated series of presentations building around and expanding from this historic study that has been conducted by the Western Electric Coordinating Council's Transmission Expansion Planning and Policy Committee. We're going to lead off with a presentation from Wally Gibson, from the Northwest Power Planning Council talking about the metrics that have been developed, that have been discussed in the West for measuring congestion.

We'll segue from that into a presentation from Dean Perry, who will be speaking to us over the phone. He's not able to travel, but he is the author of the Western study, and he'll present the study findings.

And then because it's very important that we not limit ourselves just to the numerical or tabular information, we've asked two sub-regional area experts to provide some commentary, some color commentary, if you will, on how to interpret and understand the numbers that are coming out of these studies.

So then we're going to invite Kurt Granat from PacifiCorp in the Northwest to talk about how we would understand these finds in the Northwest, and ask Bob Smith from Arizona Public Service to talk about how to understand some of the areas looking from the Southwestern and Eastern portions of the study area.

So, with that, let me introduce the first speaker. Wally Gibson is an economist who has been Manager of System Analysis and Generation for the Northwest Power and

Conservation Council, a four-state resource planning body since its inception in 1981. Prior to that, he was a consultant and worked for the Oregon Public Utility Commissioner. He is active in the WECC where he is chair of the Loads and Resources Subcommittee, which is the subcommittee that is responsible for oversight of WECC resource assessment and resource adequacy guidelines development. He is co-chair of the Technical Advisory Committee of the Transmission Expansion Planning and Policy Committee, that's TEPPC, and a member of the Variable Generation Subcommittee.

He is also active in the Committee on the Regional Electric Power Cooperation, which is CREPC, an association of western state and provincial utility commissions and energy agencies.

He has degrees from Reed College, Yale and Oxford Universities in literature and anthropology. So with those qualifications, please welcome Wally Gibson.

[applause]

Wally Gibson: The anthropology part is particularly useful in understanding of small group dynamics. It is very handy.

What I'm going to do is --sorry -- what I'm going to do is give a brief overview of some of the metrics issues and not talk about -- and then not talk about the details of them but Dean will -- and Kurt and Bob will talk about these further.

Basically, the goal of our studies is the indication of the value of expanding transmission system, so I want to talk about the kinds of congestion you can have, Western rating and scheduling practices, which may be different from loads in the Eastern interconnection, I understand, I don't know the Eastern interconnection very well.

I'll talk about the historical analysis and metrics and what the TEPPC studies produce. That's kind of little intro as to what's going to happen this afternoon.

I'll talk about the simulator flows and the nodal and channel crisis and the limitations on nodal and channel crisis interpretation in the West, which, might again be different than you see in the Eastern studies.

So it seems to be there are three kinds of congestion. There is excess request for transmission service, excess request to schedule, and excess real-time flow. What the TEPPC simulation tests show is something like a mix of the latter two things, because the simulation studies show form from economic dispatch as it's constrained by the path limits, or it may be not constrained by the path limits because, depending on whether they're basically -- are constraints.

And then they show the differential nodal prices on the associated non-zero shadow prices on the past experience. None of these studies capture the -- the forward-looking studies don't capture the aspect of excess request for transmission service in the first place; they don't really capture requests to schedule. That's because of the way scheduling done in the West -- those are important pieces.

So -- path ratings in the West take account of the anticipated parallel flows and system conditions including potential contingencies. So when we do path ratings in the first place, and before the paths are even put into service, they are extensively studied in the context of the existing system and in the context of all new lines that are about the same level of development as they are when the studies are done. So those things tap -- the initial path rating you work from.

And then there is something called "operating transfer capability" which is approximately the same, I think, in the system operating limited in NERC terms that are done every season. They are reviewed every season and updated, and then also reviewed by transmission operators on a shorter-term basis.

So what you're going to see in Dean’s studies are the OTCs as the limits against which the flows schedules are measured.

Western practice limits both schedules and flows to OTC, so if there's a derating on the path for a contingency, if there is a seasonal derating that's where the seasonal OTC is less than the original rating of the path, the ownership rights on the path may be derated consistently for that whole period. So you have to limit your schedules to a down-rated section part of your ownership.

Many Western paths are stability-limited rather than simply transmission grids, thermally limited because the Western system is, by and large, a big stringy system, it's not a tightly meshed system like you see in a lot of places in the East.

Western usage does allow non-firm counter schedules against firm or non-firm schedules, and I mention that because I think in some of Dean's graphs you're going to see the directional schedules, the combination of firm and non-firm are going to be larger than the OTC. It's only because these short-term, non-firm schedules can be netted against when you're looking at the overall net schedules on the path. And the net schedules, overall, have to be less than the OTC as well as the flows have to be less than OTC.

So when you look at just flows alone, limited flow, and what I mean by limited flow in this sense is flow below the OTC level. It doesn't really indicate a lack of demand for the service. That's because you don't see the -- excess request for the service because that doesn't show up in the flow at all. It's already -- you didn't even get the ability to reserve, you didn't get any rights, and because schedules are limited before you even get to the operating system, get to the hour, you don't get that aspect of potential congestion. So a lot of the congestion doesn't show up exactly just as in the flow data.

And the other part of that is that if there are high levels without a constraint binding, that does indicate, actually, there could be potential congestion recognizing that all this other stuff that happens before the scheduling point is a congestion-limiting device in itself.

So -- what's in status flow versus OTC versus schedules. I'm not going to say any more about that other than -- Dean will talk about that a lot. The ATC that we -- we tried to get ATC data and reservation data. There were some problems getting complete data from OATI, and so that doesn't show up in this study, although that was part of the initial desire to do a complete study of historical data.

Dean will show you some metrics -- the use of metrics U75, U90 and U99. It's just the percent of time the flow or schedule exceeds that percent of OTC. And I should note that paths are rated to operate reliably at 100% of the rating.

Just a couple of observations on nodal and channel prices -- because of the way they can be misinterpreted, I think, and we've had a lot of discussion in the West -- and I'll explain why. Just provide you -- change in total production cost per one unit change in the value of the constraint.

Nodal prices typically are -- typically affected by multiple generation changes in a constrained system, and you actually cannot extrapolate to large changes in the constraint value because these are one-unit measurements of value -- that's kind of the way a linear program works, and you cannot assume that values and nodal shadow prices are additive. So changing one constraint could change multiple prices in a system.

And the reason these are important is because there is an index that's often used -- congestion rent -- which is an index based on multiplying the path's shadow price by a total flow or path limit. It kind of roughly distinguishes between the effects on large and small lines but it doesn't really answer the question with one exception. What is the value of -- and what I said before -- what is the value of expanding the transmission system? It doesn't really tell you that because it extrapolates beyond the range of a shadow price.

The exception is that in an organizing market framework, congestive rent is actually a value that's used -- in the West there is only one organized market in that test, organized market ISO or RTO then a framework, and that's the California ISO. So generally that congestion rent index is not applicable in the West, and what we have used nodal shadow prices for in the tested simulation studies is to highlight paths of locations where a problem of some magnitude exists -- the emphasis on "of some magnitude" -- and find modeling data problems. So that's mostly why you won't see congestion rent highlighted in the studies that are talked about this afternoon.

So -- I think that's the end of what I had to say, Joe.

Joe Eto: Thank you very much, Wally. Okay, our next presentation following that introduction to some of the methods and metrics that are used will be the actual presentation of the recent TEPPC study by the historic working -- the historical analysis working group and to lead that presentation we have with us Dean Perry by telephone. And, Dean, are you there on the phone?

Dean Perry: Yes, I am here, Joe.

Joe Eto: Can you turn Dean a little softer, thank you. So, Dean, we have your presentation up and let me introduce you now.

Dean Perry: Should I go ahead now with the presentation?

Joe Eto: Let me introduce you here. I'm going to read from your bio -- Dean is a consulting engineer in the electric utility industry, currently working as a consultant for the Western Electric Coordinating Council. He currently chairs WECC's Historic Analysis Work Group, providing administrative and analytical support to the analysis of historical transmission line technical and commercial data with the objective of identifying areas of transmission congestion in the eastern interconnected transmission system. Dean retired from Bonneville Power in 1997. At BPA, Dean was Director of Transmission Planning Division for 10 years, responsible for planning the BPA transmission grid in the Pacific Northwest.

So let me now have Dean take over by phone, and Lauren, I think, will change the slides for us. So, Dean, you are good to go.

Dean Perry: Okay, thanks, I really appreciate being able to participate in the workshop this morning. I really apologize for not being able to be there, and I appreciate the folks setting it up so we can work this out.

I'll go ahead with the presentation now, and I thought first I'd mention what I'm going to try to cover in the couple of dozen slides. I wanted to talk about the data that we used, and the methods that we went through to analyze the data. Also, to rate the paths and then I've got a few examples of the results that we have developed that are in the report that -- I believe it was posted, I believe it was a draft report that's been posted, and the final report should be coming out next month.

We've been doing this analytical work using archived historical data for about 10 years, and some of the objectives of it in addition to calculating the metrics and identifying the congestion, which is the primary interest, I think, of this workshop, is that just in general by doing this we get a better understanding of the way the Western system operates, and based on actually looking at the operational data. And then we also use the results in making comparisons with model studies and serving kind of as a benchmark for the model studies that will be talked about in the panel later today.

If you can go to slide number two, this slide is a picture, of course, of the Western United States and the WECC transmission system, the black lines represent the transmission lines, at least the major transmission lines, in the Western system.

What we have done, we selected the 23 of the paths for analysis, and those are noted in the gray bars on the map. There is actually a total of about 70 paths that WECC rates, establishes a rating -- associates a rating with through a process that's developed within the WECC procedures. So of those 70, we selected 23. They are generally the major paths between the control arteries in the Western system, and these 23 paths, we've been monitoring, again, for about the last 10 years -- the performance on those paths and the characteristics of those paths and those results of the prior work are included in some reports that are available on the WECC website.

You'll note path numbers on the map. Each rated path in the WECC system has a name and also a specific number assigned to it and, as we go through the presentation, you will see reference to these numbers, and by looking at the map you can kind of determine where the paths are geographically located.

The next slide, slide number three -- now a little bit on the data that we used in the analysis, and I could hear Wally talking before about some of this already, so I'll kind of quickly go over some of this.

We, essentially, in analysis this year we used the actual power flows on the paths, and these are hourly samples of the actual power flows in megawatts. We used the transfer limits, or the OTC values, on those same paths, and these, again, are hourly samples, and they change on some WECC paths hourly -- some paths, the transfer limit stays constant.

And then the third data that we used were the past schedules, and this is the data that we received from the electronic tags, the e-tags that OATI archived and provided to us, and that was partly funded by the U.S. DOE to help us do that.

This is the first year we've ever analyzed schedule data, and I think as you go through here, you'll see the value of the schedule data they provided to us. Prior to this, we've only been able to analyze the actual megawatt flow data on the paths.

The schedule data consisted of firm and non-firm schedules, which we actually added together to get a total schedule value, and we did receive schedules in both directions on the path and from that we calculated the net schedule also, so we have information on the schedules in each direction plus the net schedule on the path that was analyzed.

Just quickly, the way this was done was the tags are all in a point of receipt and point of delivery segment format, and OATI -- we mapped these POR PODs to the WECC paths and then OATI gathered the data from the tags and converted all of the tag data to the WECC paths and presented the information to us on a WECC path basis for our analysis.

The year that we analyzed in this study is 2007. I mentioned we had 23 WECC paths. Since this was the first year we've analyzed schedule data, not surprisingly, we did run into a few problems with some of the data that we received. We were able to make adjustments to essentially all of that schedule data except for one path, which happened to be a path into New Mexico.

A couple of the issues we ran into with the scheduling data, which we did correct, were that during this time period, the transmission providers began tagging their dynamic schedules. So part of the year, some paths, these dynamic schedules were not tagged, and so we did not get the schedule information from those, but we were able to determine the magnitude for the dynamic schedules and make some adjustments.

We also, in the initial data gathering missed some of the POR PODs and OATI has just provided us the data for the missing POR PODs, so we have a little more analysis to do of a few paths with the final schedule data to complete the work that we did.

The next slide, slide four, okay, now the analysis does perform all he data. First of all, for every of the 23 paths we calculated and brought us the chronological plots; that is, the flows and the schedules over the total year period so you could see that variations over the year in the schedules and in the actual flow data. And I have two examples to show you of those plots. That was done for every path and also we calculated what we called "duration curves." Those are, really, essentially, frequency distribution or statistical plots of the flows and schedules over the year period. And those are also presented for each path in the report, and, again, I'll show you a sample of that.

We then also calculated the metrics, and I believe Wally mentioned those -- the U75, U90, and U99 metrics for the flows and for the schedules. That is the net and the directional schedules. We calculated those for the three seasons of the year, for the heavy and light load hours of the year, and for the total year, and the net result was that we ended up calculating 48 individual metrics for each path, and don't ask me why we had that many, but it just kind of ended up that way, and I'll talk to you in a minute about how we use that information to rank the paths.

And then there are some examples that I'll now go through. Two examples -- so if you could go to slide five -- that first example that I was going to show you was the path between Canada and the United States -- it's called Northwest to condition, it's path number 3 is the number that which we assigned that.

And our next slide, slide six, this is the chronological plot. Again, it's an example of the plots that we created for all 23 paths. This particular slide shows the actual flow, which is the dark blue, and also the net schedule, which should be in the green on the slide that you have.

I have actually had to make an adjustment -- I lowered the actual schedule plot by about 200 megawatts so that you could see there were actually two plots there because they directly overlay each other, which they really should when you have the -- Canada is basically a radial system off the Web system, and so schedules and actuals should be identical or very close to identical on a connection like that, and you can see by the plot that they are.

Also, on that plot, the red lines are the hourly variations in the path capability in both the north-to-south, and the south-to-north direction, and all the 23 paths, we also have those plots of the OTC variation. Those are quite interesting, I think, because you can see that for substantial amounts of time, the paths operate below their maximum capability. For this particular path, the north to south rating is actually 3,100 megawatts, and so you can see the red lines are below that a substantial amount of the time.

The reasons for that are -- well, on this particular path, the primary reason is the year's generation near the path and depending on the level of generation, the output of the generation affects the capability of that path.

Let's see, the next slide, slide seven -- this is another plot, again, for the same path for Northwest to Canada. The red lines are the same as they were on the previous chart. Now, on this particular chart what we're showing are the schedules in the two directions on the path -- the north to south direction is shown in blue, the south and north schedules are shown in the tan color, and, remember, on the previous slide, we've shown actual and net schedule. So this shows us schedules in the two directions.

The one thing to note on this particular path that we look for on the other paths also regarding usage, heavy usage and congestion -- that is the fact that on this path you can see the blue -- it goes higher than the red -- the limit towards the July, August, and September timeframe. And then in the opposite direction, you can see the schedules in the March/April timeframe are exceeding the limit on the path, and this does occur, at times, on some of the paths in the Western system where the schedules in each direction may exceed the path capability. However, the net schedule -- the next schedule on the path stays within the transfer capability of the path.

The next slide, slide eight -- this is the duration plot for the same path and, again, this is an example of the plots we create for each of the paths -- each of the 23 paths. This plot shows the percentage of time on the horizontal axis and the per-unit of OTC on the vertical axis. So we've normalized the flow in the per-unit basis, and that means that where the red dash line goes across at 1.0 on both the north to south and south to north directions, that would be a point when the schedules or the flows equal the OTC again, so the values have been normalized where the previous plots -- they were showing the megawatts.

And the way you would interpret this kind of a graph is just one example on the -- if you looked at the blue line at the top, which is the schedule from Canada into the United States, it cross the dash line at right about the 10% point, and what that means is then the schedules from Canada into the Northwest exceeded the path capability about 10% of the time, and you can look at the other curves on the path and see also the performance of the actual and the net schedule -- and the schedule in the south and north direction. Those plots were created for each of the 23 paths.

Slide nine -- this is the next example I want to quickly run through -- this is for the -- we call it COI, it's the California-Oregon Intertie, which also goes by the number of path 66, and this path is used a little bit different than the other path, but it also gives us an indication of the usage and the potential congestion on these paths.

Next slide, slide 10 -- this is, again, a similar plot to the one that we looked at with the Canada and Northwest. Again, this is for the AC Intertie of California from the Northwest, or COI. And you can see on this plot again the actual flow is in the dark blue, and the net schedule is in the -- should be, I think, an orange that you're seeing, and you can see the pattern on this path over the total year period from November through October. I might mention that the year that we look at is actually November 1st through October 31st of the following year, and we selected that because we analyzed the data on a seasonal basis, and the winter season in WECC is defined as starting on November 1st, and so we don't use a calendar year, we actually use a November-through-November year.

Again, on slide 10, the one we have there, you can see the most heavy usage on the AC Intertie. It looks like it's between the periods of about March through about September, that's when it's about the highest, and you can see how close it gets to the capability of the Intertie, which is the red lines during that time. And this particular path, all the flows and schedules, net schedules, anyway, are all in the north/south direction in this year.

Slide 11 -- again, this is a similar plot to the one we saw earlier for Canada and the Northwest, so this shows the schedules in the two directions on the AC Intertie up in the Northwest of California, with the north-to-south schedules being in blue, and the south-to-north schedules being an orange color, and you can see how these compare.

In this case, all of the directional schedules, it looks like were all less than the path capability, whereas, you may recall in the Canada Northwest we did exceed the path capability on the directional schedules.

So again, these were just two examples that I wanted to show of the same information that can be found for all 23 paths in the report.

Next slide, slide 12 -- Okay, this, again, is just the duration plot for the AC Intertie line, and you can tell by looking at this plot that all of the curves are within the 1.0 point, which means that the actuals and net schedules and the directional schedules were all less than the OTC -- essentially all hours of the year.

You can also tell by looking at the plot like this that all of the actuals and the net schedules were all in the north-to-south direction, and they're all above the zero line on this particular case.

One thing I was going to mention, I think, on these kinds of chronological plots, one way we were able to check our schedule data this year was to look at the plots where we have the actual flow plotted with the net schedule. And, generally, you should see similar patterns and similar magnitudes on those plots, and we were able to identify -- when we had problems with the schedule data, this is the major way we were able to identify it, was we didn't see a consistency between the net schedules and the actual flows on the paths. So that's one way we use these chronological plots.

But the biggest benefit, probably, to the chronological plot, though, I think is being able to understand the usage of the paths over the total year period.

Okay, next slide, slide 13 -- Now I want to move into the metric calculations, and go to slide 14. I believe I hear Wally on the phone -- or heard him present a definition of the U75, U90, and U99. For those of you that are not familiar just to review that again -- that represents the percentage of time that the flow or the schedule, whichever one that we're looking at, exceeds, for the U75, it would be exceeding 75% of the path transfer capability on the hour. And, again, those capabilities do vary on a regular basis, and so we track the path ratings, or path capability, to compute the U75, U90, and U99.

We calculated the metrics for actual flows and for the schedules, and as I mentioned before, we did it for the schedules in both directions and for the NEC schedules. We calculated the metrics for the period of the total 8,760 hours of the year as well as breaking up into the three seasons and also we broke the total year into heavy and light load hours so we could understand how the paths usage varied with heavy and light load hour usage.

The next slide should be slide 15 -- This actually just breaks down the individual metrics that we calculated, which we've kind of gone over already. The actual flows -- there were 12 metrics that were calculated for the actual flows. They were U75 and U90s for the time periods that are shown. The HLH stands for "heavy load hour," and the LLH stands for "light load hour." We didn't calculate a U99 because that's the -- essentially would be the percentage of time that it exceeds essentially the path rating, which is U99 or very close to it, and the actual flow never exceeds it. So -- it would have all been zero value numbers, so we didn't calculate U99.

For the net schedule, we calculated the three U75, U90 and U99 for the same time periods, and there were 18 of those metrics that were calculated, and then we calculated the same metrics for the schedules in each path direction, and there were 18 more metrics, so it totaled up to 48 metrics, total, that were calculated for each path.

Next slide -- Okay, I've got, I think, three bar charts to quickly go over. These just illustrate there are additional ones that were calculated, they're in the report. These were all the U75 metrics, and what this shows are the path numbers or across the horizontal axis, the U75 value is on the vertical axis, and so you can pick any one path and determine what percentage of the time that the flow -- in this case, this is actual flow, so this particular chart shows a percentage of the time that the path flow exceeded 75% of the path capability.

One thing I want to note to make sure the curves are not misinterpreted is that the zero line, the zero U75, does not mean zero flow on the path. That means if there was a path at zero -- that means that it never exceeded 75% of its path capability. An example of that, just so that that's understood, because that's often misunderstood, is that you can have a path that's operating 100% of the time at, say, 70% of its rating, that would show up as a zero on this particular chart because it means it would not have exceeded 75% of its rating. So keep that in mind as you interpret the results.

So, again, this particular chart shows the three seasons, all hours of the year, and how the U75s resulted. Path 19 happens to be the path with the highest utilization, and you can see the red line is the summer, and so you can see that during the summer it exceeded 75% of its capability 80% of the time.

Now, I believe that Kurt Granat may be addressing path 19 later. Path 19 happens to be a path that's pretty well dedicated to the integration generation, and then you can see the characteristics of the other paths.

Next slide, slide 17 -- This is the same information. U75 -- in this case, it's for the net schedule, and you interpret this graph the same way, and so these are bar charts that show the percentage of the time that these paths -- the net schedule on these paths exceeded the path capability by 75% of the time. This is the seasonal plot for each season.

Next slide, slide 18 -- And, again, this is a similar plot again. This happens to be the plot of the U75 for the directional schedules, and what we do here is pick the schedule direction that's the maximum of the two directions, and that is the quantity that's plotted on these bar charts. Again, there are schedules in both directions on most paths, and we select the path, which has the highest schedules in the direction and show that. This, again, is a season plot, and it goes, again, with the other plots.

Next slide, slide 19 -- Okay, this is not really a metric. In a way, I guess it could be considered one, but it's not one of the 48 metrics, but I wanted to show you that we also determine the maximum flow on the paths. This particular case, it's for the three seasons, and you can see that the maximum -- and this is actual flow, this is not scheduled, this is the actual flow, and so you can see that practically all paths at some time of the year approach the path capability, the path rating, which would be 1.0 on this chart.

About the lowest on the right, I guess, is a particular path that's down around 60% is about the highest that it got, that it reached on an actual flow basis.

The actual flows -- excuse me -- the maximum flow, we calculated at the 99% probability level, so it's not the actual highest hour over the year, but it's the 99% probability level, or it was only exceeded 1% of the time. And that's a definition that we've defined for maximum flow.

Next slide, slide 20 -- What I'd like to do now is quickly move into the ranking method we used, and then show you the results of the ranking, which was essentially the end result of the study.

Excuse me, slide 21 -- we actually used four different methods to rank the paths, and if you can kind of visualize, we have a lot of metrics that we have calculated, and we've got -- there's a total of 48 metrics we calculated for each path, and then the problem is what do you do with all the information to try to get something out of it to rank and to try to identify the most heaviest used paths.

The way we did this was we selected four different methods, I'll just call Method 1, Method 2, Method 3, and Method 4. And then from those four methods, and I'll go over those quickly, but from those four methods, we picked the highest paths that were ranked using each of those four methods, and that is what we eventually ended up with -- the grouping of what we called the "highest used grouping" of paths.

So let me quickly first go over those four methods. Method number 1 and method number 2 used actual flow data. The metrics calculated for the actual flows. Method 1, we actually just summed up the 12 metrics that were calculated for actual flows, so we summed the U75, U90, and U99 for the seasons and for the heavy and light load hours. We just literally added those values up, and then we -- that attributed a number to the path.

Method 2, rather than sum them, we picked the highest of those 12 metrics, and that was the second method we used, and so that attributed a value to the path based on the highest metric that it had.

Method 3 was using the net schedules, and, again, for the method 3, we summed the -- in this case, there were 18 metrics because we calculated U75, U90, and U99. I forgot -- I may have misspoke on the actual flow. There was U75 and U90 but not U99. So that schedule, we had three metrics, three U-values for the seasons and for the heavy/light load hours. That produced a number, which was attributed to the path of the net schedules.

And then Method 4, we used the schedules in the maximum direction of the two directions, and we just picked the highest metric that was calculated for those, and that became a value attributed to that path for Method 4.

So those were the four methods, and in a minute I'll show you a couple of examples of how that -- what that looks like. And then, again, what we did was we picked the highest three paths in those four methods, and that resulted in a total of eight paths that I'll show you in a couple of more slides, which we called the "highest used paths," or a grouping of the highest used paths of all those that we looked at.

Next slide, slide 22 -- we're getting close to the end -- slide 22 just shows you how Method 1, what the result of Method 1 was, and, again, that's where we added the metrics of the actual flows, and you can see the highest -- the path at the highest utilization using that ranking method was path 19 again, which is the Bridger West Path that Kurt will probably talk about -- what's dedicated to generation input.

The next path was Southwest of Four Corners, and then the Montana and Northwest and then the California/Oregon Intertie, there's a transformer down in Arizona called Four Corners Transformer, and then the Pacific DC Intertie line -- those were the first -- one, two, three, four, five, six paths using that method.

The next slide, slide 23 -- again, this is using Method 4. I'm not going to show you the other two methods just to reduce the time here. Method 4 shows the results of, again, Method 4 was using the maximum of the directional schedules, and you'll get different path results, a different ranking, with this methodology. In this case, you can see the sequence of the paths. Path 47 is the path into New Mexico. So 2a is the next one -- 2a is the path between Colorado and Arizona and New Mexico. The Bridger West, we already talked about, and Montana Northwest is evident. West Dubois is in central Idaho, and then Montana to Idaho is between Montana and Idaho.

Next slide -- in fact, go to slide 25 -- and this is the bottom line, I guess, of the results of the usage analysis using our historical data and went through the calculation the metrics, and then through using those four ranking methods, it resulted in these four-- excuse me -- these eight paths were identified as the most heavily used paths this particular year, and this can vary from year-to-year, depending on how conditions in the system change.

There is a caveat that is not final, and that is because we -- as I mentioned at the beginning, we have received some new data from OATI to new scheduled data for some of the paths, and we need to go through that and then re-calculate the metrics, the ranking, and the most identification of these paths.

Our report -- I won't get into this now. Basically, also, recommends some improvements for our succeeding future worth on calculating the metrics and doing a historical analysis, and those will be in the report. One of them will be to investigate further the ability to use ATC data and reservation data and reservation status data from the OASIS sites, which I think could be quite valuable. This particular year, the data turned out to be not usable.

The next slide, which is the last slide, slide 26, is just a geographic representation of where these eight paths were located in the Western system, and the red bars are those eight paths. Essentially, what they really represent, I think, is getting generation, getting energy from the Eastern part of the interconnection into the Southwest and into the Northwest. And then also we had the AC Intertie between California and Oregon, also showed up as a heavily utilized path.

So I believe that concludes my presentation, Joe, and we're going to handle questions at the appropriate time.

Joe Eto: Okay, this is Joe and, again, thank you very much, Dean. I hope you'll stay on the line because we will have a question-and-answer session after the last two panelists speak. The tremendous amount of numerical information here and, really, it's very important that we recognize that congestion is more than a bunch of numbers, and so I've asked two sub-regional experts to speak to how best to understand these numbers with respect to some of the findings, and at least Dean's preliminary work and, really, how to interpret it. You know, of course, we're looking at only one year of data here; of course, we're looking historically at a time two years ago, effectively, and so here to tell us a little bit more about how, from their perspective, we ought to be interpreting what these numerical findings are telling us, are two experts.

And the first one I want to introduce is Kurt Granat. Kurt works for PacifiCorp--PacifiCorp Transmission Strategy as a Principal Planning and Financial Analysis Consultant. He's worked with PacifiCorp since 1985 in areas including Regulation and Cost of Service, Power Resource Planning, Transmission Main Grid Planning, Major Projects, and the current Transmission Strategy. He has worked on western regional planning efforts, including the WSCC Regional Planning Task Force, the Western Governors Association’s 2001 Conceptual Transmission Plan, and follow-up SSG-WI efforts, the Rocky Mountain Area Transmission Study, and the current WECC Transmission Expansion Planning and Policy Committee work groups. With that, Kurt?

Kurt Granat: Yes, thank you, Joe. One of the things I wanted to talk about quick before we got into these is just mentioning how, with the transmission use, we have to watch the things, you know, measure a lot of things, and it's important what we measure, but there are a lot of things, uses, that don't really get seen. Wally's already mentioned we don't tend to keep track of how many megawatts of contracts we've refused. Yet alone, we have no way of keeping track of how many people were discouraged but could see the problems coming in and didn't bother to make any request.

In the West, we typically do transactions bilaterally, and a lot of the transmission rights are held to provide options. It's an optional use, it's not an obligation, so depending on your seasonal needs, which can be weather-driven--it can be weather both from the water standpoint or temperatures--you might need access to market points where you know you can get resources, or in the event you have something that leaves you with a lot of resources where you could market them. And so we have rights, people who own rights to and from the same market. And you can see it when they schedule it, but that option value doesn't show up in what the usage shows.

When I looked at the list of the most powerful congestion points, it occurred to me that, thinking also of my modeling work, a lot of times what, the powers pop out that are from general regions to other regions. Montana to Northwest, Bridger West, both on the list, on the top 10 list, were showing up. They're getting power out of Wyoming and Montana. The other major path on that is Tot 3. And Wyoming and Montana, that region, it's a long ways from those things.

The three major paths were all built to facilitate specific coal facilities back in the '70s and '80s. Montana to the Northwest was built for Colstrip, and the path is 2,200 megawatts; Colstrip's 2,100, roughly, and about two-thirds of Colstrip is dedicated to utilities in Washington and Oregon. So they're scheduling two-thirds of that path out.

Bridger West is basically right, just beyond the step-up transformers to the Jim Bridger Generation. It's a 2,200-megawatt path. Jim Bridger is 2,120. So there's not a lot of extra capacity. In fact, the 230 system right now could only move another 600 up out of those lines if the plant was gone.

The plant is dedicated to Idaho and Northwest loads. It's actually in our Western Control Area, which is Oregon and Washington, not our Eastern Control Area, for how we handle it.

These three paths make up about 85% of the capability of moving power outside of the Montana and Wyoming region. And all three of the paths, Tot 3 was built to help move Laramie River Station down to loads. And Laramie River has three units, but only two of them operate in WECC. I think the third is in MAP. I believe one of them can be flipped, although for practical purposes, it stays in WECC. It's 1,100 megawatts. The path, where it's measured, is worth up to 1,600 megawatts, but it's a very complex path, and I'm not particularly familiar with it.

All three of these also use remedial action schemes to, if there's a problem with the transmission generation, either gets dropped or redispatched or dispatched in rapidly.

Now, I'm looking, here's just an illustration of the size of the paths and also the size of the generation resources in that region. One of the things, when you look at those generation resources, you'll note that there's like 8,700 megawatts of generation, about 2% of which is gas-fired. The rest is coal, wind, hydro, and very low cost. So there's not a lot of high-cost generation that you could displace up in that region.

There also isn't a lot of load in that region, and what load there is tends to be heavily industrial. And industries like oil and gas fields, so large compressors, large pumps, nice, flat loads. The transmission within the region tends to be designed to fit that, that generation, and our load pattern, and it can be designed without a lot of need for the fluctuation that residential and commercial loads would put on you. So the bottom line is, there's not a lot of extra room, and there's not a lot of high-cost generation that you could displace up there.

And why these paths keep coming up is that there's a huge resource potential in those states. The map on your left, the colors is courtesy of NROW, and it's basically the wind areas, and you'll see very large, contiguous, high-quality wind areas scattered in Wyoming. Well, they're not all that scattered; they're all over the place. The map on the right is the coalfields in Wyoming and Montana; actually both of those are Wyoming and Montana.

So what you see is there's just these huge, both renewable and conventional resources that could be tapped up there. And the, also, another thing, too, there actually, like for CO2 capture, there actually would be a lot of uses up there in enhanced oilfields, enhanced gas production. I noticed a while back that the oilfields at Teapot Dome, which generated one of the political scandals back in the '20s, is very close to our Dave Johnson Coal Plant.

On the specific paths, here is Montana to the Northwest, or Path 8 is on Dean's slides. Again, about 1,400 megawatts of the 2,200-megawatt path is dedicated to resources in our, to moving the Colstrip Plant to utilities in Oregon and Washington. The path itself is two 500-kV lines that were built, really, as part of the Colstrip Project. It's not a lot of loads. Colstrip literally is, I'm not sure, 150 to 200 miles to the east of where this is being metered, so there's a lot of space to cover in the West.

So, and it's two 500-kV lines. The rating does depend on meter action schemes at Colstrip if there's a problem. On the east of that top line, there's about 2,500 megawatts of thermal, 300 megawatts of hydro, and at least 150 megawatts of wind. Wind gets hard to keep track of, because it's been changing rapidly. Major wind resources are planned out there, and there's potential for large coal or lignite additions, as well, in the east.

Now, there are several--on this path, it's interesting. There actually is ATC listed on it. However, for the most part, the parties are facing additional charges to bring it into the loads in the Northwest. Also, because there are firm schedules coming in from the Northwest, from Oregon and Washington into Montana on us eastbound, there is additional capacity that's available on a non-firm basis. And there are several proposals to upgrade this path or create large alternative paths. Northwestern was considering revamping the path, additions to the existing path to increase the ratings, as well as projects like the, what they call the Mountains--well, it's MSTI, I think that's Mountain States Transmission Path. Anyway, and TransCanada also has some projects on that.

The Bridger West Path, Path 19, this is one that PacifiCorp and Idaho Power own that was built to move the Jim Bridger plant to Idaho and west. Again, it's rated at 2,200 megawatts. Bridger is 2,120. And the three 230-kV lines that feed into the Bridger Station would add some additional capability out of Wyoming, but that would be limited.

There's over 600 megawatts of wind and 1,000 megawatts of coal, and that's on PacifiCorp's system alone. There's additional resources out there. I just didn't have them all down. It's fully dedicated to the plant. And the rights are fully dedicated to the current owners and heavily used, as you noted. PacifiCorp and Idaho being competitive companies, we like to point out that it's number one on the list here and actually load up above some people's DC lines. But it doesn't leave much extra room.

It also has a number--the plant was built in '69. The contracts agreeing to how these lines get built and operated are about that vintage, and so there are limitations on how the rights can be used, which impact the ability to sell any additional on it. There's little to note, counter-schedules coming in from the west to Bridger, so that limits how much non-firm can be sold on it. This one, PacifiCorp's Gateway Project, would add a large alternate path to this.

Okay. I think here we're, this one, the AC Intertie, Pacific AC Intertie, or COI or WECC Path 66, is rated north to south at 4,800 megawatts and south to north at 3,675. It consists of three 500-kV AC lines. They're metered, basically, at the California border with Oregon. And these actually, the planning for these dates back into the early '60s. I think the first ones went, the first pair of 500-kV lines went in service at about 1969 or '70.

The driving force on this was seasonal exchanges. I should mention that the Pacific Northwest, due to the huge flows on the Columbia River, and it's like 100 million acre-feet a year on average, you can't store that much water. And so we can only store about one-third of the annual runoff on the Columbia. So we tended to end up being in a boat situation where we had plenty of capacity, but we were energy-limited. So the planning was all energy-limited. Part of the reason why the Bridger lines and Colstrip lines look so skinny for the size of the plant hanging on the end of them is it was offline for a week because the transmission was down. It wasn't a capacity problem. They were designed to trickle-charge and let you tweak things in the Northwest.

And the Northwest also peaked during the winter. So California peaked in the summer, Northwest winter, there was a lot of ability to make use of each other's systems to cover our needs. And so these seasonal exchanges drove a lot of the original purpose. Now it's become a big hub for energy and economy transactions. And it's also a very liquid, or relative to Northwest, fairly--or the West--it's fairly liquid, so it's a good spot to have access to in case we really needed it for emergency use.

There's also, there's not a lot of generation when you get into southern Oregon there. So like if there's power going off in the Idaho to Northwest path, generally, or at Summer Lake, particularly, the eastbound flows on the Summer Lake line tends to impact your ability to get the power down to California. The Alturas Project, which taps, basically it comes off and heads down towards Reno, also impacts that ability to use that.

And when you get below the border, you can see a lot of lines just below where they marked COI, and there's a lot of hydro plants down there. But if hydrogeneration is up, that will impact the ability to move power down COI.

Tot 2C is the fourth and last one I'm going to be talking about. This consists of a single 345 line that's measured between Red Butte and Harry Allen. This line really stretches back to Sigurd. It's about 250 miles long with load in the middle of it. It was built--basically, it facilitates a lot of energy and power, peak hour trading and again, largely is an option for reserves. It peaks in both directions, and it really depends on the season and time of day. Even though both Utah--or the Utah system--peaks in the summer as well as Nevada Power down at Las Vegas peaks in the summer, Nevada Power's peaks tend to be much longer, so I think it opens up some ability to trade back and forth. You know, they're still worrying about peak loads at 9:00 or 10:00 at night, whereas in Salt Lake City you don't. Anyway, and so it's trading economy, energy, and things.

Last slide, I thought I should put up the, you know, we are working on things here. This is the slide that shows PacifiCorp's Gateway Project, both in relation to where our support service territories are, as well as to where the wind resources are. And basically, at PacifiCorp we have been working on studying these problems for a long time. What we started focusing on was our customers, particularly the Utah load growth might require. We bounded a lot of generation, gas-fired generation, locally, but there may be limits on how much we can do on that, as economic as well as air shed and things, water. And to access remote resources, the logical place, we figured, was going to be Wyoming, whether they're conventional or renewable. And so we laid this out. We've sized it, basically, around what our own customers' needs would be, but the path would be flexible. It could be expanded, depending on whether a partner were to come forward and commit.

Anyway, with that I think I'll yield the floor here.

Joe Eto: Thank you, Kurt. Our final panelist is Bob Smith. Bob is presently Director of Energy Delivery Asset Management in the Planning Department at Arizona Public Service Company in Phoenix. Bob has a Master's Degree in Electrical Engineering from New Mexico State University and is a Registered Professional Engineer in the State of Arizona. Bob has worked in the electric industry and for APS for 23 years in the areas of Transmission Planning, Construction and Maintenance, and Transmission and Control Area Operations. Bob has represented APS in several regional planning forums, has been extensively involved in WECC activities, including two years of sharing the WECC Compliance Monitoring and Operating Practices Subcommittee, and he's presently Chairman of the WestConnect Steering Committee.

Bob Smith: Thank you, Joe. Good morning, everyone. Thank you for being here, and thanks for having me. When Joe called me about a month ago to ask me if I would participate, he said, "Bob, we'd really like to have a regional expert." I thought, "Well, that's kind of neat. Joe thinks I'm a regional expert." And he said, "You'll get all the information and you can read the report and see what you think."

So I got the report, and you heard Dean earlier express some challenges getting some of the data together. And when I read through the preliminary report, I found that three of the four paths that they were struggling with were not only in the southwest footprint, but APS was the path operator. So I think I'm really less of an area expert as I am the hit man at APS to be sure we got all the data together.

The other thing is, I don't know if Joe knows this or not, but Dean certainly does. Before I got into the power industry, I sold drugs. The good news is it was legal. I have a license. I'm a registered pharmacist. The bad news is you don't make as much money that way.

But anyway, I think Dean thought that I could be helpful since I have two professions where I solve congestion. You can boo at that, you can boo at that.

So we heard--well, actually, for those of you that have been awake, you should have picked up on two things this morning, I think, that are important. One is through Dean's data, we have a very good correlation between schedules and flows in the Western Interconnection. And it's not just the paths, the examples he showed you, but all the paths I've looked at. And I think what it means is that we've done a good job of planning, and we have a good planning process in that we have good flowability on our paths.

The other thing that at least I've learned, and Brad Nickell, you should take note of this, is that when we renew Dean's contract next year, we want to get away from this pay-per-graph thing that we're doing.

Well, Dean gave you a lot of information. I'm following Kurt. I'm certainly not going to go through all the points Kurt made, because they're all valid for the paths that I'm going to cover also. But I kind of consider Kurt and I the color commentary. You know, Dean went through all the statistics so you know the standings. You went and heard a lot of individual statistics, but we're doing maybe the play-by-play or the sports center top 10.

At least I have a colorful slide here for you to look at from the north side of Phoenix looking south at Camelback Mountain and nice saguaros and the sunset.

The first path that I will cover is, well, we call it Four Corners West. I think Dean referred to it earlier this morning as the Southwest or Four Corners. But it's the same thing. The Four Corners Power Plant is a coal-fired power plant. The first three units were built in the late '60s, I believe, 200-megawatt size, roughly. Solely owned by APS. And then later, in the '70s, there were two of the larger 750-megawatt baseload coal plants. Edison owned half of those, and the other participants that you see here in the lower box are the owners of 4 and 5. So the total plant capacity is 2,110, and the Four Corners West Transmission Path is basically to get that energy out of the Four Corners Power Plant, west into California, and then down south into Phoenix and Tucson.

There's a 500-kV line that goes from Four Corners to Moenkopi and then over on into El Dorado in southern California. That line is owned by APS, but it has been leased on a long-term basis to Edison ever since it was built. So basically, the Cal ISO has all the transmission capacity on that line.

The two 345-kV lines that come out of Four Corners and then go on through Troy and on into the Phoenix area are owned 100% by APS, and we use those lines to move our share of the Four Corners Power Plant and some other wind contracts that we've had. We've had one 90-megawatt wind contract from eastern New Mexico in the Santa Rosa area for at least two years now, and then we're just implementing another 100-megawatt wind contract, it's an area south of Albuquerque that will be scheduled to be in service, I believe, this summer. So that energy's coming down, as well as some economic purchases, but there's not a whole lot of energy available in this area beyond the coal. Some of the ownership, particularly PNM, Public Service of New Mexico, and El Paso Electric, is scheduled back around through transmission into Mexico.

This path is--well, all the time, on a net scheduled basis, scheduled east to west, it's fairly utilized. There are a couple of contracts that are in the reverse direction. I'll give you an example. PacifiCorp owns one of our units at Troy. Troy's another coal-fired power plant. APS owns three units, and PacifiCorp owns a unit there that's about 350 megawatts, and they have rights to get it back up into their system. So there will be a lot of times when that is energy is back-scheduled, and APS can use a short-term non-firm transmission for things like wind energy. But you can't credit that and sell additional long-term firm in the predominant flow direction. So it's sort of one issue that causes this path a lot of times not to be loaded up to its rating, as you'll have reverse schedules or just inability to use the, I guess, the capacity that's not being utilized downstream because of rights that are available back upstream.

The California ISO, if you look at this, Edison's share of Four Corners is about 750 megawatts. And the rating on this line is more on the order of 1,150. They will purchase--well, purchasing entities will use California ISO transmission to bring other energies into the West. But generally, there is some capability in that direction.

The next of the paths that I'll talk about is Tot 2A, which consists of, I believe it's two 345-kV lines and one 230 line that basically comes down through southwestern Colorado into northwestern New Mexico. 690-megawatt rating. The owners are Western, Public Service Colorado, Excel, and Tri-State. And this is mainly used to deliver the Colorado River Storage Projects or the dams on the Colorado River to load. Also, Tri-State has one of the Springerville generators and uses this path to move that energy up into their system, and then some merchant activity. So this may be the one path that there is a significant back-and-forth, but it's not yet a really large rating.

Anybody here have friends or relatives in El Paso? This is what they refer to as the "one-way ticket to El Paso." This is the South New Mexico path, but it really, if you think about it, it is the transmission into El Paso. And this is more of an import limitation issue. It's a load pocket issue, really, than a commercial path. About 940 megawatts for the three lines. These are three different 345-kV lines that are owned by El Paso, Public Service New Mexico, and Tri-State.

There are two merchant generators on the load pocket side of this path that are scheduled in the reverse direction, but I'm pretty sure that El Paso uses the transmission freed up by those reverse schedules to access more economic generation outside of their load pocket.

So those are the three paths that were in Dean Perry's top eight or ten list or whatever. But I did want to spend a little bit of time on the major paths going into California from Arizona, mainly because if you look at future congestion, these paths often come up as congested paths. And in the first DOE study, this was identified as critical congestion, and in fact, a good swath of this land here was designated as a National Transmission Corridor or whatever the specific designation is.

So I want to talk a little bit about that. The total capability of the path today is 8,055 megawatts. We're going to go through, I think, a goring review of each one of the lines. So there's a total of, I believe, six EHV lines on this path. There's the Navajo to Crystal, and then on into southern Nevada, lines owned by Nevada Power, LA, and the US Bureau. And that's got a TTC of 1,422. The Moenkope-El Dorado is just really an extension of the Four Corners line. APS owns this, but it's leased to Edison, so Cal ISO has the capacity, 1,555. The Perkins-Mead is the newest of the lines, the only one that's really not associated with baseload resource. APS, Salt River, Western, LA, and some other California entities own that. It's 1,300 megawatts of capacity. WAPA has a 345-kV line worth 450 megawatts that's in the same right-of-way between Liberty and Mead.

Then there are the two lines out of Palo Verde going into California. There's the Palo Verde-Devers line that Edison owns, so this is capacity 100% managed by the Cal ISO. It's 1,802 megawatts. And the line going into Yuma-North Gila and then on into San Diego that is shared by APS, the Imperial Irrigation District, and San Diego. It's got a TTC of 1,526.

So various owners. For the most part, this path is used to move Palo Verde generation, the nuclear and all of the--there's been 6,000 megawatts of combined-cycle gas units developed out here in the last eight to nine years. So altogether right here, you have 10,000 megawatts of generation. So between this, the coal at Navajo, and Four Corners, that's really what's moving across here, plus any kind of market activity going into California.

The West of the River path is just sort of the extension on into to California, and you can see--I'm not going to go through all of this--but it consists of a whole bunch of lines coming from the El Dorado Valley south of Las Vegas on into southern California. And also, the Devers line, some other lines coming in from IID into southern California, and then this is the line going to Miguel in San Diego. So the combination of all this is good for about 10,600. So you've got about 2,500 megawatts additional capability here than you have over here in Arizona, and that's because you've got to get all the Hoover allocation in. And there was a time when you had to get the coal out of Mohave in. Since then, Mohave's shut down, so there's probably some room on this path also. We don't see these paths show up historically as congested.

And this is just kind of a big-picture overview. And I guess the point I want to make here is, going back to a couple of Kurt's slides, the future potential resources in the Rocky Mountain area--wind--if we were going to get a significant amount of that into either Phoenix or the black hole over here in California--and really, all the energy just stops off in Phoenix to catch the Cubs' spring training game, then it goes on into California. But you would need to shore up this path into, I think, it's Tot 2 at Colorado, New Mexico, into Arizona. You're going to have to improve the Four Corners West path.

And depending on how much you're trying to move, you're probably going to have to add some transmission in here also. Edison's planned to build a second Palo Verde-Devers line, and Arizona entities have plans to build another line to North Gila, plus the Sunrise Power Link, probably get this taken care of in the future. But there would need to be additional plans in this area.

And then the last point I wanted to make, and this is a little bit off topic, but I think it's sort of what Kurt wound up with also, and Robin, I don't want to steal all your thunder. You're going to go in details into some of this later, but I think--well, I think it's important of enough point that maybe you need to hear it twice.

Because one of the things that the first Congestion Study determined was that there was an area of concern around the Tucson and Phoenix area. And I think it's because we portrayed these areas as load pockets and have done for a number of years now reliability must-run generation studies to show that even though we don't have transmission capability enough to meet all of the load here, that the 20% of the peak capacity that is required to be met by local generation is really only a few hours of the year. That generation is in the market at those times, anyway. In fact, the studies have always shown that the cost of that liability must-run generation is zero.

But the point I want to make here is all of this stuff in red is planned transmission except for this piece of the Southeast Valley Project, which is a project going from the Palo Verde hub all the way around south of Phoenix and then back up into the southeast part of the valley. This part is actually built, and the rest of it is permitted and will be constructed--at least at this point, the plan is by 2013. And Salt River project is managing all of this, and they have all the permitting.

APS has a project that's the Palo-Verde-TS5-TS9-Pinnacle Peak Project, which is a northern loop around the valley, if you will, that winds up at Pinnacle Peak and is going to really reinforce the northeast part of the valley. It's all permitted, and it all will be built by 2016. However, this piece right here, which I think is the most important piece of it, we are going to begin construction within a couple of months, and it's scheduled to go in service in 2010.

So Rob will give you some more information on that, but I think the point is, at least from my point of view, especially with the decrease in the load forecast that we're seeing today, this area is going to be in good shape for 10 and beyond, maybe even up to 20 years with this planned transmission.

With that, I'll turn it back over to Joe.

Joe Eto: Thanks, Bob. Thank you very much, Bob. I'm going to open it up to Q&A, but I'm going to take the prerogative of the moderator to ask a couple of questions of my own. I want to thank you, especially, Bob, for commenting specifically on some of the areas that DOE had identified in its first study. And in that spirit, I'd like to ask Dean and Kurt and Wally, you're from the Northwest also, to speak a little bit about the two other areas of concern that were identified in the 2006 study, one being the San Francisco Bay area. If there's anything in the historical record that speaks to that, I'd be interested in hearing what your findings are. And then the other being the Seattle-Portland corridor and what in the historical data speak to those.

Again, we will have panels later on today and tomorrow speaking about future studies in which we'll talk about some of these conditional areas that were identified in the first study, but now I want to just focus on--and Bob, you've spoken very eloquently about the critical area that was identified in one of the areas of concern--but I want to just make sure we circle the wagons and get information on the other areas of concern that were identified the first time around. So, Dean, do you want to speak first to the granularity of the historic analysis vis-à-vis San Francisco, and then secondly, about your numerical findings with regard to Seattle-Portland? And then I'll ask Kurt to speak more contextually about Seattle-Portland specifically.

Dean, are you on?

Dean Perry: Yes. Regarding the granularity of the work that we did to analyze the historical data, in terms of looking at these, I guess, little areas within the system, I guess I would say that maybe unfortunately, the data that we are looking at, those 23 paths, are really major interconnections, and they don't get right down to the smaller areas within the system.

There is additional data that, I guess, particularly with the actual flow data, that might be available if we wanted to dig down into some of the particular areas of the system. But really, the, what we looked at primarily deals with the, more of a macroscopic view of the transmission system, Joe. I'm not sure if I addressed the question exactly, but that's as I heard it, and that's kind of my response to it.

Joe Eto: Well, that's fine. We just wanted to make sure we understand the limits of what you were able to analyze and that we're not missing something about San Francisco that would be in your analysis.

Can you speak, then, to what the record tells us about Seattle-Portland in terms of what you saw historically in 2007? Dean, I wanted to ask Dean if he could speak to an area of concern that was identified in the 2006 study, which was the corridor between Seattle and Portland, and I wanted to ask him, wondered if that was, what the historic information from 2007 show with regard to that path.

Dean Perry: Between Seattle and Portland, if that was, I think what I heard was the question, again, the paths that we looked at in the Northwest didn't get internal to the Northwest. There is, again, additional, there are paths between Seattle and Portland, WECC paths, that I believe there is data available that we could look at, but we haven't actually looked at it. We've looked at, of course, coming into the Northwest from Canada, coming into the Northwest from the East, and then going out of the Northwest, particularly between Seattle and Portland. We haven't had a chance to actually look at that data.

Joe Eto: Okay. Thank you. Let me ask Wally and/or Kurt, being from the Northwest, to speak to what the historic record might say about that area, or how we ought to understand what might have happened in that area since then.

Kurt Granat: Yes, this is Kurt Granat of PacifiCorp. I think a lot of what was happening was the, traditionally, there's one section there was the event of a single 500-kV and a lot of underlying system, which worked well for the generation that we had, say, in 1980, which was about when we stopped building lines, where you had Trojan on the south end, a 1,000-megawatt plant, and you had, Trojan was a nuclear-powered station. And you had the Centralia plant at 1,300 megawatts on the north end of that system. And it was sort of, that was the balance.

Since that time, Trojan was shut down and decommissioned, and so the south, southern generation, what's there is now all gas-fired, and they're just recently adding some large combined cycles, or at least one, on the south end of that. But on the north end, there were, I think, three or four 500-megawatt combined cycles added around, close to where the Centralia plant was, which the result is that buying's going south. And I think there was some, the BPA had some control issues and has been taking actions to get that under control since. But I think that was the change that had happened.

Joe Eto: Thank you. Did you want to add to that, Wally?

Wally Gibson: I would. This is Wally Gibson with the Northwest Power and Conservation Council. The I-5 corridor was actually a part of several paths internal to the Bonneville balancing area. And as Kurt mentioned, it had some problems a couple of years ago. Bonneville is actively engaged in an expansion project on the I-5, in the I-5 corridor north of Portland. They haven't finally committed to the decision to build the project, but they're pretty much through the process of working on the NEPA process right now, which has, because Bonneville's a federal agency, is a big deal for it. But I think, everybody expects that that, the I-5 corridor will be expanded as part of a general expansion to take account of the increasing wind generation at the east end of the Columbia River Gorge, because you get that, the I-5 corridor actually picks up a bunch of parallel flow that goes across the Cascades north and down, as well as some of the parallel flow that goes through the Gorge and up to Seattle. So there's still a flow in both directions.

But the basic message is Bonneville is actively engaged in addressing that issue, and everybody expects it's going to go to completion.

Joe Eto: Thanks. That's very helpful. So I want to ask a general question to the entire panel. Dean, your analysis focused on 23 specific paths, but I know that within the path rating catalogue, there's something like 69 of these paths in the West. And I want to just make sure that now, again, restricting ourselves to the historical record, whether we're missing anything by not having considered some of these other 40-some-odd paths. And just to make sure that it's not just for the looks, but there's also good reasons why we weren't looking in other places. And so either from the other analysis you might have done, Dean, or areas that you, the experts here, are aware of, are there other areas in the West that, from the historical perspective, ought to be ones that we should make sure we take a close look at?

So let me ask Dean first and then open it up to the panel to see if they want to add anything to that. So Dean?

Dean Perry: Yes, I think, I believe that of the 23 paths that we picked, I think we, again, have all of the major paths in the Western Interconnection that are probably of most interest to folks, and that was really one of the bases for selecting those 23 paths. There are, of course, additional paths, the additional 40 or 50 paths that could be, some of them could be looked at. Those that are, those paths, some of them are internal with the control area, and we wouldn't have access to the schedule data from the e-tags for those. I believe right now the tags are only between control areas, so we wouldn't be able to get information on the levels.

But again, back to the importance of the paths, I think we picked the, I believe, unless Kurt or Wally or Bob have some other ideas, I think we picked all of the major paths that people most often refer to when we're looking at enhancements to the interconnection as a whole and on more of a bulk system or a bigger, larger system basis.

We did, the 23 paths, back when we selected them some time back, they were reviewed by users of the system, the providers and planners, and at that time, anyway, folks kind of agreed that those were probably the most important paths to monitor on a historical basis, which is what we continue to do.

We can always add additional paths or make changes in the future as we need to, but I think that's kind of my thoughts on it now, Joe.

Joe Eto: Okay. Thank you, Dean. Do any of the panelists want to add something to that?

Bob Smith: Yes, Bob Smith, APS. I think I just agree with Dean from the Southwest perspective, anyway. I think there's a couple of things. One, I couldn't think of any other paths that have commercial demand that are significantly restricted beyond the paths that we went through here. And then the other thing is, and I think it was illustrated by the sort of map of the overall Southwest, if you look at future resources in, say, the Rocky Mountain area, that might be trying to get through the Southern Path into California, I think the paths that we've selected are the ones that you would likely need to reinforce to allow that to happen.

So I guess, Joe, what was the third type of--?

Joe Eto: Just if we're missing something by not having looked for it.

Bob Smith: I'm trying to think of the initial study. You have the critical congestion, the areas of concern, and the other one was conditional?

Joe Eto: The conditional, we'll talk about in the context of the paths on future studies of congestion.

Bob Smith: So I think, though, that the conditional congestion that was coming out of the Rocky Mountain area, the paths that we've talked about already and that Dean included for the Southwest would be the ones that would have to be reinforced to help solve that issue.

Kurt Granat: Yes, Joe, this is Kurt Granat. I think, yes, there are things that are missed, but for the purpose of your study where you're looking at the congestion, the day-in and day-out impedance of energy markets, I think we've caught them. I think we have caught the ones that are needed.

Joe Eto: Thanks, Kurt. Wally, do you want to add anything?

Wally Gibson: No, thanks.

Joe Eto: Okay. All right, let me open it up to the audience if there are questions. I ask that you step to the mike, identify yourself, and then ask your question.

Doug Larson: Doug Larson, Western Interstate Energy Board. And actually, two questions. Dean, are we seeing, in your analysis--this is for 2007--if you've done the analysis of historic flows going back a number of years, are you seeing any trends in greater utilization or less utilization of the transmission paths?

Dean Perry: Yes, Doug, as I understood the question, if I heard it correctly, it's regarding looking at trends, and if that is the question, I didn't mention, but we have over the last two years been looking to see if there are any trends in use. We looked at it last year and we looked at it this year. Not a real scientific way of looking at it--we just kind of tried to get an idea a little bit of what's going on from a macroscopic viewpoint.

And I guess I would kind of conclude--it's not real definite--but I would kind of conclude that we seem to be seeing a lower, a reduced utilization or usage on some of the lines, maybe due to reduced load growth or maybe due to the fact that there is some construction going on now, which might be unloading other facilities. But I think we're seeing a slight trend towards a possible unloading of some facilities. And we'll continue to do this in the future. As we look at additional historical studies, we'll continue to look at trends. And it's more on a macroscopic, bulk system level, but yes, we are looking at it, Doug, and that's kind of what we're finding so far.

Doug Larson: Thanks. Joe, if I could ask one more?

Joe Eto: Sure.

Doug Larson: Because from where I'm standing, Dean, is that one of the missing pieces from the data you have is we don't have good ATC data to include in this analysis. We looked at historic flows and we looked at schedules, but we didn't have good ATC data. And I hope this will be remedied in future years.

But I'm wondering both, Dean, if you could explain the problem with we had with the ATC data, and then maybe Dean and the rest of the panelists speculate if we had that data, what would it tell us?

Dean Perry: Okay. Yes, regarding the ATC data, yes, you're right, we did try to gather--in fact, OATI did gather the ATC data off the West Trans OASIS site. What happened was for whatever reason--whether it's correct data or whether it was missing data--but all of the ATC data was at a value of zero, as near as I could tell. And yet I don't know whether it's an interpretation of the writers posting the ATC values or whether it was a matter of not posting it, or what the problem was. We just didn't have time during the study to dig into that problem. That is on our list of recommendations of things that we need to look into as to why that's happening, and is it accurate or is it a matter of problems in posting the data on the OASIS site. Right now I don't know what the problem, but it was definitely, it was not usable as near as I could tell. And I think it would be, from my standpoint, it would be very valuable to have ATC data available for us to use. It would complement the schedule data. We could get firm and non-firm ATC values.

I think also we should look at getting more information on the reservations that were made on the paths, as well as the status, as denied, refused, request for reservation rights on the paths would also be helpful.

Joe Eto: Do any of the panelists want to respond also?

Kurt Granat: Yes, Dean. This is Kurt Granat. One of the things we found on, when I was getting the data for you on our paths, when you're asking for like a firm hourly ATC number, if we've sold the path long-term firm, basically, that is their capability, because our long-term firm customers have the right to come in up to shortly before the hour and make a change in their schedules. So it's like a theater operator who has a bunch of seats that have already been sold but the people aren't there--you let somebody sit in it as long as they're willing to get out quick as soon as the customer shows up. But so I doubt that, I asked for the data and our operator merrily gave me data, and pretty soon I'm sorting through three gigabytes of zeros--something's wrong here. So anyway, that wasn't necessarily wrong on a lot of these paths where there's no ATC long-term.

Joe Eto: Thanks. That's helpful, Kurt. Did you want to comment also, Wally?

Wally Gibson: I'd just add, that's--the ATC part is one of the parts of the congestion thing that we don't see. It's the "what's not available in the first place" before any ever get to the flows in the schedule part. And as Kurt mentioned, Kurt described a lot of the ways why people use, how people use the firm capacity that they have. That doesn't necessarily end up in flows on any given hour, so that's really important to keep in mind. So that's why the ATC information will be really important looking forward, but--.

Joe Eto: Thanks, Wally. Do you have a question, Alison?

Alison Silverstein: Why, yes. Thank you. I'm Alison Silverstein. I'm a consultant to the Department of Energy, and I'd like to ask you guys two questions. One of them hinges on the point you just discussed, that both Kurt and Wally talked about the fact that excess schedule requests get weeded out and eliminate some congestion before it ever turns into data that we're looking at. But Dean shows actual schedules exceeding past capability on numerous paths for numerous hours. Can you talk about how do we interpret this with respect to congestion and what it means with respect to schedule practices?

Kurt Granat: Okay. This is Kurt Granat. Well, part of it is, I know of one exception on there. But part of it on most of the paths, if there's a firm counter-schedule coming in, the path operator will send "saw non-firm" against it. So that will, if you add up the numbers on the net basis, they'll keep it down.

The exception I can think of is the Bridger West path, and that was an issue where apparently there are two slots on the tag where capacities get entered. One shows the reservation capacity and one shows the hourly energy schedule. And the one customer has the right to up to like 1,400 megawatts on that path, but they can declare different--on their historic contracts, they have different abilities to use that for different purposes. And so if you add up the different purposes they have, it adds up to like 1,700 megawatts. And the customer noticed that Idaho, as long as they kept their 1,400 scheduled on the energy side, Idaho wasn't, the system for a while wasn't catching that. They basically were putting in their maximum reservation under these three contracts that simultaneously added up to 1,400, and so on occasion you'd, and they kept it, their actual use stayed within their rights. It's just the most modified sense to make them take what they're using it for before the hour. So that was the exception.

Alison Silverstein: Let me ask this in a different way, then. If our job is to look for where is there congestion, and we see a path that consistently has schedules in excess of path capability, or actual flows in excess of path capability, is that something that we should say, "Gee, that puppy's congested?" or should we say, "Gee, the data are funky," or "Gee, there are scheduling practices that make this something that needs more looking at"?

Wally Gibson: You shouldn't see actual flows in excess of path capability. That's a violation of--.

Alison Silverstein: What if we see scheduled?

Wally Gibson: What you're seeing on the schedules is, I think we're just seeing on the schedules, and particularly you saw that on Path 3, the Northwest to Canada path, is the sum of the firm and the non-firm schedules can exceed--the direction, in any given direction, can exceed the OTC in that direction. And what you're seeing is the Western practice of allowing non-firm schedules against--this is basically allowing non-firm schedules against firm schedules. I don't think Western practice allows you to, you wouldn't see a sum of firm schedules exceeding OTC, but you can see firm plus non-firm exceeding OTC, and that basically means you can manage that problem, because these guys can get kicked off on the spot if there's a reliability problem.

I think how you interpret that is there is excess demand for use of that path. I think that's pretty clear. And in the Northwest to Canada, that is an issue, and I think there are some plans in the offing to expand the capability, particularly north to south, which is the one where you're seeing that spike in scheduling, and it's non-firm plus firm scheduling. This is Wally Gibson.

Alison Silverstein: This is Alison with another question. Dean's last slide showed the most heavily used transmission paths in the West. These are, and this is your opportunity to tell us once again, on the record, whether a most heavily used transmission path should be viewed as one that is congested and why or why not.

Dean Perry: That's actually a good question, and I don't know whether I can go on the record right now to say whether they are congested or not, and that's always an issue that goes through my mind, is whether heavy usage means congestion. And I think generally, a congested path will be shown as being heavily used, but the reverse, a heavily used path may not be necessarily considered to be a congested path. And obviously, the Path 19, the Bridger West, is a prime example that we often refer to, at least with the most heavily used path, but I would think probably users of it today would say it is not congested today, because it was actually designed to be used that way. And so I guess, again, I'm not trying to avoid this, a firm answer. I'll give you a non-firm answer. I think it's more that congested paths will show up as being heavily used, but the vice versa isn't necessarily, isn't necessarily always the case. And I don't know, others may have some comments on the particular paths we have listed. But I think in general, that's kind of a general response.

Kurt Granat: Yes, this is Kurt Granat. And yes, and I think, obviously, looking at the top list is a real good start. But it keeps getting more complex than that, because what would happen. You know, Bridger West is a good example, because that's very much how it was designed to be used. It was designed to trickle the energy into the Northwest to allow the hydro system to be recharged at night and flexed during the day. The system behind it really can't move much more power to Bridger. So, I mean, you could, if it was upgraded to 2,800 or something, that would be nice, but beyond that you would need to be looking at stuff into Wyoming, and to get it up there, you'd be looking at a new line off into Idaho, and then from where do you go from there?

So just one of the reasons for the footprint, like on PacifiCorp's projects, but you have to look, I mean, you obviously look at the path, but then you have to look at other aspects of it.

Alison Silverstein: Thank you.

Joe Eto: One more quick question, Rich?

Rich Bayless: Joe, this is Rich Bayless at Northern Tier Transmission. Just to amplify on Alison's question a little bit, Bridger shows up as the most loaded path. And it is. It's a complicated issue, though, as whether it is congested and how to fix it. The Northern Tier parties, Idaho and Pacific, have a gateway sort of project set to try to alleviate that congestion and make--but it is not only congestion in real time and ATC-wise, but in the queues for transmission requests, there was also a whole bunch of queue requesters in there looking for the paths going west. So Pacific's building new capacity out of Wyoming for two purposes--one for their network loads requirements, and they also have a plan to build a second line, super-size that task, if you will, to handle the queue requests and to look at the congestion going west.

Under today's commercial framework, they went out and looked for commitments to build that additional capacity above what they need for network load, basically build a second path and line because of the congestion, because everybody wants that path because of the queue requests. Nobody stepped up to commit to that, so right now we're in a quandary, what do we do with that? Is there congestion?

On the other side, with carbon constraints coming in and a big part of that path being loaded with coal, there's not a lot of assurance down the road as to what that might be used for if they do spend the money. If they spend the money without all these through parties that want to go to the Coast paying, helping them pay for it, it will end up on their native load customers' docks, which is not a big load density area. It's the part of the country that these big highways to the Coast would traverse. And the problem their regulators have is they can't put costs aren't committed for to go to the Coast on back to network customers. So not only is the data that shows congestion an issue, but some of these other issues make it very difficult to figure out what to do next.

Joe Eto: Thanks, Rich. I'm going to call this session to a close. We're going to break for lunch now. I want to just again remind folks that this is a draft report that was presented here and commented on. We are looking both for comments on the draft report as it's been prepared to date. There's a link on the website to do that, and the Department itself is looking for more general comments about how to interpret this historic information from the standpoint of preparing its next study. The type of information you share, for example, it should be very valuable for the Department in that regard. If others have similar types of observations on it, we encourage you to get those in.

We're going to break for lunch now for an hour. We'll come back here at one o'clock. There's a light deli restaurant through the lobby down to the right. It's called the Red Rock Cafe. There's also places within walking distance of the hotel itself.

But before we adjourn, I'd like to have you join me in thanking the panelists for an excellent set of discussions about historic congestion in the West. All right, thank you. We're adjourned for lunch.

[lunch break]

Joe Eto: All right, I'm Joe Eto. Again, I'm moderating the second session. This will be looking a historic congestion Eastern interconnection, and the showpiece of this session will be a piece of work that the Department of Energy commissioned for OATI, Open Access Technology International, to conduct for us to gather publicly available information throughout the Eastern interconnection. You'll hear about three sources of data they were able to look at, and their findings about congestion.

I want to -- again, just as I emphasized in the first session, this is very much a work in progress. The draft report from this work is posted on the website for the DOE 2009 Congestion Study. Folks in the East were very helpful in helping us putting this together, but we are still doing a lot of analysis of these data, we are very interested in comments that folks might have on the study itself and how to make sure that it can be interpreted most appropriately. This session is a first to begin that process.

So we're going to lead off with Jagjit Singh from OATI. Dr. Singh is Vice President of Western Market Development Open Access Technology International, where he is currently involved in analysis, design, development of software for electric operations. He has a Doctor of Science degree from Washington University in St. Louis, along with 30 years of experience in electric power operations, planning, and control.

Before joining OATI, he was Executive Engineer in system operations at Salt River Project, where he worked for 23 years. His prior experience includes three years of work at Electric Power Research Institute and the Department of Energy performing and planning studies for when energy penetration and integration into the Electric Power System projects.

All right, Dr. Singh has been involved with industry development of OASIS, CIM, e-Tags, and other operational systems.

Jagjit Singh: Thank you, Joe. Good afternoon. I'll start off with giving a little overview of our project, and then go through the presentation after that.

As Joe mentioned, our goal is to collect and analyze publicly available data to identify congestion during 2007, and we collected data from three different systems --OASIS, Market Systems, and IDC.

If the data was not directly available, we did go to the operators of these systems and requested the data to be received for the study. And the study approach was to develop a set of matrices for congestion similar to the ones that you saw in the morning session. Oh, yeah, metrics not matrices. Data collection and then the second -- of course, we started with the data collection, then analysis of the data, and the real key to our study is the involvement of industry advisors in reviewing some of the metrics as well as the results from the study.

And the advisors have really played a very important role in producing what we have today, and we are still working with the industry advisors to get to the final report. As I mentioned already, study process -- we had three parallel works. We actually didn't do them in series. We went ahead and collected the data for each -- from each of the systems in power.

The way we were going to define the congestion -- and I think it was pretty clear from the previous presentation this morning that congestion can happen during different operating stages of doing energy transfer between two points. The reservation process is really a planning process, and the congestion can happen during that planning process that there may not be enough capacity available to make reservations. And that is the data that's available on OASIS, and OASIS data leads to that.

And the second limitation can happen is during the scheduling process, and then that would be available only from the market information as well as tags. However, in some cases, there may be data available on OASIS as schedules.

Real time data congestion is during the hour of operation, and limitations are caused during that time period are managed through the IDC process, and also the market operations. So these are the three different sets, and we will look at them separately.

The presentations have -- how we are going to do is I will be talking about the OASIS and IDC results, and then Farrokh Rahimi from OATI will talk about the market results, and he will also combine the conclusions in the end.

Before I go into the details of what the results are, we will look at the metrics and the limitations of these metrics that we used, and the data collection and availability, and then the results and the conclusion. The metrics we used for ATC/AFC were -- we counted the number of hours -- any one of these were zero separately for firm and non-firm, and if -- and then we ranked the flowgates four interfaces between transmission providers and ranked them by the yearly count. That's how we did the ranking of these flowgates and/or interfaces.

And the second set of OASIS data is the reservations data, and we did the total megawatt hours for each month, however, we ranked these again by the yearly total. And one of the differences that you look at the reservations and the West versus East is that all the reservations seem to be source and sink bound in the Eastern interconnection. In other words, the source and sink is identified at the time of reservation, and that's held, and also the same reservation may appear on more than one node.

To avoid any double counting, all the reservations that we considered were the reservations that were sinking into that particular OASIS. I want to make sure that this point is made clear, because there is the possibility of seeing the same reservation on more than one OASIS.

The limitations of these metrics -- I think I talked about this before, but these metrics only provide information regarding the mark that is for the long-term reservation process. They don't really have as much -- they don't have any information in terms of what happens in real time, for example. And so this is where the planning of the delivery of power is impacted by these metrics.

And the reservation metrics is essentially providing information on how much energy was planned to be delivered to any of the regions. And you'll see later on how I'll describe -- we tried to combine these into zones and to also compute how much reservation was done from one zone to another in terms of source and sink.

And one of the things to note here is that the ISO and RTO markets do not really use any reservation process internal to their system. So the only thing this reservation and AFC information can provide is the information where energy is being brought to their boundaries. So that's the main thing to note here.

And IDC metrics and limitations -- for IDC, we looked at the number of TLRs below level 3 and ranked the flowgates by the yearly count. And also we are still in the process of computing the total number of hours in TLR for each of the flowgates and then we will be ranking them in the same manner. This is not yet reported, however, towards the end you'll see we do have a total number for each of the major IDC regions.

And the total curtailed megawatt hours for the year also is another metric that we will compute, but we haven't yet done and it will be done as part of the final report.

The limitation on this metrics is that it does not provide the impact on individual schedules. The information that we were able to obtain is only based on a flowgate information, and if we were to look at which generation or rich loads were limited because of the TLRs, that information we were not able to catch.

Data collection and assumptions -- actually, there is a full detail list in table 5, section 3.2 of the report, which talks about every system where we collected the data if the data was available or not available. The point to notice, that most of the time, the data was available. In some cases, we had no data or the data was missing. In case of ATC calculations, there was a data that was available sometimes into the system data template, but not -- and so we were able to use that information if it was there, but in case it was not there, we were able to go to the offerings data that the transmission providers had and were able to deduce the ATC information from the offering data.

While doing this ATC calculations, we did notice that there were a lot of paths that were internal to a particular transmission provider or maybe derived from the external interfaces of these transmission providers. So the decision was made to only do the metrics for transmission provider to transmission provider interfaces. And that is to limit the number of interfaces that we would be looking at.

In case of RTO market, ISO markets, ISO in New England and New York ISO, they provided data on the interfaces in terms of schedules, which was then converted to be used as the ATC data.

Reservations assumptions were that reservations sinking into each DP controlled are considered to avoid double counting, and I already discussed that. And then also the location data -- one of the goals of the study is to portray our results in terms of geographic location. So far, you have had Midwest ISO provide us the flowgate location mapping, and so we were able to use that to generate some locational results from the AFC metrics, and these were done using weighted average of the AFC metrics computed for each flowgate to provide that information.

And the source/sink to zone were created based on essentially OASIS territory and some surrounding regions, and this was done based on the information that was either available as addresses in the [inaudible] registry or it was available from the transmission providers.

And some of these, we are still in the process of changing as we get more recommendations from the advisors. OASIS posted flowgate names to IDC names. Mapping is still being sought, and Midwest ISO has provided that to us, and we are hoping that other advisors will provide that same information.

This mapping is necessary for us to correlate if there is any kind of correlation that might exist between the flowgate metrics and IDC metrics for those flowgates.

The metrics for a firm AFC/ATC is generally higher than non-firm, which is probably expected. In other words, the flowgates or the interfaces are generally much more subscribed for the firm service and are less subscribed for the non-firm service. And then we did a summary for this presentation. We looked at the flowgates and interfaces that were more than 50% subscribed, and this table kind of lists how many were there that were subscribed and Southwest Power Pool, or SPP, looks like it has more of the firm flowgates – the 24 of those that have been subscribed more than 50% during 2007, and Southern Company is at the bottom of this list with two interfaces being subscribed more than 50%.

We didn't have any data from PJM and Entergy, so that is not available on this. And MAPP and Florida, also, there was a limited amount of data available. We were not able to get data for a few months for both of these regions.

Results for AFC -- location results -- our calculations show within Midwest ISO because that was the only region where we had the location information available. It's Minnesota-Wisconsin tie within the Midwest ISO is the most subscribed region. In other words, the flowgates in that region were the ones with the highest number of count for AFC being zero.

And location results for other OASIS, we haven't done yet, and we will be doing that here in the near future. The one other point to note here in terms of location was that Florida sub-region has only limited ties to the rest of the Eastern interconnection, and that is through the Southern Company, and that interface was, I believe, one of the two interfaces that were over 50% subscribed for Southern Company.

And mostly firm services are offered for daily and higher increments. This is just an observation looking at the data. The firm services are offered at daily, monthly, and yearly services, and where is the non-firm services are offered generally as hourly, daily, and monthly services.

The reservations total megawatt hours for firm reservations are significantly higher than non-firm except in case of PJM where we found the non-firm megawatts are higher than the firm megawatt hours, which may be due to some of the market activities that may be happening in the shorter time horizon.

We did notice that there may be some other areas with a similar reversal of the results, but that will be reported in the final report. There is a change in direction of overall reservations between firm and non-firm.

Let me talk about overall reservations before I discuss this result. The overall reservations -- what we have done is we took reservations from all the OASIS sites within the Eastern interconnection, combined them into a firm and non-firm megawatt hours, and the netting of those reservations by the zones that are reported in the tables 6.

So these reservations really provide an overall picture of reserve megawatt hours, both firm and non-firm, how they source and sink within the Eastern interconnection. So in case of firm -- the sources are from -- the majority of the sources are coming from PJM Canada into the MISO region. The sinking is happening in the MISO region, and for the non-firm, it kind of reverses in the sense that MISO and New York ISO, they're not singing but sinking into PJM East and some in Entergy and MAPP.

And so we noticed that this could be due to how the real-time market or the near-term market is affecting reservations that folks are making to move energy in and out of the market. So that's sort of conjectures here, it's not really a conclusion.

Reservations only indicate planning for schedules and actual schedules or e-tags would be better reflective of delivery. This was pointed out by several of the advisors and also if you listened to Dean's presentation this morning, it seems like that e-tags will give a better picture of what actual happens in near term.

These two diagrams are going to be showing -- or essentially show the picture of how the overall reservations that followed within the Eastern interconnection. You're probably not able to read it, but the rightmost -- those three are Midwest ISO, East Central, West and East regions, and then if you go -- and there is a WC zone, which is really Iowa non-Midwest ISO region.

And if you notice on the non-firm reservations, as I pointed out, the New York and Midwest ISO Eastern and Central and West, and the thinking here has been to the PJM East region, the rightmost one.

Next, I'll talk about the IDC results. As I mentioned before, we haven't yet received the information on the curtailed megawatt hours. We are looking into trying to get that information out of the IDC database. I believe Jim can attest to that. That information is not easily available within that database either.

So -- here we ranked -- in this particular table, we ranked them by the total number of TLRs that were issued during 2007. SPP, our Southwest Power Pool being number one; Midwest ISO, number two; ICTE and so on and so forth. I am also pointed out by Southwest Power Pool that during the 2007 there were several ice storms and snowstorms in that area, and that's why maybe these numbers are so high, because of the bad weather conditions causing many of the outages, which lead to then issuing of TLRs.

And that pretty much covers my part of the presentation. Thank you.

Joe Eto: Okay, next I'd like to introduce Dr. Farrokh Rahimi. He is Vice President of Market Design and Consulting at Open Access Technology International where he is currently involved in analysis of power and energy markets and OATI's Smart Grid activities. He has a Ph.D. in Electrical Engineering from MIT along with 38 years of experience in electric power systems analysis, planning, operations, and control.

Before joining OATI, he collaborated with the California ISO in Folsom, California, for nine years since the inception of the ISO. His prior experience also includes eight years with Macro Corporation, subsequently KEMA; Electric Power Research Institute; Department of Energy; Systems-Europe in Brussels; a little stint with Brown Boveri, now ABB. He started his professional career as a Senior Engineer with Systems Control in Palo Alto.

Farrokh Rahimi: Thank you, Joe, ladies and gentlemen. I am going to be talking about market metrics, and one thing before I start going into the details of the presentation, when we talk about market metrics, we are relying on price information, whether it is location or marginal prices, shadow prices, or also flows and congestion rents that come from the market.

Now, when we started doing this study, we started, of course, with the five existing LMP markets and the Eastern interconnection, and the total of seven organized markets in the U.S. right now or in 2007. California and ERCOT do not have a nodal pricing, and you already saw this morning there was a question about, for example, San Francisco. There is no price transparency and that is why the folks who are looking into the historical data would have problems tracking down information and congestion into San Francisco because there is no pricing mechanism to detect that. Basically San Francisco in California was declared as an inactive zone, and the congestion in San Francisco is dealt with in real time without establishing any prices as basically as reliable [inaudible] -- more or less a similar situation in ERCOT.

After the five LMP markets that we were looking at, you'll see that SPP is missing on this slide. SPP has started an LMP market that they call "LIP," in February 2007, but so far they lack a day-ahead market and, moreover, the LMPs do not have the three components that the LMPs usually do have; namely, a congestion component, a loss component, and a system component. We have developed a workaround that problem, and, however, in the present report, we do not have the SPP results.

So I'll be talking about first the description of the market metrics that we are looking at and we have defined and we have looked at. Then, at the four markets -- Midwest ISO, New York ISO, PJM, ISO New England -- that do have LMP markets both day-ahead and real-time, and then I will conclude with some observations and conclusions.

The market metrics we have looked at primarily -- it's the shadow price of congestion. So congestion frequency, or number of hours that a transmission constrained, was binding that knew it had a non-zero shadow price, and this is really what the market produced in 2007.

Basically, a non-zero shadow price for a constraint indicates that that constraint is binding in hours on one side of a generation is more expensive than the other but yet the more expensive generation has to be used because of the congestion on that particular constraint.

Now, with respect to the level, we didn't want to look at every single constraint that had a non-zero shadow price, so we established a threshold and with the project advisors, and we ended up with 5% of the offer cap in all of these markets. The offer cap is $1,000 a megawatt hour, so anywhere that the shadow price of congestion was below $50 a megawatt hour, we did not really consider that to be serious congestion.

We did look at some of the numbers below $50 a megawatt hour just for curiosity, for example, in the case of New York ISO and also in the case of ISO New England, and one of the other reasons was that we did not see a whole lot of very high levels of shadow prices over there.

Then -- instead of just looking at the total number or other statistics of shadow prices exceeding $50 a megawatt hour in magnitude, we divided them into bins. So between $50 and $200, $200 and $500, and about $500, both on the positive and negative sides.

The other metric, or the other market metric, we started defining and looking into was the Congestion Rent, which is basically the product of the shadow price and the flow, or the constraint limit, because if a path or a constraint is congested, the flow is testing the constrained limit.

In most cases, this information was not publicly available, and therefore we used the sum of shadow prices as a surrogate for this metric. In some cases, information was available, was made available privately, but we decided -- although we computed the metrics, we have decided not to include in the report for consistency and also because the information is not publicly available.

This was just basically these two sets of metrics; namely, the frequency and the sum of congestion rent related to shadow prices identify binding constraints. Now, then, the next question is how do you identify constraint areas -- areas that are generation areas where generation is constrained to get out or low pockets with energy's consent to get in. One possibility is to look at all of the transmission corridors or all of the constraints surrounding a particular area, but this market established will give us a different way of looking at the same problem more easily, and that is through the congestion component of the LMPs that they post.

So the LMP, or Locational Marginal Price that they post for each location -- it's in pricing nodes in the system, the LMPs generally have three components -- a market-wide component, which is the same in all of the nodes in the footprint. Then there is a marginal loss component that puts a positive or negative, depending on whether the particular node is close to the load or farther away from the load and how much the impact of incremental generation from that node is on the system losses.

And then there is a third one, which is the congestion component of the LMP that we call LMPCC in our analysis, and that is directly related to whether or not that particular node is in a constrained in area or a constrained out area. Several transmission paths or constraints could be conducive at the same time, but their collective impact determines the sign of the congestion component of the LMP at a particular location.

Generally, if the LMP at a particular location has a positive congestion component or positive LMPCC, it is an indicator that that location is a constraint in area. In other words, generation is difficult if you get in because of transmission constraints. More expensive generation has to be dispatched nearby and, therefore, the congestion component is higher.

A negative congestion component is an indicator that that particular location is in a constraint out area or, more or less, a generation pocket. And, again, here, in order to really concentrate on the nodes with larger magnitude of congestion components, we look at only the nodes that had the congestion component more than $20 a megawatt hour, whether positive or negative, and then also divided that into bins between minus 20, minus 40, minus 40, minus 100, and greater than 100 in magnitude.

Then, as I mentioned, the markets we looked at, or we have looked at, so far, have both a day-ahead and a real-time market, and the question was which one of these two we should be looking at of the primary market of interest. There are, actually, different attributes of these markets. In the case of PJM, New York ISO, and ISO New England, the advisors -- in discussions with advisors, the preference was to look at the day-ahead market because of its more important commercial impact. In other words, there is more volume transacted in the day-ahead market.

Now, in the case of Midwest ISO, the real-time market was actually looked at under the recommendation of Midwest ISO because they really felt that the virtual billing in the day ahead may, under some circumstances, lead into some transition patterns that may not really be necessarily a result of actual transmission constraints that actually persist in their time.

So we are looking at load, of course, for each one of these markets. We have computed the indicators that I mentioned for both day-ahead and real-time, and basically we have all of the data but then the primary one that we are going to look at to correlate the results are the day-ahead for the first few markers and real-time for Midwest ISO and, of course, when you look at SPP you have no choice other than looking at the real-time market because SPP does not have a day-ahead market.

The other question was, okay, did we look at this data over what period of time in 2007? And we chose different time periods -- the entire 2007, peak hours of 2007, off-peak hours of 2007, and then some representative months, peak and off-peak, to take care of the seasonal variations of peak/off-peak time-of-use variations and basically for all of these markets we used annual peak and off-peak and annual total as indicated on this figure in red, but for Midwest ISO, the preference was February peak for winter peak, and then April, off-peak for situations that have over-generation; August, October peak and off-peak, and then New York ISO, PJM, they had different recommendations as to what periods to choose to look at this information.

And, basically, they looked at all of these combinations of these different sample periods -- day-ahead and real-time for all of these metrics. So for each one of the ISOs we are talking about something like 80 or 90 different workbooks that we have. And each one analyzes these different combinations with a number of graphs and so on, some of which are reported in the report.

With respect to data requirements and availability, shadow price data is basically available. The only market for which we did not have the shadow prices of SPP, flows and constraint limits, as I mentioned, for PJM and New York ISO and ISO New England -- and I apologize for missing the "I" in front of ISO in this slide -- it was not available for internal binding constraint for some of them the data was available on the interfaces, an for Midwest ISO, we did have the commercial flow data but, as I mentioned for the sake of consistency, we are not including those results in the report or in the presentation.

With respect to congestion component of the LMPs, as I mentioned, all of these markets do pose three components for the LMP. PJM did not have the three components before

June of 2007, PJM did not include marginal lapses in its LMP computation, but they started doing that following the FERC order, and therefore we had to devise a batch computation approximate method to back compute some approximations to the congestion component of the LMPs, and that is also something that we will have to do for real-time LMPs for SPP.

And basically what we did, we just touched all of the load LMPs and took their average for the given hour because most of these markers use a load distributed reference for computation of the LMPs, and then the difference between the LMP at this location and this number we treated as a congestion component of the LMP -- approximate, but better than not having the data or not using the data at all.

And then all of these markers have different node types to look at. We looked, basically, at generation nodes for all of them, and also load zone nodes.

And then, finally, one of the things that we tried to do was the clustering of nodes that are geographically or electrically closed and also have LMPs that are close to one another, and that is an area that we are working on right now, and that -- that part of the analysis has not yet been completed basically. That is part of trying to correlate all of these results together.

Now, going to, very quickly, through the individual markets to give you a flavor of the types of results that we have obtained -- looking at Midwest ISO, this is the kind of a study -- you can't read this, of course -- the headings are "Binding Constraint," and "Load Chance," that means the number of hours where the shadow price of the constraint exceeded $50 a megawatt hour, and then the minimum of that shadow price for the year, the maximum mean standard deviation and the sum. And basically, in the case of Midwest ISO, all of these shadow prices are negative and basically this is the kind of information that we derive for the binding constraint.

Now, this basically shows the count and, as you see, for the count we have three different colors -- shadow prices between minus 50 to minus 200, minus 200 to minus 500, and less than or equal to minus 500, and the zig-zag line is the sum of the shadow prices that are being used as a surrogate for the congestion rent. This is the sum of the absolute value of the shadow prices.

So, again, here, on the horizontal axis, you have the different constraints, and you have the frequency of congestion and the sum of the shadow prices for these different constraints.

Many of those -- if you go to the previous figure, that counts less than or equal to to minus 500, which is shown in light blue, some of these actually have a number of hours with congestion magnitude, or shadow price magnitude, being less than or equal to minus $500, in other words, greater in magnitude than $500 a megawatt hour. And these are shown on the next graph, and here, again, we have the frequency of shadow price exceeding $500 a megawatt hour in magnitude on some of these constraints and also the sum of those constraints. Because just the fact that the frequency is higher than another constraint does not mean the sum will be higher because you are looking at shadow prices above 500, okay, some may be 1,000 -- they are still above 500 and so even though the count is lower, the fund could be higher.

So this was some sample statistics and information that relate to the first two metrics; namely, the frequency and sum of shadow prices, the sum being used as a target for congestion rent. And now we show you a couple of samples of results for the congestion component of the LMPs, and here we were looking at aggregate -- aggregates in Midwest ISO are basically mostly single-generators but sometimes collection of generators, which are near each other, maybe the units in a plant or a number of small units. So use the word "aggregate" in here. This is the terminology Midwest ISO uses.

And what this graph shows is these aggregates basically order according to the frequency of the congestion component of the LMP exceeding $20 in megawatt hour but on the negative side. So these are basically constrained out or generation-rich locations in the Midwest ISO territory.

And the next one basically again shows the same thing except that for some of these locations, some of these nodes, because you are looking in this particular graph for the entire year 2007, there were periods during 2007 when the sign was changed. In other words, that particular location that was constrained out during part of the year, or some hours during the year, was constrained in with a magnitude of congestion component rated in $20 a megawatt hour in the opposite direction.

So then this indicates that we have to now grow and look at the monthly and seasonal variations for this particular location or aggregates to find out what's going on because they are -- we cannot consistently say a particular location or a particular area is consistently constrained out or constrained in. It's maybe constrained out part of the year, constrained in during another part of the year.

The overall observations -- shadow price of Midwest ISO are non-positive. In some markets, you see shadow prices with both signs. There were quite a number of constraints with shadow prices exceeding $500 a megawatt hour, which we would consider these are significant congestion, at least in terms of the market impact they have as measured by their shadow prices.

With respect to congestion component of the LMPs, as you observe, some nodes show little change of sign during 2007 but some do change in sign during 2007, and so they cannot be consistently labeled as constrained in or constrained out.

Very quickly, going through some samples for New York ISO -- New York ISO, the way we had the public data, shadow prices are sometimes positive, sometimes negative, but then that is because of a lack of alignment between the reference direction for the flow and the constraints on this path. New York ISO project advisors provided information to us to align these constraint directions and the flow directions. And after we did that alignment, then the majority of the shadow prices were negative, as I will show you that in a moment.

With respect to the congestion component of the LMPs, we observed that many, many generators in the New York ISO footprint were electrically closed, and they had very similar LMP congestion components. So just ranking them, that would really mean that we have to rank a whole bunch of these among the first 50 top constraint resources.

So what we did in consultation with New York ISO, from each group of generators, we chose a sample, and namely the ones that are all in a power plant or actually going to close, they would choose just one of those generators in order to use that as basically determining whether the area in which that is located is constrained in or constrained out.

Some similar results for New York ISO, again, we have the statistics of the shadow prices in this table because we had not done a correction of shadow prices. You see both positive and negative signs, but then after correcting for the sign, you see that shadow prices are basically primarily negative. In the case of New York, we, as a nation, before we looked at shadow prices, not just above $50 a megawatt hour, but $10 a megawatt hour because the frequency of congestion above 50 was a little bit less.

However, when we are comparing now the results across the market, we will look at the similar shadow prices; namely, we will just be looking at shadow prices exceeding $50 a megawatt hour. What this graph is showing is that when we look at all of the shadow prices in the top ranking constraint, the majority are negative. It is only towards the tail-end that you see a little blip in here that -- it's red, so this is one of those constraints where during part of the year the shadow price was positive.

Looking at the generators, this is an example of a lot of generators being -- having similar kind of a statistic, and we are doing further refinement in this graph. This is showing the top 50 generators with congestion component of the LMP being negative and in magnitude higher than $20 a megawatt hour, and this is the sum of those.

And here is again looking at the LMPs with congestion components greater than 20 but pretty soon you see as you go through the -- after about the 10th or 20th, it's most of the time congested in the opposite direction. The blue lines indicate the congestion component being less than a record to $20, but it's the red ones are greater or equal to positive. So red ones are constrained in, blue ones are constrained out.

With respect to the observations on New York ISO metrics, very few shadow prices are positive after the sign correction, and very few shadow prices exceed $500 a megawatt hour as opposed to Midwest ISO and, again, as opposed to PJM that we will see next. In those two markets, shadow prices exceeding $500 a megawatt hour do happen rather, you know, significantly during the year. It did happen during the year 2007.

With respect to generation LMP congestion components, again, you saw that predominantly these are constrained out, and most of them show little change of sign, and some generators do change in the sign but they are predominantly constrained either in one or in the opposite direction.

Quickly going through some sample results for PJM -- as I mentioned, PJM did not have the congestion component of the LMPs from January to May 2007, because they did not compute those. They did not have marginal losses in their LMPs. So what we did, as I mentioned, for each hour we computed the simple average of the LMPs at all of the nodes and used that as a reference node LMP, and then we computed for each node the difference between the LMP that they have posted from January to May and for each hour we took the difference of that LMP minus this computed reference node LMP for that hour. So we did this computation for each hour for January through the end of May 2007.

And, again, the same situation like I mentioned in New York, multiple generation locations electrically closed. We encountered those, and so we used the first eight characters of the generation name, and the ones that were similar, we basically selected only one.

Again, this is a table that shows the statistics of the shadow price for the most binding constraints in PJM along with the count, minimum, maximum, mean standard deviation and the sum of the shadow prices. As you see, the shadow prices are all negative.

And then here it shows a subset of those constraints for which the shadow price exceeded $500 a megawatt hour -- so similar to megawatt hour so you do see that the hours of frequent -- you know, you see 143 hours for the first constraint where it exceeded $500 a megawatt hour in magnitude.

And this basically shows for the generator congestion component of the LMPs, and you see that the blue here, again, is constrained out or less than equal to minus $20, and red is constrained in. You hardly see the red. So the top 50 generators, that top 50 generator nodes were basically constrained out, and this is expected basically.

So -- for PJM, the shadow prices are non-positive. There were quite a number of constraints with shadow price exceeding $500 a megawatt hour in magnitude, and the top frequently constrained generators are constrained out, and most generation nodes through little change are fine, and some of them that do change sign have predominantly either constrained in or constrained out.

Now, I should point out that a generator can be constrained in if it is located in load pocket because the LMPs, if there is no congestion between the generator and the load -- in that particular load pocket, the LMPs turned out to be the same congestion components if the LMPs are the same. So it's not a given that every single generator will necessarily have a negative LMP congestion component. That is not true. It's only generators that are located in generation-rich areas and constrained out that will have that sign -- a negative congestion component.

Now ISO New England -- shadow prices are available only for interfaces. ISO New England does not post the shadow prices for the internal constraint. So we did not have that information for ISO New England similar to -- you know, for the other three markets we did -- for PJM, ISO New England, New York ISO -- those shadow prices that we were talking about are all other constraints that they enforce in the market.

For ISO New England, we did not have that. We had it for interfaces and, again, ISO New England -- for those interfaces did provide the flow data, so we could compute the Congestion Rent, but for consistency sake, we used absolute value of the shadow prices as a surrogate for the condition rent.

And the congestion components of the LMPs -- they are available from ISO New England, and although we did not see or we did not have the data for the internal constraint -- the impact of those internal constraints on the LMPs are reflected in the congestion component of the LMPs that we do have. Therefore, in this particular case, we should -- we can rely on the congestion components of the LMPs despite the fact that we don't have the shadow prices for the constraints that actually caused those congestion components to be non-zero.

Some sample results -- these are for the day-ahead shadow prices on the interfaces. Again, we have the total sum and the count from minus 10 to minus 50, on this can go to minus 50. What we observed about ISO New England, the congestion is low. As you see in here, we don't even have a bin that is above between 50 and 200. Basically, the deliverance of the shadow prices are much lower than the other markets that we have analyzed.

With respect to the network nodes, again, if you look at the congestion component of the LMP here, you see the top 50 network nodes ranked by the count where the congestion components of the LMP exceeded $20 a megawatt hour, and these are the ones when actually it was less than record to minus $20 a megawatt hour. Observations about ISO New England, as I mentioned, shadow prices are much lower in magnitude and frequency than other markets we have analyzed, and compared to other markets, the congestion component of the LMPs are lower in magnitude and frequency, and these concern the fact that ISO New England has much less congestion or has much less congestion than these other markets in 2007.

With respect to the market metrics, therefore, we have observed that market metrics based on shadow prices are more consistent than those based on LMPCCs, but LMPCC metrics are still useful, and among the markets analyzed, we basically found that Midwest ISO and PJM had the larger frequency and magnitude of congestion in 2007 than New York and ISO New England, and ISO New England had the least.

Now, in conclusion, as I mentioned before, these are results of these different market metrics for the individual markets that we have analyzed. The next task is actually to correlate these to one another. Some of the questions that come up, for example, are these different markets comparable to one another? In other words, a shadow price or an LMP congestion component greater than $200 in PJM -- is it comparable to an LMP greater than $200 in Midwest ISO?

Our basic assumption in doing this kind of a correlation is a positive answer with sort of a caveat, and that caveat is that the market participants, who participated in this market, if there are systematic differences, they are going to arbitrage them out. And, therefore, when you look, for example, at the day-ahead market, we expect that, over time, these will converge to one another because of this arbitrage of the market participants, and because these markets have been in operation prior to 2007, for a number of years, this arbitrage, we're assuming, has had its impact, and so you are going to assume that these numbers that we get in these different markets are comparable.

Now, when we do the SPP market because it doesn't have a day-ahead market and because it has been in operation only since February of 2007, that assumption may not be as easily made, but we'll see when we get there.

And so, another thing is to correlate the market metrics with the IDC and the OASIS ones. Again, when we look at the market metrics, some of these have to do with commercial decisions that people make. And particularly in the day-ahead market, there's literal bidding and so on and so forth, so we are going to look into that and see if these different markets reinforce each other, or they are different ways of looking at the same problem from different directions, and therefore these are perpendicular axes that we have to consider rather than parallel axes that have reinforced one another.

So these are some of the things that we are still looking into with the help of the project advisers to finalize the report. And I thank you very much.

Joe Eto: Thank you, Farrokh. I'd like to echo a comment that Farrokh made. This is the first time there's ever been an effort made to try to look systematically at the publicly available data on historic congestion in the Eastern Interconnection, and I'd like to express the Department's thanks to the many internal advisers--there's about 20 of them across the interconnection--that were very generous with their time in providing data to OATI to conduct this first-effort analysis.

What I want to turn to now are some observations and remarks that are a bit broader than the first group, in that the West has spent many years refining the methods, requesting and analyzing these types of data. Here we are for the first time trying to go through the data that's publicly available, and so we're both looking for comments about the data themselves and what they mean, what they do and don't tell us about congestion, as well as what they say specifically about some of the congestion that we see in the Eastern

Interconnection. And for this, we have a very distinguished panel of three regional experts to talk about aspects of that.

So I'd like to first introduce Jim Busbin. He's the Reliability Standards Project Manager for Southern Company. He has a BSE and a MSEE from the University of Alabama in Birmingham. His areas of experience within Southern Company include bulk power operations, transmission planning, generation planning, and substation design. His industry experience includes that he's currently the Chair of the NERC IDC Working Group. This is the group that provided data to OATI for the analysis. He's also Chair of the NERC DF Working Group, Co-chair of the Joint NERC/NAESB TLR Drafting Team, member of the NERC ORS Market Curtailment Threshold Task Force. So Jim is an expert in the TLR data and the IUC information that was used in this. I'm very much looking forward to his comments about that. So Jim?

Jim Busbin: Thanks, Joe. As Joe said, I'm Jim Busbin, and I'm a Reliability Standards Project Manager at Southern Company in the area of bulk power operations. My purpose in being here today, though, is not to specifically represent Southern Company, but rather the, as the, represent the NERC IDC Working Group as its Chairman. I'm also here to underscore the commitment of the NERC IDC Working Group to continue its support in the work of the investigators in providing data from the IDC beneficial to the identification of transmission congestion in the Eastern Interconnection.

And my remarks today will be fairly brief, but I first want to thank Joe and the Department of Energy for the opportunity to participate in this study as an industry adviser and also to participate in this technical conference today and tomorrow here in Chicago.

I lost something here. That's okay, I'll just, I'll wing it. Yeah, let's see where that picks up. Got a couple, two or three. Yeah, okay, we'll do that. I will.

Yes, the way we got into this, I guess it was in providing historical 2007 data to the investigators for this 2009 study. We were approached by the Department and by the investigators--"we" being the IDC Working Group at NERC--to provide information to them and data to them to be utilized in this study. And we were certainly very willing to do that.

I thought it might be useful, those of you that may not be familiar with the IDC, to perhaps go through a little bit of what it is and what it does. I think it's important to know that, because that's what is going to provide the data that we have seen today and will possibly see more of.

Back in the, I guess it was back in the mid-'90s, as marketing activities began to increase, you saw a lot more transactions being implemented by an increase in bargaining activity. It became unwieldy to handle those, that volume of transactions from a congestion management perspective. So it became very apparent that a tool was needed to aid reliability coordinators in their efforts to manage congestion in the grid.

The purpose of the IDC, of course, is to aid those reliability coordinators in the Eastern Interconnection in implementing the transmission loading relief procedures. So as specified in the NERC Reliability Standards, which is IRO-006, and in the NAESB, the North American Electric Standards Board Business Practice Standards, which is WEQ-008. That was split a short time back between the commercial practices and the reliability practices, and so that's--the reliability part of this is the "what is to happen" and the NAESB business practices describe the "how." And that's programmed into the IDC.

And what it actually does, is it looks at the Eastern Interconnection and all of its balancing authorities and looks at transfer distribution factors among every one of the balancing authorities in the Eastern Interconnection so that you can begin to describe transactions that flow across the interconnection, flow across, into and out of the interconnection, and what the impact is on specified flow gates.

The IDC also evaluates the effect of all market flows on all coordinated flow gates in the Eastern Interconnection. It calculates the effects of all the native load generation on specified flow gates in the Eastern Interconnection, so that what you have happening there is it begins to build matrices that are used in the congestion management process program in it. All of these calculations are updated periodically. The transfer distribution factors are updated every 20 minutes; generation to load factors are updated every hour. So it is a near real-time tool, would be the way I would describe it.

When a TLR is issued by an RC, a curtailment quantity is requested, in other words, the RC will issue a TLR, say, a level TLR 5a, for example, and he'll put a specified amount of curtailment that he needs to see on a flow gate. That's put in, and the IDC will process that and make the curtailments according to the priorities programmed in it to provide the relief needed.

And as I said, I just wanted to give you just a kind of a high oversight of what the IDC does and how it operates. And, as I said, the data that we calculate in that has gone into this study, and one of the areas that Jagjit had talked about was the need to get some of the curtailed megawatt values out of the IDC.

To move on to--and I hope that's given you something of an insight as to what it does. As I said, it's important to understand what it's doing, and it's a tool that's used in the Eastern Interconnection.

Some of the metrics, moving on into the study a little bit, some of the metrics considered in the study, as I had looked over it, were the collection of times and periods when AFC or ATC were equal to zero, when the congestion component of LMP, looked at that. Looked at market shadow price, and the area that I would focus on would be the IDC-related metrics, which are listed by RC area, be it the number of TLRs issued for a flow gate, the duration of the issued TLR for a flow gate, and the magnitude.

And what we're trying to get to here is what would we describe as congestion? What do we make of the data once we have it?

Looking at the IDC metrics, a number of TLRs issued by a flow gate relative to one of the slides that was presented by Jagjit shows the top seven RCs for the number of TLRs. That range went from 21, I think, in VACAR South to over 14,800 in the SPP area. That is certainly a notable number and will get your attention, but that in and of itself I don't believe would define congestion. If you have TLRs issued and the relief required is very low, the impact is only very slight. So it's debatable whether that metric in and of itself would define what congestion would be.

The duration of a TLR event--of course, that's just a time metric. And understanding that TLRs can change within a TLR event--you may have a TLR that would run perhaps four or five hours, and your level can change in that event. You can go from a 3, which would curtail non-firm transactions and market flows, to a 5, which would curtail firm transactions, firm market flow, and involve your NNL contributions--native and network load contributions. The duration of an event certainly is notable, but again, if your curtailment is very slight, it's debatable whether that metric in and of itself would define congestion.

The one that we get to where we're looking at the magnitude of the TLR, and you're looking at a time times megawatts curtailed, that begins to, I think, tell the story. This metric is measured by the megawatts curtailed. When combined with the time total, it provides the quantity of curtailed energy and energy--megawatt-hours, of course--for a specified flow gate. If there's a pattern of TLRs on that flow gate, you begin to see that just in the accumulated numbers so that you can specify an array of curtailed megawatts by flow gate and begin to paint a picture.

As I said, my comments were going to be fairly brief, so what I would leave you with is that, just for further consideration, to look at curtailed energy at a TLR Level 5 only, where you're dealing with firm curtailments versus the curtailed energy below the TLR 5, which in most cases would be a 3, where you're looking at the non-firm as well. I think a better picture of congestion may be described utilizing the TLR 5 data by itself, just to give you that to think about.

The other piece, I think, is the determination of just what is congestion. I think that we have to kind of back up a little bit and define what our expectations are of the power grid, what are we expecting this thing to do? Are we expecting it to allow a limitless transfer of power from any point to A to B? If we're not, how do we then measure that expectation? I think that once our expectations are known, only then can we define what congestion is.

And with that, I will conclude. And once again, I will thank Joe for having me here today, and I will take your questions at the Q&A time. Thank you.

Joe Eto: Thank you, Jim. Next I'd like to introduce Mike Walsh. He is a Senior Director for Midwest ISO's UDS, EMS, Compliance and Training Functions and Real Time Operations. He oversees Real Time Operations’ security constraints, economic dispatch, EMS network applications, reliability standards, monitoring and compliance, and operator training functions. Prior to his current duties, Mr. Walsh was responsible for Real Time Operations in the central region operation at the Midwest ISO as part of the successful start of the energy markets in 2005. Mike came to the Midwest ISO in 2000 from Mid-American Energy Company, where he served as Manager of Systems Operations. He has over 20 years of experience in the ISO power system operation, operations engineering, liability coordination, and market operation. Mike?

Mike Walsh: Thank you, Joe. Good afternoon, ladies and gentlemen. Thank you for the opportunity to speak to you this afternoon. What I'd like to do is first give you a brief overview of the Midwest ISO. I thought that might be helpful for some of you who may not be familiar with our organization and further, to help you better understand some of the results that are in the OATI OASIS and market metrics analysis. And then I'd like to finish with some specific observations and comments that we have on the results.

First, a little bit of background on the Midwest ISO. Who are we? Basically, we're an independent, nonprofit organization responsible for maintaining reliable transmission and power in 14 states and one Canadian province. Initially, we were doing this as an Independent System Operator, but very soon in the evolution of Midwest ISO, we became the first Regional Transmission Organization that was approved by the Federal Energy Regulatory Commission.

My next slide speaks to the evolution of Midwest ISO, and I'm not going to go into a lot of detail here. But I did want to point out a couple things here in regards to congestion management, which is certainly the topic of our discussion here today. As you can see here in our evolution, we became a reliability coordinator essentially around December 15th of 2001. At that time, our primary means of managing congestion was through the TLR process. However, as our evolution continued down the road, in April 1, 2005, we launched the Midwest Energy Markets, and at that particular point in time, our primary process to manage congestion became our Security Constrained Economic Dispatch.

Slide 4 is just a summary of some of the major functions that we perform. Many of these are included in the AT functions performed by a Regional Transmission Organization, but many of the things that you would expect as far as monitoring the transfers on the high-voltage system, scheduling transmission service, managing congestion. In our case, operating a day ahead in real-time energy market, and then of course, our regional transmission planning functions.

Give you a little background about the scope of our operations. Again, I won't go through this in detail. You can read this at your leisure. But I did want to leave you with some information, some key statistics just so you could get a feel for the size and scope of our operations. I had mentioned the 14 states, one Canadian province. I'd also point out the 93,600 miles of transmission, voltage levels from 69 kV to 500 kV. Today, as you can see here, there's some other information in regards to peak load, generation capacity, and some information associated with our market operation.

Slide 6 is an illustration of the MISO footprint, and I did want to take a few minutes to talk about this, because I think this is important. As you look through some of the OASIS and market results, I wanted you to have a better understanding of our market footprint relative to our reliability authority footprint.

On Slide 6 in green, this is essentially the market footprint for the Midwest ISO. In addition, as reflected in the blue, we also provide reliability coordination services for the participants within the blue states and the one Canadian province in Canada. The entire green and blue area represents a reliability footprint. So as you look through the IDC results and you look at the flow gates that are listed that were in TLR, typically you're going to see all of the flow gates--or at least those that were in, had a high amount of TLR activity--within our reliability footprint, again being the green and the blue combined areas.

The market results will primarily be associated with the green area, which is our market footprint. However, if our market does have an impact on constraints outside of our market footprint, it could be the areas in blue. It could also be areas in PJM, TVA, and other areas if we have a market impact. In the market analysis results, you'll also see some of the constraints in those areas where we're doing constraint binding. And I'll touch a little bit more on that in a few minutes.

The last thing I want to touch on here is in regards to the TSR results, you heard earlier Jagjit speaking to the zones within the MISO footprint--East, Central, and West. I wanted to point out those are not necessarily AFC zones, but to help simplify the analysis, rather than selecting all the PODs, PORs, which are typically the balancing authorities--at least those that were within our footprint in 2007--rather than selecting that high number, we tried to help combine some of that information and aligned it with our regional operations.

So when we talk about East, Central, and West, let me describe what those are. The East Region is primarily the eastern half of Wisconsin, Michigan, northern Indiana, and northern Ohio. So basically the northeastern portion of our footprint.

The Central Region is primarily more of the southern portion of our footprint, primarily the portions of Missouri, Illinois, and Indiana.

The West Region is the other half of Wisconsin, western half of Wisconsin, and everything west of the Mississippi River.

So when you look, again, when you look at those TSR analysis, and you're looking at those regions, it's basically aligned with the regional operations that we have at the Midwest ISO.

A couple of things to comment on slide seven in regards to congestion management. I just wanted to highlight what were the mechanisms that were used in 2007 to manage congestion? We have a number of processes that are available for use, but as I mentioned earlier, the main one being our Security Constrained Economic Dispatch, which is running every five minutes. We essentially used our SCED application to maintain flows within proper limits. And the benefit of our Security Constrained Economic Dispatch is that it did provide the most economic solution for market participants to not only meet the load demand, but also to manage congestion.

One of the things that the Independent Market Monitor for the Midwest ISO observed and commented on shortly after our market launch is that the SCED was a much more precise and faster application, considering that it was running every five minutes, a much quicker response to managing congestion relative to the TLR process that was utilized prior to the market start. But the IMM also noticed that there was an 85% reduction in the curtailed megawatt-hours as a result of our market operation.

One other thing I'd like to point out is the market-to-market operation, as you'll also see some of this reflected in the results. Market-to-Market is a process that was set up between the Midwest ISO and PJM, basically a process that we could use jointly to manage congestion within our footprint as well as theirs. Essentially, what we do in real time is we exchange shadow price information for the flow gates that are associated with Market-to-Market, and we also provide one another the desired relief amounts that we look to the non-monitoring party to help relieve.

So basically, what happens--I'll use an example. If PJM is looking for relief on some of their flow gates, they can send their shadow price to our systems along with a request for, let's say, a 40- to 50-megawatt reduction on that flow gate. If we can redispatch our generation at a cost lower than their shadow price, our systems will do that. I wanted to point that out again, because you will see some of the PJM constraints in our market results, and I'll touch on that in just a few minutes.

At this point in time, I'd just like to talk about some of the things that we observed in 2007 in regards to congestion. Here is a list of some of the key drivers that we identified. I'm sure that in many other portions or parts of the country, there are similar drivers in regards to loads and planned and forced outages.

A couple of things I'd like to point out that were unique for the Midwest ISO footprint in '07, in addition to the normal summer-winter peak loads, there were several Central Region BAs that did set some all-time summer peak loads in 2007, again, the Central Region primarily being--actually the southern portion of our footprint. So during the summer conditions, very warm temperatures. There were several BAs that set some record peak load demand.

The, we did see a higher-than-normal load in October of '07, much higher than expected. Rather warm fall in '07. Further complicating this was the fact that spring and fall's typically when you're doing your transmission maintenance, so the higher-than-normal temperatures drove higher-than-normal loads. That, coupled with the planned outages, we did see some additional congestion in the fall of '07.

Power transfers across the MISO footprint, typically west to east, primarily due to hydro and other low-cost generation within the western portion of our footprint. And then north-to-south flows, which are typically associated with temperature differentials--cooler in the north, warmer in the south. You'll see flows to the south in that case.

Planned transmission generation outages as well as unplanned. You heard earlier some comments about some of the storms that occurred in 2007. We did have some unique situations in the early portion of 2007 associated with some significant winter storms.

With regards to the AFC results, the MISO uses a flow-based methodology to evaluate TSRs. We have approximately 600 flow gates that we utilize in our AFC process. We have provided firm and non-firm AFC information to OATI for this analysis. In the draft report you'll see some of the results of that analysis. The top 10 most subscribed flow gates. One of the things that we're working with OATI on is there were some non-MISO flow gates in the list. We'll continue working with them to remove those from our list.

But I did want to comment on one thing that Jagjit pointed out in his results, and that the Minnesota-Wisconsin Tie was the most subscribed region within our footprint. I just wanted to point out this. Folks who are familiar with this particular region may think that's the Eau Claire-Arpin Interface. In this particular case, it's not. This happens to be a planning horizon flow gate that just happens to span across the Minnesota-Wisconsin border. It is a two-element contingency--that's a common tower contingency--that was identified as an issue in some of our planning studies. The transmission owner had requested that we add that to our AFC process, and it became a limiting flow gate. However, there have been some subsequent transmission upgrades made, and this particular flow gate's no longer in our AFC process.

The last thing I'd point out is common tower contingencies are not normally simulated in real time. Generally it's an N-1 element contingency that's simulated. However, for some common tower contingencies, if we have operating guides in place, we will simulate those contingencies. But typically, it's only when there's severe storms, especially if there's tornado warnings associated with those, that we'd actually activate contingencies like that in real time.

With regards to the reservation results, we did provide firm and non-firm TSR information to OATI. Again, we're working with them to update some of the zone information. We do have some suggested changes there which will be reflected in the final report.

One thing I'd like to point out, reservation analysis in this particular case was based on reservations sinking into the MISO. Because of our market operation, there is quite a large impact typically associated with the market operation that's not reflected in this type of information. So basically, what we're recommending at this point in time--and I'm essentially reiterating some of the earlier comments made today--we're suggesting that some additional analysis should be made, primarily focused on the schedule or tag information instead of the reservation information, because we believe it's a better reflection of the actual usage of the system versus the planned usage.

So the IDC results, for the most part, looking through the list of flow gates that were in TLR, other than a few flow gates that were not MISO flow gates--and again, we'll work with OATI to update that list--for the most part, we believe it does reflect the TLR activity that occurred in 2007. I had mentioned earlier that our list would include some of the flow gates in the MAPP region, in our West Region that are not part of our market but are under the purview of our reliability coordinator.

One thing I'd like to emphasize here is to exercise some caution when comparing the AFC results and the TLR results. The AFCs are based on forecasts, projections, and based on a series of assumptions. The TLR information, along with constraint binding, is all real-time information.

So from our perspective--and I think this really depends on exactly what kind of, what is the congestion that we're trying to analyze here. Is it congestion in the planning horizon or is it congestion in the operating horizon? If it's primarily just focused on the operating horizon, we would suggest focusing on the market, TLR, and tag data. So we think that would be a better representation of the actual congestion.

For the congestion in the planning horizon, of course, you could look to the TSR and AFC information. But again, with caution; if you're trying to compare the planning and operating horizons, there could be some differences for a variety of reasons.

Here's some information on a couple of the IDC results, two of the constraints that received the highest number of TLR activity. The first one's in the Central Region--I see I'm limited on time, so I will cut this short. Much of this you can read at your leisure. One thing I'd like to flip to in regards to the market information, again, MISO, PJM and some other MAPP constraints are in that list.

I would like to highly recommend to the DOE that you look to the Midwest ISO Transmission Expansion Plan 2008. It's a very good analysis of historical congestion within the Midwest ISO footprint. Some information in there that shows flow gate hours by year, both pre- and post-market. You'll find the 45 post-market flow gates that on average were congested more than 1% of the time. And there's also correlation to many of the upgrades that are planned to address some of the congestion in that study.

The next several slides just provide some background information on some of the constraints that you'll see in the shadow price analysis. The LMPCC results, we're still working with OATI to analyze that information. The thing to point out here is that information can be driven by multiple and even competing constraints. The aggregate nodes that were identified that were bipolar in nature in the results were primarily in the east-central Iowa region, but again were associated with some planned forced outages in the region and competing constraints.

So the thing I'd suggest at this point is working with OATI. We really need to take a closer look at this at a much finer, granular level. You run the risk, when you look at things on an annual basis like this and all the changes occurring through the system, things can be a little bit muddy. So it's probably better to look at these on a much finer granularity.

I will go ahead and finish, then. Just the comment that right now we're working with OATI to update our results and complete our review of the draft report and provide comments. Thank you very much for the opportunity to talk today.

Joe Eto: Thank you, Mike. Our last discussant here will be Steven Herling. He is Vice President of Planning at PJM Interconnection. He's responsible for oversight of the System Planning Division, which includes Transmission Planning, Interconnection Planning, and Capacity Adequacy Planning. Mr. Herling has been involved extensively in the development of PJM's regional transmission planning process and resource adequacy planning process. Recently, he has been actively involved in the development of a number of new backbone transmission projects on the PJM system, as well as efforts to enhance coordination of planning activities across ISO and RTO boundaries.

Prior to joining PJM, Mr. Herling worked for General Public Utilities Service Corporation in system operations and the American Electric Power Service Corporation in bulk transmission planning. Steve?

Steve Herling: The first slide just has a lot of statistics about PJM, and obviously, you all have access to that, so I'll move on. The next three slides are from our State of the Market report. This was prepared by our Independent Market Monitor. Basically, this one covers the frequency of various constraints on the system over 2007 and 2008. This one is the costs associated with constraints in 2008 and again in 2007.

Probably the most important piece to glean from these three tables is that if you look at the constraints, they match up very nicely with the ones that were identified in the OATI materials. If you look back at the first slide, our system, like MISO, is very much a west-to-east system. We have a huge load center running from northern Virginia up through Washington, DC, Baltimore, Philadelphia, into New Jersey, and there's a lot of energy that has to move across the system. So a lot of these constraints that you see that have the higher frequency and the higher costs are going to be related to moving that energy across the system.

If you look at the congestion that we see historically, 2007, we had about $1.8 billion worth of congestion on the system. The one thing that I would point out is that our congestion, when we look at the historical congestion and the kind of congestion that we see in the planning horizon, it is not typically due to point-to-point services and reservations. The vast majority of the flow on our constrained facilities is going to be due to dispatch through network service.

We have 160-some-odd thousand megawatts of generation being dispatched to our load, and that's all done through network services. So the bulk of these flows causing the congestion are going to be seen through our dispatch. And when we start to run our planning criteria, that is all based on the kinds of situations that drive these big west-to-east flows. We modeled through our deliverability criteria, which again simulates higher loads and lower generation availabilities, so what you see mimics very nicely the kinds of constraints that both OATI and our Market Monitor have seen.

We looked in particular at the top handful of these constraints. Twenty of these constraints result in almost 90% of the congestion. And basically, the congestion on our system--I'll come back to that one in a moment--is basically a precursor to the criteria violations that we then turn up in our planning process and plan out transmission upgrades to resolve the criteria violations.

What you see here on these two slides are the top 20 constraints. You'll see almost all of them are, we expect to be addressed through upgrades that were already identified for corresponding reliability criteria violations in the planning process. Once we push the planning process out to 15 years, we're seeing all of the congestion as violations of NERC planning criteria far enough out in our horizon that we can then put solutions in to fix it.

Obviously, the high levels of congestion we saw in 2005, '06, and '07 and '08, for that matter, were still waiting for the transmission to come into service. But if you look at some of the backbone projects that we have, we looked at four projects in particular--the Trail Line, 502 Junction to Loudoun; the Amos to Kempton line; the MAPP project, which goes under the Bay and up the Delmarva Peninsular; and the Susquehanna-Roseland Project, northern Pennsylvania into northern Jersey--in 2008 we simulated the congestion through our market efficiency process, and we came up with about $2 billion worth of congestion which matches very, very closely with what we actually saw in 2008. Those four lines eliminate 80% of that alone.

Now, the remaining upgrades in the plan--a lot of 230 upgrades, et cetera--take about another 10% off of the table. So if you look at what we've seen in 2007 and 2008, looking out into the future in our planning process, we identified the same constraints. We have upgrades in the plan, and we're resolving about 90% of that congestion.

Now, I'll jump to--well, this particular table is a simulation we did this past year. Every year we do market efficiency simulations to try to identify where there may be opportunities to resolve congestion in future years. Generally, what we're finding is because we've already tagged almost all of it as reliability problems--we haven't really identified anything as a pure economic fix yet--thankfully, we are putting upgrades into the plan to resolve the congestion. But basically, what we do, and you see here is a 2008 as-is system, shows you the $2 billion way down at the bottom--almost $2.1 billion--we then push the system out to 2012 with the upgrades and it looks like $264 million. So that's almost 90% of the congestion.

When we start looking at the remaining $264 million, we're struggling, to be honest, to find enough congestion left that we can go after with purely economic upgrades. So that the biggest challenge we find, once we get to what's left, is that the cost justification just isn't always panned out for us. Now again, we're still taking almost 90% off the table with our reliability-based problems.

Again, I mentioned we have seen some pretty high congestion years, and this goes actually all the way back to 2005--$2 billion, a little over $1.5 billion, $1.8 billion, and then up again over $2 billion. So congestion is obviously a very real problem in PJM. It is, again, a function, even though we have very, very distributed generation and load in PJM, we do have a higher concentration of load in the East and a higher concentration of our baseload generation in the West, and that's what's causing these numbers.

Kind of the last point I wanted to make, I pointed out that we're not seeing a lot of congestion left on the table to go after with economic upgrades. The part that's missing here is based on the way we study congestion, market efficiency, we do not look at new generation, generation that doesn't exist yet. So these numbers are based on the generation that we have, the generation that we know is moving forward. For example, there's already signed interconnection service agreements.

But what it doesn't look at is the opportunities that we have moving forward. I know we have panels next and tomorrow to talk about future congestion, but one of the things I think we really need to focus on is what the historic data is not going to point us to, and that's where the industry is going. And we know that we have yet more opportunities for baseload generation--in particular, renewable generation--that will continue to increase the west-to-east flows across our system, and I'm sure across MISO's system.

So these numbers that you see here, while very instructive, don't necessarily tell you the whole picture. So stay tuned. Thank you.

Joe Eto: Thank you, Steve. I want to thank the panel especially for speaking to some of the specific areas that the Department is interested in in terms of the critical congestion that was identified in the 2006 study, so Steve, thank you very much for your comments about the significance of that congestion over time beyond the period which the OATI group has looked at that issue, as well as the estimates that you have made about the changes in what you would expect on the basis of completion of those four big projects that you mentioned.

In this same vein, I want to just confirm with Farrokh, there was another area of, there was an area of concern identified in New England in the 2006 study, and your findings, I just want to confirm from the historical record, show very little congestion in the New England area. Can you speak to that, then?

Farrokh Rahimi: Yes. As I mentioned, we did not, of course, have the shadow prices for the internal constraints in New England. But the vestiges of those are reflected in the congestion component of the LMPs. And when we looked at the congestion component of the LMPs, there were, in the ones that exceed $20 a megawatt-hour, they were much fewer in number and also smaller in magnitude than the other markets that we analyzed. And that is the basis on which I had made that statement.

Joe Eto: Okay. Thank you, Farrokh. The second thing I wanted to observe is, obviously, this is a snapshot in time of 2007, and several comments were made about particular events that took place, such as the ice storm in the southwestern part of the Eastern Interconnection, and then very specific activities. And so I'm going to invite folks who might be able to provide us with comments in terms of understanding the historical record if there are anomalies or one-time events in the historical record that affect the way these metrics come out so that we're not mistaking a one-time activity for an ongoing aspect of what's happening to congestion in the East.

So with that, let me open it up to questions from the audience. Mike, New England ISO?

Mike Henderson: Mike Henderson, ISO New England. I just wanted to clarify a few things, first with respect to New England showing little to no congestion in 2007. We believe that's accurate. However, in terms of the little congestion, some of that may have been due to construction outages that occurred on our system. As some of you may be aware, there have been a number of major transmission improvements made within New England, and so we're showing little to no congestion. And, in fact, in the RSP 08 studies that we conducted, where we were looking to project future congestion, we found little to no congestion over the 10-year period.

We've also engaged in a process of conducting economic studies, which postulate hypothetical types of generation expansion in the system, varying from renewables through natural gas combined cycle. And so those studies are coming to closure. For this year, I'm showing, in fact, that we have some wiggle room on our system, including imports of renewables from the northern part of our system or Canada, as well as certainly development in the southern part of New England. So thank you for the opportunity to state that.

Joe Eto: Thanks for adding that information. That's very, very helpful to us. Other questions or comments?

Alison Silverstein: I'm Alison Silverstein. I have a question for Jim Busbin with respect to your comments on IDC and TLRs in particular.

Jim Busbin: Yes.

Alison Silverstein: Your recommendation is that we only look at TLRs that are Level 5 for firm curtailment?

Jim Busbin: Yes.

Alison Silverstein: Then an awful lot of marketer transactions and most intermittent generation would not be booked under firm. Does that mean, would your suggestion essentially mean that any demand for transmission usage that can't be filled, if it's not a TLR Level 5, it doesn't count as congestion? How do we deal with this?

Jim Busbin: Well, I think that you have to look at the product itself. If you're selling non-firm, it's sold on that basis, so that that's what comes with the product. You can, you're standing a more likelihood of being interrupted than you would on the firm. So I think the reason I say that is that from my perspective, I see that there is more of a commitment to the firm product. I think it probably goes through--and this is just a generalization--that it goes through a more stringent study process before offered. So if there's more of a commitment, I think to the offering and selling of the product--I'm not getting there, am I?

Alison Silverstein: Well, we are looking at a world in which potentially we're looking at 10, 20--significant portions of the nation's energy usage potentially coming from renewables, aka non-firm. And your recommendation would imply--and that doesn't count marketers and real-time purchases. And that would suggest that those do not get recognized as having value with respect to congestion when we're getting very clear policy directions that we need to expand the system to accommodate renewable transmission and other stuff like that. How do--do we need to change the definitions of product? Do we need to change the definitions of TLRs? Or do we just need to take some--?

Jim Busbin: Well, I think that if you want to account for that, you certainly would have to take some form of change in what we have today in order to account for that, if that's what you're asking.

Steve Herling: Yes, I'll just throw in another thought. TLRs are one of the tools in the box to resolve congestion, but it is not the metric that tells you everything you need to know about congestion. I think one of the things we're going to see is that you have to look at congestion through a range of metrics. You'll pick up, for example, if we have to start curtailing wind generation, that will get picked up in one metric or another. It may not get picked up intra-market with TLRs, but it may get picked up between markets with TLRs. So we're going to have to find a way to put all of those together somehow, not double count the congestion, to see the whole picture.

Alison Silverstein: Okay. Let me ask this another way, then. Do we need to be collecting different kinds of data and measuring different kinds of transactions at different points on the grid in order to be able to identify historic congestion more effectively?

Steve Herling: My take on it is that within a market, obviously, the stuff that I showed from Joe Bowring, and I think that does a great job of showing that congestion. What it doesn't always show is the congestion or lost opportunity across the seam between ourselves and MISO, for example, and that's where you may have to find a way to use something like TLRs or some other device to put a dollar sign to that lost opportunity. Because there's a big difference between lost opportunity in congestion and the way we put those numbers together, but it is still an inefficiency in the market.

Alison Silverstein: Okay, and let's now ask the painful question that works within PJM -- but what do I do within the entire Southeast portion of the nation or in the West?

Steve Herling: Right, and ultimately you have to put together the stuff within control areas or control zones and the stuff across the borders, which, you know, no matter what metric they use within the control zone, it may not pick up the stuff across the border. So you have to find a combination of the two that gets you everything you need to know.

Alison Silverstein: And does that mean that we need new kinds of data and new kinds of metrics to measure congestion?

Steve Herling: I have the advantage of being the planner on the metric side. I have no idea.

[laughter]

Jim Busbin: Well, I think a lot of the data that you suggest to be collected is already there. I think it's just a matter of how you sort it out. I would just go back to my comment on the expectation that you have of the power grid. Of course, and what you're saying here, there is a change coming as far as being able to account for the renewables in it so that we have to -- we have to define what our expectation is before we can begin to define what congestion is.

Joe Eto: Let me ask -- please, again, panelists, please identify yourselves when you speak. But, Jagjit, you wanted to comment? That was Jim Busbin just speaking.

Jim Busbin: Oh, I'm sorry.

Jagjit Singh: Jagjit Singh with OATI -- I just want to make a comment -- what Jim is saying that maybe we need to separate out the metrics for firm and non-firm TLRs, and we can certainly do that with the existing data. It's that the way we produce the metrics for this -- up to so far we combine them into one, and I think that -- isn't that correct, Jim?

Jim Busbin: At this point, yes.

Jagjit Singh: So I think the data is there. It's just -- well, how do we represent it -- may need the change?

Joe Eto: What I'm hearing is it would be very useful, looking at the historic record to look at TLR5 and above. It would be very useful to associate megawatt quantities with the TLR calls as well. Going forward, if renewables are only sold non-firm, there are going to be other kinds of issues that need to be sorted out if TLR is the sole source of the information on what to rely upon to look at congestion and curtailments of that standpoint.

Farrokh Rahimi: Farrokh Rahimi, OATI -- just for the future, in fact things are happening now. For example, with respect to the RPS, Renewable Portfolio Standard, there are obligations. They have a certain percentage, for example, in California of loading served with renewable, and some of this can come from outside of the state, and the tagging now -- there is a procedure in place to put the information in the tag, that is actually the source of this particular energy coming from outside the control area, renewable or not. So there are things happening for the future that will be additional information that can be used for this.

Alison Silverstein: This is Alison again -- let me ask you all another more fundamental question about data -- you said the data are there, but when I listen to your presentations, it's very clear that some data is in different places and none of the data appear to match. We do not have consistent data sources across the East. Even the data vary from interconnect -- from RTO to ISO to whatever is left. And it doesn't sound to me as though you have a whole lot of reliable data that you can compare effectively to be able to give us a consistent set of analyses using a consistent set of data. Do I understand that correctly?

Farrokh Rahimi: Farrokh Rahimi again -- I was responding to your question about the future, now you are asking questions about the --

Alison Silverstein: Yes, I'm not asking you about the past.

Farrokh Rahimi: Except the past, of course, we did not have this tagging for renewable portfolio standards, and so on and so forth.

Alison Silverstein: But this isn't just about RPS and about renewable energy. This is about flows within an interconnection, this is about flows within New York and do the numbers from New York mean the same thing that they do from SPP or from ISO? Are you getting any numbers out of Florida or Southern or TVA? I can't tell whether the data match and whether you say this is what this data means or what this metric means in New York. Does it mean something else in the Southeast? Or does it mean something else when TVA gives it to me versus when MISO gives it to me?

Jagjit Singh: This is Jagjit Singh with OATI. Alison, I want to clarify two points -- one, 90% of the data that we use for metrics was available. There are only pockets of data missing, which we are trying to get. And in terms of once we define the metrics we use the same data from whichever -- whether it was New York ISO or Midwest ISO, it was the same, and the information produced, the results would be similar in nature.

However, because of some market differences, there may be slight differences there. But, other than that, I believe the data is the same -- and same thing with OASIS and IDC data. When you use -- specifically mentioned Florida -- we had certain months of the data missing, which we are still trying to get, but the rest of the data was the same data that was available from other sources.

Alison Silverstein: And when you mean the same are you referring to equivalent layers of granularity across geography?

Jagjit Singh: Yes.

Alison Silverstein: Anyone else? Thank you.

Joe Eto: All right. Well, I think we're at the end of our session. We're going to take a 15-minute break now, but before I do, I'd like to thank the panelists for excellent presentations and understanding historic congestion in the East.

[applause]

[15-minute break]

John Schnagl: I am reminded of advertisements for mutual funds that used to appear on TV about a year ago. They touted the accomplishments of the mutual fund but, at the end, they always admonished that historical performance may not necessarily indicate future performance. That admonition has certainly come true in the last few months. These panelists will be speaking to forward-looking congestion studies, and they have had numerous challenges including things like regional portfolio standards, changing demand trends recently, pending carbon legislation, among others.

In this context, let me introduce this group of panelists who are endeavoring to look to the future and identify what the needs of future transmission and future congestion will be.

Scott Cauchois is our first panelist. Dr. Cauchois is currently a member of the board of the Western Electricity Coordinating Council, WECC, and chair of its Transmission Expansion Planning Policy Committee. He serves on the advisory committee to the Center for the Study of Energy Markets at the University of California Energy Institute. Dr. Cauchois retired as chief of the Electricity Planning Policy Branch of the Division of Ratepayer Advocates for the California Public Utilities Commission in October of 2008 where he had responsibility over load serving entity procurement and resource planning, transmission analysis and certification proceedings, and renewable portfolio standard implementation.

Let me introduce Dr. Cauchois.

Scott Cauchois: Thank you very much, John. I really appreciate the opportunity to speak at the conference and to kick off this next phase of the conference and give you a broad overview of what planning in the Western Interconnection looks like.

Alluding to your first remarks, we haven't found any black swans yet, but they may be lurking out there as we plan for the future.

TEPPC and, believe me, now we're going to switch into the West with all of our acronyms, which are different than most in the East, but TEPPC was established in 2006 as a committee of the WECC board. The WECC and TEPPC covered the entire Western Interconnection footprint of parts or most of 13 or 14 states, two Canadian provinces, and Northern Baja.

The committee itself, by charter, includes two board members including the chair, and a variety of stakeholder members whose interests I'll go over in a minute. We also have dedicated in both senses of the word, WECC staff, some of whom are here today, but staff resources that are dedicated to the transmission expansion effort in terms of directing analysis, performing production costs and power flow analysis. And being the backbone of the analytical engine, we have regular in-person quarterly meetings; we have, from time to time, teleconferences -- as we are about to have as we go through our study request window. And the second Tuesday of every month we have a coordination call usually involving 35 or 40 people from around the West just to catch up on what's happening. We often have DOE on those calls, and anybody who has got something that they think other people should know about.

The three main elements of the TEPPC charter right now are to oversee production costs and other data management, develop and implement interconnection-wide expansion planning policies and processes in coordination with the Planning Coordination Committee of the WECC and sub-regional planning groups, which are SPGs, as I'll refer to them.

And the third major element, guiding and improving economic analysis and modeling of the interconnection.

It's important -- I'll just say it right now -- we probably will allude to it a little bit more, our Planning Coordination Committee, the PCC, is currently responsible for the path rating studies that are done on proposed transmission lines. And as we move into this more advanced era of planning, TEPPC and the PCC and, in fact, other groups within the WECC such as groups that look at variable generation are now going to be coordinating, to a much higher degree, their data acquisition and their study plans.

This is our organizational structure, and I'll say right off the top, the important part of it is the Technical Advisory Subcommittee, TAS, and the working groups under it. Those are comprised of both WECC staff but largely with volunteers from entities all over the West -- the public agencies, the federal power administration's load-serving entities, generators, environmentalists, you name it, and they help design our study plans, look at our models, look for model improvements in the West, in particular, variable generation and hydro modeling are really key areas of focus. You've already heard from Dean Perry this morning, who is part of the historical analysis workgroup, and then data workgroup where we are continually trying to improve the data we use.

To give a little historical context, if you go back to the beginning of the decade and the establishment of the California ISO, there were a number of attempts in other places in the West to pull together regional transmission organizations, and there was a group with the -- you know, one of the strangest acronyms of all, the SEAMS Steering Group of the Western Interconnection that was formed to help coordinate planning among RTOs.

And as we know, RTOs in the West didn't happen except for the CAL ISO, and as we got through the middle of the decade there was definite planning and policy gap in the West. There was nobody to really pull together the whole picture. TEPPC was formed, and almost simultaneously, I guess initially, sort of an ad hoc group, the Western Congestion Analysis Task Force was formed out of SGG-WI members and others to provide analysis for DOE in the 2006 Congestion Study and subsequent to that effort, TEPPC took over their responsibilities and will be performing the same function for the 2009 study.

And before the dust even settled, of course, along came FERC Order 890 and the need for transmission owners to comply with amendments to their attachment Ks. In that case, what TEPPC did and with the help of the sub-regional planning groups is to provide an umbrella under which the transmission owners could explain to FERC how they did sub-regional and regional planning and meet the nine planning principles of Order 890, so we are very active in that.

And, of course, the heavy push for renewables was coming at the same time, and the attention that had to be paid to what was perceived as a need for more transmission. Meanwhile, our sub-regional planning groups -- new ones formed, Columbia Grid, Jeff Miller is here from Columbia Grid, for example, today. Northern Tier Transmission

Group, SWAT, which Rob will talk about in a few minutes. Some faded away, some started, they all adopted, or began to adopt, more vigorous efforts toward transmission planning but as well as a number of other activities that are not quite as relevant to today, such as A-sharing and a number of operational issues.

So -- and then we come to the DOE 2000 Congestion Study, which has been on our horizon for a quite a while. Just to give you an idea of the stakeholders, we have transmission owners, generators, state commissions, energy agencies, technical specialists, we specifically seek out such as an IRP, load serving entity, sub-regional planning groups, environmental interests, consumer interests, and then, certainly, reflecting the interests of the Western governors and WIRAB, the Western Interstate Advisory Board, which is a Section 215 group that is set up to advise the WECC.

Planning at the sub-regional level -- I could have had this on a U.S. map, but this will give you an idea -- we have the Northwest area up in the upper left, the giant thing, so we have three planning groups there; we have West Connect and three groups within West Connect. We have California, which is really planning is pretty well dominated because most of the load is under the ISO but not all. So we have California, and we have an attempt to form a California-wide entity, which has been languishing for some time.

And then on the periphery of this whole thing, I've got efforts such as the state renewable energy zone initiatives, RETI in California is one and then, of course, the Western Renewable Energy Zone Initiative, WREZ, which is way up in the upper right, and so -- as you're going to see, sub-regional planning and how it relates to regional is extremely important to us in the West and something that we're going to be moving forward to preserve and enhance.

This, which I've always called the "flying saucer" diagram first came out in a FERC Order 890 workshop, and just sort of graphically describes how we see the relationships with transmission providers and customers needing to interface and communicate at the bottom and then up to sub-regional planning groups and up to TEPPC and then back.

Among our accomplishments today are that in 2007, a year after we were formed, we did complete what we came to call a pilot study where we focused the year heavily on improvements in our models and improvements in our data, especially. But we managed to run two big scenarios -- one a heavy wind, and one a heavy solar, so looking at really fairly different types of scenarios just to see what our production results, our power flows look like, to check whether our generators are running correctly, you know, to prove out the system so that we get ready for 2008.

We also established what we call the TEPPC Protocol, and the Protocol is referred to by transmission owners and sub-regional planning groups in their 890 compliance filings, and what it establishes is that TEPPC will have an open season, or a study request window, in the same way that sub-regional planning groups do and where stakeholders can come in and make the request. We then go through a due process that probably takes just about three months of iterations to cluster and have a dialog with stakeholders to see what studies we will eventually adopt to do.

The importance of this would be the first time after we ran these pilot studies that we began at the beginning of 2008 to have some very serious requests for studies that other speakers are going to talk about that are much farther ranging than just the two renewable extremes I mentioned.

We have what we call an "annual synchronized study cycle." Our request window is November 1st to January 31st. We work hard with the sub-regional groups. We're not all on the same, exact, open season. We do annual studies, some sub-regional groups do annual, some to biennial, but in any case we've made great efforts to try to get these in sync so that stakeholders are not chasing around trying to figure out the right forum to be in.

And then like -- to comply with 890, we are a completely open, transparent process. Our data is completely public, and so on.

This is kind of a busy chart of our study cycle. There is going to be one thing that, if you just think about all these arrows going around, and the feedback loops, one of the most important things to us really is the feedback loops, and the ability to adapt quickly from year-to-year to changing policy initiatives, to changing nature of the requests that we get, to be able to take what we've learned if somebody has made an innovation in hydro or wind modeling, to incorporate that quickly, or in load modeling, and so the ability to be adaptive and to be flexible is extremely important -- and to learn as we go.

So our 2008 report, which will be adopted by the full WECC board next month will also highlight the many, many areas where we learn things and need to improve or do better.

Products in the pipeline -- you've already heard from Dean Perry, and the reason why I put that as pipeline is that his report that you saw some of the results of today, will be part of our annual report that comes out next month. The historic data and the tie-in to that with our forecast is extremely important.

Our 2008 study, and you'll see the results -- some of the results of that. We had unprecedented requests for analysis of the transmission implications of renewables, high renewable penetration rates, carbon reduction policy, possible effects of cap and trade, and, as I said, the 2009 study plan, which we are in the process of evaluating right now, simply goes even farther on a lot of these same fronts.

And I just got my five-minute warning, but I only have a minute to go, anyhow. This last page has contacts where you can get more information. We have a number of TEPPC members, actually, in the room, I'm sure -- and former TEPPC members, and one of the co-chairs of the Technical Advisory Subcommittee. If anybody from the East or anybody else wants to talk about some of what we do, we'll certainly be around to talk about it. We're happy to be here. Thank you very much.

John Schnagl: Thank you, Scott. Our next panelist is Brad Nickell. Brad currently serves as the Renewable Energy Integration and Planning Director at WECC. In this capacity, he leads the effort to support WECC members as they work to better understand the reliability and policy issues related to the integration of renewable energy in the Western Interconnection.

In addition, he manages the regional resource adequacy reporting and transmission expansion planning efforts at WECC. Brad.

Brad Nickell: Thanks, John, and I think Scott had four minutes left, so are those rollover minutes we can use for speakers? Rob's asked for some already.

First of all, you know, I really thank John and David Meyer and Joe and DOE for both having us here today as well as their continued support of WECC activities. Also, to reiterate a little bit of what Scott said, the results that I'm going to show up today in a little bit are really a culmination of a lot of people's effort -- a lot of WECC members' time, a lot of staff time, and the framework that we use in the West to get this done, I think is pretty darn effective.

Before I get started with the results, I want to quote Jim Busbin in his last slide -- "Congestion can only be defined once the expectations of the grid are known and understood." And when we look at this in a forward sense, looking at future congestion, I kind of go back and go, well, you know, congestion is really a function of where our loads and where our resources are, right? So if we're looking forward, especially the further out we look forward, this essentially becomes some type of intelligent speculation exercise of what will the load be 10 or 20 years down the road and what resources are we going to choose to meet that load?

Today I'm just going to briefly describe some of the results that will be in our report that will be approved by the board next month -- a little bit about the study scenarios, our results, and then I'll tee up some things Doug is going to talk about as far as the requests for 2009, and then a little bit about related WECC activities.

These are not all of the cases or all the scenarios we ran, but these are the ones we're going to highlight today. We ran a set of scenarios looking at 15% renewables, and then on top of that, or added to that, we did some energy efficiency, and then on top of that, we also did some looks at carbon pricing. And, again, a reminder that these are all additive, and we'll show a little bit of the cumulative effects.

Just a little bit about where we started -- for our loads, we started with the member supplied 10-year forecast. That's all the statutory requirements of the organizations -- to report that up. We start with that, and then there is some augmentation that happens based on some of the planning entities.

The transmission system, again, we have an expectation that's provided from the Planning Coordination Committee, and then the generation -- again, we get a lot of this from statutory filings. The other thing that we have to do, and this gets into a little bit of the -- I'll call it "intelligent speculation." It's the fact that many -- much of the development cycle of the resources that we are putting in now are well inside a 10-year timeframe. So we're not going to see a wind project or a gas turbine in 27 -- that's scheduled to come online in 2017.

So basically we have to go back and play speculator, and on the renewables, we'll talk a little bit on how we did that. As a last resort, each area or our load area and our load areas in our production cost model, which is what we use to run these studies, we have a resource -- basically a really high-priced resource gap -- or generation gap.

Our first case I'm going to talk about is the 15% renewables case, and the loads and transmission, we didn't make any changes from the base case. Generation -- we just pumped up the generation and took it from 8.6% and that 8.6% is essentially the current RPS standards as of the beginning of the study cycle last year, and then what we did was we interpolated them to the year 2017. That's what you get WECC-wide. And we ramped that up to 15% of total energy in the West.

WIRAB and the Western Governors' Association helped provide some specifications regarding type and amount. This really comes back from work they did as part of their CDEAC process looking at renewables development in the West, and one of the things we've really tried to do as this process has matured is bring in the best information from all the different sources that we have and try and work that into this one single combined effort.

In addition, we used a variety of resources including the state-of-the-art meso-scale wind models, and that effort, which was also funded by the Department of Energy, their wind program, and solar data, and this all came from NREL, and this helped us do a couple of things. It helped us to play prospector a little bit at the state level, and the other thing it really helped us with, because we run an hourly production cost model, is this allowed us to pull in some of the variability of a broad package of disbursed renewable generation. We'll talk a little bit more about that in a bit.

Just so you know, what did the fuel split end up being for the renewables? Not quite half wind; 16% solar; quite a bit of geothermal, 32%; and then some biomass.

Here is a graphical depiction by area of where the renewables were and what type they were, and we can see we have a lot of geothermal in those areas, and then a lot of wind and a lot of this, at least for those of us who are down in the box, it's kind of stating the obvious. If we look at where the interconnection queues are, and we look at where everybody is interested in developing these different resources, this graph here essentially embodies that to some level.

The other thing, just to quote some other sources of information besides the CDEAC work that was commissioned by the Western Governors -- the California is ready. A Renewable Energy Transmission Initiative did a whole bunch of work along the coast in states that border California. There's a whole bunch of information we drew out of there as well as member-supplied info, and I'm not talking about the statutory type but the type that is supplied by the members to basically help us ground to either location or amounts of renewables that are expected.

And then, of course, the sub-regional planning groups provided a lot of input into what they thought were the expectations in their areas of the Western Interconnection.

Key results -- and this is, again, an hourly production -- economic -- I'm sorry -- Security Constrained Economic Dispatch model. We've put a bunch of renewables in -- didn't change anything else. We saw some reductions in carbon emissions; we saw a lot of natural gas generation, and I'll show you in the front what that looked like, and then essentially nothing else changed.

So if we look at this plot, again, the same areas. The bar charts in green -- that is the increase in renewable generation, and then the red, which you don't see any of, essentially, and the yellow, which you see a lot of -- the red is coal, and the yellow is gas. And basically the story is -- anytime we put in zero-cost generation, which is how we model renewables, essentially as a must-take, is that we're going to displace the highest-cost resources. We have a lot of gas in the West, so there is plenty of gas to displace. So we see a big change in gas gen.

The other thing I wanted to highlight -- I know different circles this has been talked about in a couple of different ways. One is the value of geographically disbursed wind, and the other one is the synergy between different types of renewables, and this plot up here, this is the daily energy numbers for wind, in blue, and yellow, in solar. And what this really represents, this represents 23 gigawatts of geographically disbursed wind in the Western Interconnection as well as 7 gigawatts of solar in the CSP constrained solar power. It's not PV.

And what does this look like over the course of a year? And we see there are some annual characteristics. There are some other diurnal characteristics as well, but we get certain expectations out of the wind, as a whole. We get certain expectations out of the solar, as a whole, and if we look at them together, over the course of a year, there are some obvious synergies.

And, really, the value -- back to the members and looking back at the congestion, is we can show the effect on fleet dispatch over the hour. So one of the things we can show with this data, and this is an example of it -- but more on a diurnal, or daily, cycle is we can show the effect on ramping. Anything that's over the hour, we can actually see what the effect of the dispatch pattern is by the variable generation.

The next case -- and, again, so we took 15% renewables, and then we did a 20% energy efficiency. In the 20% energy efficiency, again, something that was led a couple of years back by the governors, and they said 20% by 2020. So this is an interpolation of that to the year 2017.

In addition, you'll see the states -- it's not all evenly disbursed. Basically, they looked at states that have had a lot of the low-hanging fruit. That's already been used up like in California versus states that haven't. So it had a whole lot of intelligence that went into it.

What did it do? Big reductions in carbon, we'll show why. We did finally dip into the coal stack in a material manner, and we had a gigantic decrease in natural gas generation, which was very interesting.

The other really interesting point about this was we actually had an increase in congestion, and at first, I would be like, gosh, that's kind of maybe un-intuitive. At second glance, well, maybe it's not so un-intuitive. If we think about the load in the Western Interconnection, 75% of it is along the I-5 corridor. So if we go from Vancouver, B.C. to San Diego, if you drive down that, you can witness -- you'll witness the 75% of the load.

So anytime -- and, in addition, the majority of our highest-price resources are also in that same area. So our generation -- that's also close to this load. So anytime we decrease the load along the West Coast, we are going to -- I'm sorry -- anytime we decrease the load along the interior sections of the West, that energy is now available to move to the West. So what we end up with is we end up displacing generation on the West before we ever displace generation in the interior on a cost basis.

There, again, is a graph that shows what the change in the dispatch pattern was in certain -- different areas of the West. Again, a big change in gas and some material change in the coal generation.

The last thing we did was we started playing around with carbon pricing, and, again, we didn't change any load generation or transmission, and we used this adder as a surrogate for a carbon tax or a surrogate for some type of cap and trade scheme. We weren't aiming at either one of those, in particular. We were just trying to put a price on the head of carbon emissions.

We started out playing around with some different numbers, and these are not part of the report, and we went up to some fairly high numbers. We kind of started, in fact, the WEIL study, the Western Electric Industry Leaders, commissioned a study by E3, and they looked at some different carbon numbers, and we started with some pricing information from that, and we're, like, well, we'll throw in, too, and see what happens, and at $60 and $40 a ton, we observed extreme shifts and, really, some results that, frankly, aren't realistic, and we'll talk a little bit about why, but it goes back to the price elasticity of natural gas and the fact that we did not move the price of natural gas a little bit.

But we ended up -- we did report a $20 adder. That's where we ended up with. We got some emissions drop above and beyond the energy efficiency case, but, really, if you think about it, in comparison to the energy efficiency, not a big drop.

We dropped some more gas generation, and -- I'm sorry -- we increased our gas generation, and we dropped of our coal by 4.5%, which doesn't look much, but when you have a high percentage of coal, that's actually quite a bit.

And it resulted in a very high increase in production cost. And I want to make this really clear -- what's all in the production costs and what the component of this is. The production cost includes, in this case, the carbon price, and you split that out of actual variable costs such as fuel, and then you look at the price of the carbon. The price of the carbon is over 80% of that cost. So the majority of that cost was the actual carbon price itself and, of course, it's not a direct variable cost.

There's the change in the dispatch stack -- we can see gas goes up, and coal goes down. We also see a little bit of some change in other areas, but not really that material -- some of the must-run units that are still distillate. And we'll talk a little bit about why that happens as well.

Key results -- so this is kind of the cumulative effect. So we put a bunch of renewables in, then we dropped the load by 17% is what the net number is -- something around there. And then we put a $20 carbon price -- $20 a ton carbon price. We get a significant drop in carbon emissions total. We get a drop-off of around 10% in our coal gen, and we get a large net drop in gas generation.

There are some really important things to draw from this, and the first one is it depends on what order you look at stuff. Had we done the energy efficiency first and looked at that separately, we would have got much different answers. Had we put in 20% energy efficiency and then did 15% renewables, well, the 15% renewables would have been a smaller number, right, because we would have had less load because it's a function of annual energy.

So it really, really matters what order you do these things in. Next year is, at least from my view, as we look forward to this, that we really need to look at doing some of this stuff a little more separate, but in the context of how much can you do in a year, this is what we could get done in a year in addition to our other things.

And the last thing -- I'm going to go back to this slide -- the big driver on all of this -- energy efficiency is the number-one driver for all of these changes.

A little bit about -- well, how did this affect transmission congestion? After all, we're supposed to be looking at that versus looking at different resource packages. We did identify some congestion. We looked at the top 10 paths that were most congested in all of the PC-4, these renewable cases.

Here is a map of the paths that we looked at. For those of you who don't live in the West, TOT is an acronym for total. I'm not sure the history on that. It's kind of funny. So we have named paths, we have TOTs, and then everything has a corresponding path number. It sounds confusing. Yes, it is.

Here's our 10 most congested paths -- a 99% of path rating, so this is the percent of the time that the path was essentially maxed out. So if we look across -- and I think what's valuable is to look at what happens when you do different things. I think that's the real value in this. I think in 2009 we're going to have a little bit -- we're going to have some additional opportunities to take some different looks at some of this. We sure learned a lot from looking at this from a cumulative effects standpoint and looking forward, you know, we're going to draw upon this experience and do some things in some additional manner.

The other thing I wanted to do before we started looking forward to 2009 is really go back to the 2006 Congestion Study and go, okay, well, since then what have we learned? So up here is a map out of the report, and it shows the paths of interest, both from a congested now and congested maybe in the future. And a couple of main points -- one, I'm going to show a list of major projects on the next slide, and the second thing I want to look at that I'm not going to address today is all of the little circles around many of our metropolitan areas. And the sub-regional planning groups and the individual entities have done a pretty complete job of looking at and dealing with all of those congestion areas. I would encourage you -- you at DOE -- go back and look at the SPG reports and some of the key stakeholders and some of this local stuff and look how they've done that.

Rob is going to talk a little bit to some of that in a little bit. From the WECC standpoint, we're really looking at some of the regional path congestion.

This is a list, and it's not a 100% complete list, and there has been some recent stuff that's not on here, but this gives you a pretty good idea of where folks are thinking about putting big interstate transmission. And if we flip back and forth between this and the previous, if we look at -- if you put in even a few of these, you really have dealt with the majority of the transmission congestion that's been identified in there.

Kind of one of the issues that we're struggling with in the West is -- as we see multiple lines, essentially, emanating from and going to similar locations, and one of the things we're wrestling with is how many -- we're looking out 10 or 20 years -- how many of these lines should we put in, you know, in our study as being -- as assumed to be completed, and that's one of the things we're going to have to wrestle with, with all the groups this next year.

The other thing to kind of take away, there's an awful lot of action going on in the West when it comes to transmission project development.

I don't know if I should have put this first or last, but maybe it's because I should leave this with you as cautions on interpreting the results, both of what we've talked about today as well as the report.

We had no price elasticity in natural gas and coal. A lot of what we did caused some major shifts. Especially I'm concerned about the natural gas side of it. In the West, roughly 40% of the natural gas usage goes to the production of electric energy. So when you make material shifts in the usage of natural gas, you know there's going to be some changes in prices. We did not bake any changes in prices in our results. We used $750 a decatherm was the price we used for gas.

Carbon reductions are heavily dependent on the order of renewables, energy efficiency, and the carbon adder. We did it in this manner this year. If you did it in a different manner, you would get a different answer.

Transmission congestion is dependent on the site selection of your renewables and your other conventional fleet that you are adding. I can't stress enough that if you move it around, you're going to change the answer.

And in our model, renewable resources have a marginal cost of zero. And that's, no conclusions can be made of comparison to capital costs associated with various scenarios. Something to look forward to in 2009--that may not be the case, because we're looking at doing that. And I'm sure that Mr. Larson will talk more to that.

And I guess before we move forward, we've got to look, the analysis of future congestion is really about speculating loads and resources, and what would happen if there was available ATC. So that's something to think about.

Looking forward, TEPPC in its open season study cycle that Scott talked about earlier, we got 23 study requests from nine organizations. There were a whole lot of common themes. The impacts of existing and proposed renewable portfolio standards as well as greenhouse gas limitations. Impact on large wind additions in different parts of the Western Interconnection, and the impacts of specific transmission projects and the resources that would go with them.

The TEPPC work groups and the subcommittees are currently combining all of these requests into a synchronized study plan for 2009. That's going to be teed up next month, and then the final approval out by TEPPC is the first of June--the middle of June. Additional links to both our reports, as well as there are a series of white papers concerning how the renewables were done as well as how the energy efficiency was done that are also on our website.

The other thing just worth mentioning, we have other related activities that go on in the West that both complement this activity that we've talked about as well as provide feed-in, information, and intelligence. And one is the Planning Coordination Committee. And the PCC tracks proposed transmission projects. It's also where path rating is done in the Western Interconnection. The Roads and Resources Subcommittee is the group that brings in--it's part of PCC--it brings in all of the information from the members that we use to, among other things, provide NERC in our LTRA filing. But we use that information as well. It goes into TEPPC.

And lastly, a new subcommittee that we've formed to look specifically at the issues of variable generation in a holistic manner. And the purpose of that, really, is to tie all these activities as far as the renewables go that are going on between the operating folks and the planning folks in TEPPC and make sure that we're looking at things in a holistic manner.

With that, thank you. Rob, I got you five more minutes.

John Schnagl: Thank you, Brad. Our next speaker is Rob Kondziolka. Rob graduated from the University of Arizona in 1980 with a B.S. in Engineering. He was employed by Tucson Electric Power Company as a Transmission Design Engineer for five years before joining Salt River Project in 1984. Since 1989, he has held progressively responsible supervisory and managerial positions charged with the planning, siting, permitting, design, construction, maintenance, contracts, operation, business plan development, regulatory issues, and regional transmission development associated with Salt River Project's transmission system. This man does it all. Presently, he holds the position of Manager of Transmission Planning. Rob?

Rob Kondziolka: Well, thank you, John. I know everyone in this room here is thoroughly excited about transmission congestion, but some of you may have noticed that there's also currently going on a basketball tournament hosted by the NCAA. It's referred to as "March Madness." You may have heard that before. I noticed that they gave us a shot clock up here, and what I couldn't figure out is how we call for time-outs. So maybe if I can figure that out in the next 20 minutes, we'll move on through here. I guess the only thing I didn't get credit for was logo creation.

Well, we've heard from Scott, we've heard from Brad, and I would like to follow up on the theme that they have put together, and I would like to address how the subregional planning activities fit in with the regional activities, and I'd like to do that through a single case study and show how that feedback loop that Scott talked about works. And then I was going to give a short update, just as Brad has done, on SWAT activities, kind of elaborate that it's more than just a congestion study that's going on in the subregional planning areas.

Fortunately, we've got some graphics here to keep everybody oriented. I realize that not everybody here is from the West, so this is sort of the orientation slide for what we mean. And SWAT is in the desert Southwest of the Western U.S. It covers New Mexico, Arizona, southern Nevada, the Imperial Valley of California, and our friends from the El Paso area of Texas.

Okay, we've seen lots of slides now on paths. And hopefully, I don't need to go through it too much. But I want to focus on the one that's in red, Path 49, and then East of River. I guess I should explain why it's called East of River and not TOT 5a or TOT 8. East of River are all of the EHV transmission lines that originate in Arizona and cross the Colorado River. And then they go into either Nevada or southern California. So East of River means they originated east of the Colorado River.

Brad did an excellent job of going through a lot of congestion studies, but what I'd like to do here is give a little bit of history of how we have seen congestion studies in the West and how they've progressed over time. If we move ourselves back to 2001, the Western Governors Association made a request for a congestion study, and if you look at the bottom of the slide, it gives a more detailed location of that study and the full name.

But back in 2001, we weren't talking renewables. We were talking book ends of, "What is the future like if we go all coal, what does the future look like if it's all gas?" And in that study, you can see here--I've shown it in red--that congestion on that path I just showed you was identified.

We skipped a year and we went to 2003. Now, Scott talked about the Seams Steering Group-Western Interconnection--SSG-WI--and it picked up the work that was initiated through that 2001 process. And you've heard Dean Perry this morning--and Dean has been really a key leader in most of these congestion studies. Well, once again, the congestion was identified on Path 49. FERA did an independent look in 2004, identified congestion from the Arizona into the southern California area. And then in 2005, even SSG-WI still is identifying congestion. And then in 2006, in the DOE report to Congress, using information from SSG-WI and other subregional groups, it was still identifying congestion.

Now, as we move to 2007 and '8, we see the color changes to blue, and now we're seeing that we're not seeing congestion of significance on Path 49. And then looking forward, it's the same thing. So the question is, what was happening in these types of congestion studies, which are all looking forward, by the way. You know, they typically look five and 10 years out. So something happened between 2006 and 2007.

I've now listed, in the column next to the regional studies, subregional studies. Well, the following year from that initial 2001 Western Governors Study, a group known as STEP--another acronym, Southwest Transmission Expansion Planning--and it is a subregional group, and I see that Jeff Miller's here, and Brad talked about them, Scott did. He got to be the leader of this specific study effort.

And in that 2002 time frame, a lot of alternatives were done in looking at what are the best ways of relieving congestion and having transmission expansion from the Arizona area into the southern California portion? And there were certainly a lot of ways to go about doing that.

Well, then, if you move forward in time to 2003, STEP took about one year to do the process. And I'll talk about that process a little bit later. But it was after that process--then there's a note there on the WECC path rating for short-term upgrades. I'm looking here at my slide here, and I see it got reformatted. In that process--Brad touched on it--but we have subregional studies which are looking more at a macro level again. Path rating studies are certainly much more specific. They get into specific plans of service, they get into specific timing, and they look at very, very specific simultaneous interactions of the different paths. So the path rating process becomes much more detailed.

And then you can see that in 2004, there was the initiation of two more path rating studies. One was for the second Palo Verde-Devers II line, and then also there's an acronym up there, EOR 9300, East of River 9300 project. And you can see there, it took about a year to do those path rating studies from start to finish.

Now, as we again move forward in time, I've compared the regional studies to the subregional process to project development. So here you can see that after the short-term upgrades--and I'll define those a little bit more afterwards--that were identified in 2003, you can see that in 2005, two years later, the construction of that project went forward, and it was placed in service in 2006. Regarding the EOR 9300 project, as you can see, that was completed, that detailed study completed in 2005. It started construction last year and should be finished in the next two months. And then lastly, and I realize this is a bit of a speculation, is the Palo Verde-Devers II. I'm showing that beginning in 2010 and completing by the end of 2011.

Bob Smith this morning had some slides on the Path 49 East of River. I'm not going to spend a lot of time here, except to say we have a lot of joint-owned transmission in the West, and Path 49 is a classic example of how complex it can be. This certainly is listing the line names, and you'll see there's six different EHV lines that make up this path, who the control area operator is, who owns the different lines. You can see for each line, there's typically multiple owners, and then the allocation of those ratings that we're talking about.

Now, the process that was used to get there, now it's going back to the STEP process, where it's kind of a three-phased approach. One was to identify some short-term solutions. In other words, let's not always have big, fanciful dreams. What can we do that will address the need that we currently have? Then there were some mid-term solutions which certainly take more time and create more effort. And then lastly, there was this long-term vision. And I would point out that part of that long-term vision was to make certain we focused on varied resources. The short-term and mid-term was really, at that point in time, gas-driven. It was looking at that price differential between Arizona and California.

The studies in here--we don't need to focus on every single study. But it started off with 26 different basic alternatives being proposed in an open stakeholder process. And if you can imagine--and I know some of you can--having 50 to 100 people who all have some very pointed ideas on what should be done working through the valuation. It was done, actually, very well, and from that point, the group was able to take that 26 different alternatives that everyone agreed should be studied, and after having the power flow results, narrowed it down to six alternatives. And then from that point, those four AC and those two DC alternatives were studied in a much more detailed--and you can see in the listing of the type of detail that was done to make the comparison for that evaluation.

And from there is where the short-term upgrades were identified, the EOR 9300 project was identified, and the second Palo Verde-Devers II project was identified.

So then looking into the improvements to Path 49, you can see we start off with the rating, and Bob Smith mentioned this morning 7500. So in 2006, the path increase was 505 megawatts greater. And then this summer, the path will increase by another 1,245 megawatts, and then in 2011, it will increase by another 1,200 megawatts. And the last project in there, the Palo Verde-North Gila II, was not part of the study that was done, and this has come since this study work. But you can see in the 2014 time frame, an additional increase in transfer capability will be added to Path 49 as well.

Okay, everyone's had some comparisons on a slide. This is the slide that's out of the DOE report to Congress, and what I really want you to focus on as far as this goes is the Phoenix-Tucson area, and then, of course, the transmission from Arizona into southern California. So that's where we're really trying to focus in on this next series of slides.

We talked about upgrades, and then we'll talk about new wire projects. This is a listing of the major upgrades that are currently or completed in the Arizona-southern California area. And if you look towards the left side, you can see from the Palo Verde area going west in 2006, the two projects that were upgraded added 505 megawatts. And now you can see on the northern part of the system for this summer, that increases the path by another 1,245 megawatts when you combine those.

And I've also shown two other upgrades that aren't related to Path 49 but are ways of taking advantage of technology to supplement the new wire expansion.

And then I'll have a box, more generic diagram. But when you look at the Palo Verde and the Phoenix-Tucson area, you'll see some gray lines showing how this expansion out of Palo Verde is going. There is sort of a southern expansion, there's a northern expansion, and the tie from the Phoenix down to Tucson area. It's all to reinforce and increase the transfer capability within that bubble that was identified in the previous DOE slide.

Brad had a slide showing a number of projects. Now, these are the ones that are much more specific to the SWAT region. In that bubble, you can see that there are six projects. I didn't want to try and show them. But I think what you have is sort of a macro approach. You can see that there's a lot of interest in trying to move energy into Arizona and through Arizona. And you can see that when you look at the Colorado and New

Mexico coming into the Phoenix-Tucson area. You can see that expansion from the Palo Verde-Phoenix area to California. Then, as Brad mentioned, there's four significant projects that are originating in the Wyoming-Montana area, coming down into the Las Vegas-southern Nevada area. And again, all those projects are to feed that southern Nevada-Arizona-southern California area.

The good news here is I'm not going to go through all these projects. What I would like to point out, though, is when you have this information, you can go back and look at this at your leisure, I've tried to put in the key information. But if you look at that right column, you'll see that those projects, that these are tagged to on that previous slide, that these are more than just planned projects. If you look at the activity level, you will notice that we have, some of that is in design, material acquisition, right-of-way acquisition. It's already in the permitting stage. Some is in construction. It's only that very last project that's still in the feasibility analysis stage. All the others are having significant expenditures to move these projects forward and have them ready to be built.

SWAT, as with, I think every area in the country has a lot of activity, and we don't need to go through it here. But it's worthwhile pointing out a few key things. And one of those is, if you look at the very bottom bullet there, it's called the SWAT Renewable Transmission Task Force. This is one that is certainly getting the most attention right now. We are in the process of trying to enhance the work that's already been done, and that is identifying renewable energy transmission zones in that footprint. Also in coming up with a conceptual transmission to make that development workable or doable. We have a finance subcommittee looking at how the renewable energy transmission can be financed. And then lastly, we've got a group working on definition of renewable transmission projects. We're not there yet.

Going through other key activities, you'll notice that there are a number of things listed as corridor development. If you look at the second bullet just below them, that CATS EHV subcommittee, development of corridors with cities and counties. And if you go to the next major bullet, Transmission Corridor Planning Work Group, and below that, the Common Corridor Structure Separation Task Force. We have a lot of time and energy in looking at how we can identify transmission, but not just leave it as a line on the map, but how to make this doable and in taking that next step in identifying specific corridors. And we're working with the landowners--and in this case here, it would be the federal land agencies and the state land departments--to specifically allow opportunities to move forward.

And then you can see there on the very last thing, in Arizona there are some orders looking at requirements of identifying renewable energy transmission projects, and the report is due at the end of October of this year.

This is a map that the SWAT Renewable Energy Transmission Task Force created last year. It's like a lot of renewable energy zone type maps that you see. It identifies quantity of renewable, generation by energy type, so you see geothermal, solar, wind. I think the more important from this map is when you look at it is we've gone to the step of identifying the conceptual transmission required to develop this renewable energy, and we've initiated activities to do reliability studies and figuring out, "Okay, does this really work?" It's not just taking that stage saying it's lines on the map, but how well does it work?

And then I will end up with, "Does this process work?" and I'll leave you with, when we had a process like this--remember, I mentioned back in 2000 and 2001 when the Western Governors had this book-end study of coal and gas. And Arizona, under SWAT, there was a parallel effort to what we see here. In that case, though, we didn't call them renewable energy zones or energy zones. We called them generation areas, and we had the same type of approach doing a shorter, no-regrets option, looking at lots of scenarios and what type of elements were common to every scenario we could create.

And as a result of that, in 2005, two 500-kV transmission lines were sited, both through the BLM through the federal NEPA process and through the Arizona Corporation Commission through their Certificate of Environmental Compatibility process. One of those lines is in service. It was placed into service last year. The other one has a 20-year certificate. So there's still another 17 to 18 years to be able to implement and use that. And I think we need to have sort of this vision out there if we really plan to take action in making certain that we secure the options to be able to build these transmission lines for renewable energy.

And John, that concludes my remarks.

John Schnagl: Thank you, Rob. The next panelist is Doug Larson. Doug is the Executive Director of the Western Interstate Energy Board, an association of 11 western states and three western Canadian provinces. Members of the Board are appointed by the governor or premier. The Board has the responsibility for all energy-related issues affecting the West. The Board serves as the energy arm of the Western Governors Association. The Board provides support for the Western Governors Association Western Renewable Energy Zone Project. The Board has three committees, including the Committee on Regional Electric Power Cooperation, CREPC.

CREPC is a joint committee with the Western Conference of Public Service Commissioners, including the regulatory, planning and facility siting agencies from the states and provinces in the Western Interconnection. CREPC is the forum for the Western states and provinces to engage the U.S. Federal Energy Regulatory Commission, the United States Department of Energy, and the Western electric power industry in discussions of regional transmission planning, resource adequacy, transmission planning, market monitoring, and other regional electricity issues.

Doug also staffs the Western Interconnection Regional Advisory Body, WIRAB, created by the Western Governors in 2006 to advise the Western Electricity Coordinating Council of the NERC, the FERC, on grid reliability issues. WIRAB includes all the states and provinces in the Western Interconnection and Mexico. Doug?

Doug Larson: Thanks, John. I'll kind of shift the discussion a little bit more to the policy side of things, and I'll also build on some of the things that Rob emphasized. And here's some of the bottom line. And the bottom line is that without agreement on which future we're planning and building transmission for, it's the equivalent of pushing a string uphill. And that's where we've done a lot of the work on transmission, both at the state and federal levels.

And I want to build on this conclusion by explaining, sort of adding onto some of the things that Brad and Scott and Rob have said about the institutional history in the West. I'm going to add a little bit about some more acronyms. I want to outline some of the existing planning, development, and permitting processes in the Western Interconnection and compare those with some approaches that Senator Reid and Senator Bingaman have offered in their legislation they've recently proposed, highlight from the strengths and weaknesses--oh, should move ahead--highlight some of the strengths and weaknesses in the existing process in the West and the Congressional proposals, lay out some of the challenges that we need to address, and then offer some of my own ideas about the path forward in the Interconnection.

Again, these are my ideas, my comments, except I will supplement them where Governors, Western Governors, have policy, I'll note that.

So this is part of the acronyms. I'm going to skip most of this just to say that we are the energy arm of the Western Governors Association and show some of the relationships with the other groups affecting the West.

What I really want to do is build a little bit on, I think, what Rob said about the history on how we do transmission planning in the West, because it's instructive. And I just want to emphasize Rob's point. In the middle of the Western electricity crisis, the Western Governors had a meeting of utility CEOs and PUCs and asked the question, "Well, what wires do we need to get out of this crisis?" And there was sort of a deafening silence. And then finally, Jack Davis, who is the, was then the President of Arizona Public Service, spoke up and says, "Well, I think we need an Interconnection-wide plan." The Governors, in their usual way, said, "Well, how about 60 days, Jack? Can you give us a plan in 60 days?" to which he then explained that, "Well, you don't actually hatch these kind of Interconnection-wide transmission plans overnight. It takes a little bit of time." And then he tactfully said, "How about we give you some conceptual ideas in 60 days?"

And it was a rather Herculean effort including a number of people in this room to pull that off. And the point I want to make is the one Rob made, is the planning evolved from there. The work that was done during that period, it focused on a base case which was coal-dominated, a gas case, and an other-than-gas case. The Governors got their plan, said, "Hey, this looks good. Industry one, could you institutionalize this?" which the industry did under SSG-WI. And so SSG-WI did its analysis a couple of years later with three alternatives. And so it was a heavy reliance on coal, a heavy reliance on gas, and now a heavy reliance on renewables.

And when the RTO effort in the West collapsed, the industry and the Governors asked WECC to pick up the ball on transmission planning. And as Brad noted, where we are now is we're evaluating a much different resource mix, one dominated by renewables, energy efficiency, and gas generation.

So the question is, what drove this change from the coal future to the one we're studying today? And I'd argue that one of the reasons that this change is underway is the policy vision enunciated by Western Governors in their Clean and Diversified Energy Initiative, that's the CDEAC acronym. By the way, we invent all these acronyms to keep the Feds off kilter here. And in 2004, and I was continuing with the Western Governors' Western Renewable Energy Zone Project, which I'll say a couple of words about.

So the point of this chronology is that we need to know the future that we're planning for, and that we're planning transmission for and building transmission for, and I'd argue that so no matter how competent and sophisticated either the industry regional planning processes are or FERC may be, to answer this, they really can't answer this question. And now perhaps Congress and the Administration will help answer this question by enacting greenhouse gas rules or a national RPS which is more stringent than what's already in place in the West, and that will provide guidance. But until that happens, the question of what we are planning for is really driven by state policies.

I'm going to spend the rest of my time talking a bit about the existing transmission planning processes, the Reid and Bingaman proposals, the challenges we need to address, and offer some suggestions about path forward. So the basic three steps in developing transmission--you plan it, you develop and finance it, and you permit and site it and eventually construct it.

So as you heard, we have, in the Western Interconnection, an increasingly coordinated and robust three-tiered planning process. That's the saucer diagram on left. And this is evolving rather rapidly. And I think, frankly, where we're at now is where the Governors back in 2001 hoped we would be at. It's an open, proactive transmission planning process. The Governors are using this process. They used it through this WIRAB Study that requested how would you get to a, which wires are needed in a 15% reduction in carbon emissions from 2005 levels. They're using it in the Western Renewable Energy Zone Project. So it's a very useful tool. We're only in, as Brad mentioned, the second cycle of the studies. We've learned a lot in this first cycle, and I think there's more to be done. I want to say a couple of things about that down the road.

I also want to note that the quality of subregional planning is really excellent in the West, perhaps in all parts of the West with the possible exception of California, where the--and Scott, you can kick me at the appropriate time--but where the ISO and the public power entities really don't yet have an integrated resource plan--or even an integrated transmission planning process. And the California Renewable Energy Transmission Initiative might help fill that gap.

With regard to project development and finance, it's important to keep in mind that outside of California, we don't have a direct link between transmission planning and transmission project development. In most of the West, it's the market participants who are going to decide what transmission project they want to pursue. The good news is there is substantial evidence that what those market participants decide to pursue coincidentally coincides with a lot of the transmission planning that's been done in the region.

With regards to the way projects are financed or have historically been financed, it is that the load-serving entity decides that it wants the power at the other end of the line, and that that delivery cost, delivered price of power--the generation plus the transmission--is their lowest-cost option. And then the load-serving entity either builds a line itself or cooperates with somebody else in building the line or contracts out the transmission service. And I think this is really important to keep in mind, that it's really the fuel choices of load-serving entities that ultimately decide what transmission's going to get built.

I just want to emphasize the point. I think a lot of what we've done in the West and nationally, it amounts to a little bit of pushing a string uphill. You know, we've offered, we've built this transmission planning process, we have FERC offers, incentive rates of return on transmission, we're designating corridors across federal lands, and we're designating National Interest Electric Transmission Corridors and preempting states in the siting of those things. But again, it's like pushing a string uphill. Unless the load-serving entity wants the power at the other end of the line, that line's just not going to get built.

And unfortunately, uncertainties over things like federal carbon policy or federal RPS policies have really hamstrung western LSEs in trying to decide how hard they want to pull on that string.

On siting and permitting, this is a joint--in the West, in particular--this is already a joint state-federal effort. The federal role is particularly with regard to permitting across federal lands. It's often the biggest hurdle to getting permits for a transmission line. But it's extremely important, because most of the West is owned by the federal government, and if you're going to build anything of any distance, you've got to get federal permits to do it.

Now, up on the state side, up until the time that Arizona denied a permit for the Palo Verde-Devers line, no state in the West had ever denied a permit for an interstate transmission line. It's also important, by the way, the Feds have another ace in the hole if they want to play it. That's the Bonneville Power Administration and the Western Area Power Administration have their own condemnation authority.

Regarding Section 368 corridors across federal lands, this is probably something that could be very effective in speeding permitting. Unfortunately, a lot of the work on designating 368 corridors was done prior to the shift, which Rob described, of moving away from a coal future toward a renewable future. So those 368 corridors may or may not be in the right places anymore.

And I'll also argue that the Section 1221 designation, National Interest Electric Transmission Corridors and foot preemption process in those corridors, so far hasn't had much effect in the West.

So let me shift here to the proposed changes by Senator Reid and Senator Bingaman in planning, project development, and permitting. Under their proposals, planning would be done by a FERC-approved, Interconnection-wide entity or entities or, absent those, FERC would do the planning. Senator Reid focuses on wires to move renewable generation. Senator Bingaman focuses on sort of transmission for any purpose. Those bills would have the FERC allocate the costs of major new transmission to customers across the Interconnection, or at least a large portion of it. And both bills ultimately put FERC in charge of siting the transmission.

So let me shift to the strengths and weaknesses of the existing planning process. In many regards, what we've got in the West right now is sort of a model of what FERC and Senator Reid and Bingaman seek. That's an Interconnection-wide, open, transparent, proactive process that's responsive to requests, that coordinates with subregional planning.

But we've also got some weaknesses in what we do now. We don't produce, as a result of these studies, a plan. We have a series of studies. We don't produce a plan. We use a relatively short time frame, which is pretty typical--a 10-year study horizon. The down side is that these assets last a lot longer than that. As Brad noted, right now in TEPPC we don't consider capital costs of the investment, although I think that's going to change in 2009. We're still struggling to more closely link the resource generation decisions of load-serving entities to the planning needs. And again, our studies aren't directly linked to projects and, in some cases, I think, here's the case where we're moving rapidly to change things. When we evaluate the transfer capacity of new projects, we do that with one project in isolation from others as opposed to collectively.

But I think the important point is here is that the planning process in the West is evolving and rapidly changing. And one of the promising additions to this Western planning effort is the identification of renewable energy zones, both at a state level and at the Western Governors Western Renewable Energy Zone Project. I was going to say a couple of things about that project. It's being done by the Western Governors Association with support from DOE. It began last May. It feels like it's not breaking a lot new ground in terms of methodology. It builds on the state WREZ processes. For example, in Texas, the CREZ process and the California RETI process.

It has four phases. First is to identify the renewable energy zones and develop supply curves for the zones. The second phase involves development of a user-friendly model to estimate the delivered price of power from those zones to specific loads in the Interconnection. The second phase also involves developing some conceptual transmission plans from those zones. I'll say a word about that in a minute.

And the third and fourth phases, which really aren't scoped out yet, the third is coordinated procurement of renewables from the zones. And this is really important in sort of our voluntary world, where you need to get multiple parties who are interested in the delivery of power from that zone to collaborate and thereby create the critical mass to build a wire. And the fourth phase, again, is not scope, but it has to do with multi-state collaboration on siting and allocation, cost allocation issues.

So one of the things, one of the other things in the WREZ process is it has made a request of WECC to study four different scenarios, if you will. And I think these scenarios are indicative of the direction the Interconnection-wide planning will need to move.

The first request is defining the characteristics of the request. It more closely links the generation plans of load-serving entities to regional transmission planning. The second request evaluates the need for wires under much more aggressive renewable goals and carbon constraints. The third request pushes the study horizon out from 10 years out to 20 years, and we begin again to accommodate or incorporate potential technology changes.

And the last request really flips the current planning process on its head. Instead of postulating the future loads and postulating the future resources and then figuring out what wires you need to connect the two, it turns it around by saying, "Well, let's just postulate an ultra-high voltage overlay and see under what conditions does this make any sense."

So these are what are called qualified resource areas under the WREZ project. It's a step along the path of getting to renewable energy zones. The colors don't mean anything other than to distinguish the difference in the zones.

With regard to the schedule for the WREZ process, this request was made of WECC in January. In February public comments were received on the map, basically the Qualified Resource areas and the inputs to the WREZ model on the delivered price of power. All right, in March--in fact, this week--we're releasing the WREZ model, and it's an Excel-based model, so you can just go to the Western Governors website and download it and play with it. In April, we hope to incorporate some of the wildlife data in drafting these zones. The wildlife data wasn't available early, and frankly, this is going to be a real tough job because the data's just often not there. And in May, we hope to have final zones, with it going to the Governors in June.

So let me talk a little bit about the existing project development and financing. And again, with the exception of the Cal ISO, we don't have a mechanism to force unwilling parties to pay for transmission. This is a business decision of individual market participants about what wires get built. As the map showed, I think I've got the same map, is we have an unprecedented number of proposed major transmission projects. Most of these are designed to access distant renewables. They're not reliability projects.

Now, the weaknesses of what we, the way we go about financing transmission from this sort of market participant-driven process, is that we're likely to end up with undersized wires for location-constrained renewables. And as a result, we're going to miss economies of scale in transmission development, and we're likely to trigger some avoidable land use fights. If we had built the line of the right size the first time, we wouldn't be going back to the same area a few years later when an increased transfer capacity may be needed.

Our existing process is resulting in a lot of duplicative projects. That's going to put permitting agencies in the unenviable position of having to pick winners and losers. Our approach may leave some big gaps in the system that, had you filled that gap, you could have increased transfer capacity substantially across multiple paths. And our current approach isn't going to create an option for quick expansion of the transfer capacity in the future.

This is the map of the transmission projects. I've just highlighted a couple here which are actually being downsized. They're being downsized because there's no immediate need that could be demonstrated for the higher level of transfer capacity. You'll also see a lot of these projects start and end in the same place.

So let me shift to permitting and siting. This is not easy to site and permit transmission. We have, however, succeeded in permitting lots of lines in the West over time. But the process takes too long. And it thus removes from consideration by load-serving entities resource options that depend on new transmission. We've got some progress in synchronizing permitting agencies, but a lot more needs to be done.

So let me move to some of the challenges, and I think there's a couple of tests here, one in which Dean's work, Dean Perry's work this morning, may address, and that is, "Are we, going forward, utilizing our existing wires?" And the second one which is going to come up, whether the Feds do this or the state does it, is, "Is the wire needed?" The third one is, "Are we right-sizing these lines to capture economies of scale and minimizing environmental impacts?"

So will Reid or Bingaman help? On the whole, I think, on planning, it will probably help as long as FERC doesn't actually end up having to do the planning, which will probably set back what's happened in the West. On financing, I think we're going to, the idea of spreading the cost across the Interconnection is going to trigger a lot of fights from parties who don't see benefits from a project. The big failure of the federal legislation is it doesn't address the issue of right-sizing a line to a renewable area, which is an area where the Governors think the federal government should have a large role.

I'm running out of time, so let me shift to the last item, which is some ideas on the path forward in the Western Interconnection. And I just want to emphasize two things. I think the focus on planning, financing, and permitting really has to be on expanding and preserving the options for quick action to reach large amounts of renewables. And we haven't quite figured out how much we ought to pay for maintaining that option, but this ought to be a high priority. The suggestion here is a development, a planned development process as opposed to what we do now, and it has a number of steps here.

The first step is we think that Governors ought to lead a scenario development effort--what futures might we be planning for? WECC needs to lead transmission planning studies that would tell you what wires are needed under these scenarios, and WECC needs to develop a plan or plans under these scenarios.

The Governors need to endorse these kind of plans, and then the federal government should be obligated to follow those plans when doing everything from granting incentive rates of return for transmission by FERC or expending federal transmission funds, whether it's stimulus money or other funds. Guiding 368 corridors. We'd argue they ought to limit the designation of NIETCs to areas that are within the plan.

So this is a brief diagram of what I just said, where the Governors would lead part of this, WECC would lead part of it, there'd be joint other parts. And let me go to the financing issue here.

Here, my suggestion is the way we've done financing in the past, which is those who want the power at the other end of the line pay for it. It's a good model for the future, with a couple of exceptions where the federal government needs to play a role. And that is in right-sizing the lines to locations with constrained renewables, and paying or paying for the option to rapidly expand transfer capacity in the future from these kinds of areas. And the Feds also ought to have a role in helping test the deployment of cutting-edge, ultra-high-voltage transmission.

And on the last slide on siting and permitting, the Governors have recommended to the Administration and Congress that the 368 designations be re-examined in light of the new work on renewables from the WREZ project and state efforts, and the DOE and FERC should refocus their NIETC designations on sort of narrow corridors to move renewables.

So I conclude where I began. Unless we have some agreement on the future we're planning and building for, our current efforts and the Congressional legislation, the legislative reforms are a bit like pushing a string uphill, and I think we can do better than that. Thanks.

John Schnagl: Thank you, Doug. I just wanted to remind Doug that the federal government has its own agency to create acronyms and keep everybody off balance. It's called the IRS.

We've heard some very interesting discussion this afternoon, and I want to lead off with a few questions that will go into a couple of the aspects that were hit pretty hard here. Scott, you laid out a very, to be perfectly honest, intricate planning process, of which you identified that collaboration with a wide variety of entities was a critical part of that process. Can you describe what efforts you have made to incorporate as wide a variety of groups as you have in your planning process? And more importantly, what benefits can you say that you have achieved by being as inclusive as you have?

Scott Cauchois: Well, I would, I mean I would say when we, there was a, when SSG-WI and the RTO effort began to collapse, the Governors and other people in the West definitely said, "One thing we need, we've got to have some sort of a Western vision." And some of that came out of difficulty. Despite the success we've had with some of the projects, some entities have had difficulty in moving projects forward and cited the lack of any kind of a coherent plan. Even though the plan envisioned initially by WECC and TEPPC, it certainly, it doesn't have regulatory teeth in it, but they wanted something where they could argue that they came to the table. Other people agreed that, especially on the interstate lines, something was needed. And so there was an incentive on the parts of lots of different entities to join in a cooperative process.

And the WECC and TEPPC certainly reached out very widely to get people involved. FERC Order 890 was a good kick in the pants to enhance that, because suddenly entities that, frankly, took part in absolutely no coordinated planning with anybody, and never wanted to, were suddenly forced to begin to look around and realize that they had to be able to show that they were cooperating and entering into something.

And then along came all the renewable efforts and the dialogues going on in the different states. And then carbon reduction policy. And these things had a lot of political dimensions, one being are the states going on their own, do they do it cooperatively with other states? And, frankly, there's a little bit of both going on. So let's see, and I'm forgetting the last part of your question, but there have been a number of efforts.

And then, certainly with the new Administration and the talk of legislation, that is certainly incenting people. We had a good TEPPC meeting last week, and the number of people, I mean, it was well attended and a number of entities who have been, you know, sometimes tried to keep us at arm's length, were gladly joining into whatever efforts we make going forward.

John Schnagl: So if I understand what you're saying is that the collaboration process does appear to, that the projects that you're proposing or that are coming out of the planning process may actually get built?

Scott Cauchois: Well, the projects, a lot of the ones that you've seen today that Rob had up, I mean, some of these really had their gestation under the SSG-WI effort and began to be identified, and they emerged. And then one of the things that's happened with the projects--I mean, we're not identifying projects yet, but we're identifying congestion and possible solutions to that. But again, there's been a real vacuum, I mean, as far as somebody to maintain Western data, I mean, the whole works.

And WECC just stepped in, also, just to fill a vacuum. So the demand was there, and then the question has always been, even without the change in Administration, the possible change in direction of federal policy, the West has already begun a dialogue about how on its own could it advance toward a plan more than it has before, with some people wanting to do that, other people being reluctant. But we've been in this constant dialogue with our subregional groups about how to do that, how to get the planning exercises done, and then of course, as FERC always asks us in the 890 workshops, you know, "Just show me when the thing gets built and I'll believe you."

So we're still a little bit at that stage.

John Schnagl: Thanks, Scott. Brad, you've identified a very major difficulty in the planning process, and that is how do you integrate proposed projects in a 20-year plan or a 20-year vision in terms of your planning process? You said it was difficult. I would like you to talk to that just a little bit more and say, you know, exactly what you're doing. It's obvious from my perspective that once a proposed transmission line gets put on a map, it never goes away. It may never get built, but it still never goes away. How do you incorporate that and all the other uncertainties that Doug was talking about in a realistic 20-year planning process?

Brad Nickell: I'll bifurcate this into two things. One is future generation and the other is future or proposed transmission. And on the gen side, some of it is fairly straightforward, but the stuff that is recorded by entities that is scheduled to go online prior to the study year, that's pretty straightforward.

Unfortunately, a whole bunch of it--wind, solar, gas, anything but really coal or nuke--has a development cycle that is inside of 10 years. So when we're looking out 10 years, and this problem only gets worse if you try and look beyond 10 years, even when you're looking at 10 years, you have to guess. And you can use a queue, the queue's a little, one way that gives you a little bit of a clue, and you can use some public sentiment. You can use the transmission projects themselves. You know, nobody's proposing new transmission. All the interstate lines that all three of us have popped up, they have the new resources at one end of them. They're not there to really relieve 3,000 megawatts of existing congestion, because that doesn't exist. So they're assuming some new resource package. So that's part of how to fill in the blanks on the generation side.

The transmission side is a little bit more difficult. Again, we have a lot of projects, and some of them are competing, and one of the challenges is, you know, if you ask any one project developer is their project going to be put in, they'll say, "Well, yeah." And we'll go, "Well, what about the other three competing ones?" and they'll go, "Well, probably not all of them."

And so what do you put in? Well, I think you go right back to the resource package, and you don't have to pick a winner or a loser. You go back to the resource packages that are proposed for different lines, and you look at those, what the congestion is, and you arrive at some answer that you can put in, some standard non-project-specific transmission, which is what we do in TEPPC, that will relieve the congestion that is identified in the case. And that really is what the expansion cases do in the TEPPC process.

And I see this from a major project point of view. As this become a bit of another enabler, or another tool in the box that says, you know, you kind of go back to the use and useful, that that helps provide some supporting documentation for that. But the TEPPC process, because of what it is, is not restricted to any one facility.

John Schnagl: Okay. Thank you. Rob, you had a slide showing a number of projects in various stages of development. You, it's very promising. You also indicated that the federal land management agencies were some of the greatest impediment of actually getting projects built. I'll ask you very directly, is that the greatest impediment of getting those projects built? And what can DOE do to help to remove that impediment? And I'll preface that with a statement that Secretary Salazar made the other day, that basically addressed getting transmission for renewables built and redoubling efforts on their part in order to, the Department of Interior, to facilitate those types of actions. So if you can basically address what is the greatest impediment? People say finance at times, some say siting, but the folks that come in and talk to us talk of a wide variety of issues. So I'd like your perspective.

Rob Kondziolka: Thank you, John. I would say probably the two biggest challenges, and right up there with siting and permitting, could be the different forms of agreements, and not necessarily the classical financing. There is money available to build transmission. It's getting the cooperation of the different parties together to put the agreements together that can sometimes be just as challenging. I do think that in the West there's a lot of good examples of how we're getting better at this. But let's not make too light of that.

When it gets to the siting and permitting, yes, I've had many years of frustration on this aspect of it, and I've recalled during the Bush administration, when the White House Energy Task Force was put together, and I didn't see any improvements with respect to that. I think it takes more than orders, and I think it takes more than statements. I think it really has to come down to a few things -- if we can go back to Doug Larson's comment that if we can get an understanding about what a long-term plan is, so that the federal land management agencies have a clear vision of what we're trying to accomplish, it would make their job easier. They are in the same process that a lot of transmission providers went through with the interconnection request. In other words, a sort of clustering, and that helped improve things.

If we can do a better job of letting the federal land management agencies understand what are these needs -- that will probably go a long way towards meeting their objectives. Because right now, during the 368 process, pretty much what we identified were existing corridors. Not where the new corridors needed to go to the renewable energy sources. So that would be there.

And then I do thing that there needs to be some form of structural changes in the way NEPA is done. I think if we don't increase the staffing at the lowest working level, I don't think we're going to be able to move these projects quickly enough. And experience tells us that the EA process and the EIS process takes much longer than the guidelines. And it's normally because you can have a project manager there, but they don't have the resources to move the project forward, it just won't get done. You need to have more real estate specialists, more biologists, cultural resource specialists, so that they can move it forward.

Now, one option could be, when I say structural changes, instead of having to have the permanent staff review a third party independent environmental consultant's work and firm it up, could staff consider hiring a second independent third party environmental consultant to work for them instead of having to go through staff all the time? That could be one suggestion that could be considered.

John Schnagl: Thank you, that's very helpful. I think you can guess you're the next one here. I have a fairly straightforward -- you've had an extremely comprehensive presentation, and I've got a very straightforward question for you in terms of kind of highlighting your conclusions.

You had a sequence for being able to address getting renewable resources developed and the generation and transmission built and going through that process, and you had a number of different layers that you proposed on one of your slides. What is an acceptable timeline for completion of that process from the top of that stack that you had to where the project is built?

Doug Larson: I don't have a simple answer. It really depends -- what's acceptable depends on what the load-serving entity needs and when they need it. And I think one of the things we need to do collectively is to figure out ways to shorten that timeframe from seven or 10 years, where normally we've been talking about transmission development to something shorter so that those resources can be considered by the load-serving entity when they're looking at options.

So I think it depends on the urgency of the need for those resources by the load-serving entity, and I guess we bought a little time with this recession, I think. That's a hell of a way to buy time, but -- so we have probably a little more time to organize ourselves so that we can, in fact, build the transmission rapidly once the need is apparent by the load-serving entity, and I don't have a year.

John Schnagl: Okay. But if I understood you correctly, something less than seven years.

Doug Larson: Yeah, and this is why I think it's really important -- an important federal role is to preserve the capacity to rapidly ramp up transfer from a renewable area, and that may take the form of maybe the federal government paying to -- paying the incremental cost of super-sizing or making ready to super-size the project from a renewable area, i.e., the

Feds pay the wider -- pay the cost of the wider right-of-way, pay the incremental cost of the bigger towers. Maybe they don't get strung until the demand arises, but you've already gone-- you've positioned yourself so you don't have to go through Rob's review at this point. You've got to string wires and put in some transformers, you're ready to go.

It may take the form of -- which is very hard, but it may take the form of trying to set aside corridors in advance of development even though you don't have a project in that corridor.

John Schnagl: We are at the closing time of this meeting. I want to do a couple of things first. I would like to ask you all to join me in -- yes, we'll get there -- in thanking of the panelists for their presentations.

[applause]

We have a couple of just administrative matters that I want to address in just a second. Yeah, we'll get to some questions in just a minute -- a couple of administrative matters before people that absolutely have to leave do. First of all, I want to let folks know that for those who wish to speak with the folks from DOE and provide comments on this issue, tomorrow after the conference we will stick around for the amount of time that is necessary to meet with you and to consult with you regarding your recommendations concerning the 2009 Congestion Study. We do ask that you sign up for time slots with MaryLee Blackwood at the Registration Desk if you intend or have a desire to meet with us. So if you do that, we'd certainly appreciate it.

I am also going to remind folks that following the close of this meeting tonight there is a reception, and there will be information that Lauren will put up on the screen here, from what I understand, concerning the reception. So just in case anybody had to leave the room, I wanted to get those taken care of. Now I am going to open the floor for questions of the panelists. Joe?

Joe Eto: Two clarifying questions -- Rob, I really appreciate your speaking to issues on East of the river. Do your conclusions also apply to West of the river, looking at the other half of that critical congestion area that was identified last time?

Rob Kondziolka: It's kind of interesting -- this is Rob Kondziolka -- Joe, kind of interesting. The focus was always on East of the river. West of the river has seen some changes as well. If you recall the information that was presented this morning on the congestion panel, it would appear that some other issues have risen up with path 46 -- not significant but that would indicate that maybe what we're seeing is some shifts from just movement of energy from Arizona into southern California moving up towards the southern Nevada into California. That may also explain, when you take a look at all those projects, trying to get from either Wyoming, Idaho, or Montana into southern Nevada, are seeing some additional opportunities and a need.

Joe Eto: Thanks, Rob. And, Brad, I want to just clarify something -- you showed some slides that talked about future congestion from the study cases for 2017. You also said some transmission is included in there, but I wanted to just have you clarify how much transmission is in there.

For example, you described some incremental transmission being built, but we have seen pictures of lots of transmission being proposed. And so how much of that is already in the 2017 case, and is this congestion that you see in several of these cases on top of that or not including those projects?

Brad Nickell: There is, and I'll have to go back the report as far as a line-by-line, what's in there and what's not, and the report does outline that. Projects reported by entities in the West that have gone through a certain process essentially get included.

Rob Kondziolka: Yeah, this is Rob Kondziolka. Joe, one of the things that does get incorporated, especially when you look out five years, 10 years, we take what is known as a "base case," and so the base case, whatever year you're looking at, has a certain amount of transmission, and it tends to be more local transmission not as far as major projects. And, you know, we have debate what should be done, or should we have some type of better rules of the road as to what's included.

My own opinion, now, is that if we add a lot of that in, it tends to disguise what otherwise might be congestion. So I know that most people want to see their project included in the plan, but I think the study does a better job if you don't include the major transmission. So you can see what's going on without it, and then you can show how that project can provide an opportunity for improvement.

John Schnagl: Alison?

Alison Silverstein: This is Alison Silverstein. A question for all of you, and it sort of builds on what you were just talking about, Rob. Some congestion is driven not by moving energy in but by the need for reactive power and local voltage support. With long lines across so much of the West, and generation so far from loads, how do you provide for local voltage support, going forward? Who does that planning? Where does it get treated, and how does it affect congestion as we look at it?

Rob Kondziolka: I'll start.

Alison Silverstein: Scott?

Brad Nickell: And this is Brad Nickell, since he took my last one, I'll take his. In the production cost models, we do not do any evaluation of security analysis as far as looking at voltage support and things like that.

Once a project starts in the rating process and, really, then we're talking about an individual process, they have to go through that, and that's where those security studies are done, and that's where, if there are any mitigating factors that need to be taken into account, those are taken into account.

If we look at kind of what's in the system now, if we look at Static VAR Compensation and, in some cases, muster on units, they are there for voltage support, that's a lot of times in support of that. But that really doesn't happen to the long-term planning -- long-term planning range just because there are a whole bunch of variables that you would have to really speculate on that would change the answer, potentially.

Rob Kondziolka: And this is Rob Kondziolka. Brad gave me time to think about that question as submitted. It is a challenging question and, Alison, it's an excellent one because as we look at the load pockets in the West, especially when you start looking at renewable energy, whether it's VAR remote or remote, it's still being imported, and if we're not adding local generation, it's going to look at a few things.

We do operational studies, and those are NERC-required studies, to look at VAR requirements, and planning studies, it's a lot of times VAR devices are put in there to make certain that you get stability in your answers, and I do think that we're going to see, when we rely on more imports, that we're going to rely on more equipment to help manage that.

Alison Silverstein: Then does that mean that the answer to who is in charge of local VAR support is the local load-serving entity? That this is essentially a local planning issue rather than a regional or SPG issue?

Rob Kondziolka: I want to say, as a qualified yes, I still think it does go back to the slide that Scott showed, which shows the interaction that, yes, the local load-serving entity who has a major load pocket will have to focus on that, but also it will have to be incorporated in some fashion in that planning process.

Alison Silverstein: Is there any risk that we are giving cheap energy with a long line and losing the savings on local voltage support?

Rob Kondziolka: Not an easy answer on that one -- if you look at those upgrades that went from Arizona into California, when those short-term upgrades were added, not only was serious compensation included -- part of it had to include a Phase 15 transformer. It also had to look at static VAR installations, and, you know, I think most engineers would say, "Well, I'd rather have skinny mass than go in that approach." But I think we'll have to find a balance because if you're not going to have that opportunity and local generation, the addition of new wire is better than an upgrade, for example, than taking these other approaches.

Scott Cauchois: Excuse me -- Scott Cauchois. I think that's an interesting question, and I'd just say, just a level up from reactive power and voltage support, you know, entities definitely are thinking about his, and I wouldn't say it's a regional planning process issue so much the way we do it, but I'm thinking about entities that are looking for innovative solutions to balancing power, and, for example, in firming and a couple of examples of that are, you know, for example, California entities looking at the Northwest and the Canadian hydro system to provide the complementary services they need to be able to import large amounts of wind power, for example.

And it's also stimulating a look at probably some of the more expensive advance pump storage projects that were sort of dead for a while, and that could come to fruition to -- you know, not necessarily right near the load center but close enough to provide an enormous service.

So there is the very local level and then there is this other -- you know, what's going to provide the ramping, the balancing, the regulating -- all that stuff.

Alison Silverstein: Speaking of ramping, balancing, and regulating -- this is Alison with one last question -- and it's for Brad and, well, anyone who wants to jump in. The accepted wisdom is that you increase levels of renewable and intermittent generation, you need lots more fast, flexible generation, which is most likely gas-fired, or else huge quantities of closely controlled demand response to adjust and firm up the intermittent that you're getting and keep the system stable.

However, your renewables analyses, to date, show huge reductions of gas-fired generation and very little coal back down, even though coal is base load. Are these purely economic studies or why are -- any thoughts on why we are not seeing greater preservation or creation of fast, flexible gas capacity to deal with all of these renewables? Is that a different kind of study or is accepted with the wrong, or what?

Brad Nickell: The hourly production cost model picks up on some of that need, and it does that in a couple of ways. The units -- the traditional gas units, their ramp rates are in there, their operating characteristics are in there. So what happens when we have insufficient, over-the-hour capability to follow the variability of wind? What ends up happening is we see what's called "dumped energy." So units that were maintained and had to be run, essentially, for the next hour or the next time period, so we pick up on that.

However, one thing we don't pick up on is the intra-hour and not the variable generation subcommittees and, as well, the whole bunch of entities in the West have multiple efforts going on in that area, and that kind of gets back to the ancillary services question.

As far as what units are on and off as far as -- I think coal versus -- I don't know if you're getting into coal versus gas -- as far as how the units are dispatched from the increase in variable generation, it's going to come off the tops of the highest marginal resource that is able to be taken offline -- or not offline, but ramped down is what's going to happen, and that's always going to be your simple cycle -- gas turbines are at the top of the stack.

However, those are going to stay on, and you'd see dump if you needed them for the next hour, and that cost was higher than turning down a combined cycle unit.

Alison Silverstein: Thank you.

John Schnagl: One last question and then we're going to hit the reception.

Richard Bayless: This is a question in a question in it's probably, for anybody in the room including you, John, I just got word that we have not received a single suggestion or economic study request at our regional planning level or at our membership transmission provider [inaudible].

It appears all of the advocates that were hammering on us to do so and set that up, -- and we may be off the air --

Anyway, all the advocates that were in the process getting our Attachment Ks, and 890s set up seem to have evaporated and are concentrating at the Congress level, it appears to us. Is Attachment K processes, the 890 processes, especially at the transmission provider level and sub-regional level -- is that still an issue and an ongoing thing given the regional planning entity and the DOE proposal for how interconnection-wide planning should be done?

John Schnagl: Oh, I can see people are jumping at that one. Scott?

Scott Cauchois: I was hoping that DOE people would say something. I mean -- yeah, Rich is right -- in the first Order 890 workshops, the renewable interests -- wind, so on and so forth -- were heavily participating in, in fact, you know, demanding access and a process that we worked very hard to set up where they could enter in all the way from the TEPPC study request to getting into the combined project studies that take place at the beginning of the path rating process.

So -- we went to enormous effort to abide by FERC's direction and their policy desires to incorporate people and make sure that a large geographic scope planning process would work and enable the people to come in. We responded to their -- some of their study requests last year and, yes, they have not been quite as present, and I guess that I can't answer the question as of why. And I heard FERC was -- we heard rumors a few months ago that they would probably start holding workshops and say, "Well, we did Order 890, and what's happened?" And we haven't heard a word out of that.

So -- I guess for the more political types than I am, that's a very good question.

Rob Kondziolka: This is Rob Kondziolka. I can certainly confirm on a factual basis that, in the West connect footprint, which covers all or part of seven western states that we have not received a single congestion study request to any of the transmission providers through the Attachment K process. When we were doing that, they were quite satisfied to see it focused at the TEPPC level, and they wanted the sub-regional activity to focus on the type of work that they had been traditionally doing.

For entities in the footprint, and this has been primarily major transmission developers, they have made their request directly to TEPPC and not through any individual transmission provider.

Doug Larson: And even though we may not have a lot of those requests, it's very nice to have this process in place, so it's open, anybody can show up. So it's not a wasted effort in this governor's mind.

Scott Cauchois: And a final thing, I guess, I mean, since Doug represents a lot of western and governmental interests, the requests that have come in from the industry leaders and the governors certainly represent renewable interests, I mean, big time. So we're in the process of dealing with those requests now. So even though they're not directly from the groups through the sub-regional, maybe all that work will get done.

John Schnagl: These folks did an excellent job of responding to that, so I'll leave it at that.

I'd like you to again join me in expressing appreciation for all the panelists today.

[applause]

And as we adjourn today's meeting, please join us for a reception hosted by the Midwest ISO, PJM Interconnection, Southwest Power Pool, and the Western Electric Coordinating Council. Thank you very much and we'll see you there.