STATE OF MICHIGAN

UTILITY CONSUMER PARTICIPATION BOARD

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MEETING OF MONDAY, DECEMBER 1, 2014

12:40 P.M.

611 West Ottawa, 4th Floor
Lansing, Michigan

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PRESENT: James MacInnes, Chairperson
Paul Isely, Board Member
Susan Licata Haroutunian, Board Member
Ryan Dinkgrave, Board Member
Michelle Wilsey, Board Assistant
David Shaltz, Residential Ratepayer Consortium (RRC)
Christopher Bzdok, Michigan Environmental Council (MEC)
Don Keskey, Great Lakes Renewable Energy Association (GLREA)
Douglas Jester, Citizens Against Rate Excess (CARE) and Institute for Energy Innovation (IEI)
Laura Rauch, MISO
Carmen Clark, MISO
Jim Wilson, LARA
Shawn Worden, LARA
Allan Pohl, LARA
Susan Weber, LARA
Suzy Westmoreland, Michigan Electric & Gas
Ed Haroutunian, Member of the Public

- - -

REPORTED BY: Lori Anne Penn, CSR-1315
33231 Grand River Avenue
Farmington, Michigan 4833

Lansing, Michigan

Monday, December 1, 2014

At 12:40 p.m.

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MR. MacINNES: Okay. We're ready to get started here, it's 12:40. I'd like to welcome everyone to our meeting here today in December. And I'd like to start by calling the meeting to order and then doing a roll call around the table and around the room here so we know who all is here. And maybe we can start with this gentlemen right here.

MR. ISELY: Paul Isely from Grand Rapids, and member of the board.

MR. SHALTZ: David Shaltz, I'm counsel for the Residential Ratepayer Consortium.

MR. BZDOK: Christopher Bzdok, counsel for the Michigan Environmental Council.

MS. CLARK: Carmen Clark of MISO, I am the regional manager of we call them central region, and Michigan is the state that I handle, so that's why I'm here.

MS. RAUCH: Laura Rauch, manager of resource advocacy coordination at MISO.

MR. KESKEY: Don Keskey, counsel for Great Lakes Renewable Energy Association.

MR. WILSON: Jim Wilson, LARA.

MS. WEBER: Sue Weber, LARA.

MS. WORDEN: Shawn Worden, LARA.

MR. JESTER: Douglas Jester on behalf of both the Michigan Energy -- or the Institute for Energy Innovation and CARE.

MS. WILSEY: Michelle Wilsey, assistant to the Utility Board.

MR. DINKGRAVE: Ryan Dinkgrave, member of the board.

MS. HAROUTUNIAN: Susan Licata Haroutunian, Detroit, member of the board.

MS. WESTMORELAND: Suzy Westmoreland, Michigan Electric & Gas Association.

MR. HAROUTUNIAN: Ed Haroutunian, member of the public.

MR. POHL: Allan Pohl, director of finance for LARA.

MR. MacINNES: Okay. We'd like to get an approval of the agenda here and consent agenda with one change. We'd like to move up the discussion on UCPB fund finances ahead of the MISO update. And other than that, I think that the agenda would remain the same.

Do we have a motion to approve the consent agenda with that change?

MR. ISELY: So moved.

MR. DINKGRAVE: Support.

MR. MacINNES: Is there any discussion? All those in favor, please say aye.

BOARD MEMBERS: Aye.

MR. MacINNES: Opposed, same sign.

Okay. Well, I guess we're going to start with you, Allan.

MR. POHL: Start with me.

MR. MacINNES: You sent us some very interesting reading material here on the process.

MR. POHL: Good, you got it. I was asked to talk about the budget process for the state and for the board; it's more of an education session than anything.

The budget process, I'm going to use fiscal year '16 as an example, which we're working on right now. The state's fiscal year runs from October 1 of each year through September 30 of the following year. Prior to that, there's a number of items and meetings and things that take place. For instance, we actually begin the budget process roughly 14 to 15 months before the fiscal year begins. The state budget office holds a meeting among departments and their budget people, that's the kick-off meeting, and it's basically an economic

forum type meeting where they go over the state of the economy, the State of Michigan's economy, and so on, and then they get into any changes in the budget development process from the previous year.

There's a number of items that have to take place as we go forward. For instance, in each appropriation bill there's language at the back end of each bill, each department's bill, it's called boilerplate, there's various sections of that that legislators put in or the Governor's office recommends that language be put in on unique items within the budget. It's, probably in our area, it's probably five or six pages, probably 30 or 40 different subsections that make up that boilerplate. Those -- any changes we want to make on that boilerplate, if we want to take items out or add additional items, we have to have that information to the state budget office by the end of September.

In October we meet with the Governor and go over any investment requests we want to ask for. We also have to submit those to the state budget office.

In early November we have to submit our current service baseline budget, which is essentially our current-year budget and then plus any adjustments we want to make at that point. That's due to the state budget

office in early November.

Any changes, such as enhancements, if there's not enough GF/GP revenue, general fund/general purposes, GF/GP, if they believe revenues are going to be down, they'll give us a number that we have to meet. And in most cases, for instance, for fiscal year '16, we had to come up with a half-percent reduction, which in our department -- and it doesn't affect the board because the board is all state-restricted funds -- but in our instance, we had to come up with $750,000 less in our FY '16 budget than what we have in the current year.

If we want to make any changes in revenue, such as fee proposals, you know, right-sizing our fees or increasing our fees to increase costs and so on, we have to have that information to the budget office also in early November. Departments that have any building requests, such as colleges and universities, they fall under the capital outlay bill. If they're planning any enhancements to their buildings and so on, they have to submit capital outlay requests to the state budget office by mid November.

Along with that, there's the federal revenue pictures. We have to submit to the legislature also by the end of November what we believe our federal awards are going to be for the fiscal year '16. So all

of that comes together in late November.

We also have to estimate our state-restricted revenues, as well as our estimated spending for the following year, and two years beyond that. We just submitted that, right, Shawn, about a week ago, and it included how we closed the books for fiscal year '14, what we estimate our revenue and expenditures to be for '15, but we also had to estimate '16 and '17, so we're out that far already.

There's a number of other things that go into the budget process, such as we have to supply the budget office with current organization charts, descriptions of all of our programs in the department, and those are due in the budget office by middle of January. And then also during January the legislature and the Governor's office have what's called a revenue estimating conference. The contract with University of Michigan, as well as the Department of Treasury comes in, house fiscal and senate fiscal, and between the four of them, they all agree on what the GF/GP revenue picture is going to look like, not just for the current calendar year, but out a year or so. Once that's completed, the Governor recommends -- or does his budget recommendation to the legislature, that's roughly in early February, I believe it's the second week in February.

Then we go to what's called the first house. There's a first house action, and what happens is within the -- within both the senate and the house, there's is subappropriations committees for each department, assigned for each department. Departments have to meet with those subappropriations committees to go over the Governor's recommendation for fiscal year '16. Those begin in February and March in the first house. And I shouldn't even say that anymore because the last few years they've done them simultaneously, so both the senate subappropes committee and the house subappropes committee schedule meetings roughly at the same time. It used to be they alternated years and they finished one house first and then went to the second, but the last few years, they're working at the same time. The subappropes committees wrap up their work usually, at least recently, by the end of April, and then in May there's a second revenue estimating conference where the numbers are finalized.

From that point on, the Governor gets together with the legislative leadership and they develop target-setting for the GF/GP estimated revenues that are coming in. That determines how much each department is going to get of the GF/GP appropriation. That's usually done by late May, by Memorial Day. And then they have a

joint conference committee after that where both representatives from the house subappropes committee and senate subappropes committee get together and they finalize or agree on both of their versions of the budget, what the final version is going to look like. At that point, once they agree, it goes to the floor in each chamber, they approve it, and it goes to the Governor for signature. In the past few years, that's been done by the end of June. Some years it's gone right up until almost October 1 of the budget year, but last few years it's been relatively quiet again.

So that's the process in a nutshell. I know I don't want to take too much time, otherwise I'm going to bore you.

But as far as the board goes, since your revenue is derived from assessments, it's all state-restricted money, all state-restricted revenue, but you can only spend up to your share of that revenue that we discussed at the meeting a couple meetings ago. I don't have estimates for what we're going to collect next calendar year yet, but it's, in most cases it's going to be slightly more than what came in this year.

So I guess that's all I have at the moment. I tried to keep it brief.

MR. MacINNES: Are there any questions

for Allan?

MR. POHL: You're letting me off easy. I know you all want to get to MISO.

MR. MacINNES: We do, but some of us still have some questions.

MR. POHL: That's fine.

MR. MacINNES: We need to get, you know, really get a good handle on how much we're allowed to spend. And do you have any updates on that for us?

MR. POHL: I'm finalizing the statements for fiscal year '14 at the moment, I'm really close on that. I also want to -- I want to get the, be able to do October's and November's of the current fiscal year at the same time. What happens in the accounting, in the year-end closing process is management and budget won't transfer the ending balances until after Christmas, but I can back into them, and that's what I'm working on right now.

MR. MacINNES: So do you have -- for purposes of today, we're going to have to be making some decisions on grants.

MR. POHL: Right.

MR. MacINNES: And so we need to know the best information available right now on how much money we are in the hole already to decide how much we're going to

grant.

MR. POHL: If you'll let me run back to my desk, I'll give you a good estimate.

MR. MacINNES: Could you come back and do that?

MR. POHL: Yeah, I can do it real quick. I'd like to say it's between 200,000 and 300,000 net that you have available without asking the Attorney General for anything.

MS. WILSEY: Just to clarify, I think there's two numbers: One is the current, the current revenue available for fiscal '15, like a 572 number or something --

MR. MacINNES: Right, 572, and then you've got to subtract what was over-obligated in the prior year.

MS. WILSEY: But using that, then the over-obligation is what we're looking for, the 260-ish number.

MR. POHL: Right.

MS. WILSEY: I believe so. Okay.

MR. MacINNES: So yeah, we need to know -- in other words, we're already over-obligated based on the money that's taken in; is that correct?

MR. POHL: Technically, no, because the

revenue that came in the current calendar year is used for the following fiscal year, but because you over-obligated in fiscal year '14, that's got to come off the top of what we collected.

MR. MacINNES: Right.

MR. POHL: I guess we're --

MR. MacINNES: So we're in the hole 200 --

MR. POHL: At the end of fiscal year '14, about 200 some thousand.

MR. MacINNES: So we need to know what that number is.

MR. POHL: Okay.

MR. MacINNES: Because we're going to have to pay the AG back, right, based on what --

MR. POHL: Whatever you borrow from the AG, you have to pay them back.

MR. MacINNES: Yeah, the discussion we had two meetings ago, we're going to need to pay the AG back, and so we need to figure out what's a reasonable payment schedule and how much more deficit we want to incur, if any. I'm not a deficit kind of guy myself as a business owner, so I don't like that. So I like to get out of deficits as quick as I can, within reason, you know. We don't have to pay it all back in one year, but

we need to know better information on that. Could you help us with that?

MR. POHL: I can have it in two minutes.

MR. MacINNES: Okay.

MR. POHL: I just have to run to my desk and get the spreadsheet right now.

MR. MacINNES: That would be great. Thank you.

I think this is going to be a really important part of our decision-making today, to find out how far we are in the hole. Those of you that have the copy of this may have read how the state doesn't want you to spend money that you don't have, and they said that a couple of times I think, and I actually think that's a good thing to do, to not spend money you don't have, unless you can handle, you know, borrowing, and it's not too much and all, I mean that you have a plan to pay it back and all of that. So that made a pretty -- when I read this, that was my big takeaway from that packet here. So I think what we need to do is know what -- about where we are, and then we can decide how much more we want to go into the hole, so to speak, for this year.

MR. ISELY: But we aren't in the hole yet, right?

MS. WILSEY: Well, again, notwithstanding

the fact that the board had no intention or idea that it was in the hole, it was an interpretation of the AG's office of their share, okay. So based on their interpretation, in this fiscal year '15, we have not overspent current revenues. That was the thing. But in past years, they said we've accrued some overages. So if we do anything more, it would add to that.

MR. MacINNES: Right. And this all came about in -- was this two meetings ago when we found out this?

MR. ISELY: It was August.

MR. MacINNES: August meeting.

MS. WILSEY: The second August meeting, late August meeting.

MR. MacINNES: We thought we had 950,000 to spend, and we only had 5 --

MS. WILSEY: We thought we had 902,5.

MR. MacINNES: The 902, and we found out in August we only have 500 some.

So anyway, what is our -- what do we owe the AG?

MR. POHL: These are preliminary, okay.

MR. MacINNES: Yes.

MR. POHL: Technically on your grant balance, you're over-obligated by 220,000 or so, that's

in the ballpark.

MR. MacINNES: Okay.

MR. POHL: You've -- we have revenue that came from during this calendar year for grants, which is 47 1/2 percent of the overall assessment of $572,257. So the difference between those two is what's available for grants before you have to borrow against -- from the Attorney General.

MR. MacINNES: And how much would that be about, do we know? For future, for this year -- so this would take us -- in other words, my question is, how much more can we grant in this year without taking on additional debt with the AG's office?

MS. WILSEY: The 35.

MR. POHL: About 35,000.

MS. WILSEY: We've already made grants. The remaining is 35,000.

MR. POHL: Okay. You know, I don't know what --

MS. WILSEY: You don't know that part. But based on the grants that have been made out of fiscal year 2015, and that was in the summary e-mail, just so you have that number, current revenues minus amount granted, 35 and change left.

MR. MacINNES: That's for the whole -- so

let's make that real clear. So we can spend for the rest of this year, all the way through the end of September of the coming year, from now until September, end September 30, we spend $35,000 in grants without going into more debt with the AG's office; is that correct?

MS. WILSEY: Right.

MR. ISELY: Correct.

MR. POHL: Right.

MS. WILSEY: That's inclusive of all grants, cost of service, plus others; not including any additional grant requests. So any additional grant requests would be the 35 and a decision by the board whether to extend the debt in this 2015, and then the payback would start coming out of the fiscal year 2016.

MR. MacINNES: Right. And so and the revenue we take in, you're saying for 2015 -- 2014, it was 572, roughly?

MR. POHL: Right.

MR. MacINNES: That was in 2014?

MR. POHL: Calendar year '14.

MR. MacINNES: And then so -- okay. So that's kind of the ballpark of what we're looking at in future years, plus a little bit maybe?

MR. POHL: The formula is based on the Detroit Consumer Price Index, so whatever percentage it

goes up is what the formula would go up.

MR. MacINNES: So it might be up -- what percentage has it gone up in the pest?

MS. WILSEY: Been kind of flat, hasn't it?

MR. POHL: It's been flat the last few years.

MS. WILSEY: It might tick up a little bit, but --

MR. MacINNES: So it's 580,000 for --

MS. WILSEY: Yeah.

MR. POHL: Roughly 580 for next year is what I would estimate.

MS. WORDEN: Yeah, I would say it's been going up 6 or 8, 9,000. It's not very much.

MR. MacINNES: So that will be what we'll have available if we don't want to go into additional debt in 2016, something on that order, right?

MS. WILSEY: Yeah. And for the fiscal year '15, we used the 572,257 number just to be safe.

MR. POHL: Thank you.

MR. MacINNES: So our decision is going to have to be -- we already owe the AG's office $220,000.

MR. POHL: No, you don't. You don't owe the Attorney General. I wouldn't say you do, only

because --

MR. MacINNES: Well, we've overspent according to what Michael Moody said, and I haven't -- you know, I contacted Valerie Brader about it, she has not changed, you know, coming up with any other --

MR. POHL: Solution.

MR. MacINNES: -- solution that I'm aware of. And so as far as I know, we owe the Attorney General $220,000, that's how I understand it.

MR. POHL: Well, let me -- as soon as we get the detail in what's been granted out the previous meeting, I'll finalize it for you. Michelle might be right.

MR. MacINNES: But for now, we need a ballpark. I mean we don't have to have it exact to the last penny right now, but if it's somewhere around there, I look at, okay, we're -- we owe the AG's office $220,000. That's what I'm hearing right now. Unless somebody disagrees. I'm just trying to get a handle on this, I want to make sure that everybody in the board understands this because of this whole way the accounting issue that we had in August. So if that's the case, then we got $35,000 yet to spend until September 30 of 2015, and without owing anymore. And so then our board is going to have to decide, do we want to go into further

debt with the AG's office, and if so, how much. And then at the same time, think about how -- what's a reasonable payback period, because they want to be -- they told us they're going to be, give us leeway, but they told us they wanted the money back, it's not a grant. So that means -- and we were talking somewhere around a four-year payback. So if we owe them $240,000, let's say we granted an extra 20,000 over and above the 35, then that would be 260,000 that we owe them, and if we did a four-year payback, that would be about 60,000 a year that we're going to have to start taking away --

MS. WILSEY: From current revenue.

MR. MacINNES: -- from current revenue for the next four years, which is about a little more than 10 percent of current revenues. So it's like, you know, just thinking about, it's like what's reasonable. We probably don't want to go way high because then we're going to have to cut our current revenues substantially, but if we cut our current revenues by 10 or 12 percent, maybe that's a -- I don't know what the number is, but this is what our board needs to kind of grapple with is like what's the right amount for us to take on. I think it's a really important question. What's the right amount for us to take on in additional debt to the AG's office, figuring that we are going to have future needs

and we have future obligations over the next, say, four years, what's a reasonable payback time? Four years is probably -- I mean we talked about that with Michael Moody. So that seems like reasonable to me. I mean we could do more or less I suppose. And what's a good amount -- I look at it as a benchmark; what's a reasonable percentage of the money we get each year that we could take and pull out without hurting ourselves too much for the next four years? So that's the kind of calculus I think we need to go through.

Anybody have any other comments or questions for Allan about that? Any other thoughts on that before we get into the process here of -- we have a fund request before us, not right at the moment, but we will soon as we get the MISO presentation.

MR. ISELY: And that 220 didn't include any of the COS case, right?

MS. WILSEY: Again, 220 is the number prior to fiscal year '15.

MR. ISELY: Right.

MS. WILSEY: So fiscal year '15 and the current grants from the 572,257 or whatever --

MR. MacINNES: Including the COS.

MS. WILSEY: -- includes all of the COS monies that have been granted.

MR. MacINNES: And we have 35,000 unspent. So including the COS and what we've already granted for 2015, we've got 35,000 left to spend; is that right?

MS. WILSEY: In current revenue.

MR. MacINNES: Current revenue.

MS. WILSEY: Without extending the overage.

MR. ISELY: Okay.

MR. MacINNES: Everybody on board with that, understand that? Anymore thoughts about that or while we have Allan here, maybe, you know --

MS. WORDEN: I have one. I'll know the assessment amount at the end of March, because February's figures are posted in the beginning of March, so by the end of March.

MR. MacINNES: Okay. That will be good. Well, for now, you know, we're probably -- this is probably going to be a moving target, that we're probably going to have to true this up periodically, and I get that and that's fine, we can do that. Obviously the better number we have, you know, the closer, Allan, that you can give us on that number is very helpful, but I think if we have a ballpark, we can start to make a plan on how we're going to handle our deficit, pay it back and

continue to do business here.

MR. POHL: I can probably have you something before Christmas, that will be the final report for --

MR. MacINNES: That would be great.

MR. POHL: -- fiscal year '14, and then the first two months of this year.

MR. MacINNES: But for now we're going to just use the 220 I think.

Okay. Unless there are other discussion items or thoughts or questions, then I think we can --

MS. WILSEY: Thank you for taking the time to be here.

MR. MacINNES: Thanks, Allan.

MR. POHL: Yeah.

MR. MacINNES: Okay. Now we have these two lovely ladies from MISO here which are going to talk, they're going to talk with us about resource adequacy, which is a very important topic, especially these days here in Michigan, and progress on the MISO Transmission Expansion Plans, which have been ongoing for several years. So take it away.

MS. CLARK: My name is Carmen Clark. Again, I am the regional manager of our central region, so I handle the states of Michigan and Kentucky

currently, so trying to keep on top of what's going on in the State of Michigan. My former life, I used to be in what we call our resource adequacy group, so I was involved with, previously, the monthly auction that we had, I was also involved in developing the policies and technical aspects of the current annual construct that we have in resource adequacy for MISO, and now I moved into more of a customer relations sort of role where I'm handling all the issues of Michigan and Kentucky, and sometimes it will span into some of our other states as well on what's happening with MISO in general with the footprint on all of our different zones, 1 through 7, plus 8 and 9 in the south. But that's sort of a background on me.

And what we're going to cover first is we're going to give an overview of MISO, just generally on what MISO is, what MISO does, what does it mean, and then I will give sort of some highlights on the resource adequacy, what we're doing right now, and Laura will give sort of an update on the MTEP status. And please feel free throughout the presentation to ask questions as we go along, we don't have to wait until the end. So if you have a question on something that we're presenting at that time, just go ahead and fire away. Okay.

Again, this is sort of our high-level

agenda with MISO: What does MISO mean; what does MISO do; resource adequacy; what's going on with MISO as far as resource adequacy; Laura will cover the MTEP process, and then we'll take questions as we go along.

So this is sort of a nice map of MISO's role. As you can see, you see these transmission lines, and it's circled up at the top, because this is what MISO does, we handle sort of directing the energy on the transmission lines. And then if you follow the arrows, you go through a distribution, which mainly is mainly your local type of utility, and then that utility, you see the poles down there, which basically says, well, then they transfer that and they do substations and that goes through what we use today as electricty in our homes. So MISO's level of involvement is the first layer there with getting the generation, transmitting that through our transmission system, and making sure that when we go home, when we flick our lights, they come on.

MR. MacINNES: Now, is that generally over 100,000 volts that you're involved? Is there a cutoff on the voltage?

MS. RAUCH: It's typically 100 kV and above. We deal with transmission, some areas do have transmission that is less than 100 kV, but in general, the rule of thumb is 100 kV and above is under our

control.

MS. CLARK: Go to the next slide, please. Just to give you, also, just the magnitude of customers' megawatts, so end-use customers would be like you and I, about 42 million within our footprint, and from this slide you can see the highlighted regions, so the blue region is what we consider our north region, the green region is our central, and the red is what we call our south region in MISO. We have approximately a demand of 126,000 megawatts, and our transmission miles of line covers about 66k.

When we start talking about resource adequacy, a lot of times we're talking about load and generation. So we look at demand and we look at generation and we look at the capacity, and currently the capacity for generation is about 176,000 megawatts, and year-to-date, we have over 400 market participants, we just reached actually 400 market participants I want to say earlier this spring. So that means that we have anything from load-serving entities to independent power producers to municipalities to co-ops, and we consider those particular entities as market participants, so we have about 400 plus across our footprint. And then from an energy market, you hear a lot about the day-aheads and the realtime energy, we have about 2.5 billion a month in

energy transactions, and that's between different parties. So there's a party that needs to buy energy through MISO's portal, there's a party that wants to sell it, and we are sort of, we link the two together; we don't buy, we don't sell, but we make it possible for those that want to do those transactions to do those transactions via our portal.

MR. MacINNES: I have a question.

MS. CLARK: Yes.

MR. MacINNES: So would a power plant that is independently owned that's an LMP node, would that be a market participant?

MS. CLARK: Uh-huh, yes.

Okay. Again, MISO's main thing is that we're independent, we are a nonprofit, but we're just mainly responsible for the transmission reliability of those that are members to MISO.

This is some historical information about we've got approved by FERC, we are regulated by the FERC, our tariff we have to file is mainly with FERC, we get that approved by FERC; we make changes, depends on how often we need to make policy changes, but whenever we need to change our tariff, we do have to get that approved, we can't just change the tariff without any approval from the -- FERC is considered the Federal

Energy Regulatory Commission, that's the commission in Washington, D.C. A lot of times when we make those tariff changes, we do have procedures through our state code or working that process that we would go through and sort of bring those issues before those state coders to implicate [sic] the changes that we're making, and then there's a timeframe where we file it. Sometimes we can get an order from FERC on saying, yeah, we agree, we can get it in, you know, typically we ask for 60-day, we can get it -- sometimes we may not get the order for years. I think one of the big orders that we're waiting on right now with, we call it Order 1000, which is talking about the transmission planning between, you know, different RTOs and on the regional basis, we are still waiting to get an order, and I think we filed something, what was that, like last year around July or something like that we filed our compliance order, and we're still waiting for FERC to give us something. So it really depends on the magnitude of it. With it being a regional planning piece of it, it's bigger because it also touches our neighboring RTOs, which is PJM and then SPP to the south.

And our role for MISO is basically that we make sure that the grid is reliable. So we want to make sure at any given time that we don't -- what we don't want to have is outages on our grid. We want to

make sure that all the time that energy is flowing from our power plants down to our houses. So we want to make sure that, at least from that perspective, that our transmission grid stays reliable, there's nothing that's interrupting that, and we want to make sure that our policies are also conducive to making sure that we ensure the reliability.

MR. MacINNES: And energy doesn't stop at the state lines, right?

MS. CLARK: Right, exactly. There's no point I'm at this, you know, I'm at mile marker 100, I'm stopping, no; you have to continuously keep it flowing because you can -- a lot of times you think that maybe something's concentrating in one area, but it's really not, it has sort of a multiple impact on the system when you go from one place to the other.

And as I mentioned before, MISO, we don't generate anything, we sort of just handle to make sure the transmission can happen between the power plant to your local utility company, and then they kind of handle all the poles that you usually see in like some of the residential neighborhoods or your commercial accounts if you're a business owner or Walmart store or things like that, they handle that.

So this is sort of still what we do and

what our role is. Again, we're independent. Some of the bigger thing is that we're independent. We do want to make sure that we deliver reliability services to our customers, we want to make sure that our market is efficient, are we providing the lowest cost of electricty to our customers. And we want to make sure that we're doing the planning on a regional basis, so we're looking at things holistically, we're not just looking at things in a local area, but we need to look at things from a regional standpoint just to make sure that we are answering the questions and we're providing the service for all of our customers all the time.

MR. MacINNES: Could you talk to us for a minute or two about your governance structure?

MS. CLARK: Our governance structure, basically we have a -- we have the board, and under the board we have different committees, and then we have stakeholder working groups. So when you hear us mentioning about stakeholder working groups, such as the loss of load expectation working group could be one, that particular working group will report to a committee, and I think that's the market subcommittee, and then those -- and those committees report up to the board. So it's the board, the committees, and then the stakeholder working groups, and that's the structure of how we get things

done in MISO.

MS. RAUCH: Yeah. And to put a finer point on it, our board of directors is an independent board of directors, they are elected by our members, and we're just increasing that to a nine-person board of directors; we used to have seven, we'll be electing two more. So they help guide our process.

So like I've worked a lot with the system planning committee of the board of directors, and they're the subgroup that really looks, are we planning correctly, and later we'll talk about their principles. But it's are you following your process as written in your tariff. Each of our stakeholder forums helps the board of directors understand that, but they're also stakeholder forums in two ways: Not only are they open to public stakeholders, but they're led by stakeholder chairs as well.

So we have planning advisory committee which looks at the planning processes, we have subcommittees which look at technical details. We are very heavily invested in our stakeholders and making sure we get the right input from them across the board on all of the planning markets operational issues we face on a regular basis.

MS. HAROUTUNIAN: I have a question.

Does that mean that each state, which I assume are your stakeholders, has representation in all of this and input in all of this?

MS. RAUCH: We work very closely with the states. There's actually an Organization of MISO States, or OMS, that works as a committee, and state regulatory commissions is a sector in our process. But a lot of what Carmen's job and her whole group's job is to make sure we're working well with our states.

MS. HAROUTUNIAN: And do states have people participating or not?

MS. RAUCH: Absolutely. We'll have commissioners participating, we'll have regulatory staff participating as well. In my previous job I did transmission planning, and we'd have Michigan subregional planning meetings, and usually we had probably five to ten Commission Staff at those meetings. So the state staff is very involved.

MS. HAROUTUNIAN: Okay. Thank you.

MR. MacINNES: And you also have utility, load-serving entities as parts of your stakeholder group of some --

MS. RAUCH: Yes. We have probably nine sectors, state commissions, load-serving entities, independent power producers, end-use, transmission

owners, and environmental, I'm missing a few there.

MS. CLARK: We have the TD, the transmission developer sector, that's the two that just got added, we have that. We do have a consumer advocate, I want to say, sector as well.

MS. RAUCH: And the transmission-dependent utility sector is probably it. So we have -- in some of our committees, we have formal voting structures where we make sure each segment of the MISO customer base or MISO stakeholders has a voice and has a vote, even though that voice may be .1 percent yes, .2 percent no, and .7 percent abstain.

MR. MacINNES: So do the utilities, the big utilities, IOUs, have a big say in this process?

MS. RAUCH: It's a balancing act. We try to look at what each of our members say to get input from each of those, and then at the end of the day, we try do what's right. In stakeholder forums, we do often ask for motions and votes, but they are advisory. So that's part of getting back to what Carmen was saying about independent. We spend a lot of time listening to stakeholders. At the end of the day, we have to make sure we're considering all viewpoints and doing what's right.

MR. MacINNES: And obeying the laws of

physics.

MS. RAUCH: Laws of physics are very hard to break, so we try to make sure to follow those as closely as possible.

MS. CLARK: First and foremost. Yeah, so the questions about involvement from the commission staffs and if it's a vertically integrated utility, those are -- everyone's welcome and has definitely voice in our stakeholder process, we don't exclude anyone from not participating. Even if you're not a member of MISO, even if you're someone, a consultant type of role and you're not a member of MISO, all of our information is public pretty much, depending on some of the technical task forces, you know, you have to have a nondisclosure agreement, but pretty much you're open to participate on any of our committee calls and stakeholder working group calls, so everything is open to not just our membership list, but those that just want to educate themselves. Sometimes it's just a college or university that wants to look at, you know, some of the power planning type of things, and they're welcome to participate as well.

MR. JESTER: If I may, just for the board's information, CARE, supported by the grants you've given, has participated and specifically fit within the public consumer representative sector that she mentioned,

as well as participating in appropriate of the work groups.

MS. CLARK: Are there any further questions?

Okay. Moving on to the nitty-gritty of this presentation: Resource adequacy overview. We have a lot of things right now coming into play that we're really looking into what's going on with MISO's resource adequacy program, not just the piece of generation load, but what are some of the policy things coming down the pipeline implementing -- we'll go from left to right.

Up here you can see MATS, and we have the nature of the regulation. What it stands for is Mercury and Air Toxics Standards that's coming on board. A lot of -- some of the retirements that we've been talking about, you probably heard about this in the media, FERC filings, units retiring due to MATS, basically deciding if they're going to spend the money to upgrade their units to comply with some of these EPA regulations, or if they will decide to just retire them because they feel like these upgrades that they would have to do would not be economically in their best interest to do so. So that's been some of the biggest things that have been discussed lately in public forums and our stakeholder working groups and our committees is the upcoming MATS.

MISO does have a process for if units do retire, they are required to give MISO six months' notice; this is called our Attachment Y process. MISO at that point look at that particular unit and determine if it's needed for reliability purposes. If we determine that it is needed for reliability purposes, we will then go into what is called a system support resource and deem that resource as being needed for reliability so to prolong the, to extend the retirement so that until we come up with another solution, we go through with what we call a system support resources, and there's payment involved for keeping those resources to those customers on board, but that's something that you've probably been hearing about in the media more so than anything about compliance with EPA regulations with the MATS.

We also have what we call the CSAPR rules coming up as well that will also impact what some of our market participants decide to do with their units.

And then the recent 111(d) has been a big topic of discussion on the Clean, the Clean Power Act, and this is for the carbon dioxide for new and existing units. And basically new units will start having to comply with those new rules beginning in the '15-'16; and beginning in 2020, existing units are on par to try to come up with ways to deliver cleaner power. The EPA has

proposed some different time lines to start that. MISO recently filed comments as of I want to say November 25 on, yeah, we understand from the EPA perspective this is something that you're requesting to happen, but the, sort of the disconnect was with the implementation; is the implementation a reasonable amount of time for states and other utility companies to go towards a clean power plant. And they set out this timeline that says so much from renewables, you want to eliminate the carbon dioxide that we're emitting from our plants, but we have to look at from a timeline perspective, is this reasonable.

Because when you take a power plant out of service, you have to look at -- we have to look at the, for MISO, what's the reliability piece of this implementation, and if there's some transmission implication to it. So you can't just take the power plant out of service, you've got to look at the whole system, the grid, and say, well, we're taking this out of service, what does this mean for our grid. And it is not just easy as unplugging something. You have to figure out, okay, if I unplug this, do I need something in its replacement; and then the other side of that, and if I do this, what is the timeframe that I need to get this replacement done?

So looking at something, next year's

2015, looking at trying to figure out solutions in five years is quite a tight deadline for a lot of companies to make. And so our comments were really based upon the implementation of these existing units in particular, you know, when they're trying to figure out a generation solution, a transmission solution, or most of the time it's both. You know, five years' planning may not be enough time for those solutions to come into play when we need stuff on the system right now.

MR. MacINNES: Of course, one could also argue we've been talking about these rules for some years, so it's not like, oh, it's a new rule, we got five years to do it. I don't know how you address that.

MS. RAUCH: Yeah. And that's something that's interesting, because I agree, I mean these rules have been being talked about for quite a while. And what I've heard, for better or for worse -- MISO doesn't have really a position here, we're more concerned about reliability -- but folks have trouble planning until they know the exact details of the rules, because -- and in some aspects they've -- I've heard comments saying that if you plan ahead of time, you might be penalized by rules because they'll take your previous plan as your base point, whereas if you hadn't done the easy fixes, you'd be starting from a more toxic place and so have an

easier path to get there. Now, you can talk about societal benefits there, but I think that's -- until you see these finalized, it's very hard for people to know how should I act and how quickly.

So our main concern is really if -- especially with some of the interim measures, if you have an interim goal, does that really give you a good first step, or is that first step 90 percent of the way there, and so at the end of the day, you really have to take drastic steps to get there that might turn the lights off.

MR. JESTER: I've just got a followup question. In your transmission planning in particular, at least for the last several years, you've always had several planning scenarios that you evaluated plans against. How did the EPA proposal under 111(d), the Clean Power Plan, compare to the range of scenarios that MISO had previously considered; was it within or outside of that range?

MS. RAUCH: Again, until you know the details, it's hard to say. I would say the 111(d) proposal that we saw come out is above and beyond the planned retirements we were previously anticipating, however, it's still very much a work in progress. We did a specific study on 111(d) really earlier this year

because that's when we had the information to analyze it fully. So while we try to bind things with our future scenarios, and I think we captured some of the aspects, we didn't necessarily capture the complete picture. And the other thing is those future scenarios look at system economics quite a bit, they don't look at reliability violations associated with individual generation retirements, and that's really the near-term concern for 111(d) is if a particular plant goes off line, can the system -- can the lights stay on in the area around its providing voltage support, or do we need to keep it all in line, and what's the economic impact of that?

MR. JESTER: But had you or had you not had scenarios that anticipated this level of reduction in carbon emissions?

MS. RAUCH: I'd have to look, and I can get -- I can e-mail out the details. I don't know if we actually had, certainly not by 2020, the level of reductions that we are currently anticipating.

MR. JESTER: Thank you.

MR. MacINNES: And part of that is maybe you could explain the N -1 criteria in that reliability.

MS. RAUCH: So one of the things that we plan to on a reliability basis is we plan to what Jim said is an N -1 scenario, and that is take the system as

it is with everything, perfect day, everything's online, take one generator, one transformer, one line out of service and make sure the system's reliable.

What you're looking at when a generator retires, though, is you're looking at an N -2, which is having two units out at your starting point and you go, so you're taking one step back from the happy spot we'd like to be at because you have this generator which may be a critical facility out of service and then taking additional system pieces out on top of that.

So I'd say we would look at this, but I don't know that we studied -- again, it's going, and if you plan for two units out, if you have a generator out in the area, you're not planning for three units out, and so on. So it's interesting watching the dynamics that change as you receive particular generator outage requests. And it's not something we necessarily want to speculate on, certainly not publicly, is that a particular generator might be retiring, because there's a lot of lives that are impacted by that, and until the actual owners have made that decision, we don't want to cause undue worries that people might not have their job if they, maybe they're fine for 5, 10, 20, 40 years from now.

MS. CLARK: And I think to add to that, a

piece of this Clean Power Plan involves the state submitting information on what they have, and so that's another missing piece that we don't have right now, the states are working on their plans, and so it's like a holistic view. As I said before, we have, Laura mentioned the generation: Are they doing anything about it; are they going to retire? And then we have the state planning, because each state is responsible for submitting their own plans on how they want to comply with the Clean Power Plan, and it's still a moving piece because once the state plans come into play and once those get finalized, and then we'll probably go in and look at things again to say, okay, so now the state plans are in, what is it going to do, and those have not been finalized as well. And then you still have the generation piece with retirements. We give information -- we only give information where we've looked at retirements that have been approved, we don't really look at, you know, speculatively, we can't really say that, yeah, we've got, you know, 12 gigawatts, whatever that number is, that may be retiring, but when we start looking at actually at cost and benefits and things like that, what MISO has to do, we have to look at things that we have approved as retirements, and again, those retirements of units don't have to give MISO only

six months' notice. So as you can see, every six months these numbers could still be changing, and then once you get the state plans in, there's another change to consider when we start looking at our studies.

MR. MacINNES: And we saw that with Presque Isle.

MS. CLARK: Uh-huh, yeah.

So this slide represents -- we divided MISO into two different regions; again, it's central and north, and the south region. And these particular numbers were driven by -- we have started doing an annual OMS survey. Laura mention the Organization of MISO States with the different state commissions participating, but we did this based upon, well, let's go and do a survey with our load-serving entities looking at load and generation and looking at some of the outer years and what does that mean long-term planning part. So when we did this survey, we looked at central and north, and then south region. And this is based on 2016. So this is going to -- this is based upon the planning year beginning June 1 of 2016, ending on May 31 of 2017, just to put it into perspective.

So what this shows is that our central and north regions will have a shortfall of 2.3 gigawatts, plus there's an additional 1.1 gigawatt, there's a

current plant located in MISO that is going to PJM in 2016, so you have to add those two numbers together, and you get about a, I think it's really about a 3.3 gigawatts, it's not quite 1.1, and we had a surplus of the south at 2.5 gigawatts. So this is just saying that an over -- in an overall system, when we look at 3.3 and 2.5, we do look like we're having, as far as a capacity, the reserve margin shortage, we have that in 2016 as a result of the OMS survey result. So this is just saying, based on the information that we have currently from the survey, Attachment Y information, this is what MISO's projecting. We will also be updating these numbers I want to say in the spring of next year --

MS. RAUCH: Finalizing.

MS. CLARK: -- and publish -- finalizing again in June on the 2016 just to make sure that there's nothing else that changeS with the Attachment Y or anything else going to PJM that we don't know about. But basically we'll -- we're going to keep on going on with this process because what we feel like we need to do from a company is look at this and keep everyone abreast of where we're at, because this became a big topic. I think some people were shocked to find out that the implications of retirements and EPA and MATS and all those things were going to have an impact on MISO as a

total system when typically we're so used to seeing reserve margins in the 20-percent range, and now we're seeing those ranges decrease with companies deciding to retire those units and other companies deciding to I'm not going to do all these upgrades to get the unit, to have the unit going, I just don't -- it might not be economical for us to do so. But we wanted to report this information out as a result of our survey so that people can understand what some of the implications are to the MISO footprint as a whole.

And then we also, the next slide will go through what it looks like for a state-by-state -- not state-by-state, but by zones. And so Michigan is actually two different zones, but we, you know, today we'll look at Zone 7, which is mainly the Lower Peninsula of Michigan. But this gives you an idea of this is what we, based on the information that we have today, this is the current projection.

MR. MacINNES: I think Chris Bzdok had a question.

MS. CLARK: Sorry, Chris.

MR. BZDOK: So I understand the blue chart, the blue bar on the central and north region. And then the tan bar, the 97.9, is that a peak demand projection?

MS. CLARK: Yes.

MR. BZDOK: And then the reserve of 14.5. How do you, roughly speaking, determine how much reserve margin as a percentage of demand you need in a particular year?

MS. RAUCH: You want to skip to that slide?

MS. CLARK: Yes.

MS. RAUCH: Can you flip ahead a few slides.

MR. BZDOK: So that's my first question. And my second question, which maybe is related, is how does that level of reserve margin in 2016 that you're projecting you need, how does that compare with the levels of reserve margin you've projected historically.

MS. CLARK: So we'll go -- we'll go ahead and go through this slide. So basically when we determined, we determine the reserve margin as part of our loss of load expectation working group, and we determine it, basically our standard measure in MISO is one day in 10 years. I'm sorry. We determine our reserve margin through our loss of load expectation study, it's called LOLE, and we determine that reserve margin based upon our standard of one day in 10 years. And one day in 10 years, as you can see, hard to see from

the chart, it's like 14.8 percent I believe in the 20 -- that's the 2016 plan year. So we determine that through our, through the one day in 10 standard, and we determine what the reserve margin should be based on that particular information. And what we do is we look at our peak demand that we have for MISO's system, our total peak demand, and we basically say, well, based on the peak demand and based on the planning reserve margin that we determine, we determine if it's, just say if it's 90,000, or 100,000 is probably a better example, if we determine that our peak demand was 100,000 and our reserve margin was 10 percent, so we would say 10 percent of 100,000, that means that that's the amount that we need to keep in reserves to make sure that we maintain the one day in 10.

MR. BZDOK: How do you determine the 10 percent, though; is that the one day in 10? In other words, that's like the amount of outage -- that's sort of like you're laying a peak demand on a peak outage?

MS. RAUCH: No. So what we do is we start with what we call a 50/50 forecast, so this is a peak forecast that we think there's a 50-percent likelihood that it's going to be higher, 50-percent that it's going to be lower.

MR. BZDOK: Okay.

MS. RAUCH: Then we do a series of probabilistic of Monte Carlo simulations where we look at, take actual generator data, find out what their forced outage rate is, and we take a lot of this kind of deterministic data and use it to do a probabilistic analysis of what the future may look like. So when we say it's .1 day per year, it's actually the amount of generation required to have that, the probability of loss of load each day add up to one day in 10 years. So it's a probabilistic simulation starting from an average peak load. But you can go up to -- and we'll do simulations up to a 90 percent, 90/10, which is there's a 10-percent chance that the load will be higher, 90-percent chance that it's going to be lower. We don't worry too much about the other end of the spectrum because you have enough generation for it.

MR. MacINNES: So this is based on the 50/50 analysis?

MS. RAUCH: Yes, sir.

MR. MacINNES: So when you say like one day in 10 years, that's your benchmark, right, 14.8 percent, so .1 days per year. Now, when you say -- let's take -- when you say -- let's take the one day in 10 years scenario. Does that mean you're out for the whole day, does it mean you're out for 15 minutes, what's the

outage time?

MS. RAUCH: So it would actually be the -- it's not -- great question by the way. It's not that you are out for a whole day, it's that each day, you have that likelihood of being out. So the sum of all your peak days in our simulation gets to be -- your probability adds up to one day in 10 years.

MR. MacINNES: So it could be that that one day in 10 years could be, could equate to you were out 15 minutes for one day in 10 years --

MS. RAUCH: So it --

MR. MacINNES: -- or an hour?

MS. RAUCH: No, it's actually -- so it would be over 10 years you are out peak hours a sum of 24 hours, so you're out one hour one year, one hour the next year. It is -- keep in mind this is a peak construct, --

MR. MacINNES: Right, right.

MS. RAUCH: -- and so this doesn't look at your storm outage, this doesn't look at some of your forced outage situations.

MR. MacINNES: Right. But I'm still trying to get a handle on this. One day in 10 years, so that -- so what that means, then, is that that's the equivalent of a 24-hour day every 10 years; is that right? I'm trying to understand that. What does that

mean?

MS. RAUCH: It's the equivalent of, over a 10-year period, would you sum up to an outage -- your peak time you would be out because you don't have enough generation for a total of 24 hours.

MR. MacINNES: For all the peak times over 10 years --

MS. RAUCH: For all the peak times over 10 years.

MR. MacINNES: -- would add up to 24 hours of peak times over 10 years?

MS. RAUCH: Yes.

MR. MacINNES: Okay. That's what I wanted to understand.

MR. BZDOK: And I think my question is much dumber than Jim's. 14.8 percent, then, represents the amount of generation on the system that is randomly out in that one in 10 year sort of probabilistic day?

MS. RAUCH: It's the reverse. It's the amount of capacity over and above your demand you need to have so that your --

MR. BZDOK: To deal with your one in 10 year peak set of outages?

MS. RAUCH: Yes.

MR. BZDOK: Okay.

MS. RAUCH: So that your risk of having a general -- of having insufficient generation to meet load is equal to that one day in 10 years.

MR. MacINNES: So let's try it another way here, just to make sure I got this. So .1 -- let's do it on a per-year base. So .1 day per year, that would be, since there are 24 hours in a day, .1 is 10 percent, it would be 2.4 hours each year, that you would be out 2.4 hours each year; is that right?

MS. RAUCH: Yeah.

MR. MacINNES: If you do it .1 days per year, that's the equivalent of 2.4 hours per year, that if you have 14.8-percent reserve margin, then you could be out 2.8 hours -- 2.4 hours per year and meet that?

MS. RAUCH: Yes.

MR. MacINNES: Okay.

MR. JESTER: If I can go back to Chris's question just to clarify. There are two elements of uncertainty that they're trying to overcome: One of them is forced outages, power plants that don't work when they're supposed to; the other is uncertainty in the forecast of the demand peak, and those roughly divide in this 14.8 as 7.2 percent for demand forecast uncertainty and 7.6 to cover for forced outages.

MR. BZDOK: Okay.

MS. RAUCH: And the other question I think you asked was how is this compared to our historic. Historic resource adequacy was very easy because each year we said, yep, we have 30-percent excess, we're good to go.

MR. BZDOK: Got it.

MS. RAUCH: We've only recently been seeing, getting close to margins, and we had our first taste even last year with the really cold Polar Vortex. We weren't at the situation where we had to do anything drastic, but it made us sit up and take notice. If we had similar cold weather when we're more capacity restricted -- and this is the entire U.S. continent really -- it might have been a very scary place to be in, because there were a lot of different factors at play; the cold weather was causing more forced outages, fuel shortages due to everyone wanting to also be warm and run their home heating at the same time. So traditionally this has been a summer peak, but we're -- it also can be a winter peak concern. So it's something that's very real and something that we're taking very seriously.

But when you look at what does your reserve margin mean; it's all probabilistic, it's how much risk of outages do you want to have, and specifically, how much -- how much of a risk are you

willing to take with not having enough generation to serve your load. So that's what this curve shows is that as you start cutting into that reserve margin, because we aren't seeing actual generation shortages against load, but we're seeing shortages against the reserve margin, you start seeing a risk, an exponential growth to the risk for generation-type driven outages.

MR. MacINNES: And then if you are out, let's say you're, those two and a half hours, what are you going to do? Demand, demand shed, do rolling blackouts, what are your options?

MS. RAUCH: There are about six operational steps we can state, starting with, for summer peak, starting with demand response and getting to different characteristics. We're looking into if we have to go through that entire list, what should be the end state. But it would have to be some sort of load shed because you don't have enough generation to meet your load.

MS. CLARK: And before we go to that, we call it our emergency protocols, we will look at, you know, our different operating reserves, you know, we'll go through that piece of it, we'll look at what we call our load modifying resources, that's a step where we, early on where we'll look at it, and the load shed

pieces, our final event, that's meaning that out of all these different resources that we called up on, we still didn't have enough, and currently we have about eight gigawatts of load-modifying resources that are registered as capacity. So if you think about the magnitude, if we're going through all those steps and we still don't have enough, then we get into what we call our step five procedure, which is the load shed piece.

MR. MacINNES: Well, and my sense is -- I recently heard a similar presentation from MISO, and my sense was that even demand response was not something people were anxious to do for some reason. And to me, that would be one of the first -- I don't know what your priorities are, but --

MS. CLARK: It's a step two, it's a step-two process, so we have five steps, and it's part of -- it's our step-two process.

MS. RAUCH: And I think part of the reason that is the actual contracts for the demand response, there's a, if I understand it correctly, there's a limit in the number of times utilities can call on that, so it's more of -- I think it's more in the scenario where if you are having this issue, it's probably going to be because of a weather front that might be hanging around for a while, so you want to try

to see what can you do that's more repeatable before you start taking these contractual arrangements and calling on them instead.

MS. CLARK: Right. Our qualification process that Laura was speaking to for our demand response, whether you're an interruptible load or you're a behind-the-meter generator, you have your own generator at your site that you can turn on, in order to qualify and get sort of our -- qualify as capacity, you have to be able to be interrupted for at least five times during the summer for a minimum of four hours' span. So you have some people, depending on their contracts with their commercial clients, that may have their contracts set up like that, but you also have some people that can -- that tell us, well, I can be interrupted all the time, I don't have a minimum, you know, and you have some that say, well, no, I want to keep it at five because maybe I have a contract to where I don't want to interrupt, I don't want to interrupt someone doing a processing plant more than that because they have to figure out work schedules, they have to figure out when they're going to run things, or they may have a third shift coming in where their production is at its greatest or something like that, so you have those type of things.

There's another thing that MISO just

implemented, it's called voluntary load management. So even though you have resources maybe that you didn't, you didn't register with MISO, but you still have those available, and we've implemented something where we've had those companies that have those type of, we call them voluntary load management in excess of what the requirement is of those eight gigawatts that we may, you know, be able to call up on, too, so they may also be helping with the situation to hopefully not get to the step five.

MR. MacINNES: So I just had a conversation with Wolverine Power people, we're looking at putting in a 230 kW diesel engine for emergency for our water system, and I wanted to use it as a DER, and Wolverine said you can do that, but you have to be able to run it 200 hours a year, which is a lot different than the 20 hours that you just mentioned. They said that that was a MISO requirement, my understanding.

MS. CLARK: I'll have to look at that, because an EDR, if you're talking about the EDRs where you price it, is that what you're talking about, price it?

MR. MacINNES: Yeah. Well, they were going to give us $2.50 a kilowatt.

MS. CLARK: I'll have to find out if

there's a 200-hour -- that's the first that I've heard of that.

MR. MacINNES: Which, by the way, one of challenges we're having in doing this, the behind-the-meter generation, is the EPA regulations for this size generator don't -- they're too complex. Like I only want to run it 20 hours a year, and the air regulations are onerous, I might not even be able to do it because of that.

MS. CLARK: Yeah, it's the internal combustion engine, the ICE.

MR. MacINNES: Yeah.

MS. CLARK: Yeah, the EPA rules are it's a hundred hours maximum, I believe, and then 50 hours of those can only be used for what we consider nonemergency and maintenance and things like that. And initially they did have some very restrictive rules, but they recently --

MR. MacINNES: Because they were calling them tier four rules.

MS. CLARK: Yeah.

MR. MacINNES: They said, well, these tier four rules, you can do it with an emergency generator, but if you want to be a peak shaver, oh, no, you got to adhere to tier four rules.

MS. CLARK: That's the limitation is because they changed the nonemergency piece of it, yeah, and it's a hundred hours, it's a hundred hours total, and then you have to -- you can't go over so much if you're trying to use it for peak shaving.

MR. MacINNES: So it makes it difficult to meet the EPA rule and to meet the MISO rule if it's 200 hours to get the incentive to do that, which I would think MISO would be wanting to incentivize people to do DERs, I would think, because I was only planning on running it 20 hours a year.

MS. CLARK: Yeah, I would have to look into the -- that's the first I've ever heard of 200 hours, so I would have to look into that to find out if that's true. I know from a capacity standpoint, we just, like I said, it's five times for four hours. If you want to look at it as an EDR, which means that I'm going to set a price, say my price, if the price is at 100 megawatts an hour, that's what I want, that's what I want to get for MISO to run my unit. But I really would have to check on the 200 hours to see if that's a limiting factor. I know 100 is what the EPA has set out, and then I will check on the 200 and get back with you on that one.

MR. MacINNES: So it's pretty serious if

you were to take the 2.9 days a year for the 5.2-percent reserve margin, so for actually 2.9 full days a year, that could be probabilistically offline, or you wouldn't be able to service the load.

MS. CLARK: Yeah, that's correct.

MR. MacINNES: That's pretty serious.

MS. RAUCH: Yeah. Although I think one thing to say is this is a projection based on where we are today, and I think part of the reason we are putting out these numbers and talking about them so much is so that we can change them. So it does take time, but I think that's the advantage of talking about it now and really having the informed discussions on -- and submitting comments to EPA on timing of these is to start having the discussions and then seeing what we can fix and how we can fix it.

MS. CLARK: Anymore questions? We'll go back.

MS. WILSEY: Here?

MS. CLARK: Yes. So previously I spoke about the different zones. At the bottom of this chart, you see 1 through 9, these are different zones, and then you see the states that are basically allocated to these particular zones, and again, this is all for the 2016-2017 planning year. You can see that Zone 7, which

is lower Michigan, we're projecting about a 3.0-gigawatt shortfall for the 2016 planning year. What this means is that, according to the load that we receive from our survey results and the generation, that there's not enough, basically not enough generation to cover that load in the reserve margin that we looked at calculating. So we're saying that we look at being about three gigawatts short in Zone 7 for the 2016-2017 plan year. And this is by zones.

The previous slide gave an aggregate kind of number of I want to say it's a 2.3, and then you add the number, about a one gigawatt for the Covert plant. This is just saying in total, including the Covert plant, this is giving a zone-by-zone basis on what MISO is looking like. And you can see in Zone 8 and 9, which is our south region, you can see the green, indicating that they were, based on the results of the survey right now, they're planning to have a 2.5-gigawatt surplus.

MR. JESTER: How do the system support resources fit into these numbers?

MS. CLARK: The system support resources, well, if you're a system support resource, you're still providing service to MISO, so you would still be considered as part of the planning process. If you are a resource that's planning on retiring, we would not have

included you in that, MISO would not have included that plant for that particular resource in it. But a system support resource would still basically be on line with MISO. If after that system support agreement is over we determine that we've got a transmission or generation solution, that particular plant is no longer needed, and you say yeah, if it's no longer needed, I want to go and retire, then that's when MISO would change and update those numbers.

MR. JESTER: Do you know or can you say if the plants under system support resource orders in the Upper Peninsula are included in the projected surplus for Zone --

MS. CLARK: They're included. Anything that's on an SSR, which means that's it's currently running inside of MISO, is counted as capacity. But if they -- if it's not on an SSR and they say, I -- you're no longer needed, we don't have an agreement with this particular plant owner, and they want to retire, at that point MISO would take those units out of retirement. So there's different things, because the system support is -- this is sort of a capacity standpoint. The system support is the other part of it, the day-to-day I've got this resource running to make sure that the voltage in this particular area is supported. But until that

resource decides that I'm not going to, or we're no longer needed in MISO, we're going to continue to keep it, we don't take it out of base numbers.

MR. JESTER: So if all of the SSR plants in Michigan's Upper Peninsula were to be retired, the surplus in Zone 2 would be wiped out, and a little more?

MS. CLARK: It would be, yeah. Well, you've got two different states covering it, so it would depend on if there's some things -- in Zone 2, it depends on two things: It would depend on what's in our queue now to be added as generation versus what's going out. So if you just say, well, yeah, everything from -- that's in our SSR process right now for Michigan goes away, then yeah, you could potentially see a shortfall in Zone 2, and nothing else is added.

MR. MacINNES: So it looks like you've got and excess of .7 gigawatts, and the Presque Isle plant is .4 or so. Even if the Presque Isle plant were to be closed, it looks like you would still have a surplus in Region 2; is that right or not?

MS. CLARK: That's only for Presque Isle. I thought it was about what, 4 -- I can't remember the megawatts --

MR. JESTER: I think it's .56.

MR. MacINNES: .56.

MS. CLARK: Yeah, so you're looking at --

MR. MacINNES: But that's still below .7.

MR. JESTER: But we also have Escanaba and White Pines.

MS. CLARK: Yeah, you have other ones. I was going to say you also have White Pines and you have Escanaba, so you would have to consider those as well, and I think there's about what, seven something, I can't remember how many units on the SSRs, but you've got two other ones to consider that are on SSRs in the Upper Peninsula in Zone 2.

MR. MacINNES: So Michigan is really the main -- northern lower Michigan, or lower Michigan, is really the problem child in MISO right now?

MS. CLARK: I wouldn't call them the problem child. I wouldn't want to call them that, but I would say that they're definitely a cause for concern from a capacity planning piece of it.

MS. RAUCH: One thing that we don't have here but that we do look at is it's -- we do want to look at one other piece, which is if Michigan's short, can you import into the state? So we do annual tests on the capacity import limit, which is one of the pieces to fit into this puzzle and something that's, again, Michigan will continue to want to watch, but the capacity import

limit does give us some help to make sure that Michigan's not quite as red as it seems.

MR. MacINNES: Chris.

MR. BZDOK: Just a followup on that. I mean there's a ton of generation in the little PJM nugget in the southwest part of the state. Isn't that really what's driving the load that, the shortfall in Michigan, and isn't that -- isn't this in some ways artificial because you've got so much generation right there that's in the state but it just happens to be in PJM?

MS. RAUCH: So any generation that is cleared in the PJM auction -- because keep in mind, PJM is doing the same sort of balance. So if they have capacity, even if it's located in Michigan, that is being used for a PJM load, it is taken out. So it's not the physical location necessarily, it's who has rights to that. And so that's why we have kind of the red dash with Covert is it's a generator that literally was about a bus from MISO to PJM, and so by switching a few things, they're now in the PJM market, so MISO load isn't using it.

MR. BZDOK: Covert and a whole nuclear plant.

MS. RAUCH: Yeah. And you're right, there are other generators in that area, certainly,

that's a pretty generator-dense area.

MS. CLARK: Any other questions? Go to the next slide.

MR. MacINNES: I guess I have another question on that previous slide. So what steps are being taken that you can tell us about to address this shortfall, projected shortfall?

MS. RAUCH: What MISO can do is we have the ability to require transmission to be built, so we're watching the transmission linkages very closely. We also have the ability to provide information on generation, but we do not do generation planning, that's the state role. So we're working very closely with the states to really convey what the image is, to continue to update it, and to facilitate discussions on what the potential solutions are.

MR. MacINNES: And there are several gas turbine plants that are being considered. Has that been factored into this?

MS. CLARK: No. Well, basically the -- we have our process for what we call interconnection with generation interconnecting into MISO. Anything that basically -- we have a study process that we're doing, and so once we look at those studies and once -- there's a phase called a definitive planning phase; until that

generation goes through that particular phase, which means they put up a sizeable deposit and they basically at that point have committed to building that generation, we won't include it. We don't include anything that's sort of speculative. If you said that, yeah, we plan on building it, it's sort of still considered a potential project, but not a definite project. So until you enter that planning phase of MISO, it's not included.

Now, once we finish our next round of studies, which will be in February for those that have submitted generation interconnection applications and we go through that planning process in February, after that's done, then we'll have a better idea if people want to go through the next steps and say, yeah, I'm ready to connect, I'm willing to do the network upgrades necessary to do the connection, and then once that process funnels out, we will then update the numbers to include it. But until we go through that planning phase, it's still considered maybe they will, maybe they won't, because if they find out how much work they'll have do and how much it may cost, they may not want to do it. So we don't include it because you still can really at this point, you can say no, MISO, I'm not doing it until you have to really put down the sizeable deposit, and that basically saying I am going to do it, I'll willing to do the work,

I'm willing to do the upgrades to get it done.

MR. MacINNES: And that process takes -- I've been through some of that process with a project I worked on, but it seemed like it would take, it could take a year or longer.

MS. CLARK: Yeah. It usually takes about, I think we say to MISO to do, fully do the study and determine, it takes us about six months to give the output to the customer, and then they have -- you know, they can decide when they want to say, yeah, we're going to go do it. So it could take a year to when they say, yeah, we're going to definitely go and do this project. And once we get the okay from the customer, then that's when MISO will start incorporating that particular generation into our planning processes. Good question.

And this is sort of the, I think it goes along with the next slide that we talked about previously on what does it look like going into our future years. And we have the 2016-17 that we were looking at, and we talked about the different zones, and Zones 1 through 9, what does that mean, Zones 1 through 7, what does that mean. The 3.3 gigawatts, basically that's saying that our reserve margin with that 3.3 gigawatts is going to be less, so we're looking at 11.5-percent reserve margin, and you look at the between '15-16, our reserve margin is

at 16.6 percent. So we're saying that, as Laura mentioned, that their reserve margin is basically decreasing as we're looking at the 2020 year especially and some of the EPA regulations. So we're seeing that this shrinkage in the reserve margin going forward, and that gigawatt shortfall just means that we're, we're not planning for that one day in 10, that that one day in 10 could go up, I think we saw something about a 2.5 or something like that, so we're not doing the one day in 10 because the reserve margins are getting shorter as we go out. And again, the reserve margin is looking at load and generation. So it's the 50/50 forecast, it's the generation, and looking at their availability to meet the load obligations in MISO.

Any questions?

And this is the slide that we talked about previously, and it connects to the previous slide. As you look at -- as we go out longer term, we can see sort of those planning reserve margins shrinking. Hopefully once we get some people through the interconnection process, we can have something a bit better. And if you look at the 2020 year, if you remember, that was the year of the Clean Power Plan that the EPA was implementing to have the Clean Power Plan, so you look at that year and you look at what could

potentially happen to our planning reserve margins. As we decrease those planning reserve margins, I think the takeaway from this slide is that, you know, we will be going through those five steps of our emergency operating procedures. So that means that we will likelihood be going through the implementation of our, we call them our EOPs.

MR. MacINNES: So do you think that most of this will be solved through generation, or will there -- and will there be a portion of it that's solved by interstate transmission?

MS. CLARK: I don't think it's one solution, I really think it's probably both. I think it's looking at -- and you're solving -- Laura mentioned import limits and things like that; that is very pertinent to making sure that if I have generation in Indiana, that I can get generation to Michigan, and still be reliable. So I think it's both, I don't think it's just one particular solution, I think it's a generation solution, and it's a transmission solution, and you have to look at, you know, Upper Peninsula and think about, well, yeah, if I take out Presque Isle, I still have an issue, I still have a reliability issue on the grid, and I think you have to look at both. I don't think it's just one thing.

And I think Laura sort of kind of hinted on this, is what we're doing is we're working with state commissions, we're working with our customers to make sure from a long-term perspective that we have the load and we have the generation lined up correctly, we're looking at this, we're updating this on, looks like an annual basis now with the survey results. MISO has contracted with the Purdue State utility forecasting group, they're doing some independent load forecasting for MISO, the results I believe are going to be reviewed in Dec -- well, this month, December, on that. So we're trying to make sure that we have the things in place and we have sort of some of the outputs of that, and we're looking at things from different perspectives, we're not just trying to rely on one piece of information, but we're looking at, okay, we're getting this from a load perspective, what are they really saying, you know, are -- we made some assumptions on load growth, what does, you know, our independent load forecast say, is it in line, and maybe sometimes it's not, because you can use different assumptions. But we're also looking at trying to figure out different ways to look at the resource planning perspective.

There were some question I think some stakeholders raised about our generation interconnection

process; you know, is there something that we can do there that could make that process go through a little bit easier. We're also exploring, we have what we call some unused capacity, that basically it has to still go through our generation interconnection process, but there's no network upgrades to be done, so this is something that's pretty much easy to go through, submit the application, we determine that no network upgrades will need to be done, so you will get more capacity basically out of these particular units.

And then we're also, like I said, we're looking at tariff stuff. The outage coordination piece is important because we're trying determine as far as, okay, likelihood of having outages. The Polar Vortex was very crucial in making sure that, you know, are we accounting for these resources correctly. If we get a temperature below a certain point, how do we ensure -- how do we know for sure that those units at 20 degrees below are going to be operating at the capacity that we need them to. But, you know, we're looking at different policy changes just to make sure that we can get the amount of generation that we need when we need it from a footprint.

So the thing we can't do is we can't look at these things in silo processes, we have to look at it,

you know, we have several different planning processes from generation to transmission, and we have to look at those processes together.

MR. MacINNES: So at the IEEE meeting in D.C. this summer they talked about the accuracy of different forecasters, that there are some forecasters are that are very accurate and some that are not so accurate. Have you -- I'm sure you've, MISO's looked into getting the best of the best on load forecasting.

MS. CLARK: Yes, yes.

MS. RAUCH: And load forecasts are something we get from our members, it's not something that we historically have done, because they're the ones obligated to serve their load. The reason we're doing an independent load forecast is because, like you said, sometimes numbers get misplaced, we want to have some gut check on is this right or is this wrong, so having the independent load forecast allows us to do that.

MR. MacINNES: I think that's a great idea.

MS. CLARK: And we've implemented some sort of controls, too, to where we're looking at, this particular year I know is that we're looking at the forecast and we're looking at the changes from year to year and just looking at it from a does it make sense

point of view, we're doing sort of the check to say, okay, well, this is what it was last year, are they really going to have a 10-percent load growth, because if they have a 10-percent load growth, there'd better be a huge plant going in there to account for that. So we're doing some of our checks when we're getting these forecasts as well from our LSEs just to make sure that they are reasonable according to some of their historical numbers, and there may be a justification for it, but it does help to make sure that when we get this information, we're sort of doing another doublechecking on them.

MR. MacINNES: Doublechecking.

MS. CLARK: Questions?

MR. MacINNES: Did you have a question, Susan?

MS. HAROUTUNIAN: This is all very orderly and everything, and everything continuing on as usual. What kind of disaster planning are you doing, whether it's weather, sabotage, what if things go down?

MS. RAUCH: So one of the things we don't have here but we do on a regular basis is we'll do seasonal assessments, and that's basically look. We just looked within -- finished our winter assessment of if things are really, really bad weather wise, will we still be okay, or what do we need to prepare people to do. So

we looked at the last seasonal, we looked at something that's kind of as severe as the Polar Vortex we had last year where you had more outages to deal with the weather issue. We also have a lot of southern members, so hurricane planning is now something we deal with as well.

From a sabotage point of view, we actually have been spending a lot of time, especially with some of the attacks on substations, trying to figure out what those critical facilities are, and some of the new regulations that are coming out are looking at those, making sure you're very safe around them, and also looking at things like spare equipment strategy. So if you have some of these spare equipment pieces that take a long time to replace, do you have a good option so you're not just saying, well, this is out, it's going to be out for six months.

MR. MacINNES: Like a large power transformer.

MS. RAUCH: Exactly. So we're spending a lot of time -- a lot of those discussions, especially the sabotage ones, tend to be very, very, very protected because we don't want to be publicly saying here are our weak spots, but we do have what we call critical energy infrastructure information agreements that once folks sign, they can really contribute to those discussions,

and that's essential because usually it's those local utilities and local planners that can help us with them.

MS. HAROUTUNIAN: Okay.

MS. RAUCH: Okay. So again, thank you for coming. My name is Laura Rauch, I'm manager of resource adequacy coordination now, my previous life was in the reliability planning group, so I know I've been able to speak to you guys under that guise before. I'm going to give a fairly quick update on our MISO Transmission Expansion Plan, our MTEP.

So we talked a little bit about the governance structure, and this is an example of that. These are the MISO board of director planning principles. So every time we ask the board of directors should we build this, which is basically what our MISO transmission expansion plan is, it's a list of projects we think should be built, they say, well, show us how you followed your planning principles; and so these are things like making sure that we look at economics, look at reliability, keep the lights on, look at policy, how are you reacting to things that are coming down the line, both state, local, and federal, and if you're asking someone's to build, are they doing so because they're getting benefits out of it.

One of the new things here that you might

not have noticed from last time is we now have one that says make sure you play well with your neighbors. So we're spending a lot of times working with SPP, with PJM, with our neighbors, because electricity doesn't stop at state or RTO boundaries, and we need to make sure we're operating and building to maintain that.

Next slide, please. So at the end of the day, really what we're trying to do is hit a sweet spot where you're minimizing generation costs, you're minimizing transmission costs, and that gets to a point where you're minimizing the total cost of energy to customers. So if you look at your bill, you have a lot of different pieces on it; usually the bulk of that is your fuel costs, but you also want to make sure that you have the transmission to get generation from the generator to the load, and that you're not building too much transmission where it's just gold-plating the system. So we try to do this in an open and transparent manner so that we can use crowd sourcing, get good ideas, and make sure we're getting everyone's needs met to the extent we can.

So when you look on the next slide about some of the moving pieces, there's a lot of different things that fit together. There's new members that are coming in, we just integrated the southern region;

there's congestion, economic limitations that mean that we can't get the cheapest generation to serve our load. Load forecasts we've talked about. Fuel prices and availability is something that's new, especially when you look at a shift to natural gas, you need to make sure you have the pipelines for that as well. Order 1000 is a large order that was issued probably a few years ago at this point, but it has a lot of moving parts on who gets to build transmission and how you play nicely with others. And then you have a lots of different policy-driven changes that we look at.

And so at end of the day, what we do is we try to consolidate these conceptual ideas into concrete planning with reliability analysis, keeping the lights on; economic, keeping them on for the least cost possible; long-term resource adequacy, which is my group, making sure you have enough generation to serve your load; and several other things that are looking at resources coming online, resources coming offline, and who gets to build transmission in the future.

So if you go to the next slide, MTEP's what we call an annual 18-month process, which is we do it annually and it takes 18 months to finish it in general. So we just finished our MTEP analysis for 2014, probably within a week we're going to be sending the

final report to the board of directors for their approval. And when we talk about MTEP, it's really encompassing all those public pieces from the previous slide into one report. So it's looking at your reliability assessment on the NERC side, your economics, which are, we've studied intensively and are continuing to study, we have the resource piece in there, and then we have a lot of stakeholder discussion that got us to the point where we could have a report.

And please, if you do have questions, stop me.

So MTEP --

MR. MacINNES: I have a question.

MS. RAUCH: Go ahead, please.

MR. MacINNES: So you're talking about MTEP 2014. When did you start the MTEP process, I mean was it 2008 or 2000 -- when was it?

MS. RAUCH: I think the first MTEP report was '05, I want to say. We've really been doing them very regularly, on an annual basis, since '08. So what we've done in recent years is when I -- a few years ago I was involved in the MTEP report, and it was probably about three-inch thick paperweight; we've tried to make it so it's a good summary now and links to the three-inch thick paperweights of a lot of other studies.

MR. MacINNES: So if you were to take all of the MTEP projects through 2014, how much money was intended to be spent, roughly, since the beginning?

MS. RAUCH: I'd have to look it up. It's -- this year is about 1.8 billion, and that's probably a normal year. I'd say we've probably been about a billion a year. We did have a larger year with the 2011 with the Multi-Value Projects, we were around 6.5. So it's, so '05 through '14, I'd say we're probably $10-15 billion worth of transmission investment.

What you'll see, though, is that the vast majority, especially by project accounts, and by cost, too, but especially by project account, is local projects. So we have another slide on this, but if you look at the project breakdown, we have our baseline reliability, which are the projects to solve the federal NERC reliability violations, so this is -- you might have a 100 kV line that's, or 138 kV line that's overloaded with another line next to it. So we have a few of those. We have some new generators that are coming in and they're building projects to make sure that they stay reliable.

But most of them are these other projects, and these fall into a few buckets. They can be economic projects where they don't meet the benefit/cost

ratio; they can be reliability-driven upgrades, and usually that's what they are, they're driven by the utility reliability needs, but they're not NERC violations, so they could be condition, they could be less than 100 kV lines, but they're to solve -- utilities say we think that this is needed to solve issues, we'll take it through a stakeholder process, and assuming we see the same need, we'll go forward. But a lot of times these are things likes woodpeckers are attacking our wood poles and we need to replace them before they fall over.

MR. MacINNES: So that would be at distribution level, then?

MS. RAUCH: That was actually a transmission tower.

MR. MacINNES: Really.

MS. RAUCH: It was a fairly old one, but it was a transmission tower. We also had an instance where farmers were taking shortcuts into their field and the transmission lines were too close for their tractors and combines to go underneath.

MR. MacINNES: So these would all be transmission level projects, over 100 kV, it could be transformers, towers, wires, that sort of thing --

MS. RAUCH: Yeah.

MR. MacINNES: -- breakers?

MS. RAUCH: And actually, great transition. Let's go to the next slide. You'll see that most of these are upgrades to existing equipment, and you'll also see the spread of these. So but we do have some new transmission lines in here. Most of them, again, are upgrades to transmission lines. And we say 100 kV, although some areas I've seen 41.6 kV transmission line; it's all about there's a seven-factor test which says is it transmission, and it's all about kind of what type of trans line it is. So if it passes that or if it's under the MISO functional control, we are planning for it.

MR. MacINNES: So what about FACTS devices, do they fall into that?

MS. RAUCH: FACTS devices, I believe we do have some that we'll look at, but I couldn't name any off the top of my head.

MR. JESTER: Question.

MS. RAUCH: Yes.

MR. JESTER: I looked back through all of these I think. There have been a significant number of projects nominated that would have increased transmission into the Upper Peninsula, almost all of them failed by large margins on benefit/cost tests and things of that sort, and yet we clearly have a problem. Can you talk a

little bit about why that is so?

MS. RAUCH: Thank you. So when we talk about transmission projects, we have several different cost allocation buckets, and unfortunately I did not bring that slide with me, where we say for MISO to say this must be built, here are the benefits that we can use for that, and those benefits are benefits that we've defined with heavy stakeholder input. So, for example, our economic benefits are adjusted production cost benefits. There may be other benefits to building the transmission lines that we can use for Multi Value Projects, but if you want a stand-alone economic project, it has to reduce your adjusted production cost, which is basically freeing up cheaper generation to serve load. So that's one thing. And we've looked at lines going to the U.P. under those economic metrics, and they have failed. It's -- what we've seen is that the Upper Peninsula is really a reliability issue, but until you have a generation retirement, you don't have a case to build for a reliability issue if there isn't some other NERC violation that has occurred. It's something that a six-month timeline seems like a lot, but not when a transmission line takes several years to get through the process and build. So it's something that we work, are working on very carefully and working on very hard right

now, especially with the Upper Peninsula.

What are the solutions there? MISO can propose transmission solutions, we can work with the state to consider generation solutions as well, and probably the answer could be a combination of both. So once -- now that we know this generator is retiring, what is the transmission that should be built, or what are the solutions for the area that can be built?

But you're right, we have looked at this from an economic point of view, we did a Northern Area Study; unfortunately, at that time Presque Isle was in and out and ended up saying that they were going to be in service during the study period, so it was left in, but still, it's not an economic problem, it's, from a MISO-defined, MISO-stakeholder-defined economic criteria, it is very much a reliability issue, we're looking into it very strongly.

MR. MacINNES: So that would be the N -1 criteria, and voltage support probably would be part of that?

MS. RAUCH: Yeah, I believe the issue that we've seen is a lot of voltage reactive power needs, if you take away the generator, you're taking away a lot of the ability to keep the system voltages up, and that translates into a non-reliable system for the local area.

So just an example of trying to get to those optimal solutions requires a lot of meetings and a lot of time, we're very lucky that our stakeholders devote this time so that we can come with a good solution. For example, in Michigan we'll do several subregional planning meetings here held in various places throughout the state, also some technical study task force meetings which discuss each of projects we're recommending for approval. And in the technical study task force meetings, we protect those with agreements so that we can openly discuss really what the weak points of the system are, points of failure, without worrying about identifying points of sabotage for the public eye.

So we spent a lot of time talking with our stakeholders throughout the footprint, and really it's because of that we've got into the set of solutions that we have at this point.

That's good, I think. Was there another slide there?

MS. WILSEY: I don't think so.

MS. RAUCH: So questions, comments, discussion?

MR. MacINNES: That was a great --

MS. CLARK: Wow. This is great, lights on/lights off, that's kind of like what we're talking

about, aren't we?

MR. MacINNES: Yeah. But a great presentation by both of you, very informative and helps us understand how all the pieces fit together.

So any questions from the board? Anyone?

MR. BZDOK: I guess I have one. So this will sound more argumentative than it should, but help me understand the catch 22 with U.P. You've got Presque Isle is an SSR now for reliability reasons, and it wouldn't need to be an SSR and we wouldn't need to be incurring all these expenditures if there was a transmission line, but the transmission line can't get justified on reliability reasons because Presque Isle is still functioning.

MS. RAUCH: No, I think when you look at Presque Isle where we are now, it's much easier to make the case for transmission upgrades, and we are looking at both upgrades coming in from Wisconsin or going down through under the Mackinac Bridge. Where we have trouble is when Presque Isle says I'm just going to continue operations; so there we can't -- we don't have a violation where we can say, you really -- we're going to force you to spend this hundred billion or hundred million or $500 million to build this upgrade; we could support it if it comes forward from the utilities, but

they're the ones who best know the likelihood of the generation being there. So now that we have a generation retirement, we're in a much better place to actually have good solutions. When the generator is saying I'm going to be here, we can identify risks, but that's about it.

MR. BZDOK: So the be here phase was the Wolverine merger phase, and then you guys got an Attachment Y?

MS. RAUCH: Yes, yes.

MR. BZDOK: How long ago?

MS. RAUCH: When was the last time I was here; I feel like we had this discussion?

MS. WILSEY: October of last year.

MR. MacINNES: It's been about a year, over a year.

MS. RAUCH: So I think the start of last year we started the Northern Area Study. Initially we did have Presque Isle offline in that study, then we put it back online because of the, because of the statement we were told that it was going to be online, and then we received another retirement request.

MR. BZDOK: Okay. Thanks.

MR. MacINNES: A lot has happened since then. Okay. Any other comments or questions?

Well, again, thank you very much. It was

a delightful report and very informative for us, so appreciate you coming up from Indiana to visit with us.

MS. CLARK: It's a pleasant drive.

MS. RAUCH: It was very pleasant.

MR. MacINNES: How about if we take a five-minute break.

MS. WILSEY: Yeah.

MR. MacINNES: And then we'll resume and do more business. Thank you.

(At 2:38 p.m., there was a ten-minute recess.)

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MR. MacINNES: Okay. Shall we get started here. One of our board members has to leave a little early, so.

Okay. The next item of business here as we resume is the RRC grant request.

MR. SHALTZ: Thank you, Mr. Chair. Last August we submitted a grant application to the board; part of the grant application was for some GCR reconciliation cases, and the board has already passed on that particular grant proposal. Today I want to present the part of the proposal that deals with the four GCR plan cases that we asked for in that proposal.

The Residential Ratepayer Consortium, just to remind you, is a collaboration between two

organizations, the Area Agencies on Aging Association of Michigan and the Michigan League for Public Policy. Both organizations have statewide memberships and constituencies, and basically they advocate the interests of residential customers of Michigan's gas companies.

We're seeking to intervene in the GCR plan cases of the four major gas companies in Michigan; Consumers Energy Company, DTE Gas Company, Southeastern Michigan or SEMCO Energy Gas Company, and Michigan Gas Utilities Corporation. These four companies comprise over 95 percent of the residential customers in Michigan, and in the GCR plan cases that will be filed at the end of December of this year, these cases affect about 60 percent of the average customer's bill each month, some cases it's higher. These cases will start probably beginning to mid February is when the first prehearing conferences will be scheduled, and will go from there.

What we're proposing in the grant that we submitted to you is to do the review that Act 304 requires in these cases. The statute sets out a number of items that the Commission has to review for reasonableness and prudence, and basically our proposal proposes to audit each of the filings for those elements. The first element is typically the sales forecast, which comprises numbers of customers and assumptions about

weather, what demand is going to be like.

What will be interesting in this round of cases, this will be the first time that the utilities will have an opportunity to integrate in their GCR plans any lessons they learned from last winter when we had the extreme weather. So we'll be looking very carefully to see if they simply ignore last winter and sort of just do business as usual, or if they actually change their demand forecasts to make modifications on how they project for colder-than-normal temperatures.

If they do make modifications, that will have a ripple effect through their GCR plan, because then they're going to have to modify their purchasing requirements, how they operate storage, and how they plan to obtain supply from the Gas Customer Choice customers who they have contracts with in the colder-than-normal weather. So each of these elements sort of has an interrelationship with one and other.

We'll continue to look carefully at how well the utilities are doing in lining up both firm and interruptible gas transportation contracts. All the utilities have a number of contracts that expire each year, and so these contracts are up for renewal, and we want to see whether they're getting the best price to best fit their system supply characteristics.

We've been very successful in getting three of the four gas companies to scale back on the degree of fixed-price purchasing that they've been making because we've been able through time to show that even though the purpose of those programs was to bring stability in rates, they have not performed as well as simply buying gas at index on a monthly basis. So the one company that's sort of a holdout is DTE Gas Company, which still purchases 75 percent of its requirements at that level.

Frankly, I think if the Commission this year continues to allow DTE Gas Company to continue doing that, it doesn't make sense to continue pursuing that issue. Each year the Commission says, we want more data, show us more. We've sort of gotten the burden of proof shifted around a little bit. This last round of cases the Commission said, we want the Company to make a robust presentation of why 75 percent is still needed, so we're hoping that in this round of cases, we're going to have either the thumbs up or thumbs down on this. If we don't get them to turn around on it this time, I doubt that we'll be looking at that in the future.

One of the things we've seen recently is that the gas companies have informally and formally been floating with the Commission Staff and the parties some

new proposals for modifying what are called their GCR contingency matrixes; these are things in their rates that allow them to bump up their GCR factor if certain things are going on in the market. The Commission has approved these, with some limits on them, but now we're hearing noises that the companies actually want to use this mechanism to try to collect under-recoveries within the same GCR year; so if they were short in February, they want to be able in May to increase their GCR factor to collect what they didn't. The problem --

MR. MacINNES: Does that mean that they'll give the money back within the same year if they over-collect it?

MR. SHALTZ: Well, that's the problem. These are always one-way streets, you know, we never have a two-way street going here. Every time we suggest that there needs to be a balance, they always fall back on saying, well, we have no incentive to over-collect because we have to pay interest on those. Well, it's basically cash refinancing for them, and there is some real, I think, advantages for them to do this. So we'll certainly be scrutinizing them. We've always opposed these contingency mechanisms because we think that the reconciliation phase of the case is usually an adequate remedy for them. Nowhere else in ratemaking is there a

reconciliation phase where they get to go back and collect where they didn't, what they didn't collect in the first place. So we think those are going to be big issues.

In our proposal, we give you a list of other items that we typically put in our audits in these cases, and we'll continue to do that because we find in doing discovery, a lot of times in routine discovery we'll discover things that are different from prior years that they're trying to do for the first time, so I think we'll continue along that path.

We've always worked closely with the Attorney General's office to try to coordinate our efforts to make sure that as many issues as possible are covered. Typically where we do have an overlap in testimony, we make sure that it's complementary and not duplicative. This year Mr. Erickson has retired, so we'll be working with Mike Moody and John Janiszewski. Don Erickson may be coming back on a part-time basis on some cases. But that will be sort of a new dynamic this year because Don always took the lead in these cases, so we'll have to probably pay more attention to the collaboration and coordination part of the effort.

The budget we've proposed to you is a little over $27,000 per case. I was certainly paying

attention at the beginning of the meeting about the budget constraints you all are facing.

So just to refresh your memory, what you did in the GCR reconciliation cases is when you decided how much was available to fund our intervention effort, you basically instructed us to decide how best to allocate the money; we would certainly welcome that approach again, because I think the way we need to do this is to get through one or two rounds of discovery to really get a sense of where the most important issues are going to be and which companies are going to be most important before we decide on a final allocation of where the money should go. So I'd be happy to answer any questions you have about the proposal.

MR. MacINNES: Okay. Does the board have any questions about this proposal?

MR. ISELY: What sort of timeline is that on the discovery components?

MR. SHALTZ: The filings are made right at the tail end of December. Because of the holidays, we usually don't get into actually reviewing them for first discovery requests until the first or second week of January. So I would think by the time the prehearing conferences happened at the beginning and middle of February, we'll have our first sets of discovery out. We

usually hand them to the company at the prehearing, because in GCR plan cases, unlike reconciliations, you can't start your discovery until you become a party to the case; once we're a party, we can actually physically hand the discovery over to them. So I would think that by end of February, March 1, we should have a very good sense of where the issues are going to be in these cases.

MR. ISELY: Okay.

MR. SHALTZ: And we'd certainly report back to you on that, let you know how we think we're going to allocate the dollars in these cases.

MR. ISELY: Thank you.

MR. MacINNES: How much would you spend by then?

MR. SHALTZ: Not very much. You know, it's typically petitioning to intervene, doing the initial review, and putting together one or two rounds of discovery, so that typically runs within 15 to 20, maybe 25 percent of the budget at that point.

MR. MacINNES: And that would be for each of the four?

MR. SHALTZ: Yep. And we know sort of going in what the key issues are going to be for some of the companies. For two of the companies, we've been able to enter into settlement agreements where they basically

adopted our recommendations informally, so we know that those issues are sort of taken care of. So we think that probably the two bigger companies, Consumers and DTE Gas, will be the ones that have the most potential issues for advocacy this time around.

MR. MacINNES: Any other questions for David?

Okay. Well, I think maybe it would be good to have a discussion. Michelle, do you have any comments you want to make, or thoughts? I was thinking about just having a little discussion here about how far we want to go into debt further and, you know, just what we want to do here with what remaining small amount of funds we have.

MS. WILSEY: Well, I think so you're in that position, David's total request was 109,000 and change; if you supported that in its entirety, that would take you about 70,000 further into an overage situation. You may want to moderate the funding more in line with some affordability with the ability to David to report back.

David, I think you need let the board know a little bit about what you can work with; you know, if they grant you a certain amount of funds, can you approach the issues that you're planning in one or two

cases and maybe not the other, that type of thing, so, you know, if you want to moderate the request.

The board can continue to consider additional funds, but again, anything over that 35 is deciding to go a little further into arrears.

There's another big set of cases on the horizon, PSCR reconciliation cases are out there as well. Right? So if any parties are thinking about wanting to be involved in those cases, which historically there have been, that's another group of cases to kind of have in mind as well for parsing out funds. And so right now we have one issue in front of us, and beyond that, you know, at least one other big group of cases that may come before the board as requests going forward. So I think the first issue is, you know, making that decision about what is the overall temperament of the board in terms of taking on additional debt, if we want to call it debt, whatever everyone calls it.

MR. MacINNES: I call it debt.

MS. WILSEY: Right. I'm calling it debt. There's been a lot of like forward spending and borrowing and deficit debt. If the board wants to begin to be austere this year, then a smaller approval would be in order, and some guidance to the other grantees on whether its, you know, thought process is to be austere and

limited going forward or if you're going to be open to further requests for funding.

MR. SHALTZ: Mr. Chair, I was thinking a little bit what Michelle was saying. I think if I was in your position, the first thing I would want to think about is, okay, we know how much you owe the AG, so I think one of your initial decisions has to be is how quickly do you pay that back; because if you have an amortization schedule to for, it was 220, so if you do it over four years at 55,000, for example, you know that this year out of your total allocation off the top, you have to subtract 55,000, so that tells you what you've got left for this year.

And for the second question that Michelle asked about, you know, what could we work with within this budget; you know, I've talked to my expert witness about the budget problems we're having this year and I've talked to my clients about it. You granted us 60,000 for the reconciliation cases and, you know, we certainly understand that that's going to mean that probably we're going to have to do the most of our work in about two of the cases out of the four. I think we could do, for this year -- I'm not suggesting this is adequate funding by any means -- but for this year, we could probably do that for the plan cases, too, in that range.

MR. MacINNES: In the 60,000?

MR. SHALTZ: 60,000 for the four cases.

MR. ISELY: Well, to the broader issue of how long a payback schedule, you know, we have the 220 from last year, right?

MS. WILSEY: Yes.

MR. ISELY: Essentially.

MS. WILSEY: That's what we have, yes.

MR. ISELY: We have several pieces here that we're looking at adding to that this year, right?

MS. WILSEY: Potentially, yes.

MR. ISELY: Okay. Essentially if we're looking at -- if we ignore the COS cases and look at what we're spending other than that, we'd have to be in the, between 4 and 450 to make it a four-year pay back, and between 450 and 5 to make a five-year pay back essentially, assuming 575,000-ish, so we're making some assumptions, sort of back-of-the-envelope calculations?

MS. WILSEY: I don't think they're wildly off, but 70 -- what did we say, 10 to 12 percent of the total, 574, puts you roughly in that areas, although we have a little growth.

MR. MacINNES: Well, I think, as was pointed out, one of the first questions is what's a reasonable payback time, I mean what's the sense of the

board on that? You know, it seemed like when we had our conversations with Michael Moody, I mean he seemed to be --

MS. WILSEY: Four years was fine; five years, he was starting to get a little iffy, but would go back with it; anything beyond that, I think they might start going, you know --

MR. MacINNES: Yeah. So it's probably four or five years are our two choices. How do people feel about that?

MR. ISELY: I personally would argue that you target the four, and if we have another emergency, it gives us a little bit of slush room.

MR. MacINNES: That's a good point.

MS. HAROUTUNIAN: We have to take into account, as I know everyone is, our purpose here. If we cut back too drastically, we might as well not do anything, because we can't -- we can't get enough done with unduly limited funding is where I'm going.

MR. MacINNES: But yet we have a pretty, if you read this document, it's pretty hard and fast on don't spend money you don't have. It's --

MS. HAROUTUNIAN: It's my understanding from what's been said that the Attorney General is willing to have us continue as long as we pay back; and,

therefore, I think our role in all of this is to finesse what we think we can support, and at the same time get a sufficient amount of work done that our existence is the way it should.

MR. MacINNES: Get the maximum amount done.

MS. HAROUTUNIAN: Yeah. But the caution is, well, we can't do everything we'd like to do. Mr. Shaltz is helping by saying, well, I think with these other cases, I can also do it for less out on a temporary basis; I'm sure that's true of everybody because they want to keep doing what they're doing, so it's a balance in there, and we have to make sure that we're doing as much as we can.

MR. MacINNES: Absolutely. I agree with all of that. So that said -- I mean I agree with that, what you just said -- what's --

MS. HAROUTUNIAN: What's the right number.

MR. MacINNES: -- what's the right number. I mean we're a board, we're here to make a judgment on this, that's what we get the big bucks for, right, but to take a considered judgment on what's reasonable. So what do we think is a reasonable timeframe, and recognizing that, you know, the AG's

office is flexible, but yet I think there are limits to it, too?

MS. HAROUTUNIAN: Right.

MR. DINKGRAVE: I would say I agree with what's been said, I think the four years is a good place to aim for and start, and it does give us, like you said, Paul, though, room in case something unexpected does happen or there's some opportunity that comes up that we really feel the need that we have to invest in and maybe increase the borrowing for. And like you, Jim, I'm inclined not to carry debt for longer that we need to, and I think, again, five years is going to be questionable in the eyes of the AG maybe or they'd have concerns about it. I think when we talked about it with them and they seemed very comfortable with them with four and it seemed to a fairly reasonable proposition given the amount off that we're talking.

MR. MacINNES: And there's no interest.

MR. DINKGRAVE: Right, that's what I was thinking, I can't get this kind of deal.

MS. WILSEY: Well, we didn't know there was a debt to begin with.

MR. DINKGRAVE: Given that, given this is the reality of the situation, then yes, we do have debt, how do we handle it, so I would be supportive of four

years, while trying to balance, like you said, the very reason we're here, trying to maximize the dollars we do have during that time.

MR. MacINNES: Michelle.

MS. WILSEY: One perspective on the reason that you're here, the cost-of-service cases coming up right now have caused a great deal of austerity in the traditional PSCR cases, whereas next year, even though we're cutting back, there probably aren't cost-of-service proceedings, at least newly initiated ones, and therefore, there actually will be more money available for the traditional PSCR cases even with the pullback. So you're kind of balancing austerity driven by new legislative cases, and the hit is going to the traditional Act 304 cases; next year, while there will be less funds, more of those funds will be targeted to the traditional cases.

MR. MacINNES: A lot more actually.

MS. HAROUTUNIAN: Yes. Okay.

MR. MacINNES: And that was kind of a special circumstance, and I think that with the legislation and everything, I mean the Governor's office and the legislators wanted that, wanted us to be at the table; not everybody did, but most did.

MS. HAROUTUNIAN: Can that translate into

any more money from somewhere to accommodate that need?

MR. MacINNES: I don't know. I don't know. You know, we've explored this with the AG's office -- well, with Valerie and I made some other outside contacts with some people that have been involved with the board with Act 304, and my sense of it is that it's, the way it is is what was outlined by Michael Moody, that's the reality. I haven't heard anything different from that. In terms of more money, I mean we could go ask the AG this if they'd grant us some money. That would be nice.

MS. HAROUTUNIAN: No, but I wasn't thinking of the AG. Other -- the legislature wants this, the Governor wants it.

MR. MacINNES: Well, it's already been funded, it's a one-time, we did it, it's been funded.

MS. HAROUTUNIAN: But out of our regular?

MR. MacINNES: Right.

MS. HAROUTUNIAN: Well, we need -- we're in a bad spot at this point.

MR. MacINNES: I know we are.

MS. HAROUTUNIAN: I mean it depends on what people want.

MR. MacINNES: Right. I don't know of any other funding mechanism offhand. I don't know.

Michelle, do you?

MS. WILSEY: There was just some discussion about, you know, maybe down the road when they take up the energy legislation and review it, maybe it will be a point of discussion. But even if more funding was requested, there isn't -- there isn't a process under way that would do anything for this year.

MR. MacINNES: Yeah, this is done. I kind of look at this as that cost of service, that's a done deal, we're going to be in the case and --

MS. WILSEY: I just mean in general, our fund, the board's funding has been determined months ago for this year, so what we're drawing from in future years maybe, but this year, not so much.

MS. HAROUTUNIAN: Well, okay, if you say future years, if we have incurred the part of the deficit based on the COS cases, what about in terms of helping us pay back the AG, if there can be some help with that based on this one-time event that the, both the unexpected debt, and really faultless debt that we got, and the imposition of these cases on us and the requirement really that we have to do these cases, well, based on that, maybe we need -- it's not like we need a ton of money. We need a little bit more from somewhere else to help make us even and be able to keep moving.

MR. MacINNES: Well, $250,000, the cost of the COS cases, would go a long way.

MS. HAROUTUNIAN: It would, yeah.

MR. MacINNES: I agree with you.

MR. DINKGRAVE: Is there any precedent for supplemental appropriation for this board's use, do we know?

MS. WILSEY: Supplemental appropriations are --

(Multiple speakers.)

MS. WILSEY: But from where, though?

MS. HAROUTUNIAN: Well, the legislature would have to appropriate it from the general fund, whatever.

MR. MacINNES: Well, we could certainly approach, you know, the Governor's office and see if there's anything they might. You know, I've done that once, and I haven't heard any --

MS. HAROUTUNIAN: Is there any advantage to approaching it legislatively, or is that not worthwhile?

MR. MacINNES: I don't know. I don't know how forthcoming the legislature would be and how we would -- you know, we'd probably need to talk -- the AG is our lawyer, right, so we probably need to talk with

their offices and ask them.

MS. WILSEY: I think a lot of this advocacy comes from the groups that use this fund to advocate in the cases, so I think the burden of making the case that there isn't adequate funding for consumer representation in these cases comes from the consumer representation groups that want to be there. I don't know that it's even the board's role, other than providing the information and maybe saying, we don't have sufficient funds to meet this obligation based on X, Y and Z; then the question is what advocacy is or isn't getting accomplished as a result, and what additional resources are.

MS. HAROUTUNIAN: And so all of you would have to talk to people, too.

MS. WILSEY: So I think that's where, for example, the legislation that was passed that allowed for Utility Board funding to be used in these cases, did that come from this board? Were you advocating for it? Were you? Were you? Were you? No. Somebody did. It wouldn't just materialize. So there are people out there with interests, and they would pursue that, just like they did in that instance.

MR. MacINNES: Well, no matter, I mean that said, good idea, maybe there is a way to get some

additional funds, but I think today we have to, --

MS. HAROUTUNIAN: To deal with what we've got.

MR. MacINNES: -- we've got to deal with reality here. So we need to figure out, first of all, what's the, I think what's the right time period.

MS. HAROUTUNIAN: Four years.

MR. MacINNES: You're good with the four years?

MS. HAROUTUNIAN: Yeah.

MR. MacINNES: That works for me, I think four years would be fine.

MR. ISELY: Four years starting when, this year or next year?

MS. WILSEY: No, next, fiscal year '16 funding.

MR. MacINNES: Yeah, '16, so it would be October of next year.

MR. ISELY: So under those conditions, if you wanted to even the pain across all the years, it's coming out to, quick calculation, about 450 a year, assuming the sort of growth that they've been talking.

MR. MacINNES: So but let's say -- now let's start with what we owe here.

MR. ISELY: Right.

MR. MacINNES: So we owe 220 --

MR. ISELY: Right.

MR. MacINNES: -- divided by four.

MR. ISELY: See, I'm including in this year a little bit.

MR. MacINNES: So that's 55 -- so right now, where we're at, if we don't fund anything, we have something like 35,000 yet, that would be 55,000 a year, Which would be about, let's see, 10 percent, 9 1/2 percent of what we would get in a typically -- so I think one of the questions is, you know, how much of what we get each year are we willing to take away and put into debt service. That's the next question.

MR. ISELY: That question comes from the primary cases that we're supposed to be involved in, and if we look historically at those cases, there's a dollar amount there.

MR. MacINNES: Right.

MR. ISELY: And I haven't fully calculated that, but it tends to be in that 4 to 500,000 range. Am I right?

MS. WILSEY: Yeah. I'm -- yeah. I would have to go back and look, because I'm not clear if you consider, for example, the federal case funding as traditional or not. Okay. Because we've spent a lot

more than that, and rate cases come up and special proceedings come up, and energy optimization, so I'm not sure what's in that bucket. That bucket's grown. And I'm still -- I'm not quite sure of the math, because if we have 574 and then project it at 580 and we take the 55 away, I just come a little north of 450. So am I wrong?

MR. ISELY: I wasn't looking at the 220, I was looking at 220 and then spending 400 beyond the COS case this year. All right. So that put us -- that puts us -- that adds something more this year. So when I do it, in order to do, to smooth it this year plus the next four years, it comes in to about 450 a year.

MR. MacINNES: So maybe what we need to do for now, or for the next meeting, is maybe do some analysis of that, maybe, if that's something you can help with --

MS. WILSEY: Sure.

MR. MacINNES: -- Michelle, and any of the board members, taking a look at what have we historically done without these special situations. Just kind of give us a ballpark. So, you know, because we can always change this, we can change our decision the next time if we want to, you know.

So if we do that, we've really got one case here we're talking about. Well, I guess we have

others that can come up. But what -- and I think, again, it kind of gets back to, at this point knowing what we know, how far do we want to go in, what are we willing to spend out of that 500, let's say it's 575, to -- that's the total, though, right? That includes the administrative and the --

MS. WORDEN: No, that's just the board.

MR. MacINNES: That's what we can spend?

MR. ISELY: Yeah.

MR. MacINNES: 575, okay.

MR. ISELY: Can I just sort of note that given what he said he needed to get through February, to get to February was within what we already have to spend, that we can probably deal with this and then have this discussion at the start of February and have the extra data in hand.

MR. MacINNES: Yeah, that's right.

MR. ISELY: And so we can bridge ourselves there --

MR. MacINNES: That's a good idea.

MR. ISELY: -- pretty quickly, but I don't want to do that and -- I don't want to do that if we're not amenable to spending the next chunk.

MS. WILSEY: Right, yes.

MR. MacINNES: Well, but you'll know a

lot more, I mean -- and the next chunk is -- I mean I guess we'd have to see what the success possibilities are for the next chunk. But I think that would be a reasonable --

MS. WILSEY: But the difference between -- if I'm hearing you and you're suggesting we grant the 35,000 today, let them get to work, the minimum is 60, so we'll consider the other 25 north of that if the cases demand it, that you're open to that case, you know, at least the minimum scenario, and then do you want the PSCR reconciliations also considered at that meeting so that you kind of have a better idea of the total? Would you guys be able to do that?

MR. ISELY: I think we'd appreciate seeing all that at one shot because we're at a zero sum game at this point.

MR. MacINNES: I think the key is at the next meeting to really have some handle on what's the normal level that, you know, everybody can live with. And David, my sense of what you said was to get you through February would be 20 or 25 percent of the total?

MR. SHALTZ: That's correct.

MR. MacINNES: So if you had 109, let's say 25 percent of that is 27.

MS. WILSEY: 270.

MR. MacINNES: Or maybe we could just says 25, because you said 20 or 25 percent --

MR. SHALTZ: That's fine.

MR. MacINNES: -- and would get us going --

MR. SHALTZ: Yep.

MR. MacINNES: -- and then we'd still not be borrowing any more and we'll have time to consider, do a little more homework, and you and I should probably talk some more.

MS. WILSEY: And Paul.

MR. MacINNES: Yeah, and Paul, the economist, to help us. So I think that sounds like a plan.

MR. SHALTZ: That sounds good.

MR. MacINNES: And no use making a decision any sooner than you have to.

MS. HAROUTUNIAN: That's right.

MR. MacINNES: Okay. Do we have a motion, then, to proceed on this grant request?

MS. HAROUTUNIAN: So moved.

MR. MacINNES: So moved. We have a motion to fund $25,000 at this point and revisit the whole situation at the next, at the February meeting?

MS. HAROUTUNIAN: Yes.

MR. MacINNES: Is there support?

MR. DINKGRAVE: Support.

MR. MacINNES: Is there anymore discussion? Okay. All those in favor, please signify by saying aye.

BOARD MEMBERS: Aye.

MR. MacINNES: Opposed, same sign.

Okay. That takes care of that for now, but we have more homework to do.

Okay. Moving on, the next item was the schedule for the meetings, which I have here somewhere. Okay. So we have a proposed schedule for the meetings. Has everyone had a chance to review that? Do we have a motion to approve that?

MR. DINKGRAVE: So moved.

MR. MacINNES: Do we have support?

MR. ISELY: Support.

MR. MacINNES: Any discussion? Okay. Hearing none. All those in favor, please say aye.

BOARD MEMBERS: Aye.

MR. MacINNES: Opposed, same sign.

Okay. So let's --

MR. ISELY: Is that the end of our votes?

MR. MacINNES: That's the end of our votes.

MR. ISELY: Then I'm going to apologize and excuse myself.

MR. MacINNES: Okay. Well, you were here for the important votes and discussion.

MR. ISELY: I apologize for leaving early.

MR. MacINNES: Okay. Grantee reports. Let's see. You're representing CARE?

MR. JESTER: IEI and CARE.

MR. MacINNES: Okay. Why don't you start us off.

MR. JESTER: Institute for Energy Innovation was funded to participate in the 2014 PSCR cases for both Consumers and DTE. It took a bit of wrangling, just a reminder, but we did wind up in those cases. We submitted testimony in both of them really around two issues: One is that the utilities have the opportunity to do more energy efficiency than they are required to do during the energy optimization program, and that doing so would be at lower cost than the cost of the power supply expenses that the companies otherwise incur. In fact, right now the cost of energy efficiency is less than the cost for just the fuel, not even speaking to the capital investment. And then secondly, that the companies have the opportunity to use load

management measures, and we picked particularly something called conservation voltage regulation, to reduce power consumption and, therefore, power supply costs.

MR. MacINNES: Is that kind of like having lower water pressure at your house and you'll use less water in the shower?

MR. JESTER: It is like that, but it's only by a couple of percent at selected times. So we put in testimony on those. In the DTE case, I was cross-examined, and we're now into the sort of wrap-up stages of these cases.

Perhaps most important is that Consumers asked the ALJ to rule that testimony wasn't germane to these kinds of cases, trying to argue that it's really only the, sort of the cost of operating power plants that count, and the ALJ decided against them in favor of considering the testimony, and they've now appealed it to the Commission.

One of the things we were trying to get at was really the sort of fundamental question of, you know, do things that the companies ought to be doing but are not, are they eligible to be considered here, and can we get some attention to them. So it looks like we're going to litigate that. So no answers yet, but that's where things are.

And then on behalf of CARE, we're operating with two grants this year, one was a bit of a catch-all, there's some funds to be spent on the smaller utilities, the PSCR cases on the smaller utilities, and you left a lot of discretion to CARE on how to allocate that. I'm not completely current on, you know, the decisions there, but I do want to tell you that the Attorney General has engaged Ken Rose and Bob Burns, a couple of the people who normally work for CARE, to be involved in the complex set of cases involved with the SSR payments and the other high costs in the Upper Peninsula, and they've had some success in getting FERC's attention. Because of the work that they and the Attorney General did, the burden of proof has shifted a bit from us to the companies on the cost allocations there. We're still many months from resolution, but I think that's a good thing. And then in conjunction with that, we've started to see in the PSCR cases from the utilities that are affected requests based on these allocations of costs or request to increase rates. So those are all still a ball of yarn and still being worked through.

And then finally, you granted a small amount for us, principally me, to engage in MISO-related activities. I was a little bit late today because I was

on a conference call with the public consumer representative sector about an upcoming discussion that will be held by the principal MISO committees, planning advisory committee and market subcommittee, on demand response. In each of those meetings they identify a hot topic and ask all the sectors to contribute, and that is the hot topic for December. A lot of moving parts in that, there's one that I want to mention to you just to flag for your future consideration.

MISO allows load management resources that were mentioned earlier to participate in the various markets. Amongst those are programs that we typically have here in Michigan, interruptible power supply programs, where other ratepayers essentially incur the cost of discounted rates for the customers who are able to participate in those. It's appearing that there are pretty week sort of measurement and verification programs or elements of these programs to ensure that, if called upon, we will indeed get the response that's been promised, and that's a matter that we probably should be paying attention to within the state rate cases, general rate cases.

MR. MacINNES: And that's been a concern of the utilities, right, that people won't really deliver the goods?

MR. JESTER: Yeah. Yes.

MR. MacINNES: Okay. Any questions of Douglas? Thank you.

How about if we go to Chris for the Michigan Environmental Council.

MR. BZDOK: Certainly, Mr. Chairman, members of the board. Christopher Bzdok on behalf of MEC. I have a lot I could talk about, but I know you have a long -- you've had a long meeting already.

So we had the Consumers 2014 PSCR plan hearing recently; I'll give you the rundown on that. I could give you a preliminary read on the 2015 PSCR plan cases for Consumers and DTE, I have new data on renewable energy. We are tentatively -- well, we are proposing, CARE and MEC, to give the board if you would have time on your February agenda a detailed update on the cost-of-service cases, including a presentation --

MR. MacINNES: That would be great.

MR. BZDOK: -- with questions and answers. I think that because those are a different, those are a different category of cases than we've had before, it's just going to be longer than a grantee report, so we propose to do it as board education if the board was amenable to that. So really it's a matter of what else, what else do you want to talk about?

MR. MacINNES: What do you think is the most important for us to hear?

MR. BZDOK: Let me tell you a little bit about the PSCR plan cases, the new ones, what we're seeing there.

One of the things -- and a lot of these are evolutionary or organic in terms of, you know, issues that we've been talking about and how are we seeing them develop. One of the things that we've talked about is the use by both utilities of sorbents, we've talked about DSI and ACI for mercury, to deal with mercury and to deal with acidic gases, things like sulfur dioxide, and that on a number of the older plants, including Campbell 1 and 2 for Consumers, and including a number of the DTE units, River Rouge, Trenton Channel, St. Clair, they are, rather than putting in very high capital cost scrubbers, they are proposing to use DSI to try to achieve compliance with some of these new emission limits, some of the things that Laura and Carmen had up here, and that that was -- that would add a higher PSCR cost on the one hand, and also, we believe they are presenting to the Commission very optimistic scenarios about the costs of those sorbents, the amounts that will need to be used, the amounts of pollution that will be reduced by using them, and the other complications that may ensue with

operation of the plants, et cetera, from those sorbents.

Yeah.

MS. HAROUTUNIAN: What kind of complications?

MR. BZDOK: There are some issues between the use of REF fuel and the use of DSI, for example, that's one complication. Another complication has to do with part of the DS -- part of the strategy of using DSI to reduce sulfur dioxide and acid gases requires the utilities to burn ever more western coal and ever less eastern coal, because the eastern coal, which has the higher heat content, has more sulfur. So they burn the more and more western coal, right, and they've -- Consumers, for example, has converted Campbell 1 and Campbell 2 so that it can -- Campbell 2 I know so it may burn 100-percent western, and when you burn all western, you have a lower total capacity --

MR. MacINNES: Heat rate, too.

MR. BZDOK: Yep, lower heat rate, lower total capacity, some higher costs, and this DSI plan depends upon doing that. Now, Consumers in cross-exam in the plan case last month, their fuel witness disclosed that they are having a very hard time getting western coal this year, and this was actually in a cross-exam of a testimony that, where he was saying we need to use, you

know, these spot replacement prices for dispatching because we need to keep bidding the coal plans in because we need to keep burning the coal because there's just always more and more coal coming in and you can't breach your contracts. Well, we got an hour and a half into that and all of a sudden the October surprise was, well, we're actually million short this year, which one issue is then you really don't have a big problem getting rid of coal, you have a problem getting coal. Obviously it's an unusual year. But the plan case for 2015 says they are having difficulties getting western coal, so they are going to probably have to rely more on eastern coal. Well, the DSI plan requires western, and now you can't get western because of weather and because of the back-in crude oil and all of the other things that are going on, so now you got to go back to eastern and you really run into sort of a thorny situation here. So I mean those are a couple of examples.

MR. MacINNES: So we should clarify that with the western coal, it's lower efficiency, higher heat rate?

MR. BZDOK: Yes, lower efficiency --

MR. MacINNES: Lower efficiency, higher heat rate.

MR. BZDOK: -- higher heat rate, which

is -- yes, you're absolutely right, which is, higher heat rate is less efficient and, therefore, more expensive.

So that's a major issue in the Consumers 2015 plan is how do the plans you've been advocating for DSI and this lower capital cost way of trying to sustain, you know, extend the lives of some of these units is now running into the fact that you're now planning on solving your transportation problems for western coal by buying more eastern. And these are preliminary observations. I don't have any answers for you, we haven't sent out any discovery, the prehearing is on Wednesday, but those are major issues for the eastern.

DTE, this continued relationship between DSI and REF and the complications there, how are they dealing with this one-hour -- you know, one of the slides here was the NOx for one-hour sulfur dioxide limits, a portion of Wayne County has been declared nonattainment for sulfur dioxide, that portion includes River Rouge and Trenton Channel. And then there are questions of can you use enough DSI to meet your obligations to reduce your sulfur far enough that are being driven by this nonattainment area. They confirmed in 2015 the retirement of Trenton Channel 8 and the retirement of Trenton Channel 7 in 2016, which is something we talked about in the fall. We also talked about how Trenton

Channel 9 had some relationship to those units because of the ring where they use excess steam and excess power, there's going to be a 50-megawatt derate of Trenton Channel 9 as a result of the retirement of these other two units, which is good; there's going to be a 45-megawatt derate of River Rouge because of needing to use lower sulfur coal to comply with the one-hour NOx. On the bright side, there's 98 megawatts of more wind coming in 2016, 4 megawatts of more solar, expanded capacity of the Ludington pump storage, so there's some other resources coming in to offset some of these other problems.

The other big news in, two pieces of big news on the DTE side is an announcement in the plan that they are working with a company called Spectra Energy to develop a new gas transmission pipeline to bring Marcellas shale gas from eastern Ohio up to Michigan, and that may be related to potentially a plan to build a combined-cycle plant by DTE for natural gas, it may be related in part to DTE's recent announcement that they've purchased the 700-plus megawatt simple-cycle Renaissance plant, which is one of the plants that was for sale in the Consumers IRP proceeding, so that's an independent power producer simple-cycle plant. So that -- and then that's going to be a firm transport agreement to bring

this gas in from eastern Ohio. So how is that going to deal with PSCR coal use; to what extent are they going to burn gas because they simply have to burn as under these firm commitments; how does that all relate to everything else that's going on? Those are going be issues that are explored in this case potentially. And how does this Renaissance plant fit into the PSCR, because it's supposed to be completed first quarter of 2015. So you've got 700 megawatts of new simple-cycle that's under company ownership, how does that relate to what you're doing on the PSCR side, and also how does it relate when we get to February on the cost-of-service side, because in the press that they've sent out about the simple-cycle plant, one of the things DTE is sort of triumphing is simple-cycle plants are a really cheap way to add capacity for our peaks. Well, if you can add capacity to meet your peaks on the cheap, but you're going to sock the residentials for your capacity cost of generation entirely based on peak, which includes all of your expensive base load, you know, these are issues that, these are going to be major issues in the cost-of-service cases, and we'll present all that, we don't have any of that yet, you know, but these are things that are going to come up.

MR. MacINNES: How about the must-run

status of the coal plants, the automatic must-run --

MR. BZDOK: Sure, I can --

MR. MacINNES: -- and the PROMOD and all that stuff that you're doing?

MR. BZDOK: Yep, yep. Can I use the board?

MR. MacINNES: Sure.

MR. BZDOK: You'll indulge me for another minute. So as you know, the board funded last year and this year us to work on the PROMOD piece, and we've talked -- and I've sent you detailed information about DTE already last year, and so we did it with Consumers this year. And we did modeling that said if you remove what our consultant called unprofitable must-runs, so he said, he agreed tentatively that just cycling all the coal units all the time is not economical, but he said, you can look and you can look at units that are modeled as being uneconomic for month-long periods in the plan year and in the five-year forecast, and if you designate those units in those months as economic, you can save money, and which makes sense. If I can look at -- if I'm selling anything and I can look out five years and I know what I'm going to get in revenue and what my costs are going to be and I decide I'm not going to sell or I'm only going to sell if prices rise that month or my costs

lower than month, overall I'm going to be better off revenue wise, so it's not counterintuitive, and he was able to put some numbers on that, and it was -- I don't have the numbers off the top of my head, but I think it was like a million 8 in the plan year and 8 or 9 million over the five-year forecast. And I may have my cases confused, but these are the kind of, you know, scales that we're talking about. Just by saying on months when we are projecting, based on our own modeling, we didn't do any variables, just on our own modeling we're projecting these are going to be uneconomic, you can save some significant money; and the Company came back and said, well, we reran your model and you had this flaw and this flaw and this flaw, and some of those are germane and some of them are not, and we ran the model with these corrected, and it's actually, your PSCR costs, your total PSCR costs are actually lower if you must-run the units all of the months, all of the months in the out years of the forecast, so the out years in the five-year forecast, not the plan year. So by selling at a loss every month -- by must-running even the months when you're selling at a loss, you're actually going to save money for customers, which makes no sense. I mean intuitively it makes no sense.

And what we think is happening, and we've

briefed all of this, so this is not any secret, what we think that what's happening is when they model the system costs, what the Company does is they, they project a revenue, and the revenue -- well, it's not just a revenue, they -- they do not project a revenue, excuse me, they project an LM, they project a locational marginal price, and that locational marginal price, you know, kind of goes up and down, you know, peak and off peak, et cetera, et cetera, and then based on the LMP and the expected dispatch costs for the plant, which include this fictional replacement spot cost, which is not what they're really paying on the coal plants, they have a -- they can say, well, these are the resource that are dispatching at any particular given interval and time and it's the resource that are clearing the LMP.

So I mean one resource is dispatching here and one is dispatching here and one is dispatching here, and that's how all the Company -- and that generates a projection of energy by the Company, that's being generated by company-owned assets. And they are also projecting a demand over all the same time intervals for a load for the Company's customers. So they are projecting a load and they're projecting an energy generation, and then they are projecting a cost, a total cost to provide that energy so the cost of providing the

energy from the units they're dispatching for the amount of that time that they're dispatching. And then what they produce is -- and then there's a difference, there's a delta always between, I mean almost always between the load at any particular given interval that they're serving and the generation that they're generating, right, so they're either generating more than their load or they're generating less than their load, and if they're generating more than their load, then they record a purchase. Sorry. If I they're generating less than their load, they record the difference as a set of purchases at the market price in that interval; and if they're recording less -- if they're generating less than -- if they're generating more than their load, they record sales for the amount of generation over their load at the price.

MR. MacINNES: And that's to MISO --

MR. BZDOK: Yes. System sale, just market sales, right.

MR. MacINNES: Market sales.

MR. BZDOK: And then they go -- and so they get all this information and they figure out, well, how much energy do we generate, what was our load, what were the costs of generating that energy, and they sum that all up, right; and there's fuel, and there's -- I

mean there's just all these costs, right, and all of these costs to meet the generation. And then one of the costs is the net sales, you know, purchases and sales, how do they net out, and there's some cost to that, and that cost is in the, for a plan year, it's like $15 million, right.

MR. MacINNES: Is that a cost or a benefit?

MR. BZDOK: It's a cost. Well, it's a net cost of sales. Basically they're buying -- they're buying year-in and year-out more than they're selling, right. So and then they add up all these costs. So yeah, net sales cost. I don't have the sheet in front of me, I'd be using more accurate terms if I did. And they all -- and that's a total PSCR cost.

What's really important here is, and we think, is that's not how they operate their system, that's not how they operate in the market. In the market, they sell all their energy in and they buy all their energy out. Right. They sell the energy from their plants in and they buy energy, including the energy from their own plants, back out, which is why we think that the unit-by-unit profitability, or net energy value they call it, is important. But they don't think it's important because they don't model their system costs

based on the profitability of the units, how much at a given interval are they spending to generate power versus how much are they getting back. So because they only buy when they don't have enough generation to meet their load, and they consider this separately, if you must-run units, you're always going to generate more, and so you're always going to buy less, which is going to say your net purchases and sales is going to be lower if it's this separate little line item that covers what's left over at the end.

And I don't know, I don't know how the profitability of individual units washes out in the sum of all the sales, but this is a key difference -- by treating their system sales as what's left over after they've met their load, and modeling that as a separate expense, that's what we think is driving this result that if you must-run units even when they're unprofitable, you still have lower total PSCR costs because you have lower net system sales costs; but if you're actually modeling where you're selling it all in and you're buying it all out, those are going to be negative months, those are going to hurt your system costs, we think.

And so this is kind of, this lack of -- so the cost of doing the must-run versus not and then this apparent difference between the way they're modeling

it and the way they do it is these are the central issues on the must-run in the Consumers case as of right now, and that's sort of current through the cross-examination of the modeling witness a few weeks ago.

MR. MacINNES: So when do you think you'll get a resolution of this or flesh it out?

MR. BZDOK: Well, we've submitted initial briefs and then we'll have reply briefs, and we'll see what the ALJ does with that.

MR. MacINNES: Complicated.

MR. BZDOK: Yep, yep. So that's the latest on the modeling. It's been very, very interesting, and we think productive.

MR. MacINNES: Okay. Sometime you and I should talk about that a little longer --

MR. BZDOK: Okay.

MR. MacINNES: -- because it's kind of confusing, I got to say, at least to me.

MR. BZDOK: Happy -- that's why my first question was how long do you want to spend.

MR. MacINNES: Yeah. That's a complicated one. I'd like to think that through some more. But I'm glad you're on it.

MR. BZDOK: Happy to -- any time the board wants to go into deeper depth on that stuff, we're

happy to do that.

MR. MacINNES: Okay. Well, we're kind of running short of time here, and I mean we like to try to get out of here by 4:00 if we can, or a little after. So maybe next time we could talk about cost of sales and --

MR. BZDOK: Yeah, yeah.

MR. MacINNES: It was nice to get that MISO update, but it was a -- it ran quite a bit, but it was very informative, and we only does that once a year.

So Don.

MR. KESKEY: Yes. I'll be very, very quick. And thank you for the opportunity.

On behalf of GLREA and under the board's 2014 grant, we've been involved in Consumers Energy's 2014 PSCR plan case, which is U-17317; and in that case Consumers fought our intervention very hard, however, the ALJ granted the intervention and Consumers appealed to the Commission and the Commission issued its order in March of 2014 determining that GLREA had a right to intervene by right, not just permissive, but by right. The case went on to hearings; in fact, the hearings were held during the period of October 21 to 23, and briefs have been filed. The initial briefs were filed last, I think it was November 21, and there will be reply briefs, and then the administrative law judge will determine the

issues.

But in that case we presented testimony, which Consumers also filed a motion to strike all of our testimony and exhibits, but that was also denied by the administrative law judge and is subject to the full briefing. But in that case, as I've indicated before, our testimony went to the fact that the five-year plan forecast by Consumers was flawed and deficient and incorrect because they are projecting either flat or declining contribution of solar energy to their mix of power sources, and we believe for many reasons cited in our testimony that that's wrong, and that solar energy has some -- becoming extremely more economic in terms of the difference between cost and benefit, and that the forecast is an error as a result and that it should be required to be modified in future cases.

In the companion case of DTE Electric PSCR plan for 2014, which was U-17319, again, Edison challenged our intervention before the ALJ and the ALJ granted the intervention and Edison did not appeal that determination. We filed testimony in the Edison case tailored to their five-year forecast, which suffered the same maladies and the same problems as Consumers Energy in forecasting a flat or declining contribution to solar energy, and presented similar reasoning and remedies to

address that. In that case, the hearings have been held, the briefs have been filed, and we're waiting for a PFD from the ALJ.

In the new cases under the new grant, 2015, Consumers Energy, U-17678, we have filed our intervention, the prehearing I believe is Thursday, December 4, and I don't know whether we're going to have another fight on intervention or not, but I think with the precedent issued by the Commission itself, that it would be, I guess if I were Consumers Energy, I would not challenge the intervention. That schedule will be set at that prehearing.

In the other case, DTE --

MR. MacINNES: Excuse me, Don. How did they argue against your intervention, what was the thinking?

MR. KESKEY: Well, there was a number of things. Number one is they're trying to say that we're advocating to dictate to Consumers Energy to increase the amount of solar energy in the system, and we're saying, no, we -- what we're pointing out is that your plan and forecast are deficient and flawed because it doesn't match reality for a number of reasons. And also, they had indicated, well, you're really a trade group. Well, actually the organization consists of a lot of individual

ratepayers of Consumers Energy and meets all the tests under the Commission's two-prong test for having standing to intervene. Then they say, well, you know, you're just going to go on a fishing expedition; we said, no, that it's going to be focused on these issues, and that's what we followed through on. We had substantial discovery, but it was tailored specifically to the issues that we are proposing.

MR. MacINNES: So to follow this through, I mean where is this going to go? You know, you've been granted intervention, you've said, hey, you know, your model doesn't face up to reality in the world here today: Where is it going to go from there?

MR. KESKEY: Well, if the Commission has an opportunity to agree with us and to find that the forecast of these two big utilities is flawed and that in reality behind that flaw is perhaps utility intransigence against looking into solar -- like at the last meeting, I indicated I&M Power is going into a large solar program, 17 megawatts in the next two years, and they're going up to a few hundred, I believe, and so, and they -- their witnesses point out all the benefits and all the reasons why they think this is the right thing to do. Well, if that's the case, then why not Consumers Energy and DTE.

So as the Commission and the Governor and

others become more aware and interested in renewable energy, the Commission would have the opportunity to tell these utilities to have a more robust presentation of their policies on solar and what they're going to do about solar and what their plans are, and point out that it should be fixed in the next case, the next cases that will go along.

And the benefits of this economically is that there's no question that solar has come down in cost tremendously, that the public is increasing an interest in it, that if you can have community solar where people contributed to an entity to do this, that there's a tremendous opportunity for solar to blunt the peak in the summer months when the residential and other air conditioning loads are at peak.

MR. MacINNES: Well, look what's happening in California, right, they're doing it.

MR. KESKEY: And the initial presumption, that oh, well, Michigan's climate is different, this is not -- you know, that perception can be easily rebutted, because during those four or five months in the summer particularly you have real opportunities for solar. And so I think solar is an opportunity to empower customers to do more about their energy needs and costs, it is a, sort of a movement away from a monopoly-captured model in

the sense that if companies or residential customers can plan solar into their operations, that they are independently then either paying less to the utility for energy or they are contributing to the grid.

MR. MacINNES: Do you think this could lead to Michigan really going through and identifying the value of solar with these many different components that make up the value of solar, having that be at least discussed or considered?

MR. KESKEY: I think so. And to some degree, it's happened. But Minnesota is really one of the leaders on this value of solar in terms of interest by the legislature and the commission and in their cases and in their policies to address the value of solar and start planning.

MR. MacINNES: I think they put a value of something like 14.2 cents --

MR. KESKEY: That's correct.

MR. MacINNES: -- on it.

MR. KESKEY: And they had the components of that.

MR. MacINNES: They break down all the components and add the benefits of each component.

MR. KESKEY: So in the new DTE case, U-17680, our intervention was granted at the November 25

hearing, and Edison this time did not oppose the intervention. So we again will take a look at these new cases and again build on the prior cases in terms of trying to move the interest and remedies on solar energy forward.

MR. MacINNES: Okay. Well, you've been quite an advocate for that, and there was a question mark when it started, but looks like you were able to be, to intervene basically, so.

Okay. David.

MR. SHALTZ: We are currently in discovery in the four GCR reconciliation cases, we're developing testimony to be filed at the beginning of the year. And what I'd propose is doing a brief review of what that testimony is at your next meeting when I have more conclusive stuff from my expert about what we're going to be saying.

MR. MacINNES: Okay. Anything else?

MR. SHALTZ: No.

MR. MacINNES: Okay. The next item is public comment. Do we have any public comment?

We have scheduled the next meeting, Monday, February 2 at 12:30.

Do we have a motion to adjourn?

MS. HAROUTUNIAN: So moved.

MR. MacINNES: Okay. We're adjourned.

(At 4:10 p.m., the meeting adjourned.)

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STATE OF MICHIGAN)
)
COUNTY OF MACOMB)

I, Lori Anne Penn, certify that this transcript consisting of 139 pages is a complete, true, and correct record of the proceedings held on Monday, December 1, 2014.

I further certify that I am not responsible for any copies of this transcript not made under my direction or control and bearing my original signature.

I also certify that I am not a relative or employee of or an attorney for a party; or a relative or employee of an attorney for a party; or financially interested in the action.

Lori Anne Penn

December 16, 2014
Date

Lori Anne Penn, CSR-1315
Notary Public, Macomb County, Michigan
My Commission Expires June 15, 2019