BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	**UNDOCKETED**
Commission review of Electric Utility Ten-Year Site Plans.	

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PROCEEDINGS: **WORKSHOP**

BEFORE: CHAIRMAN JOE GARCIA
COMMISSIONER J. TERRY DEASON
COMMISSIONER SUSAN F. CLARK
COMMISSIONER E. LEON JACOBS, JR.

DATE: **Monday, September 27, 1999**

TIME: Commenced at 9:30 a.m.
Concluded at 3:50 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

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IN ATTENDANCE:

ROBERT ELIAS, FPSC Division of Legal Services.

MICHAEL HAFF, ROLAND FLOYD, TOM BALLINGER, ROBERT TRAPP and CONNIE KUMMER, FPSC Division of Electric & Gas.

ROBERT SCHEFFEL WRIGHT, Duke Energy NSB Power Company.

MATT BLANKNER, Orlando Utilities Commission.

LEO GREEN, **ROBERTO DENIS, HENRY SOUTHWICK** and **STEVE SIM, Florida Power & Light Company.**

DAVID BYRNE and **EDWIN FRAZIER**, City of Tallahassee, Florida.

GARL ZIMMERMAN, Seminole Electric Company.

MARIO VILLAR, and **KEN WILEY,** Florida Reliability Coordinating Council.

BILL POPE, **MIKE MARLER**, Gulf Power Company.

BEN CRISP, Florida Power Corporation.

TODD KAMHOOT, Gainesville Regional Utilities.

PAUL ELWING, City of Lakeland.

MARK WARD, Tampa Electric Company.

ROBERT MILLER and **MYRON ROLLINS**, Kissimmee Utility Association.

IN ATTENDANCE CONTINUED:

RICK CASEY, Florida Municipal Power Association.

JON MOYLE, JR., PG&E.

RANDY BOSWELL, Jacksonville Electric Authority.

P R O C E E D I N G S

(Workshop convened at 9:30 a.m.)

CHAIRMAN GARCIA: Good morning. I'd like to welcome you to today's Commission's workshop on Ten Year Site plans. We're going to hear brief presentations from different groups that have filed with us and we're going to start with the Florida Reliability Coordinating Council which is probably going to make the longer of the presentations.

I would ask you that because I think Staff has some -- a lot of questions, that try to make your presentations as brief as possible, so that they can -- it will be more efficient for the questioning time. Clearly, there's -- I hope there aren't any surprises today, but if there is anything that you want to bring up, please let us know, and then, obviously, Commissioners will probably ask some questions early on, and our hope is to be out of here by 4:00, and if we can do better, that would be even better.

So, if the Commissioners have nothing to add, we're probably going to sit down here and you can -- the Florida Reliability Coordinating Council can begin.

MR. SOUTHWICK: Good morning. I'm Henry

Southwick with the Florida Reliability Coordinating Council. I'm the chairman of the Reliability Assessment Group. And with me on my left is Mario Villar, who is the chairman of our Resource Working Group who has done the studies there are going to be presented here today. And to Mario's left is Ken Wiley who is the executive director of the FRCC. So with no further to do, I'd like to turn it over to Mario.

MR. HAFF: Excuse me, Mario. I think from the notice and agenda that went out, we had public comments going first. I don't know if anyone is here though. I haven't seen LEAF yet or anyone else. And if not, we'll just go ahead and go on. But I just wanted to note that the notice had that first. Seeing none, I guess, go ahead, Mario.

MR. VILLAR: Good morning. My name is Mario Villar. I'm chairman of the Resource Working Group for FRCC and I will be making the presentation this morning. Before we get in the specifics of the work that was done by FRCC, there is some housekeeping matters that I'd like to cover. They're basically left over matters from the 1988 review. And I'd like to give you a little bit of background as to what the FRCC did last year and how it leads to the work that

was done this year.

Is there anyway that this can be made a little bigger? Is there any way to adjust that some? Well, it's a little washed out, but we'll do the best we can.

In '98 the FRCC adopted a 15% reserve margin for the peninsula. It conducted a reliability assessment study and it developed a methodology where we compared the projected components of the reserve margin calculation against actual data for the last five years to analyze the suitability of the 15% reserve margin. In other words, to conduct a test of the 15% reserve margin.

We presented the results of that analysis at the 1998 Ten Year Site Plan Workshop and then the Commission, in it's report to the Department of Environmental Protection and DCA in December, included in that report some Staff concerns. These concerns were basically along four lines.

High unit availability. Staff was concerned that recently there have been a change in unit availability on the positive side and there were concerns as to whether that was sustainable or not.

We at FRCC believe that utilities have invested significant dollars to achieve that high unit

availability. We believe those units availabilities are sustainable. We've shown the improvement in availability and we believe that that will remain.

In addition to that the Commission has started some Staff audits of this particular issue and I believe those audits are still ongoing.

With respect to continued assistance from Southern Company, I think Staff expressed some concern as to whether that assistance will continue to be available in the future. We don't see any reason to doubt any assistance from the north. There is not only Southern Company, there is a whole SERC region and actually the whole eastern interconnection that we could draw upon.

This is not a reserve margin issue. It's basically considered in the lose of low probability analysis. And one of the sensitivity analysis that we have used in that LOLP analysis is no further assistance from the SERC region or the eastern interconnection. So we don't think this is an issue in the future.

There were two specific issues that Staff had also in the report. That was extremely low winter temperatures in Christmas 1989 and also the Staff had conducted some probabilistic analyses on the FRCC data

and it reached some conclusions in that respect. I'd like to cover those two issues now.

These are some quotes from the Staff documentation that was presented at the August 25th workshop. Paragraph 6 basically deals with a probabilistic assessment results and there Staff concluded that summer reserves were adequate based on their analysis and that they had some concern with the generating capacity during two specific seasons; the winter of 1999/2000 and 2000/2001.

The emphasis there is by us, and basically that Staff conclusion at the time was the random number assessment suggests planned summer reserves are adequate.

Paragraph No. 12 deals with the extreme winter temperatures, and in particular, the Christmas 1989 backcast which was basically a calculation performed by Staff based on Christmas '89 conditions from which they attempted to quantify what could happen under extreme winter conditions.

And I'd like to draw your attention to some language in there that says blackouts will range from about half as bad to twice as bad as what occurred in 1989.

We believe the Staff's analysis in that

regard is incorrect and I'd like to turn to that now.

Kind of hard to read here. Basically this is a duplicate of one of the Staff slides from the August 25th workshop. I believe it was Page 6. These are Staff numbers, and while we disagree with the Staff analysis, I won't discuss all the deficiencies at this time. I'd like to point out a few of those particular areas where we do have a disagreement with Staff and take you through what they did.

If you look at Row C, that is one of the assumptions that Staff is using and that is that 23% of capacity will be unavailable. That is basically a calculation drawn from the data from 1989 as to the utility capacity that was available and the amount of capacity Staff calculated as being unavailable in Row B. From those two numbers you derive a 23% capacity unavailable number.

I'd like to also call your attention to Row I, which is the percentage of peak load error that Staff calculated. Again, that number is drawn from the row right above it which is the actual peak, which is not really an actual peak but is an estimated number based on an aggregation of the load that was actually served by utilities, plus the estimated unserved load. So even though it's shown as an actual

number, it's not necessarily an actual number.

From that the Staff calculates against the forecasted firm peak a peak error of 16.9%. Again, this number is based on an aggregated amount on a noncoincident basis. So it's not necessarily reflective of reality.

The load not served in Row J is also calculated on a similar basis of aggregation of utilities of estimates of nonfirm load, again, on a noncoincident basis.

The basic assumption that Staff used is that nothing has changed since 1989. They then go to the next column, which is their forecast of what would happen under Christmas '89 conditions, and apply the same 23% number that they calculated for Christmas '89 to the 1998/1999 number shown in their last year's resource plan to arrive at an unavailable utility capacity of 8,749 because this actually escalated since it's based on the number right on top.

So they're not only assuming that nothing has changed since 1989, but they're also assuming that the numbers that were out are going to be even -- there will be even more megawatts out.

With respect to the amount of actual peak that will be experienced, again, they are assuming

that 16.9% of the forecasted firm peak from 1999 would also be unserved yielding the actual percentage peak here in Row H.

Those assumptions are incorrect. This Commission conducted an assessment of the 1989 Christmas freeze and issued an order, Order No. 22708, in which they directed that a statewide emergency plan be adopted for the state of Florida. That plan has been adopted and has been incorporated into Commission rule. I think it's rule 256.0813, I believe. That plan tells you what to do in the event of an emergency. It contemplates the number of levels of alert. It provides for public notification, conservation appeals, et cetera.

Also Staff is assuming that the same amount of megawatts that were out on scheduled maintenance are going to be out on scheduled maintenance in 1999. Not only the same amount, but even a greater amount because, again, this number has escalated since it's based on a higher base. Utilities have changed their maintenance practices significantly and no longer schedule maintenance around the peak periods.

In addition to that, there were a number of megawatts that were out on forced outage in 1989. Those megawatts were out for different reasons. Some

of them were, there was a curtailment of gas supply into the state of Florida. All of that has been addressed since then.

There were some units that were gas only units. The firms -- the supplies for those units has been firmed up so it's not reasonable to assume that those megawatts will not be available.

In addition to that, there were some units that were dual fired capable units when they were switched from gas to oil, and those units were run on oil. There were some problems associated with some filter problems. Those problems have been corrected so there's no reason why those units should be assumed to be unavailable in 1999.

There were some problems associated with freezing water/control lines. The Commission ordered the utilities to review the winterization plans. We reviewed the winterization plans and fixed those concerns. So there's no reason to assume that those megawatts will be unavailable.

As far as actual numbers, the gas only units represent an approximately 225 megawatts. The fuel filter problem with dual capability units were about 2,000 megawatts, and the winterization plan issues effected about 3,100 megawatts of capacity. So this

number of 8,749 is highly inflated in our opinion.

One major flaw with the analysis is also that Staff fails to take into account what utilities call operational measures. That is, conservation appeals, voltage reduction, availability of nonfirm purchases from the SERC region, load SCRAM capability in the DSM units, et cetera.

That is significant amount of additional megawatts can be used in the event of an emergency. Those are not accounted for in the Staff's conclusion that there will 8,226 megawatts of unserved load.

What I'd like to do now is turn to another chart which is a corrected version of the one we had before. And, again, these represent the Staff numbers with some changes that we made to it. The bold numbers are additions to the Staff chart.

If you look on Row B, what I've done there is I split the 7,900 megawatts that Staff said was unavailable in 1989 into two categories; forced outages of 4,334, and the actual number that Staff showed in their August workshop was 4,333, but my staff wouldn't put a number in there that didn't add up to the full 7,900 megawatts so they rounded it up by one megawatt.

The next number below is the amount of

scheduled maintenance outages in effect during Christmas of '89.

And the equivalent amount of megawatts for 1999 is shown on the column on the right-hand side. It's 3,992 megawatts when you escalate it up from the Christmas '89 numbers. I have subtracted that number for illustrative purposes only from the unavailable capacity because we're not planning on having all that capacity out during winter peak type conditions.

I have made no other adjustments for any of the other changes that I have discussed that have taken place or corrected measures like the dual gas capability issue, the winterization plans, et cetera.

That leaves a forced outage amount of 4,757 megawatts or 12.5% utility capacity unavailable. Again, this is only for illustrative purposes. I'm not necessarily agreeing with any of the numbers in here shown by Staff, et cetera. And I am not showing all the corrections that could be made to this analysis.

That 3,992 megawatts needs to be brought down in Row F to show the total utility capacity available from which you can calculate the potential deficiency.

I have also made, like I said before, one of

the things that Staff doesn't consider is any changes that have taken place since 1989. One significant change that took place since 1989 is the utilities have changed the forecasted methodology and -- or at least one utility has. I didn't have figures for all the utilities so I used an FPL adjustment only.

FPL, in 1997, made a change to its forecast which results in a reduction relative to what was calculated here by Staff, or about 800 megawatts from the Staff amount.

In other words, what FPL did in 1997 was to change the low winter temperature calculations, resulting in an increase in the FPL forecast of about 800 megawatts in this particular year. So in order to make this 3,566 number shown in Row G for 1999, to put it on an equivalent basis to the way the forecast was done in 1989, we needed to have an 800 megawatt reduction in that forecast. Otherwise, you're not comparing apples to apples. From that you come up with an adjusted forecast to put it on the same basis of 3,486 -- 66 megawatts.

COMMISSIONER CLARK: Excuse me. Let me ask, what change allows you to adjust the peak downward? I don't understand. If you changed your methodology, what's the justification for that?

MR. VILLAR: I'm not adjusting the peak downward. What I am doing, Commissioner Clark, is basically that, what Staff has done is they have assumed that everything that took place in 1989 is the same, and applied those conditions to the peak and all the other categories that they use in this analysis for 1999.

Now, they use 16.9 forecast peak error and they applied that same 16.9 forecast peak error to the 1999 data. But because we don't have the forecast being calculated on the same basis, in order to apply a 16.9 forecast peak error, you'd need to adjust the forecast by the increased forecast that FPL had in order to put it on the same basis.

In other words, in order to be comparing apples to apples and in order to be able to use the 16.9 adjustment, you need to make this 800 megawatt adjustment. In other words, you're not going to have a 16.9 forecast error because we have changed the forecasting methodology. So it's unrealistic to assume that you're going to have a 16.9% error.

COMMISSIONER CLARK: What was the change in methodology that allows you to do that?

MR. VILLAR: We lower the winter temperature from -- Leo here? From 37 or to -- what was it?

34 degrees, Leo?

MR. GREEN: 37 to 34.5.

MR. VILLAR: 37 to 34.5.

COMMISSIONER CLARK: Okay. So after 1998 you're forecast was based on a lower temperature?

MR. VILLAR: That is correct.

COMMISSIONER CLARK: All right.

MR. BALLINGER: Can I jump in real quick? This is Tom Ballinger with the Staff. Mario, is what you're saying is because of the change in temperatures, you'll never have an error rate as great as 16.9% in the future?

MR. VILLAR: It's unlikely to have one, or at least under the conditions that you're assuming here, Tom. That's all we're saying.

MR. BALLINGER: But that's what you're trying to illustrate?

MR. VILLAR: That's correct. Yes.

COMMISSIONER JACOBS: Is the effect of lowering temperature, does it broaden the peak -- the observed peaks that you're looking at so that that reduces the number of errors that you observed in that same time?

MR. VILLAR: It doesn't broaden the peak. The peak stays the same.

COMMISSIONER JACOBS: No. I understand that the peak stays the same. But you're observing temperatures over a period of time and because your temperature now is lower, what you're saying is you're going to pick up more observations here?

MR. VILLAR: I don't know if it's in terms of observation. Maybe it would be better if Leo addressed the question.

COMMISSIONER JACOBS: Just tell me how the lowering of the temperature effects the reduced error rate.

MR. GREEN: By assuming the lower temperature, the fact is that their projected value goes up. Okay. By having that value goes up, there is -- it's very unlikely that we're going to miss by that same amount.

COMMISSIONER JACOBS: Okay. Thank you.

MR. VILLAR: With that adjustment to the forecast firm peak and applying the same 16.9% of forecast error to this adjusted forecast shown in Row G, we come up with an actual peak, an adjusted actual peak, of 40,758 as opposed to the number that Staff had, which was the 41,694.

When you substract from that the adjusted available capacity on Row F, looking at Row J right

now, you come up with a potential unserved load of 3,298 megawatts. And then when I'm making a final adjustment which is based on the amount of operational measures the utility estimates is available is the year 1999 of 3,844 megawatts, and it results in no unserved load, in fact, there's some megawatts left over to serve additional load based on these estimations only.

And, again, this is just for illustrative purposes. There could be a significant number of corrections made. We haven't attempted to make all of those at this point.

Conclusions are that we don't believe it's realistic to assume that during instances of extreme weather there will be a repeat of the conditions that existed 1989, and that the lessons learned from the Commission and utility actions does then need to be recognized and those have significantly mitigated and alleviated the potential for unserved load under extreme weather conditions. And with a set of more realistic conditions, we don't think that there will be unserved load.

MR. BALLINGER: Mario, did I understand that you just stated that given similar circumstances the Peninsula would serve all load?

MR. VILLAR: I'm sorry, Tom?

MR. BALLINGER: Did you just say that under similar situations you expect the Peninsula to serve all firm load?

MR. VILLAR: We think under similar circumstances temperaturewise, and even not accounting for some of the things that are here, we don't expect that there will be unserved load.

MR. BALLINGER: Okay.

MR. VILLAR: Under more realistic assumptions for forced outages, scheduled maintenance and taking into account operational measures.

I'd like to discuss a little bit the second remaining issue from 1998 which is the Staff's probabilistic assessment.

MR. BALLINGER: Before we move on, I got a couple of questions on the Christmas as facts have been brought up. Do you know how much in '89 of natural gas fired generation did not have oil backup?

MR. VILLAR: There were 225 megawatts from what I recall, Tom. It was Cutler 5 and 6, and a couple of Deerhaven GTEs from Gainesville. And at the time Cutler 5 and 6 did not have firm gas supplies. We do have firm gas supplies now. That was the reason why Cutler 5 and 6 was interrupted, and I don't know

whether Deerhaven has firm gas or not.

MR. BALLINGER: Do you know how much in the future -- we're adding a lot of natural gas generation. How much of that is planned not to have oil backup, roughly?

MR. VILLAR: I am not aware of the number of megawatts, Tom, but to the extent that it has a firm gas supply, that should take care of the issue. Because the reason why the interruption occurred is because those contracts, even though the plants were gas only units, they did not have a firm gas supply at the time. And if do you have a firm gas supply, it's not subject to interruption. In 1989 those gas supplies were subject to interruption.

MR. BALLINGER: So it wasn't that the wells were freezing up in Louisiana; it was the fact of a contractual matter is why they were interrupted?

MR. VILLAR: The gas was diverted to other uses because it was not firm.

MR. BALLINGER: Okay.

MR. VILLAR: If you don't have it firmed up, it has the lowest priority on the system and it gets interrupted.

MR. BALLINGER: Thank you.

MR. VILLAR: The Staff's probabilistic

assessment is the next issue. And there, this is just another reminder of what Staff had found before. I'm not going to dwell on it. But basically Staff found that there was a very short exposure, I would call it. This is another replicate of a Staff graph from the workshop, and I think this was from the September 11th Commission workshop.

And the only thing I'm going to comment on this is I'm going to use it to say that Staff assumed that for each -- if you look at the row for FPL, for example, each one of these data points has an equal probability of occurrence in order to arrive at the random number that they use here. They get the same for, I think -- I believe it was ten utilities.

The major point of disagreement that we have or one of the points of disagreement and one of the deficiencies that we believe is attended with the Staff methodology is that they do assume that the probability of occurrence is equal for each one of these data points, and it's not.

These two charts -- again, they replicate what Staff did. This is the 1998 Ten Year Site Plan figures for the summer. And the numbers that Staff found inadequate under their analysis was zero. No inadequacies.

For the winter, Staff focused on the winters of 1999 and 2000 with a probability of nonmeeting load according to their numbers of 6 % and 8.3%. Those were the areas that they identified as having some concerns.

Specifically where we disagree with Staff is, like I said, the assumption of equal 20% probability from each data point. That fails to recognize that there has been significant change in the way utilities operate their system; changes in forecasting techniques, improvements in reliability, et cetera, that render that assumption invalid. That's one of the reasons why we disagree with the Staff analysis.

Also, they're drawing from a very small sample size. Only five years worth of data. And by drawing from that sample size, coupled with the assumption that they are assuming the probability is equal, it renders their conclusions questionable.

Also, they're not recognizing that the FRCC reserve margins are calculated on an aggregated noncoincident peak basis.

What I'd like to do is run through a couple of very brief examples of what happens, and I'd like to run through the sample size here real quick.

This -- on the left-hand side where you see the Staff 1998 plan evaluation for the winters of 1999/2000, those were the two winters -- and 2000/2001, those were the two winters of concern to Staff. They found that, based on their calculations, that 6% of the time it would be inadequate for the winter 1999/2000 and 8.3% of the time for the winter of 2000/2001.

On the right-hand side you'll see we replicated the Staff methodology, but added one year of data, the 1998 data. By adding the 1998 data and doing the same analysis that Staff did on a random sampling basis, the numbers changed significantly.

Now, all a sudden, we had in 1999/2000 a 6% inadequate. We dropped that down to 1.6%. For 2000/2001 the number drops from 8.3% to 2.9%. Again, this is without any change to Staff methodology.

So we don't believe that the assumptions that Staff used because of their major deficiency, assuming that the probability of occurrence is equal, that it's an appropriate one to make, particularly when you have such a small sample size.

And, again, just having a greater number of samples is not going to fix the problem because it still leaves the probability issue unresolved. That is, you don't know what probability each one of those

events has because of changes that have occurred since that event took place. And this methodology does not recognize any of that.

There have also been some changes in generation maintenance schedules. And by making an adjustment that FRCC did in the 1999 analysis, we make -- and running the Staff analysis with a different number of megawatts out, you reach a totally different conclusion.

I'm not going to run through all these examples that are here because I don't want to take up too much time.

And again, changes in forecasting techniques; the one we described before that FPL changed by approximately 800 megawatts. The reason why you have 750 here is because it's a different year. All of those affect the conclusions that Staff reached and the methodology. So the assumption that the probability of occurrence for each one of those events is equal, it's unsupported.

We believe the methodology is deficient because of the sample size and the fact that it assumes an equal probability of occurrence for each one of the data points and it's mechanical. It does not consider changes and improvements of various

factors and you cannot draw the kind of conclusions that Staff drew from it.

In addition to that, it fails to recognize the use of operational measures or the fact that they might have a probability of -- even if the analysis were correct, that it had a probability of not meeting 200 or 500 megawatts of load.

It's incorrect also because it does not recognize the availability of over 3,000 megawatts of operational measures.

MR. HAFF: Mario, I have a question. This is Michael Haff with the Commission Staff. Weren't these operational measures available in 1989?

MR. VILLAR: They were significantly different, Mike. And if you go back to --

MR. HAFF: I mean, it's brought up over and over that we're not going to have any problems because of these operational measures, and it just seems to me like these were available in '89 and yet we still had unserved load.

MR. VILLAR: They were not available to the same extent. The reason for that is that in 1989, one of the biggest contributors to these operational measures is the DSM features, and the load SCRAM capability of the DSM programs. That adds significant

number of megawatts.

In 1989 I believe there were somewhere in the order of maybe 200 megawatts of DSM measures available as opposed to the thousands of megawatts that we have now.

In addition to that, the public appeals has changed significantly since 1989 as a result of the Commission order to implement a statewide program or a statewide emergency plan that address the conservation issues and public appeals process. There have been changes made to building codes, et cetera. So we don't believe it's the same basis.

If you look at the numbers from '89, there appear to be a difference between the unserved load and the -- I think it was the forecasted peak. The actual difference between the two numbers is like 6,000 megawatts, but you only showed to like 4,744 megawatts of unserved load. Part of the 6,000 megawatts -- I'm sorry. Part of the 4,744 difference to the 6,000 megawatts, it's what you could call either operational measures. I believe part of it is also the fact that you're doing it on a noncoincident basis. But there were like -- by their own numbers from 1989, it appeared to be that there were like 1,300 megawatts of what you could call operational

measures, if you believe the data.

MR. HAFF: You say 1,300 megawatts were available at that time as opposed to 3,800 now?

MR. VILLAR: Well, let me get the number here if I can find that.

MR. HAFF: Ballpark is close enough.

MR. VILLAR: You got to realize that part of that is purchase -- nonfirm purchases from other utilities like Southern Company and stuff like that. So some of that did come in. I can't find that graph right now.

If you take the difference, Mike -- let's use this other one. I was trying to get the clean one. If you take the difference between what you show as actual peak in 1989, and you subtract that from a total capacity available, you get a difference of about 6,000 megawatts. Yet the only amount of unserved load shown was 4,744 megawatts. So the difference had to come from somewhere. It was either purchased from somewhere else, conservation appeals, et cetera.

MR. BALLINGER: Mario, I have a couple of questions. This is Tom. Do you realize or recognize Staff hasn't used the probabilistic method in the '99 assessment?

MR. VILLAR: Yes, I do. I was just bringing it up because it was an unresolved issue from last year. I did not know whether you were using it or not because you haven't made your presentation here.

MR. BALLINGER: And correct me if I'm wrong, but if you take something and you do a simple averaging of numbers, doesn't that also assume that you've got the similar -- same probability for each of those occurrences?

MR. VILLAR: No, we're not because we're not assuming any probability to it. All we're doing is for testing purposes, Tom. We're not assigning any particular probability to it. We're only using it as a test.

MR. BALLINGER: Okay. But isn't the mathematical effect the same? That you've taken the same error rate for each year and given it the same probability when you simply --

MR. VILLAR: No. I think the only place where we wind up being the same is the median may be the same, but then you calculate a probability in your analysis and you go off to the extremes and you attempt to predict what the extremes are. We don't do that.

MR. BALLINGER: Okay.

MR. VILLAR: We have -- in our analysis, and you'll see that later, we do look at the extremes, but we just look at sensitivities assuming the worst error that we had during the time period. We don't assign a probability to that.

MR. BALLINGER: Do I also understand -- I'm back on Page, I guess, 15 of your slide where it shows the scheduled maintenance put in the 1,000 megawatts.

MR. VILLAR: Yes.

MR. BALLINGER: That still shows an inadequate, a shortfall, if you will, based on the percent. Now, I understand the megawatts are much smaller. And are you saying that that shortage would be made up by inner ties to Southern or other SCRAM measures, things of that nature?

MR. VILLAR: Let me go back to slide 15 for a minute here and make sure I'm on the same page you are.

Now, we weren't conceding that there were going to be 1,000 megawatts out. All we were doing is making an adjustment to show some megawatts out. But again, based on your analysis, Tom, if you look at 1999/2000, what you're basically projecting there is that there's a very small probability that you're not going to be able to serve load based on these

assumptions.

In other words, 98.5% of the time under your analysis, I'm okay. I think that's pretty good. And in addition to that, this doesn't take into account operational measures or that I have over 3,000 megawatts available to the system.

MR. BALLINGER: Okay.

MR. VILLAR: I'd like to turn now finally to the FRCC load and resource plan and the reliability assessment.

First graph is a projection of what the firm peak demand is going to be for the state, and again, the way FRCC compiles the data, this is noncoincident firm peak demand. We're, at this point, not calculating any data on the basis of coincident peaks.

The change from 1999 to 2008 is roughly 24% for the winter peak and about 21% for the summer peak or 900 megawatts per year growth rate for the winter peak and about 800 megawatts per year for the summer peak.

These are the net capacity additions and you can see on the right-hand side -- let me see if I can focus this a little better. Oops.

The difference from the 1998 plan to the 1999 plan is a significant number of additional

megawatts. We have 9,728 megawatts added through 2008 versus 7,800 megawatts in last year's plan. Roughly 24% higher. Again, this number is only utility capacity being added. It does not include QF contracts, imports, et cetera.

For the winter term, we have a similar picture. 8,725 megawatts shown last year versus 10,744 or roughly 23% higher megawatt additions than last year.

CHAIRMAN GARCIA: Where does that increment come from? I'm sure you said it. I just missed it. Is it just your re-analysis of the situation you're in and you're going to put more generation into the ground?

MR. VILLAR: The plans are not the same, Mr. Chairman, and also we have a different year. In addition, we have one additional year, 2008 versus 2007, which is what we had before. I haven't broken it out specifically for what it is, but the plans have changed from last year. For example, in FP&L's case we have additional megawatts.

CHAIRMAN GARCIA: Right, but, obviously, this is 10 years out so clearly you always change them, but that's a significant increase.

MR. VILLAR: Yes, it is.

CHAIRMAN GARCIA: Okay.

MR. VILLAR: Again, this one dispatchable DSM and it shows existing and cumulative additions at time of summer peak. And for clarification purposes, when we say cumulative additions, the numbers in the white up here is the net additions. It is not a truly a cumulative number there. Some -- there might be 80 megawatts in the year 2000 added, for example, but there are some also that go away because of plans that go away, et cetera. So this only shows a net increase. This is for summer peak.

We have a similar picture for winter peak. Again, the numbers above the existing amount are the net additions in DSM programs. And part of the reasons why there's a dip in the curve is some utilities are changing the amount of DSM that they have. This shows the effected DSM is not as cost-effective as it used to be perhaps and other different changes to the system.

This one basically shows the amount of firm imports coming into the state and they do vary through time because some of the contracts expire in the early years. For example, the firm purchases, Tallahassee has some purchases that are expiring in '99 or 2000. So the numbers do change through the years.

The available transfer capability into the state is shown on the right-hand side and those will be available for nonfirm purchases, dialing assistance, et cetera.

CHAIRMAN GARCIA: Can I ask you, why is it so low in 2000? Is that because it's already committed? This shows what's available. I'm sorry.

MR. VILLAR: It's only the -- all you show there is a net after the firm commitments.

CHAIRMAN GARCIA: Okay. But this isn't new capacity; just there are no contracts that are going to be there?

MR. VILLAR: There are no new firm contracts in there. It's just a change in the existing contracts.

CHAIRMAN GARCIA: Right.

MR. VILLAR: The one number that's going to change, I think the owned megawatts that we have shown on that graph is the shared amount, and in the 1998 plan the number was 867 megawatts. The number of megawatts has changed since then. So it's a little higher than that. But again, so have some of the other contracts in terms of the actual megawatts.

The fuel mix, we have it shown in this graph. Last year we had a significant number of --

not last year. I'm sorry. Relative to 1998, you'll see natural gas goes from 17% consumption to about 37% of the mix in the year 2008. That represents basically the addition of significant amounts of combined cycle and gas firing capacity into the state.

Here are the FRCC reserve margins projected for the period. And you'll see they all go above the FRCC standard reserve -- 15% reserve margin standard, which is the solid line that goes -- cuts across the middle.

And again, it should be understood that these reserve margins are calculated on a noncoincident basis. If you were to apply the load diversity factors, these reserve margins would be approximately 2% higher.

I want to turn now to the reliability assessment analysis that was done by FRCC this year, and we focused on two areas; loss of load probability analysis and reserve margins.

The LOLP analysis is different from the reserve margin analysis because reserve margin only looks at the time of peak. Loss of load probability looks at the whole year and the load curve throughout the year. So we are trying to answer the question as to how likely are we to have sufficient capacity to

serve a load each day as opposed to the peak day, which is what the reserve margin looks at.

It also takes into account what the forecast load is, the load profile, the availability of units, both for planned maintenance and forced outage rates, and it conducts an assessment of the system for each one of those days and then sums the probabilities of each one of those days to arrive at a conclusion for the whole year.

We don't consider, in this particular analysis, the frequency or the duration of the outage, but just the fact that it actually occurs. And we measure it against the industry standard one-day-in-ten-years loss of load probability.

The results of the LOLP analysis are presented here, and I can't focus this thing very well. The reference case is what the FRCC load and resource plan contains, and it's based on the most likely assumptions or what we believe is the appropriate method of analysis. We showed no violations and there is a couple of graphs behind this that shows what the actual numbers are.

We conducted an additional set of sensitivities to the LOLP analysis from the reference case, and one, which is the item No. 2 there, is we

assume that there will be no usage whatsoever of load management interruptible loads; no direct load control. That had absolutely no effect on -- had some effect on the loss of load probability, but it didn't raise it above the .1 per year standard.

We also assume that we had a three percentage point increase in the steam unit forced outage rate from the projected forced outage rates for those units. Again, we showed no violations under those conditions.

We then assumed some changes to the load forecast. In particular, we simulated some extreme type winter conditions and more extreme type summer conditions and we found no violations.

Just for clarification purposes, I think what was assumed for the winter was two, four day periods during the month of January where the load was a certain percentage above where we had normally forecasted. And I think for day one we were assuming a 5% increase in demand.

For the second day of that four day period we assumed a 10% increase in demand. And the third day I think it came down to about 7.5%, and the last day of that came down to a 5% increase over the forecasted peak and we did that twice in the month of

January.

So we had two incidents in the month of January that we looked at or fairly demanding conditions. Again, we found no violations.

For the summer, it was a similar analysis that was done. There were two, one week periods that were assumed during the month of August above the forecasted peaks, and again, there were no violations.

The FRCC reference case is -- we consider it robust enough to all sensitivities examined so that we don't believe that there is any probability of concern.

I'd like to turn now to the reserve margin standard.

MR. BALLINGER: Mario, before we leave that, can I ask a question? This is the first time you've actually presented the results, all the sensitivities to Staff. I noticed in the '99 reserve margin analysis it just had a statement that they were similar to '98, but Staff hasn't been made aware of any of these values yet until today; is that correct?

MR. VILLAR: As far as I know, that's correct, Tom.

MR. BALLINGER: Okay.

COMMISSIONER JACOBS: I have a question.

MR. VILLAR: Yes.

COMMISSIONER JACOBS: This year we had a sustained period of high temperatures in August. I think probably a week or two of above average temperatures. How would that play into your analysis?

MR. VILLAR: Well, you're comparing forecast to actuals so it doesn't actually play into it. But we did do a sensitivity analysis, like I said, for both the summer and the winter peaks when we forecasted. And we assumed, in the case of the summer, two one-week periods during the month of August where we had exceeded the forecasted peaks at that time and we saw no violations. But during the month of August this year we didn't have any interruptions as far as I know.

COMMISSIONER JACOBS: No, we didn't. Wasn't there one week, though, where there were -- wasn't there one week in August where we had -- we didn't have interruptions, but we had the reserve?

MR. BALLINGER: In '99?

COMMISSIONER JACOBS: Yes.

MR. BALLINGER: I believe it was April we got into an alert situation, if I'm remembering correctly. It was right around -- and it was right before, I think, TECO had the explosion at Gannon. It

was the few days prior to that we were in an alert status for a day or two. I see Henry nodding his head. But I think over the summer, so far we've done okay.

MR. VILLAR: I think one important thing here is that, the fact that we have an alert doesn't mean anything. It's part of our plan. The reason why we declare an alert is so we pay attention to what's going on so we can take the appropriate action; make sure there are units that are available; that we do have the availability of nonfirm power purchase from somewhere else if it's necessary; that we have the ability of operational measures to call them into play if need be. But the advisories and alerts, et cetera, is all part of the plan.

COMMISSIONER JACOBS: Going back to the original question. When you say you assume two weeks in August, is that one day of that week or for the sustained --

MR. VILLAR: It's the complete week.

COMMISSIONER JACOBS: Okay.

MR. VILLAR: I can tell you exactly what it was that we assumed. For the first day, actually we had -- for the peak day we assumed a 6% increase over the forecasted peak; three days of 4% increase; one

day at 2%, and two days at 1%. And we did that twice during the month.

MR. BALLINGER: I'm sorry. Could you run through that slower, and also for the winter one? I missed it the first time through.

MR. VILLAR: Sure, Tom.

MR. BALLINGER: For summer first.

MR. VILLAR: Summer was --

MR. BALLINGER: First day was plus 6%.

MR. VILLAR: Well, it was a peak day. I don't remember whether it was the first day or in the middle of the week. Dave Dawson here? Mike, do you recall?

UNIDENTIFIED SPEAKER: No.

MR. VILLAR: Okay. For the peak day it was 6% increase, Tom.

MR. BALLINGER: Okay.

MR. VILLAR: Then we assumed three days at 4% higher in the fork, and then the forecasted firm peak; one day at 2%, and two days at 1% for the summer.

MR. BALLINGER: Two days.

MR. VILLAR: And the winter was, the first day, a 5% increase in the demand. The second day, a 10% increases in demand. Third day, 7.5% increase

over forecast. And the fourth day, 5% increase in forecast. And as you remember, the winter peaks here traditionally are maybe one, two days; not necessarily four.

MR. BALLINGER: So if I understand right, for winter you did a four day window, if you will, of a gradually decreasing temperature and then slowly warming back up. And for summer you did a week period where it gradually heated up and at peak day it was 6% over the forecast?

MR. VILLAR: Well, actually the winter -- the first day for the winter was 5%. The second day resulted in 10% because of the buildup.

MR. BALLINGER: Right. And then it starts warming up?

MR. VILLAR: And then it starts coming back down, correct.

MR. BALLINGER: All right.

MR. VILLAR: For the reserve margin --

MR. BALLINGER: Mario, I'm sorry.

MR. VILLAR: Go ahead, Tom.

MR. BALLINGER: Did you do a similar sensitivity on reserve margin using these weather assumptions?

MR. VILLAR: I'll get to reserve margins in

a minute to show what we did towards the end here.

MR. BALLINGER: Okay.

MR. VILLAR: Now, reserve margin calculations look at the excess of total firm capability or firm load. For that they assume that each of the components that go into a calculation is available 100% of the time or it's there and called upon at the time of peak.

What the FRCC did is, we looked at the five components that go into reserve margins, which are the ones listed there; utility-owned generating capacity, firm QF capacity, et cetera, and we developed a certainty factor for it.

For example, if you take utility-owned generating capacity, and over the last six years in this case, because we added one year's worth of data, utility-owned generated capacity at the time of peak was available, not 100%, but perhaps 94%. We assigned a 94% or a .94 certainty factor to that particular component.

We did similar analysis for firm QF capacity, import capacity, et cetera. We applied a certainty factor to each of those. What we're actually doing is trying to measure how well we've been doing over the last five, six years against what

we projected was going to be there at the time of peak. Just for purposes of testing, how far off we were from that. And remember, reserve margins are supposed to account for these uncertainties and the availability of these factors.

The focus of the analysis was twofold. One was to determine whether the Peninsula's reserve margin met the FRCC's 15% reserve margin standard. And two, to confirm whether or not that standard continued to be adequate given the latest figures that we have been seeing in terms of certainty factors for these components, et cetera.

Basically test the utility's projected reserves against recent historical performance and contingencies, and then combined that information with engineering, economic judgment to make -- to reach conclusions from that.

Now, these get complicated because we get into what we actually did, and I'd like you to keep these in mind.

The first item there shown, which is a base case, is what FRCC believes is the most meaningful case; the most likely case that we believe will occur. It contains the 1998 actuals and projections that were added to last year's database. For last year's

analysis we used 1993 to 1997. We added actual data for 1998 to the analysis to develop these certainty factors for each one of those components.

Then we made a couple of improvements to last year's approach. We added a noncoincidence adjustment factor for load forecast to recognize the fact that there is load diversity in the system, and it's not currently included in our analysis or was not done in the 1998 analysis yet as a fact of life.

And two, we made an adjustment to the winter 1993 actual and projected data for utility installed generation. And the reason for that adjustment was basically that the winter peak in 1993 occurred very late in the season and the certainty factor is supposed to measure the unavailability of capacity at the time of peak due to forced outages, basically, or my unit is broken.

And by that time in March we had scheduled maintenance of some units so we didn't feel that it was appropriate to use that figure because it didn't actually test the brakes for the units. It was very late in the year and we had sufficient capacity to take the units out for scheduled maintenance to meet that peak so we had no problems whatsoever.

Scenario 1, it's only shown here for

illustrative purposes. It compares the figures with last year's work. It does not contain any of the changes that were made in 1999. It only adds one year's data to the database that was used last year, but it does not include any of the other changes.

Scenarios 2, 3 and 4 are basically the major sensitivities that we conducted against the base case and they are focused on the major contributors to this -- the driving factors that affect the reserve margin calculations. The biggest drivers are the need for reserve margins. Basically that is the availability of utility installed generation capacity. Where in Scenario 2 we took the worst data point for the whole six year period and we applied that to the base case.

All the other assumptions remained the same in terms of the certainty factors. In other words, for all the other certainty factors, we used the average number that we had used in the base case.

For Scenario 2, for utility installed generation capacity, we used the worst number from the six years' worth of data.

Scenario 3 applies to, again, the other major driver of the need for reserve margins, which is the load forecast error. In Scenario 3, again, we

used the worst data point during that six year period even though that worst data point is -- I believe it was the winter of 1994, and we have made some changes to the forecasting methodology that I described before that change the possibility of that really occurring again.

In other words, I am not going to have as high a forecast error because I have changed the methodology by lowering the temperatures. Still we applied that to the Scenario 3.

And then Scenario 4, it's a combination of Scenarios 2 and 3, where we take the worst case for utility installed generation and the worst case for load forecast error and apply both of them at the same time.

This table is very busy, but just basically tell you what it actually shows. You have the FRCC reserve margin criterion here on the left. The numbers right to the right of that are the actual projected reserve margins by FRCC; what we are expecting to be. And these numbers, again, they are shown on a noncoincident basis. So, again, if we wanted to make a load diversity adjustment to these numbers, it would be like two percentage points higher.

The base case scenario shows what the needed reserve margin would be for each -- for the base case with the certainty factors that we have used in the analysis. In other words, applying the average of the six years' worth of data of each one of those reserve margin components, what reserve margin would I need in order to account for those certainties -- for those uncertainties associated with those components.

So, for example, in 1999, given those uncertainties, I could meet the load with only a 6% reserve margin.

Scenario 1, I'm not going to discuss, because like I said, it was only there for illustrative purposes for last year's analysis. Let me go to Scenarios 2, 3 and 4.

Scenario 2, again, shows the adjustments that were made to the base case. In this particular case for Scenario 2, it was a utility installed generation capacity. We changed the certainty factor to put the worst case in there. When you put the worst case utility certainty factor -- utility-owned generating capacity certainty factor, you see the numbers for the needed reserve margins change from the base case. They go up. I would need a higher reserve margin in order to meet my -- the certainties under

that scenario.

The numbers on the bottom here -- the questions, basically, on the bottom just say, answer the question of, is a needed reserve margin, for the first one, to account for the uncertainties less than 15%, yes or no. If it's less than 15%, we're okay with the 15% reserve.

The second question goes against the actual projected reserves. And then here it shows the conclusions as to what each one of those different scenarios show.

And I'd like to take a moment for -- to go through those because you might look at some of these numbers on the bottom and you might say, well, we got a problem. Not the case.

You not only need to look at what the scenarios show, but also how it likely is to happen, when is it likely to happen, and what other measures do you have available to you in order to mitigate the effects of this if it were to happen.

Let's look at Scenario 4 because it's the worst combination of them all. And if you look at Scenario 4, you'll see that the projected reserve margins for the Peninsula, 16, 18, 20, et cetera, appear. These are -- if you compare these numbers

against the projected reserve margins, we're okay against what we are currently projecting.

And, again, remember that these numbers could be understated by two percentage points because they're done on a noncoincident basis. So these year shouldn't be a concern.

So now we're looking at the last years here, these figures here, which are the last four years of the analysis. Well, a lot can happen between now and then. The plans can change significantly. Again, the reserve margins are calculated on a noncoincident basis, so if I apply a coincident factor to these numbers here, I am not really that far off from those numbers because these numbers are higher by two percentage points.

I also have the availability of operational measures, which, like I said, is over 3,000 megawatts available to the utilities.

So in summary, Scenario 4, we're looking at something that we might have some problems way out in the future. This doesn't take into account the use of operational measures. It doesn't consider the fact that these actual reserve margins on this side are done on a noncoincident basis and we do have the availability of a lot of other measures to us to

mitigate the effects of what could happen. Plus, we're looking at an extremely unlikely scenario because if the load forecast scenario, worst case scenario, basically assumes that we have the worst forecast error for each one of those years.

In other words, we didn't apply just one factor and we said the worst forecast error was 10% and applied it for years 1999 to 2008. We took the worst forecast error that was possible for a forecast applying to 1999 and put it in that year. The worst forecast error for a forecast that would apply to this year, et cetera, for each one of those years. So the probability of occurrence of those events, it's extremely unlikely in our opinion.

MR. FLOYD: Mario, I've got several questions about that assessment in summer, but I also have about winter. And I think I'll just let you go through the winter. And so I won't interrupt this, but I didn't want to pass that page without letting you know I got some questions.

MR. VILLAR: No problem, Roland.

The winter scenario presents a similar picture. Again, I'm not going to take you through each one of those, but let me explain before you become totally confused with the fact that I have

negative numbers in the base case.

That basically what it does is because of the certainty factors that we have been experiencing or that we have been seeing applied to the load forecast error in the winter, we've had very mild winters. Therefore, the certainty factor applicable to the winter is a number that reduces the projected forecast from the one that we have. And what it does is it basically says that if we applied that certainty factor and we get the kind of forecast that we would expect, we could meet the load with less reserves than we currently have now. So if we have the amount of reserves that we have now with the kind of load that we have projected now is here, that would be zero reserves, we could have -- what the actual forecast that we could project given the certainty factor would be done here. So it would be negative relative to where the zero reserve point is now.

I don't know if I've totally confused you with that, but that's the reason why we have negative numbers in there. Just basically means that we need less reserves than what we have now given the projected forecast that you could get under those conditions.

Again, in the winter, we have similar

results where, as each scenario goes, the numbers increase and you would expect when we apply the worst forecast error for load to have the one having the most effect, remember the certainty factor for the winter normally here is a very low number, resulting in low reserve margins. So only when you get to Scenarios 3 and 4 do you actually see something significant happening. That is because that's where the winter -- the worst winter load forecast error was applied in both Scenarios 3 and 4.

One of the things that needs to be considered in looking at this is, again, Scenario 4 is extremely unlikely and we have two points here where there might be some concern. These, from here to about here, are very close to the FRCC's current projected reserve margins, and again, since this reserve margins are calculated on the basis of noncoincident peak, if we were to bump those numbers up by 2% they would meet or exceed these numbers. So we don't see it as a concern.

This -- that adjustment would also reduce the difference between these two numbers. The issue with these numbers is they're so close in time, there isn't anything we can do about it from a planning perspective most likely. But, we are also not

recognizing here the fact that we have 3,800 megawatts of available operational measures. So even though this might look like we might be a little short, we can do something about it. We can take appropriate steps to take care of the problem.

When we get back out in the later years, we can take care of it by similar concerns like operational measures, et cetera. Plus, we're way out in the future, so the plans can change significantly between now and then. We shouldn't worry too much about this.

In addition to that, one thing that I mentioned before that affects our confidence in being able to meet these numbers, is that these forecasts and the forecast error that was applied here is based on the winter of 1994. We have changed, or at least FPL changed, its methodology so that we do not expect to see the same kind of forecast error that we saw in the winter of 1994. I don't recall what the number was that was applied. Steve? Is he around? Where's Steve Sim? What was the forecast error that was applied for the winter, the worst winter?

MR. SIM: I think it's 13%, subject to check.

MR. VILLAR: Somewhere in the 13% range.

But since there have been some improvement in load forecasting methodology, we do not expect to have as high a load forecast error as we had before, and yet here we're applying some very hard numbers to these scenario sensitivities that we've conducted. So we do not expect that these numbers would, in reality, pan out.

In other words, the likelihood of Scenario 4 occurring is extremely remote based on all the things that have changed since then, and the fact that if it did happen, we do have 3,800 megawatts of available operational measures that we could put in place.

COMMISSIONER JACOBS: Are you aware if, in Florida, there is the -- what's been dubbed these hot spot scenarios? In the problems that have occurred in other areas of the country they've indicated that they've had adequate access to capacity but the problem is that in the hot spots transmission and distribution issues limited the ability to bring in much of that capacity. Does that affect Florida, and if so, has it been accounted to for in the analysis?

MR. VILLAR: I think you may be talking about transmission constraints into particular areas that do not allow assistance from outside that particular region to come in.

In this particular case, we have assumed as part of the operational measures the availability of assistance from the rest of the eastern interconnection to the extent that transmission capacity was available. So if there were 1,000 megawatts of transmission capability available into the state, we were assuming that that was available into the state.

We do not see that as a transmission constraint at this point because that's nonfirm transmission. However, if it were to happen, that would still leave us with roughly 2,800 megawatts of operational measures that we could take account of within the state to mitigate the potential effects of this. So I don't see that as a problem.

COMMISSIONER JACOBS: So as I understand it, you've assumed that the constraints would exist outside the region and your analysis would account for that?

MR. VILLAR: We assume that there were about 900 to 1,000, depending on the year. I think it was 961 to 1,062 megawatts of tie-line assistance, let me call it that for simplicity sake, coming in the from the southern region.

If you do away with that number of

megawatts, we still have sufficient megawatts and operational measures in the state in terms of public appeal, voltage reduction, load control SCRAM to take care of these issues here.

COMMISSIONER JACOBS: Okay.

MR. BALLINGER: Mario, can I ask a question about the operational reserves within the state?

MR. VILLAR: Yes, Tom.

MR. BALLINGER: You said that voltage reduction and all and conservation appeals. Does it concern you that that's kind of a reduction in the quality of service at that time? I understand we're probably in an emergency situation; it's very cold or very hot and you're asking people to conserve. But does it concern you that we're pushing that envelope; that we're having to ask people, our customers, to either conserve on their own or reduce voltage to certain appliance, that they may not run as efficiently, things of this nature?

Doing your load management SCRAM, which is out of the ordinary from when you normally do it, I understand it's in the tariffs, but are we getting to that level where we're starting to rely on those more and more? And are the customers really aware of it?

MR. VILLAR: I don't know if the customers

are aware of it, Tom, but we don't believe that we're going to get into that kind of extreme conditions that we have here shown in these scenarios.

What we believe is the most likely to happen, given the kind of assumptions that we have, the most reasonable assumptions is the base case. In the unlikely event that we were to get there, we will follow what the state emergency plan has, which is to go out for public appeals, how to mitigate circumstances to deal with that kind of extreme temperatures, et cetera.

I don't think it's unreasonable to do that. You know, it's not something that we exercise on a regular basis or we don't expect to exercise on a regular basis. It might be an unusual event and to deal with unusual events in that regard, I think is prudent.

MR. BALLINGER: Okay.

MR. VILLAR: In summary, I think the FRCC confirmed the continued suitability of its regional reserve margin standard of 15%. Will maintain better than 15% reserves for both the winter and summer through the addition of significant amounts of megawatts for both summer and winter periods, new generating capacity.

The LOLP analysis confirmed the analysis that we had done in terms of the reliability of the state and it looked at the probability of being able to meet the load on each one of the days rather than just on the peak periods.

And from that we conclude that the existing and planned resources are sufficient to reliably meet the needs of Peninsular Florida customers under reasonably expected conditions. And we believe the FRCC's load and resource plan is suitable.

That concludes my presentation. I'd be glad to answer questions. Roland.

MR. FLOYD: I'm passing out a little handout. It's from this year's reliability assessment study. Just a few selected pages. And I want to ask you a question starting out on Page 21.

CHAIRMAN GARCIA: 21 of your presentation, right?

MR. FLOYD: It's Page 21 of their reliability study.

MR. VILLAR: Right. Of your handout.

MR. FLOYD: There should be a Page 21 at the bottom. Do you have that, Mario?

MR. VILLAR: I'm trying to put it up here so the people can maybe try to see it.

MR. FLOYD: Okay. We've got extra copies.

CHAIRMAN GARCIA: I think if you turn on the lights there that are above the --

MR. VILLAR: Where are you focusing on?

MR. FLOYD: This Page 21. Look at the right-hand column where it says "Needed" Reserve Margin.

MR. VILLAR: Yes.

MR. FLOYD: As I understand it, your methodology or FRCC's methodology produced these numbers as what was needed in each of the years 1999 through 2008. And I notice in the last three years it's 13%.

And down below, I'm reading the writing on this page, it says referring to that column, this result indicates that both the FRCC's reserve margin planning criterion of a 15% level and the higher than 15% planned reserve margin for each year are more than adequate.

Now, I'm assuming when you say that, I'm looking at this 13% and the 13 is less than 15, and even less than 17, 18 and 17, so by your methodology that's adequate. In fact, it's more than adequate because you got a little room there between 13 and 15.

MR. VILLAR: From that standpoint, yes,

Roland, it's correct. The one thing that I'd like to clarify is that our methodology does not produce what the reserve margin ought to be. This is for testing purposes only. In other words, our methodology is not designed to come up with what the ultimate reserve margin ought to be. It's just used for testing a particular reserve margin that has been arrived at all ready.

MR. FLOYD: Can I believe these numbers, thought, in the right-hand column that that is what your methodology showed you needed or not?

MR. VILLAR: When we say needed, we're referring to, given the uncertainty factors that we have used in the analysis, we can meet the load -- the projected load with those uncertainty factors given these level of reserves in the right-hand column. That's what it means.

MR. FLOYD: Let's leave aside the question right now that you have not determined -- you haven't come up with a methodology to tell us what the reserve margin should be. You've only come up with a test for your 15% that you assume. I'm going to leave that question aside for now.

MR. VILLAR: Okay.

MR. FLOYD: All right. These numbers here

say that the 15% is adequate because it's less than 15. Now, what worries me -- it kind of scares me about this methodology, from years 1999 through about 2004, your methodology says you can get by with 10% or 11%. That's your method.

MR. VILLAR: Given the certainty factors, yes. But so what? You know, given what we've seen in terms of certainty factors over the last few years, that doesn't mean we're going to operate there.

MR. FLOYD: Fine. But I know you've got planned more and your standard is greater than that, but tomorrow you could vote to have a standard of 10%, FRCC could if it wanted. Based on your methodology you could say, well, let's just have 10% or 11% because we don't need 13 until you get out to 2006.

MR. VILLAR: Well, Roland, I think we could speculate as to what could happen and anybody could vote to until we're -- we stay here for the next 300 years. I don't think -- we're not going to go there.

MR. FLOYD: You're not speculating, though, about what your methodology produces. That says about 10% or 11% through 2004 would be adequate. Okay. I got another handout.

What I'm passing out now is last years. No. I'm sorry. Stay on that same handout. I want to go

to winter reserve margins over on page --

MR. VILLAR: 25?

MR. FLOYD: Yes, sir. Page 25. I have a similar question on this. I just want to confirm it and you seem to be agreeing with me about it.

According to this, in 1999/2000 winter, that's the winter coming up, we only need 5%. By your methodology we could get by with 5%. Not saying you would adopt that, but your methodology produced that number.

MR. VILLAR: Yes, our methodology produced that number. But that's not what we're advocating or anything like that. Just basically says that if you use the certainty factors that we have, you could account for all those certainty factors with a 5% reserve margin. Basically because winters have been so mild that the winter certainty factor is -- the adjustment on it is high enough that it wipes out anything else that might be effected by the unavailability units or anything like that.

MR. FLOYD: Let me call your attention to Page 16 and 17 that I handed out in the first handout. Do you have Page 16? That was probably the first page after the cover page?

MR. VILLAR: 16 is the one that I have here.

MR. FLOYD: I'm reading a sentence here in the second paragraph. "The base case is the case which the FRCC believes is the most meaningful case analyzed."

Over on Page 17 you say something similar. "The FRCC believes the base case" -- and that's the case that generated those negative reserve margins. "The base case is the most meaningful case because of these two improvements." Well, we're talking about the two improvements you made.

But anyway, "to the approach and because of the fact that is captures a truly representative set of values." So your results that were based on a truly representative set of values and what's the most meaningful case, you come up with negative reserve margin, and that's scary to me.

MR. VILLAR: Why is it scary? We are not proposing to go there. We look at sensitivity analysis, looking at the worst case, et cetera, and we're not changing anything. The numbers are what the numbers are.

MR. FLOYD: I tell you why it's scary to me. We do not control what FRCC says is a standard. And you can go down there and vote tomorrow that 10% is your standard based on your methodology. I don't like

your methodology because of the numbers it produces. But, I'm not saying you would do that. I'm just saying you could do that. And --

MR. VILLAR: So if I had six years' worth of data that pro -- I use the exact same methodology, but the number in there showed 25% you would be happy with that?

MR. FLOYD: No. I don't like the mechanics of your methodology, but I'm not going to go into that now. We can save that for the hearing.

But, anyway, let's move on to the second handout that I just handed out from last year's study.

MR. VILLAR: Well, I want to make clear, the FRCC is not producing to carry negative reserves.

MR. FLOYD: That's right. And you even have planned reserve margins much greater than your standard, but I don't know what would keep anybody from selling firm capacity outside of the state because you have more than what your methodology shows you need. I couldn't prevent somebody from doing that.

MR. VILLAR: Well, speculation I don't think is going to get us anywhere.

MR. FLOYD: I'm not speculating on what you will do or might to. I'm just saying you could --

utilities can do that, and you could justify it based on your methodology because it produces numbers that are so small.

I want to go to the second handout for the 1998 study. I think I passed out Pages 9, 10 and 11 from that study. And by the way, that's from the exhibits in the study. Do you have that?

MR. VILLAR: You talking about Pages 9 and 10?

MR. FLOYD: Right. 9, 10 and 11.

MR. VILLAR: Okay. 9 and 10 is a summer reserve margin, and 10, it's the winter. They show similar results to the ones that you were talking about at some point.

MR. FLOYD: Exactly. That's it. What I wanted to ask you about is -- let's look on Page 10. And in column 16 you have needed reserve margins component over there. This is similar to what you've done this year except you didn't put it in quotes last year.

And notice on year 2004 and 2005. You go all the way over to the right, Column 16, you have 12% is what your study showed your test, or however you want to characterize it, when you were testing it against 15 reserve margin, that came out to be less

than 15. You follow me?

MR. VILLAR: Okay. I'm following what you're saying, but --

MR. FLOYD: Okay. Now, what I want to do is compare what you're study showed for that same year under the same methodology by adding one year data. What does it show? Look at this year's study and see what Scenario 1 showed for year 2004 and 2005. I think it shows you only need 1%.

MR. VILLAR: Okay. I don't have it in front of me, but basically we are looking at 1998 stuff and you got to remember that we did a couple of things.

We removed the winter 1993 data for utility installed generation because we didn't think it was representative or has an effect on it.

We have an additional year's worth of data where we also had a very mild winter, so that also tends to affect the numbers.

MR. FLOYD: That's the only difference, what you just said. You added one year of data and you told me last year --

MR. VILLAR: No, we did not, Roland. There's a number of changes that were made which we --

MR. FLOYD: Scenario 1?

MR. VILLAR: What's that? I'm sorry.

MR. FLOYD: Scenario 1 you told us was so we could compare with last year. You just got through saying that a while ago.

MR. VILLAR: Okay. Is this Scenario 1? I don't know what this is. This is 1998.

MR. FLOYD: Mario, I told you to compare that with 1999 Scenario 1.

MR. VILLAR: I understand that, Roland, but I don't know what went into this number. I haven't seen this number in I don't know how long.

MR. FLOYD: Well, the 12% was what your method produced last year. Would you agree with that? You may disavow it now --

MR. VILLAR: It may be, but I don't know what winter No. 6 is. I'm taking your word for it. I can't compare it. I don't know what this number is at this --

MR. FLOYD: I'm going to show you how to compare it. Look at -- on Page 10 you'll get a number of 12%. Now, this year you gave us a study and said, Scenario 1 was what we would use to compare with last year's study because you didn't make your coincidence factor changes and so forth. And so I looked at this year's study under Scenario 1 and I found for that same year you're saying we only need 1%. Now, those

are the numbers there. I'm not making these things up.

MR. VILLAR: I have not compared these two numbers, Roland. I would be glad to go back and look at them or have somebody look them --

MR. FLOYD: I'm not asking you to do anything --

MR. VILLAR: -- and give you an explanation for them, but I don't what it is at this point.

MR. FLOYD: All I'm pointing out here is -- and I don't want to get into a debate on -- is your methodology last year showed, and this is methodology that's scary to me, but -- and this is the reason. Last year you say we need 12% in 2004 and 2005. For the same year, this year, with one year's additional data, you tell me I need 1%. What that tells me is you're method is not very stable. You add one year data and all of a sudden you got reduced from 12% to 1% is what is needed.

By the way, that's the problem. You have the same problem that you said Staff had with only using five years of data. That's all you used, too; five data points.

MR. VILLAR: I understand that.

MR. FLOYD: And when you added six data

points you had a big change in there. That makes me nervous.

MR. VILLAR: I understand that that one data point is going to change. But what it's going to change is the median and I'm not assigning any probabilities to any of these numbers, unlike what Staff did last year. I'm not assuming that anything is going to occur in any particular way. And we are also recognizing all the assumptions and the changes that have taken place. It's just that this is the only data that's available.

MR. FLOYD: Well, it's kind of shaky data when you come in here one year and say we need 12%, and the next year you come in and say, well, one will do. It makes me wonder.

MR. VILLAR: I don't think it's shaky data. That's what the data shows. But, again, I haven't compared these two numbers. I'd be glad to take a look at it.

MR. FLOYD: All right. Thank you.

MR. BALLINGER: Commissioners, Staff still has several questions. I don't know if you want to take a quick break now because we're about to go through the packet of information that we handed out earlier.

CHAIRMAN GARCIA: Yes. Let's go ahead and take 15 minutes and then we'll start again with you, Mark.

(Brief recess.)

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MR. BALLINGER: There's a sign-up sheet over here on this thing. We need everybody to sign up so we can keep an accurate attendance list of today's proceedings. And I understand Mr. Henry Southwick wanted to say a little bit before we went on with Staff's questioning.

MR. SOUTHWICK: Just a little bit. I just wanted to point out that at the FRCC what we adopted was a 15% reserve margin standard. We did not adopt a methodology per se. We recognized that there is no perfect methodology and that's why we didn't do it. So what we adopted, as I said, is the standard, and I wanted to assure you that we have no intention or plan that I'm aware of at all to change that standard. Certainly not to lower or raise it at all.

MR. BALLINGER: Thank you. I told Mr. Villar he could probably go ahead and sit down for this because the Staff packet is a little cumbersome to be putting up on the overheads, but everybody should have the Staff documents packet we handed out

earlier. I know we sent it to the Commissioners before the workshop. If you need any extra copies, let me know. And I will get started.

Mr. Villar, if you could turn to Page 2, which kind of summarizes our 1999 concerns of the FRCC methodology. And I'd like to say that a lot of these are similar to what we had in '98 in that we're concerned about the low LOLP values. In other words, they tended to produce results of reserve margin of 6% to, 8%, roughly. What that means is that reserve margin is now the driving factor. Is that again the same case in '99?

MR. VILLAR: Yes, it is, Tom.

MR. BALLINGER: Really, we have had no experience at 15%. I know utilities have used it as a planning criteria, but LOLP has been driving -- when generation has been added, utilities haven't actually operated near 15% for quite sometime; isn't that correct?

MR. VILLAR: Well, part of the reason, among others, why LOLP was driving the reserve margins that were needed by the utilities was the fact that we had not as good unit availability as we have currently. And because we have made significant improvements in unit availability, the focus has changed from LOLP to

reserve margin and the two methodologies complement one another. We're not proposing to abandon looking at prior methodologies.

MR. BALLINGER: I understand. But basically now that we've gone to reserve margin being the key factor, we really haven't had -- sustained experience having reserve margin being the driving factor. That's kind of what's concerned Staff, when we get especially such a low level of 15%. We'll get to a little later in the packet of why that's a concern.

What I'm trying to point out here is that a lot of these concerns were also raised in '98 and we still have similar concerns.

MR. VILLAR: I understand, Tom. I just wanted to clarify the FRCC standard is a minimum standard and the projected reserves are higher than 15.

MR. BALLINGER: I understand.

I think what Roland brought up earlier, our concern this year is the dramatic changes from the '98 analysis to the '99, basically, with just one year of additional data; how the results swing significantly. And I think that gives Staff some concern, much like the FRCC had concern over our probabilistic method; that the lack of data can widely influence the

results. That gives Staff some concern about relying on, that of saying something is adequate or not.

The reliability during off-peak periods, this is probably a new one. We didn't have it as much in the '98 assessment but in '99, it's kind of come to light that maybe this is an area that needs further work. And then, again, the Christmas of '89 backcast, that's kind of an acid test that Staff does. We just try to see should we be no worse off than we were in Christmas of '89 as kind of a threshold issue. Again, I think looking at this year's test, we've come up with it's really hinging on maintenance, of when maintenance is scheduled and when the peak would occur. And, again, that kind of resolves with that other one with during off-peak periods as well. Those two interplay. And I think that's really what the Christmas backcast is telling us, but we'll get to that more as we go through the packet.

Page 3 and 4 basically show projected reserve margins that came from the FRCC FCG aggregate plans of years ago and they're indicated there on the side. And this shows that projected reserve margin has been declining for some time; isn't that correct?

MR. VILLAR: The actual reserve margins, yes. One point I'd like to comment on, Tom, is if you

look at the data you have there, a lot of the reasons why those reserve margins were very high had nothing to do with being driven by any reliability criteria or standard. We had a lot of oil backout being put in place, et cetera, which resulted in excess capacity. And that's the reason why reserve margins were higher.

MR. BALLINGER: Wasn't part of it, too, that LOLP was the driving factor back in those days?

MR. VILLAR: LOLP might have been the driving factor at some point, but I don't believe in the 50 to 40% reserve margin LOLP had anything to do with that.

MR. BALLINGER: Would you -- let's go on to Page 5. This shows some recent experience. Again, this goes to my questioning about we really haven't had experience at 15%. What this does, it looks at each year and it took the prior year's forecast and showed what the reserve margins were. And really since 1991 is the only time we had any experience of a 15% reserve margin; everything else has been higher, 18, 24, 19%. And that's what is troubling Staff, is now that we're adopting this standard of 15%, historically, though, we haven't had the experience there and that's why we're a little concerned. We want to be on the cautious side. And I just wanted to

point that out that also, probably, in those earlier years, as you said, that LOLP was the driving factor and so units might have been added because of LOLP violations and not reserve margin violations.

Let me go on. I think you stated earlier, too, the next page that you still believe LOLP to be a viable tool, don't you?

MR. VILLAR: Yes, we do.

MR. BALLINGER: Okay. But now it's no longer become the driving force because of high unit availabilities and things of that nature.

MR. VILLAR: That's correct. And we're still looking at it. If for some reason unit availabilities were to decline, LOLP results would probably show that.

MR. BALLINGER: Okay. I'm on Page 6 of the Staff handout, it shows a little table there. And in 1997 the FRCC actually did a comparison, if you will, of the .1 LOLP to reserve, margin and it showed these values here of about .1 would equate to about a 6 to 8% reserve margin. Are the results similar for '98 and '99? I couldn't track those numbers down anywhere.

MR. VILLAR: We didn't do a computation, Tom. But given the actual LOLP results we have

experienced recently, I would expect the reserve margins on a LOLP basis to meet just a .1% number to be significantly lower than the ones that we're projecting. So it might come in in the same range as the '97. I just don't know.

MR. BALLINGER: I'm going to digress real quick here because of something you handed out today, which is the first time I saw -- back to your analysis or your presentation, you didn't show this chart on the overhead slides, but it's Page 31 of your presentation. It shows all the results of the sensitivities on LOLP.

MR. VILLAR: My pages are no longer in order. Let me try to find them here.

MR. BALLINGER: We can --

MR. VILLAR: Yes, Tom.

MR. BALLINGER: And I'm looking at the Column that says "No Direct Load Control."

MR. VILLAR: Correct.

MR. BALLINGER: Okay. Now, to me what that said is that basically what you did is you assumed all your load to be firm load and did a LOLP analysis, except for other DSM measures, such as air conditioning and things like that, but basically load management and interruptible load were not exercised

and you calculated the LOLP values. Is that correct, that sensitivity?

MR. VILLAR: I'm sorry. You said something about air conditioning load? You lost me on that one.

MR. BALLINGER: Perhaps not. That's already embedded in the load forecast. But this sensitivity basically took the nonfirm load.

MR. VILLAR: The interruptible and the DSM programs --

MR. BALLINGER: -- part of your reserve margin.

MR. VILLAR: -- not to be available.

MR. BALLINGER: -- and treated them as firm load for LOLP calculations. So these numbers being so low tells me that the peninsula should be able to serve all of its load management and interruptible load and never interrupt them. That they are reliable enough. There's enough reserve margin out there to serve those people 24 hours a day, seven days a week. That's what these LOLP numbers tell me.

MR. VILLAR: No, they don't.

MR. BALLINGER: Then what do they say?

MR. VILLAR: That's just a sensitivity to that.

LOLP just looks at a particular set of

conditions and produces a result based on those conditions. It doesn't mean that because LOLP analysis tells me this particular answer, I am going to be making all kinds of assumptions as on how the system is operated and whether I'm going to be able to serve load under all conditions.

MR. BALLINGER: I'm not. But from a reliability standpoint, if LOLP is still a viable alternative, these numbers tell me that I could serve all of my firm and nonfirm load and never interrupt them because the value is less than .1.

MR. WILEY: This is Ken Wiley, Tom.

We discussed this extensively last year and the prior years, especially in 1997, and I think we were indicating to you that back when one-day-and-ten-years LOLP was the significant planning tool that was driving things, we were experiencing equivalent availability factors of around 80% in this state. And now we're between -- somewhere between 88 and 90%; quite a significant increase in unit availability.

And we're not sure what one day -- or what day per ten years, or whatever, applies when we're up at the 90% availability. One-day-in-ten-years and 80% availability was a good combination, and we understood

that back in those days. We don't feel that one-day-in-ten-years is the appropriate number with these high availabilities which are approaching 90%. So we don't know what it is.

MR. BALLINGER: And I apologize, because this is the first time I've seen this data today.

Let me go back to the Staff handout, again, on Page 6. If I understand correctly, Mario, it probably is okay to assume that a .1 LOLP would equate to about a 6 to 8% reserve margin for '98-99.

MR. VILLAR: I don't know what the actual number is, Tom. I wouldn't expect it to be significantly different from there but I don't know.

MR. BALLINGER: Okay. Given that FPL is about half of the peninsula system, would you expect there to be a similar correlation between their LOLP and reserve margin numbers as compared to the peninsula numbers? I mean, should they be pretty close?

MR. VILLAR: I haven't looked at that. Perhaps Steve Sim can answer that question better.

MR. BALLINGER: I'm just asking you from the FRCC, would you expect that to happen when you aggregate and look at a total system basis.

MR. SIM: Tom, if I understand what your

question is, would FPL expect to see similar LOLP results?

MR. BALLINGER: Yeah.

MR. SIM: The answer is no.

MR. BALLINGER: Okay. We'll get there. Thank you.

Mario, I gave you another handout which you handed out earlier --

COMMISSIONER CLARK: Well, you can't leave that pending. Somebody has got to explain that to me.

MR. BALLINGER: We'll get there. I want to first prove that they --

COMMISSIONER CLARK: Can he explain it now, Tom, while I'm still thinking of it?

MR. BALLINGER: Well, maybe it would be helpful to show how different they are and then he can explain. That's all I was going to do next.

MR. VILLAR: I'll let Steve get into it in detail.

Part of the reason, Commissioner Clark, is that there's a significant number of assumptions that are different, in particular, the number of units, the availability of the different units, et cetera, which are different between FRCC and FPL's, but I'll let Steve comment on that some more.

MR. SIM: Tom, this was one thing I was going to touch on very briefly in the FPL presentation. I would not expect the FPL system to have similar LOLP values to the Peninsular Florida simply due to the size differences between the systems and specifically the number of units, the much greater of units in Peninsular Florida than there are in the FPL system.

MR. BALLINGER: Would you expect several orders of magnitude?

MR. SIM: What I would expect for FPL is on the order of .0-something, .01, .07, something along those lines for FPL's system. Given exactly similar circumstances for Peninsular Florida, I would expect out several more decimal points of zeros before we got a significant digit.

MR. BALLINGER: Okay. And these concerns were raised last year, and I know FPL had some concerns about the FRCC analysis because their first take was it should have been much closer. They were concerned with the very low LOLP numbers that the FRCC was coming up with and they didn't correspond with their values.

I never got a clear explanation as to why the difference was. It appears that the FPL and the

FRCC agreed on something. Staff has never been made aware of clearly why the difference is there; never seen the numbers to justify why the difference is there.

MR. SIM: Tom, I think the answer for that is we didn't have an answer for that last year during the FRCC presentation. One thing FPL did during its 1998 planning work is we did an independent assessment of LOLP for different size systems keeping all assumptions similar and then varying one at a time. We looked at a generic utility system of about 15,000 megawatts, the FPL system size. We then grew that system and shrunk it down to 5,000 megawatts and up to 45,000 megawatts to try to convince ourselves that we could, indeed, believe the validity of the LOLP results we were getting, both for FPL and for the FRCC. And we were able to convince ourselves that those numbers were not only reasonable but should be expected.

MR. BALLINGER: Well, perhaps you could impart that knowledge to Staff and we'd like to mull over that.

MR. SIM: We'd be happy to share that with you at a convenient time.

MR. BALLINGER: Okay. I'm on to Page 7 now.

And what this is is from the -- I guess it was an item at the agenda of the FRCC basically saying what the FRCC would do with this standard that's been approved now or adopted by the FRCC.

And the way I understand it is that if a utility is shown to be below the 15%, that the FRCC would find out who the offending parties are, notify them, and also notify the PSC. Is that a correct summarization of this?

MR. VILLAR: If you found that a utility was below the 15%? No, that's not the case, Tom.

MR. BALLINGER: No. If the Peninsula was below the 15%, the FRCC would seek out who were the offending parties to cause the whole Peninsula to drag down and notify those party or parties and the Staff.

MR. VILLAR: We would assess the circumstances and identify how far off we are from the 15% standard; how the various parties are affected et cetera, and then we would make a report to the Commission and to the FRCC board.

MR. BALLINGER: But the FRCC would take no independent action, if you will, or sanction of a party. They'd get the parties together and see what they could work out?

MR. VILLAR: It would be reported up to the

board. I don't know what the board would do. I can't answer that one at this point in time.

MR. BALLINGER: Okay. Do you honestly expect --

COMMISSIONER CLARK: Let me ask you a question. Do you think that's likely to change depending on how -- if the legislation that is being proposed to change NERC to NAERO, might they take some action under the new legislation, do you know?

MR. VILLAR: That might be something that Ken could probably answer better than I can.

MR. WILEY: I don't anticipate that the adequacy issue is going to be handled by the NERC legislation.

COMMISSIONER CLARK: Okay.

MR. BALLINGER: In all honesty, what are the chances of that happening in the out-years, of somebody being below 15%, knowing now that it's a standard?

MR. VILLAR: I guess it would be remote but --

MR. BALLINGER: It would be what?

MR. VILLAR: Remote.

MR. BALLINGER: Okay. And if it happened in the earlier years, say first, second, third year -- I

think you said there's really not much we can do about it from a planning perspective.

MR. VILLAR: In terms of adding units or something like that, you're probably correct on that. As to whether some other measures can be taken, that's something else. Operationally there's a lot of tools that are available to utilities to take care of short-term problems.

COMMISSIONER CLARK: Tom, let me interrupt just a minute.

I just want to make sure that in the early years where there's less percentage reserve margin, that's still only assuming an import of, what, 1400 megawatts?

MR. VILLAR: What, Commissioner, I'm sorry, import?

COMMISSIONER CLARK: What is the import capability figured into that margin of reserve?

MR. VILLAR: Import into the state? Ken has it here. 1999 it's contracted firm interchange of 1640 megawatts.

COMMISSIONER CLARK: How much more could we import if we needed to?

MR. VILLAR: Let me go back and refer to it. I think we're talking about a thousand megawatts.

COMMISSIONER CLARK: Okay.

MR. BALLINGER: But my point I was getting at is in the short term, the FRCC again would notify or try to find the parties and get them to work it out, but it would be more operational things; it may be securing a short-term contract over the interties, things of this nature.

MR. VILLAR: If reserves were to drop blow 15%?

MR. BALLINGER: Yeah.

MR. VILLAR: They are not below 15%.

MR. BALLINGER: If they were. I'm trying to get a hold on the FRCC's procedures of what they would do if this standard is violated.

MR. VILLAR: Yeah, they would look at it. And remember, the FRCC also has an Operating Committee that looks at this stuff on a regular basis; not just on a long-term planning basis.

MR. BALLINGER: I'm going to go through something that's kind of an example of how I think it would work and how it has worked in the past and what happened.

Back in '97 the Staff had some concerns about a couple of utilities' plans which had unspecified purchases or unidentified purchases. And

the FRCC correctly removed those from its aggregate plan and that showed reserve margins declining down to about 8%, or 5% in the out-years.

There was a lot of hullabaloo going on about what to do. The FRCC then, when it did its 1997 reliability assessment, added back in another 1500 megawatts of now committed capacity from various utilities who had updated their plans.

Is that kind of the process that would happen again, is: One, the FRCC identifies there's a problem in reserves; two, they get together with the affected parties; and three, they rework their plans to make it fit the standard before any formal finding by the Commission.

MR. VILLAR: Tom, I wasn't directly involved in the 1997 study. I was not looking at that kind of stuff at the time so maybe Ken would be better off --

MR. WILEY: I wouldn't characterize it as reworking plans to make it fit the criteria for Commission purposes, though. So I'd object to that comment, Tom.

But yes, we did in 1997 go back to those unspecified units and we talked to all of the utilities that had that in there and indicated that something had to be more clear than that. And as a

result of that, they did provide some clarification to some of those capacities as to what they were doing in anticipating without violating some of their confidential matters, and we ended up including some of that capacity back in there as a result of those bilateral conversations.

MR. BALLINGER: Okay. We can move a little quick here. Page 8 is just a letter I sent to you Mr. Wiley, and I also sent to all of the other utilities last year. And Page 9 is just a summary of what our concerns were in the 1998 assessment and that was just to kind of show they are very similar in '99.

Up to the reserve margin driving this, that LOLP is no longer the driving force. The main reason is high generator availability, if I understand right. In the last three to five years, we've seen availabilities increase up into the 90% range; is that correct?

MR. WILEY: Yes, that's correct.

MR. BALLINGER: Okay. And on Page 10 -- this is something -- I'd like you to look down in that middle box where it has Peninsular Florida and the in-service dates. And if I do the math right, it looks to me that about 26% of our capacity is 30 years or older. And do you still think it's reasonable to

assume a high generator availability with such an aging fleet going forward in the future for the next ten, 15 years?

MR. VILLAR: Tom, I haven't seen these numbers so I can't confirm them, but in general terms there's a significant amount of dollars that each utility spends on improving the availability of their units and performing operation and maintenance on those facilities to be able to make sure they are available when they are needed.

So to the extent that the utilities have spent those dollars and continue to maintain those facilities, yes, I would expect the availability of the units to continue to be there.

MR. BALLINGER: Even for old units that are 30, 40 years old?

MR. VILLAR: There's nothing wrong as long as you are maintaining the unit with -- the 30, 40 year old unit.

MR. BALLINGER: Okay. I think Henry stated earlier, too, that really the FRCC adopted a standard, not really a methodology, because a methodology changes; it's a work-in-progress. You're always updating it and looking at it. Did I characterize that right, Henry?

MR. VILLAR: Yes. You know, like data points, for example, as methods change, et cetera, some of those prior years data may not be useful anymore. They may not be representative of what the future conditions would be like.

MR. BALLINGER: Right. And this year you did some things like the noncoincident factor -- or a coincidence factor, I should say, and removal of the '93 data to try to improve the methodology.

MR. VILLAR: That's correct.

MR. BALLINGER: Okay. On Page 11 --

COMMISSIONER CLARK: Let me ask a question on that.

I thought you continued to assume -- you continued to use noncoincident in your analysis, but then you said you could assume that the reserve margins would be 2% higher if you used coincident.

MR. VILLAR: What we did, when we reported both the forecasted FRCC reserve margins, we did not put in a noncoincident factor adjustment. In performing our analysis in terms of the scenarios that we looked at, we did include a load diversity factor in there, a noncoincident adjustment, because we felt it was the appropriate thing to do.

MR. BALLINGER: Okay. On Page 11, this is a

table I got last year attending one of the FRCC meetings and going through this process. And it shows the generation certainty factors, the data that was used to calculate this. And I raised this at the last hearing in '98 and I'm wondering, are you still relying on this basic data again, just adding a 1998 column -- and I understand you removed '93 -- but, basically, these would be the same numbers?

MR. VILLAR: I haven't seen these numbers before but I would assume so. Steve says there might be some minor corrections, Tom, but otherwise it should be --

MR. BALLINGER: Okay. I mean we asked for the certainty factors a while ago. We still have yet to receive them. So this is all I've got.

If you'd look at the data for Orlando and Seminole, and they are showing zeros as certainty factors for their generation compared to peak, and does that mean they are perfect for five years? Or does this data give you some question that maybe they didn't have all of the data they needed?

MR. VILLAR: That's the data reported, Tom, as being available at the time of peak.

MR. BALLINGER: But does it concern you, from the FRCC, to rely on this data when it looks a

little suspicious? That they've had no errors in their generation availability? And, again, this was brought up in '98.

MR. VILLAR: It could happen.

MR. BALLINGER: Okay.

MR. VILLAR: I don't see any reason why.

MR. BALLINGER: Okay. Did you question OUC and Seminole about this?

MR. VILLAR: I didn't personally, no.

MR. BALLINGER: Did anyone at the FRCC?

MR. VILLAR: Steve says that, yes, that Seminole was questioned on it.

MR. WILEY: Tom, this is Ken.

You know, you indicated that you haven't seen this data. And I would just like to, for the record here, indicate that some of the reasons you're not seeing a lot of data this year is because the Commission decided to take these particular matters of reserve margin, and all these other things surrounding them, and put them in a docket. And as you know, we were hoping that you were going to be very involved in our study this year, but the Staff was not able to because of a lot of complications surrounding the fact that we were in a docket. So I just wanted to say that for the record.

MR. BALLINGER: Let me move on. Let's look at this table here.

If I recall from what you did, is you removed the '93 generator availability data because that peak occurred in March, you had a lot of units down for maintenance.

MR. VILLAR: I'm sorry, Tom. What are you looking at?

MR. BALLINGER: I'm still on Page 11.

MR. VILLAR: Page 11 still?

MR. BALLINGER: Yeah.

In the '99 study you removed the 1993 data because the peak happened in March; you had a lot of units out for scheduled maintenance.

MR. VILLAR: The winter data, that's correct.

MR. BALLINGER: Looking at the bottom totals, that had the largest impact on generator uncertainty, if you will, with 1993's, right?

MR. VILLAR: Yes.

MR. BALLINGER: Okay. And then you also in '99 included a coincidence factor on the peak load for all of your scenarios.

MR. VILLAR: Except for scenario two.

MR. BALLINGER: Right.

The combination of these two adjustments, doesn't that serve to raise the reserve margin? Or conversely lower your needed reserve margin?

MR. VILLAR: It will lower the needed reserve margin because you're taking into account that load diversity does exist. So you do need less reserves to meet a low diversified load than you do a nondiversified load, yeah.

MR. BALLINGER: And you kept the same standard of 15% both in '98 and '99 as far as the bar that your measured --

MR. VILLAR: The FRCC standard is a 15% minimum reserve standard.

MR. BALLINGER: Okay. If you get an extreme winter like we had in Christmas of '89, or severe cold, wouldn't you agree that diversity kind of drys up; that basically all of the utilities are peaking at the same time?

MR. VILLAR: Not necessarily, Tom. I looked at the data you guys had in the '89 report, in the back of the report, and the only way the data was reported was by morning and afternoon. You could have diversity. One utility might have peaked -- for example, let's take just the afternoon peak. One utility might have peaked at 3:00 in the afternoon,

another one at 5:00. You still have diversity among utilities in terms of when they actually peaked within the same day.

(Comment from audience.)

MR. BALLINGER: Well, that's not my recollection from the '98 data.

COMMISSIONER CLARK: You know, I think just --

MR. VILLAR: '89 data, you mean.

MR. BALLINGER: '98 data. I'm sorry, go ahead, Commissioner.

COMMISSIONER CLARK: In preparation for the docket, I think it would be useful to understand what diversity of peak did occur during 1989.

MR. VILLAR: There's no way of knowing, Commissioner. Because the data is not reported that way.

COMMISSIONER CLARK: I just heard somebody say that Corp peaked on the 3:00 in the morning.

(Simultaneous conversation.)

MR. VILLAR: Some people might know at what hour they peaked.

COMMISSIONER CLARK: I think it would be helpful to know because --

MR. VILLAR: All right. We'll try to see if

we can come up with that. But all we had was the actual Staff report from '89, and from that Staff report it was impossible to come up with what the coincident peak was.

MR. BALLINGER: What I recall from the 1998 study, when the FRCC provided Staff all of the data, is there was very little diversity on winter peak for these five years that you did for a historic database. That virtually every utility was peaking on the same day at the same hour in the winter, and these were mild winters that we had in historic. I have it back here in would of my folders. I'll probably have to dig it out and have it for the hearing that we go for.

But it brought to me that when we get a cold, a severe cold front that gets all the way down to Miami, everybody's peaking at about the same time. People still get up about 6 o'clock in the morning and take shower and turn their heat on and go to work.

MR. VILLAR: I'll try to look at the data the Commissioner has requested and see if we can come up with that, Tom. But we did have a independent consultant look at the load diversity in the system, and the numbers we applied were the numbers that the consultant arrived at based on the data we had, which was the data from the last six years.

COMMISSIONER CLARK: I would only comment, to the extent you want us to take comfort that you can take account of load diversity in determining an appropriate margin of reserve, there should be some basis for us to conclude that that is appropriate when you have an extreme weather condition.

MR. VILLAR: I understand. We'll see what we can do there, Commissioner.

MR. BALLINGER: Back to the coincidence factor, my reading is not all of the utilities within the FRCC agree with using a coincidence number when aggregating peak demands or testing a reserve margin analysis. Is that your understanding, too, that there may be some dissension in the utilities?

MR. VILLAR: The RWG looked at the issue and there was no dissension at the RWG in terms of conducting the analysis.

MR. BALLINGER: Okay. If we go with a coincidence factor that's applied, how do you suggest that the Commission compare past FRCC aggregate plans? That we apply the same coincidence factor to all of them? Do we ask the FRCC to go back and develop a coincidence factor for the 1994 plan, '93? How should we go forward?

MR. VILLAR: I don't see any reason why you

need to compare to what happened in the past in terms of comparing loads now. Things change and you constantly need to adjust. You don't need to be adjusting prior practices or methods, Tom, I don't think. You just basically need to recognize what the future will hold and the basic changes that have been made and methodologies, et cetera, from here on out. I don't know what it serves.

MR. BALLINGER: Okay. On Page 12 now of the handout, this was basically a compilation of data from a letter we sent back on Page 8 of all of the utilities. If you read Page 8 it says, "There's attached tables. Please fill them out." This is the compilation of those results.

And I'd like to, if you can, from the FRCC perspective, and all of this load diversity and everything else, does it give you some concern that -- let's see Seminole, Tallahassee, JEA and TECO have different temperatures for the same city?

In other words -- let me see here. Like for Seminole and Tallahassee, they forecasted 19 degrees for their peak in the winter. But the City of Tallahassee uses 22 degrees for their peak load. For Seminole, they use 24 degrees in Jacksonville, yet JEA uses 23 degrees. Seminole uses 32 degrees for Tampa

yet TECO uses 31. Does that give you any concern when trying to do a compilation of data, that the individual utility forecasts, they are not doing the same temperature profile for the similar cities?

MR. VILLAR: I'm not a forecaster. You need -- perhaps Leo Green can help with that one.

But, for example, in the Miami area, whenever you see the television stations, they report the temperatures in Miami at five different places in the Greater Miami area five different temperatures, so where you measure the temperature might have something to do with it. I don't know, Tom.

MR. BALLINGER: But if you're applying a coincidence factor, I'd assume you'd want to know that the individual forecasts were accurate to begin with before you apply a coincidence factor.

MR. VILLAR: Leo.

MR. GREEN: It is possible that utilities might have different temperatures. If Seminole goes back 30 years and Tampa goes back 20 years, you could have a different average temperature. And there's nothing wrong in that because it's a statistical answer. You want to correlate data with temperatures. If Seminole is using 30 years and they want to correlate 30 years of temperature with load data, it's

okay. So you can have different temperatures.

And I'd like to jump back to the diversity you mentioned. In Christmas of '89 North Florida was coldest on the 23rd of December, South Florida was coldest on the 24th. We do not know when the state peaked because a lot of load was not served. But if I look just at temperatures, it would suggest that even in Christmas of '89 there is some diversity on the system.

COMMISSIONER CLARK: Just so I'm clear, it doesn't matter that each one uses a different temperature as long as they have correlated it to what their peaks are.

MR. GREEN: That's exactly correct, Commissioner.

MR. BALLINGER: Again, on this Page 12, I'm looking over at the column of percent of reserve margin of nonfirm load. And the data we got in '98 showed that for winter, Florida Power Corporation was relying on 94%, basically, of their reserve margin was made up of nonfirm load; that being load management interruptible load. Tampa Electric Company was 66.8% of all their reserves was nonfirm load.

To me that tells me that they are planning to interrupt their interruptible customers, they're

planning to exercise load management at time of winter peak. Because virtually everything is in the DSM side of it. Yet your LOLP numbers for '99, to me, say they could probably serve everything in the state.

Does it concern you having that much nonfirm load making up reserves for Peninsular?

MR. VILLAR: I think the nonfirm load has been something that has been addressed by the Commission. All of these nonfirm load issues and the amount of nonfirm load that each utility has on its own system has been done on the basis of what is cost-effective to that utility and approved by the Commission in accordance with the goals. From there on out, I can't comment anymore because each utility has its own individual needs and particular characteristics that I'm not aware of.

MR. BALLINGER: So from a reliability standpoint, though, for the Peninsular, it wouldn't bother you if all of our reserve margins were nonfirm load if that was proven cost-effective?

MR. VILLAR: Generally there's a point in which nonfirm load becomes non-cost-effective before you reach 100% of reserves. If you do have a certain amount of reserves in nonfirm load, you ought to use them.

MR. BALLINGER: Do you know if the '99 plan shows similar numbers as far as percentagewise?

MR. VILLAR: I haven't look at it on an individual basis. I don't know what the numbers show.

MR. BALLINGER: Okay. Page 13. I'm really only going to ask you generally here. This is -- we had some concerns in 1998 of a heat wave, and power being sold and bought, people alleging being gouged by price marketers.

Do you know in 1999 did we have a similar experience as far as were there any like in -- I guess it was April of this year, we were under an alert -- was the purchase price of power fairly high?

MR. VILLAR: I don't know, Tom.

MR. BALLINGER: Okay. On Page 14 through 16, a letter from Mr. Jenkins to Mr. Adjemian who was your predecessor, I think, last year with the RWG. And the two attachments show a historic thing of temperatures at various cities. And the highlighted days are when there were two or three consecutive days below the trigger temperature shown up at the top. And those trigger temperatures are temperatures in which a utility would issue an advisory, if you will, per that emergency plan.

A couple of things I get from this letter

and exhibits, is that one, it shows that from 1990 to date we have had pretty mild winters. And I think you said that earlier. You could see, like, for Miami, there's been no advisories up through '94, and then we had a couple, '95, '96 and '97, but they have been real close to the trigger temperature of 40 degrees.

MR. VILLAR: That's correct.

MR. BALLINGER: And the same has been pretty much true throughout the state.

I think it also shows that there's been -- 1, 2, 3, 4, 5, 6, 7, 8 -- 9 coincidences where we have had two or three cold days in a row. In other words, that it's just one day that it gets cold and then it warms back up. It will be a semi-sustained cold period, at least going back to 1970.

MR. VILLAR: Yes.

MR. BALLINGER: And then on Page 17 just kind of graphically shows that. And basically that data was taken from this chart and just put it in graphical form to show the typical trend. It will be cold one day, it may be cold the second day and start warming up the third day, much like the sensitivity you did for LOLP.

MR. VILLAR: Okay.

MR. BALLINGER: I'll ask this, I asked

earlier: You didn't do a similar sensitivity on a three-day cold period for reserve margin. What you did is take the worst uncertainty factor and applied it to the load forecast and saw what the reserve margins came out; is that correct?

MR. VILLAR: We looked at the time of peak. Reserve margin only looks at the peak.

MR. BALLINGER: So you don't know what a three-day sustained cold front would have on reserve margins?

MR. VILLAR: A three-day sustained cold front? I would expect it to be similar to the analysis that we did in Christmas of '89 where we showed we could probably meet the load.

MR. BALLINGER: Okay. Now, we get to Page 18. This was similar to what you had in your presentation, which was a Staff chart that we did back in 1998. This has been updated a little bit more. Let me walk through and explain what the changes are before we go.

First off, it assumed in the plan side -- let me back up again. The Christmas of '89 column is data taken from the Staff Report that gathered data from utilities to present actual forced and planned outages and expected load that was unserved. So all

of those numbers came right from that report and they are actually what occurred.

The second column is from the FRCC 1999 Load and Resource Plan. Those numbers came directly out of that.

And the third column is what if that plant had been at a 15% reserve margin? In other words, it just adjusted utility generation down to a level to get 15% reserves, and then did the rest of the calculations.

I'll point out up at the top in the small print -- it may be a little small to read -- that the availability of utility generation was not the 77% that was assumed back in '98, but rather was 92.4% and that came from the certainty factors of generators in the 1998 study. So basically it assumed that all utility generation had an availability of 92.4% at time of peak, which matched up with the FRCC's certainty factor. That was taken separate after maintenance was pulled out, as you see in Row B.

And, really, all I want to do is a comparison between 18 and 19, is just to look at the only difference between the two sheets are that maintenance is included on Row B. Then the rest of the calculations follow out in the same methodology.

Then what it tells me is if you look at Row L, I guess it is, that without maintenance -- in other words, the FRCC did not have any scheduled maintenance and we had a similar event as in Christmas, and, again, I know we can argue about the 16.9% load forecast error, but let's assume that to happen -- that if there was no maintenance plan, that even a 15% reserve margin should result in less megawatts not served than Christmas of '89. But, however, if you had maintenance scheduled during that time much like you had in Christmas of '89, that there was scheduled maintenance going on, and we got hit with a cold front, the number would jump up above what happened in 1989.

I guess what I want you to think about of what I get out of these two is that maintenance is really critical, especially in a off-peak time when peak can happen. Do you agree with that statement?

MR. VILLAR: Maintenance is critical all the time, yes.

MR. BALLINGER: And isn't it true that -- you know, you do maintenance in off-peak periods but you can't tell when a cold front is going to come or when we're going to get a heat wave like in April. So those periods are really where utilities are most

exposed?

MR. VILLAR: I wouldn't necessarily agree with that. Generally, if you are in one of these valley periods, let's call it, or off-peak periods, even though you might get a peak during that period, the peak is generally lower than the peak you would experience in the peak period. Even though you might have some units out for maintenance, you probably are still able to meet the load.

MR. BALLINGER: Like you said earlier, that this past five years the utilities peaked -- in '93, anyway, they peaked in March, not January or February.

MR. VILLAR: Yes.

MR. BALLINGER: And Christmas of '89, that happened over a weekend, which typically has lower loads than a week day; is that correct?

MR. VILLAR: For residential load, not necessarily. Because generally the residential load tends to drive the winter peak. This is a big contributor to it.

MR. BALLINGER: But from a system load, everything I have seen is that weekdays are your peak days and weekends tend to drop off.

MR. VILLAR: Generally, they are. But if you are in a holiday weekend and everybody is at home,

and you have an extreme winter temperature, everybody is cold; they have their heaters on and the peak may be more pronounced than it would be when people are sitting at the office where they have more efficient systems going on, et cetera, and strip heating at home is turned off because they happen to be in the office or at work.

MR. BALLINGER: Page 20, just to kind of show you where that number came from the maintenance. This is a sheet I got from the FRCC that we get periodically -- kind of sporadically, actually -- that shows plans for maintenance of utilities. And you can see there, in December, the third week of December, of 2955 the utilities actually were planning to do some maintenance in the third week of December. Again they had zero in the fourth week, and then very little in January and February, as you would expect. But then again back in March, the first week in March, they have almost 2000 megawatts scheduled for maintenance.

I guess that's what is concerning me is these valley periods of scheduling maintenance. Has the FRCC done anything to look at those periods from a reliability perspective?

MR. VILLAR: Tom, one thing that's not evident from here is you have an August 20th FRCC

projection of what reserve margins were going to be and what units were going to be out for maintenance. I know in this particular year, by the beginning of December, there was significantly less number of megawatts out for -- scheduled for maintenance in the period in question. And that is based on a shorter term forecast where you get closer to it and you see what the projected loads are, et cetera.

The FRCC from an Operating Committee and individual utilities look at what unit maintenance they need to do on a regular basis and they are constantly updating the numbers given the projected conditions at the time, whether the units are out for maintenance or they have a forced outage, et cetera. All of that gets taken into account. So no one number at any particular time is actually representative.

MR. BALLINGER: I know. This is just the latest one I had. We don't get them all every week or every month or anything like that.

MR. VILLAR: Sure.

MR. BALLINGER: Okay. Page 21. This goes back to again what Roland was saying --

MR. VILLAR: Before we leave this, Tom, I'd like to make a couple of points on your graphs, on your charts on 18 and 19.

If you just make a couple of minor adjustments to your numbers here, taking into account the changes that FPL, for example, made, the 800 megawatt change in the forecast, and still applying your 16.9% load forecast error to these numbers, and take into account operational measures, there will be no unserved load in here. And I would expect similar conditions to occur on Page 19.

MR. BALLINGER: So that again goes to your statement earlier that you would expect if we had another Christmas freeze of '89, the Peninsula should be able to serve all firm load.

MR. VILLAR: Under more reasonable conditions. I'm not telling you that at any particular point we're going to be able to serve all the load all the time. There might be some instances in which we might be able to. But under more reasonable assumptions and conditions, we would expect to be able to serve the load.

MR. BALLINGER: What more reasonable? I'm assuming it gets down to, what was it? 23 degrees. How cold did it get in Miami on Christmas? If we have temperature like that, you're saying you expect to serve all firm load.

MR. VILLAR: Based on the conditions that we

have in our analysis, yes.

MR. BALLINGER: Can I go to 21? This goes back, again, to what Roland was pointing out, the difference between the '98 and '99 study and how they jumped with the addition of one year.

Now, these numbers are both the base cases for both studies. It's not the Scenario One. So in other words, the 1999 study includes the impact of the coincident factor and the removal of '93 data, but it's one the FRCC believes is the most reasonable case. Okay?

All this table really shows is that summer looks pretty close from what we got last year, at least the data looks somewhat consistent. I know It gives Roland some concern in the early years that we could get by with 8% reserves, but it's close to what we had last year.

What's concerning is in the 1998 study, in the winter, where you go from the 13% in the out-years to zero and minus 1%, that's a significant change with basically adding one year of data and doing these other improvements that you said.

Does that bother you with the methodology that it's that erratic?

MR. VILLAR: No, it doesn't. This is what

the results show, Tom, and we incorporated some improvements to the methodology; this is what the data shows. And, again, we're not saying that because this is the results that we're changing our reserve margin standard. Our reserve margin is the minimum 15% reserve margin.

MR. BALLINGER: So you think that --

MR. VILLAR: And we not only look at these numbers, but we look at sensitivities associated with those numbers, we look at extremes in the other direction and we also rely on a LOLP analysis. So we look at all of the factors in order to arrive at a conclusion as to whether or not our reserves are adequate. We think that based on all the factors and all the circumstances the reserves are adequate.

MR. BALLINGER: Okay. So it gives you no heartache at all that a methodology to test a reserve margin gives you such drastic results from one year to the next?

MR. VILLAR: No, it does not.

MR. BALLINGER: Okay. In general, would you agree that planned reserves have an impact on operating reserves?

MR. VILLAR: Operating reserves are the use the plan reserves. You plan for something. Once you

have it in place, then you operate the reserves you have planned once you built them.

MR. BALLINGER: And generally, the more planned reserves you have probably the more operating reserves you'd have and vice versa?

MR. VILLAR: Well, I mean, It depends on what you do with them, yes.

MR. BALLINGER: They are at your disposal. Obviously they are in the ground. They are there.

COMMISSIONER CLARK: I don't understand that.

MR. BALLINGER: If you plan to have 2000 megawatts three years from now versus planning to have 1500 megawatts two years from now, you're going to have less operating reserves obviously.

COMMISSIONER CLARK: When?

MR. BALLINGER: -- going with the lower amount.

COMMISSIONER CLARK: When?

MR. BALLINGER: Two years from now.

COMMISSIONER CLARK: It depends on what gets built. I don't see the relationship at all.

MR. BALLINGER: Let's say this: Let's say that the plan is to have 4,000 megawatts of reserves two years from now. That's the plan. But now because

of a standard, we're going to say, "No, I'm only going to plan to have 3,000 megawatts available two years from now because of a change in a standard." That has also had an equal, if you will, effect on operating reserves that you will have available then.

COMMISSIONER CLARK: At that time.

MR. BALLINGER: In other words, if you go from a 20% reserve margin to a 15% reserve margin, you have less operating reserves as well. Is that a general movement or principle that you see?

MR. VILLAR: I would say so. But the question is whether you need those operating reserves or those plan reserves. If up don't need them, then it's fine to have them.

MR. BALLINGER: I understand. I'm just trying to get -- there is a correlation, though, between planned and operating?

MR. VILLAR: Only from the standpoint that if I built X number of megawatts and I have it available on a regular basis, and I can do -- we can have maintenance on them or to account for forced outages, et cetera, yes, to some degree there is, but not very direct.

MR. BALLINGER: Maybe this would help. If for the past ten years utilities were planning at 20%

reserve margins and were always right about 20%, that gives you X amount of operating reserves. And now they decide we don't need to plan for 20%; we can plan for 15. That would give you X minus some number of operating reserves on a going-forward basis, would it not?

MR. VILLAR: Yes.

MR. BALLINGER: Okay. That's all -- I mean, I thought this was pretty simple. I didn't mean to make it complicated.

MR. VILLAR: Okay.

MR. BALLINGER: I'm on Page 22. And what Staff has done is tried to show this relationship of planned and operating reserves to try to get some actual feel. And let me explain a little bit about what these columns are and what they mean.

Is it your understanding when there's a Peninsular Advisory, does that mean that we've reached some temperature thresholds per an emergency plan? (Pause)

MR. VILLAR: I'm sorry, Tom. I was talking to Ken Wiley here.

MR. BALLINGER: Okay. When we reach an Advisory for the Peninsula, does that mean that there has been certain temperature thresholds reached within

the Peninsula?

MR. VILLAR: I don't recall how the emergency plan is set up.

MR. WILEY: Yes. Yes. You can reach either a temperature threshold or a specific utility might be calling for conservation measures. Those are two things that could occasion an Advisory.

MR. BALLINGER: But generally they are caused by temperatures.

MR. WILEY: Yes.

MR. BALLINGER: What we did, is we got some actual Capacity Advisories from the FRCC over the last couple of years on these specific dates and it showed the operating margin we had. So like in June 16th of '98, there was an Advisory, which meant it was hot probably that day, but we had 2600 megawatts of operating reserves so we were fine. We weren't in danger of losing any load but we were still kind of keeping everybody aware of what was going on. Is that a fair assessment of how it works?

MR. WILEY: Yes.

MR. BALLINGER: And you could see that through 1998 we had several Advisories through the summer, but we had plenty of operating reserves so there was no problem of getting into a problem.

Now, if we get down to where our operating reserves are less than the largest unit in Florida, which is 910 megawatts, that throws us into an alert state. Is that correct? A little bit more significant event.

MR. WILEY: Yes.

MR. VILLAR: Yes.

MR. BALLINGER: And that's because when you're at that level of operating reserves of your largest unit, that if that largest unit were to trip off line suddenly, there would be a lot of chaos going on. There would have to be interchanges going over the ties, hopefully. Hopefully, Southern would be there. And if they weren't there, we might have a disconnect from the southeast interconnect.

I mean, I'm trying to get -- is that why an alert is a critical situation; that you really sit up and pay attention when you get to an alert status?

MR. WILEY: An alert level is one that we take very seriously and it basically just puts red lights in every control room.

MR. BALLINGER: And basically what that is telling you is from a system standpoint, we're operating pretty close -- you know, if nothing happens we'll be okay, but if we lose a large unit we might

have to be scrambling around. Is that correct?

MR. WILEY: If we lost the largest unit, we would be interrupting some firm load, yes.

MR. BALLINGER: Okay. In 1998 we didn't see any alerts because we had plenty of operating reserves. But in '99 we had one alert situation in April of '99. I think we referred to that earlier today. That we had some unusually hot weather in April. There was probably some scheduled maintenance going on as well, and we got to this level of operating reserves. Now, we didn't lose any firm load that I can recall in April of '99. Is that your recollect as well?

MR. WILEY: We did not.

MR. BALLINGER: Okay. Now, what this chart tries to do is say, all right, look over on the far left where it shows what the reserve margins were for that time period. In other words, in 1998 there was 6,260 megawatts of reserves, or 19%, in '98. And this was taken from FRCC data just the year prior so it should be pretty close to accurate, I'm hoping, or at least timely. And then that far right column, it took that planned reserve margin, it took what the difference in megawatts would be if you went from 19 to 15%, and then subtracted it from the operating

margins shown in the middle column. And what that does, is it tells me that if we had been at 15%, we wouldn't have had the operating margins, first off, that we actually had, and actually we would have been into alert status quite a few more times than we were. And, again, I think this just goes to exhibit the interplay between planned reserves and operating reserves.

MR. WILEY: What your analysis shows me, Tom, is that our 15% planned reserve margin would have been adequate to get us to this. We would have had an alert two times during the summer of 1998 and we would not have lost load.

MR. BALLINGER: Well, you don't know because nothing tripped. We don't know actually what happened, is my understanding. The FRCC doesn't keep actual results when we go through Advisories of what happened.

We would have been on alert status two times in '98 and three times in '99. And had we lost a unit, we would have been in deep trouble. In other words, what I'm saying is it's pushing it closer to your operating reserve margin envelope.

MR. WILEY: I think there's a lot of "we don't knows" in your analysis, not just these three

specific ones.

MR. BALLINGER: And I would agree. Do you -- like say, for example, let's take April of '99, we were in an alert status. We lost no firm load. Now, had we been at 15% we would have really been in alert status, and if we had lost a unit of 150 megawatts, we would have blacked out, or some utilities would have blacked out some customers. So we were operating -- if we had been at 15%, we would have been operating at a margin of only 150 megawatts before firm load was lost. That's what that tells me.

MR. WILEY: Well, that's what your numbers point out. I think that, first of all, you're looking -- our 15% planning criteria is a peak load criteria for summer and winter. It doesn't necessarily apply to the summer months. However, as you know, as part of our analysis we do look at all of the months. You just referred to that a few pages ago. And we used 15% when we look at things.

So we certainly did look at whether or not we had 15% or greater reserves during April. And as you know, that particular April was a very hot April. It was above our forecast expectations; very much so above it.

MR. BALLINGER: Okay. I'm going to move on

now to the last bit of pages.

This is more for clarification for everything. There's been some confusion about the Commission's reserve margin rule or the adequacy of resources, and some utilities seem to rely on it, that the Commission has adopted a minimum planning reserve standard, if you will. And what I'd really like you to do is turn to Page 24, which was a Staff recommendation, that addressed a clarification that Tampa Electric brought forward after this rule was adopted. And, basically, Tampa Electric asked to clarify this rule was for pricing purposes only, and not for prudency or planning reserves. And the Commission agreed with that clarification. Unfortunately, that did not show up in the Order adopting the rule. The Order adopting the rule just said here's the rule. Is that your understanding of how this rule became into existence?

MR. VILLAR: I understand that some utilities are interpreting it the way you said it, Tom. This is what I recall from the discussions that took place at the time. That it was for pricing purposes, but the language of the rule -- it's definitely -- you can read it absolutely the other way, that it's not for pricing purposes.

MR. BALLINGER: Well, how would the FRCC interpret this rule? Would they see it as a pricing rule?

MR. SOUTHWICK: It's my understanding it's a pricing rule. I don't know that the FRCC has officially interpreted it at all.

MR. VILLAR: Yeah. I don't think we have.

MR. BALLINGER: Well, Henry, are you speaking on behalf of FRCC or Florida Power Corporation.

MR. SOUTHWICK: Actually, I was speaking on behalf of myself. (Laughter)

MR. VILLAR: I don't think the FRCC has addressed the issue, Tom.

MR. BALLINGER: Okay. That's all the questions I have, Commissioners.

COMMISSIONER JACOBS: I have a brief question.

MR. TRAPP: Well, Commissioners, before we moved away from the FRCC presentation, there were just a very few questions I wanted to ask with respect to continuing studies and further activity that the FRCC may or may not be pursuing. And I'm not sure who to address these so I'll address them to Mario or to Ken, whoever can best address them.

I think Ken mentioned earlier that there is a lot of uncertainty associated with the LOLP methodology of calculating reserve adequacy. And he mentioned we just don't know what we've got anymore with respect to LOLP.

The question I had for FRCC was -- Ken, have you made any plans or do you intend to take any steps to further analyze what level of LOLP in Florida is meaningful?

MR. WILEY: Our study group has addressed that question for the last two years, Bob, and I guess we don't have a precise answer at this stage. We're thinking about getting involved in something that I believe the General Electric group is looking at to see if that could help us answer it. But specifically, no, we don't have anything on the drawing board.

MR. TRAPP: So your plans are not to abandon the study of LOLP, but to try to see if we can recalibrate the model?

MR. WILEY: We're definitely not abandoning it.

MR. VILLAR: Bob, I don't know that there's any need to recalibrate the model at this stage. We had some discussions on that issue this year, and

there was some questions lingering from the 1998 time frame. And based on the discussions of the members at that stage, they felt fairly comfortable that the model at this stage was representative of current conditions, but it may be something we might want to look at some more again. I don't know.

MR. TRAPP: When was the last time the one-day-and-ten-years was looked at with respect to its validity? How did you pick one-day-in-ten-years?

MR. VILLAR: The one-day-in-ten-years has been around longer than I have been in the utility industry, I think.

MR. TRAPP: 1970 arena?

MR. WILEY: Yes. It was in the '60s and '70s that we migrated into that. And it was for two things. It was -- the industry was pretty homogenized at that time, and I think that was the case of one size kind of fit all. And actually in the '60s, and -- I even hesitate on saying this because I remember this -- is that we actually went back with some historical data for the peninsula during those days, and kind of played a "what if" and ran loss of load probabilities. And sure enough, our actual experience indicated that one-day-in-ten-years was about what we were. And we sat there and reflected on

those historical years, and said those were pretty reliable years. Yeah, we liked them. So we kind of had an anecdotal acceptance of the one-day-in-ten-years back in the '60s and '70s.

MR. TRAPP: So it made us feel good and we adopted it and they've stuck with it for 30 years.

MR. WILEY: Yes, sir, until these availability rates climbed up to where they are.

MR. TRAPP: And I would also remind you that unit costs have fallen from the 12 to $2,000 a kilowatt that were looked at when we calibrated it back in the 1970s. I would suggest that $350 a kW or $400 a kW is a lot of difference in terms of cost that one can afford reliability.

Anyway, I'd appreciate it if you'd keep us abreast with respect to your plans to further pursue the LOLP question.

The next question I had, had to do with -- we have had some discussion here today about tightness of reserves during off-peak and shoulder hours. I'd like to know what the FRCC has discussed with respect to the further study of this issue.

MR. WILEY: When you say "tightness of peak," exactly what do you mean there, Bob?

MR. TRAPP: It seems like we have these

alerts and these capacity shortfall crises mostly around off-peak periods, not peak periods. Yet the reserve margin criterion that we seem to be driving the system off of is based on a single peak-type analysis. Has the FRCC studied the shoulder months, the relationship of maintenance that's taking place in that period of time and the probabilities of abnormal weather or circumstances arising that time that seems to be the reality of what's happening out there? Or do you plan to study it?

MR. WILEY: Well, I think our study is once a month we update our maintenance program for the next rolling 12-month period of time. And we go through there and we analyze what the reserve margins -- the resulting reserve margins are after we maintain them on a week-by-week basis. Our maintenance schedules are actually scheduled on a, you know, specific day that a unit would be taken out, and it would be brought back in on another specific day, and that's how detailed we have broken that up.

MR. TRAPP: I thought I read in some of the minutes that Roland and Connie had brought back from the Operating and Engineering Committees that that had been addressed in one of the committees and it was going to be looked at further. I guess that's really

where I'm going. Is there a more formal study of this going on or just business as usual?

MR. WILEY: I was going to get to that.

One of the "look sees" that we do is to make sure that any resulting week that falls below 15% reserve margin is looked at in detail by the proper people in our Operating Committee and they are flagged. And we have been discussing in this particular group whether or not we want to codify that 15%, because at this stage it was kind of a reference; it wasn't an absolute. So we are talking about codifying that.

MR. TRAPP: I'm sorry, I missed perhaps some of that. You're looking at making a monthly 15% reserve margin criteria?

MR. WILEY: When we go over our operating reserves after maintenance of putting in there that anything that is less than 15% will be reviewed in detail, and I mean very much detail, by our Operating Reliability Subcommittee. And this is a monthly type of an analysis.

MR. TRAPP: Let me move on to my last question. It has to do with the treatment of noncommitted capacities.

We've heard testimony here today that you're

taking into account -- at least in your LOLP calculations -- noncommitted transmission capabilities with the Southern Company. And we're witnessing the growth as a result of Congress acting in 1992 of the EWG industry. I think the Commission is aware of at least 3100 megawatts of announced noncommitted capacity that might be coming into the state.

My question to the FRCC is what steps is the group taking with respect to the identification of that capacity, the verification of that capacity, and the assessment of that capacity with respect to adequacy of the Florida grid?

MR. VILLAR: I think one of the things that we talked about this year, Bob, at the RWG was whether or not to include some nonfirm uncommitted capacity in our analysis. And the consensus of the group was that at this time it was unnecessary to do so. We did talk about including noncommitted capacity in the LOLP calculation, just like we could include the assistance from the SERC region. But given the levels of LOLP that we were experiencing, it was unnecessary to include them in the calculation at this time. We could have, but we decided not to. And that could include --

MR. TRAPP: Why would you discriminate with

respect to the noncommitted capacity in the state?

MR. VILLAR: I'm sorry?

MR. TRAPP: Why would you discriminate with respect to the noncommitted capacity in the state and its impact on the grid?

MR. VILLAR: We're not discriminating against the noncommitted capacity. It was just unnecessary. The levels of LOLP are so low that all it was going to do was drive the number even lower.

MR. TRAPP: Why was it necessary to include uncommitted transmission capacity?

MR. VILLAR: It's not that it was necessary. That's one of the sensitivities that we performed to exclude that. It has traditionally been included. We could have included a lot of other stuff in the LOLP analysis. We could have included nonfirm QF capacity. We could have included a lot of other things. Operational measures. There were a lot of other things that could have been included. It just did not matter in the LOLP calculation, so we did not include them at this stage.

MR. TRAPP: Would you --

MR. VILLAR: We could include them in the future, but it's just going to drive the LOLP number even lower.

MR. TRAPP: Again, my question has more to do with reporting requirements. With respect to reporting and identification, what are the plans of the FRCC to identify the capacity that's coming into the state?

MR. WILEY: Our specific plan is we have put a group together to discuss this particular issue and to identify what our going-forward policy should be in this area.

Currently our policy is that when it comes to the QFs, any QF that has firm contracts, they are included as part of our firm capacity and it goes into our reserve margin and calculation. When it comes to merchant plants, any load serving entity, such as New Smyrna Beach, that has a contract with a merchant plant to purchase power, that contracted capacity is included in the reserve margin calculation and it is -- that's the case this year. And we know this is a growing issue and we will be addressing it prior to putting this report together next year.

MR. TRAPP: So you anticipate having some mention of it or addressing it somehow in next year's Ten Year Site Plan? Is that what I'm hearing?

MR. WILEY: It will be. Yes.

MR. TRAPP: Thank you. That's all the

questions I have, Commissioners.

COMMISSIONER JACOBS: I guess it would be simple to say that -- well, not simple because what you've done is explained a very complex process. But to kind of boil it down, you've -- with your certain analysis and such, you kind of say we looked at historical data and we determined with a 15% margin it would be okay, based on what history has taught us. Is that okay?

What I'd like to ask you to do, look at three trends I have seen, and see if you agree with those trends as being legitimate, first of all. Second of all, if you would speculate the impact that they might have on your analysis.

One, I think we've gone through a lot but just let me say that we've looked at the weather issue and we've looked at the atypical weather patterns. But the thing that jumps out at me when I look at those patterns is that there's a recurrent trend of extremities over the course of several years. I mean, if we'd have one year where we have one out-of-the-norm weather condition I could say see it. But it seems like we have several years where we have had weather extremities. And in one or more of those instances they occurred outside of what you would

expect to be a normal peak time.

The other thing is low growth patterns. I don't know if it's going to continue, but I just happen to notice in your data the total peak demand from -- I believe it was '97-98 to '98-99, was on the order of 5,000, close to 6,000 megawatts in one year. That's probably an unusual event. But my concern is do we know that that's an unusual event? Do we have any idea or data that suggests that it would not occur or reoccur with any frequency in your -- in the time frame of your analysis?

And then the third point that I would be interested in is, we've heard on many occasions our -- with not much verification -- I take that back. We have had dockets where companies who have large load, who are on interruptible or -- I'm sorry, they are on DSM, who have come in and expressed a very real hesitance about remaining on those now that they are seeing increasing patterns of interruptions.

For the moment if you accept Staff's analysis, what you would expect is that those interruptions would continue at present levels, perhaps even increase? Therefore, I would sense that those companies would even have greater concerns. And perhaps you might lose a few large load customers off

of interruptible. And I notice that in your analysis, there is some decrease -- in your calculation of reserve margins, there's some decrease for that component but it's not a large decrease. You basically stay stable over the ten years.

So those three factors, in my mind, are of interest in this particular plan. I'll be interested in how you dealt with those.

MR. VILLAR: Let me comment on at least a couple of those, and then maybe I can turn one over to someone else.

With respect to the weather extremes, if you recall, Commissioner, we had an extreme weather scenario included in there. And I think within the extreme weather scenario, we capture whatever might be included within those variations that you were concerned about. So we have looked at those weather extremes. In addition to that, the analysis that we performed with respect to some corrections to the Staff 1989 Christmas projections for 1999 gives us comfort that within the existing parameters we can serve a load under the kind of conditions that might be expected if the type of temperatures we experienced in 1989 were to be experienced again.

You have to remember, there were a

significant number of improvements that have been made to utility forecasting techniques, to methods of dealing with the public. Corrections made to reduce the number of forced outages were experienced. Changes in schedule, maintenance practices, et cetera. So all of those give us sufficient comfort, and we think we'll be able to handle the weather extremes.

Let me address the DSM customer issue. We looked in the 1999 assessment at the certainty factor we had developed in 1998 for the availability of DSM. And we asked each utility, given the experience in the last year or so where some customers had expressed dissatisfaction with the DSM programs, and there was some drop-off rates, to give us their expectations for what they thought they would be able to get in terms of DSM certainties; to take into account the fact that some customers were dissatisfied, and whether or not they had a pool of customers from which to replenish that DSM supply.

Given those instructions, we got back some data from the utilities that basically allowed us to reach what we used 1999 as a certainty factor, where each utility was taking into account if I lose a certain amount of load based on customer dissatisfaction with the number of interruptions, I

have these many customers that are eligible for the rate and that I can replenish that DSM load. To the extent that at some point in the future we might not be able to get to replenish that DSM capacity, then there will have to be changes made in the individual utility plans. But all the utilities are cognizant of that fact and they will take it into account in their planning practices.

Your middle question had to do with load growth and I think it may be better if Leo gets into that one.

MR. GREEN: Could you please repeat the question, Commissioner?

COMMISSIONER JACOBS: Yeah. On that one, I've tried to find the year here -- there was a year in your tables where the total peak increased on the order of close to 6,000.

MR. GREEN: Last year, summer, right?

COMMISSIONER JACOBS: Yeah. One year.

My concern would be in your data, your projected data doesn't anticipate that kind of an increase again in any of the out-years. So I'm wanting to understand, how did you rule out the fact that that might not occur again? If there's data that supports that? If so, how you adjust for that.

MR. GREEN: Yes. It could happen again. We do not consider it as a normal situation. We look at it in the sensitivity analysis. But to give an example, 1998 was an extremely hot year. And I hate to bring in FPL data here, but I'm more familiar with FPL.

This year our peak is like 400 or 500 megawatts lower than what it was last year. Our total sales this year, at the end of the summer, is at 1%, this year over last year, lower; negative growth in sales to give an idea how hot it was in 1998. It could happen again. And that's why we have reserve margins to take care of those uncertainties that could happen. And we address them in -- by looking at the sensitivity analysis that Mario referred to.

COMMISSIONER JACOBS: Thank you.

COMMISSIONER CLARK: I think I have a question he may need to answer.

Do you see -- is the gap between, say, your average demand and your peak demand narrowing or getting larger?

MR. GREEN: The gap is getting smaller. Meaning to say that the nonpeak load is growing faster than the peak load.

COMMISSIONER CLARK: Okay. Do you have any

percentages you can tell us, or, I guess, I'd be happy if I saw that in the margin of reserve docket, if I saw some document that gave average demand and peak demand and how -- the trend.

MR. GREEN: I don't have that right now but I could provide you with that data.

COMMISSIONER CLARK: All right.

CHAIRMAN GARCIA: All right. Do any of the parties have any questions? (No response.)

We're going to take a 40-minute break and reconvene promptly at 40 after. (Lunch break.)

(Thereupon, lunch recess was taken at 1:00 p.m. and reconvened at 1:45 p.m.)

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CHAIRMAN GARCIA: I think the next presenter is FP&L. Whenever you are ready.

MR. SIM: My name is Steve Sim. I'm representing Florida Power & Light and our Ten Year Site Plan review. I've got about a dozen pages and it's broken down into four areas. We are going to talk about the resource additions that FP&L plans; a little bit about our LOLP reserve margin projections. And then we're going to go into two items that Staff had listed that they'd like to discuss; projections for winter 2000, winter 2001 and then a brief

discussion of nonfirm load.

First of all, in regard to our resource additions for the next ten years. Our current plan is showing approximately 3,300 megawatts and the numbers I'm going to give you primarily are going to be summer megawatt ratings. 3,300 megawatts of supply side resources over the next ten years. And for comparison, looking at the last two site plans before the 1999 site plan, we previously showed 1,600 megawatts back in the '97 filing and 2,600 megawatts in the 1998 filing.

And breaking down the 3,300 megawatts we've got some changes to existing plants of a little over 300 megawatts. Some of our existing purchases are going to decline by about 150 megawatts. We'll be repowering our Fort Myers and Sanford units and the plan shows that total a little over 1,800 megawatts. And then we're showing three new combined cycles coming in totalling a little over 1,250 megawatts.

This slide gives a little bit better, I guess, time view of when these capacity additions are coming in. We've got some changes to some of our existing units happening over the next couple of years, and then in 2001 the Fort Myers repowering begins.

We have about 200 megawatts net capacity coming in at Fort Myers due to the combustion turbine additions, while we're working on the steam units. That becomes compete, the repowering project in 2002, for a net of a little over what we're showing here, 201 plus 725, so a little over 925 megawatts of net increase at Fort Myers due to the repowering.

A similar situation at Sanford. A phased in operation with the CTs coming in first followed by the full repowering. We then show that, primarily on this page, that the market combined cycle unit addition No. 5 and No. 6 happening towards the later end of the time period, and then one additional combined cycle coming at the tail end of this period for a total of almost 3,300 megawatts. And these projections assume that FPL's new DSM goals are achieved.

And the recently approved DSM goals amounts are shown on this page. These are the year-end summer megawatt reductions. And the note at the bottom is just kind of a remainder to me that in regard to the original DSM goals that were set in 1994, to date we're approximately 250 megawatts ahead of schedule in meeting those goals.

We're not representing that we'll be able to maintain that pace of achieving more DSM than what we

have in our goals, but I think it's a pretty safe assumption that we'll be able to at least meet the DSM goals amounts that we're showing here on the top of the page.

Switching gears a bit to our reliability studies that were a part of the work that went on to come up with a Ten Year Site Plan, we utilized two methodologies; the loss of load probability and reserve margin. And we treat them equally important.

The criteria we use are the industry standard of a maximum of .1 day per year for LOLP, and we use a minimum reserve margin standard for both summer and winter of 15%.

Using those criteria, this is what we are projected to have in regard to LOLP in the second column where we easily meet the .1 day per year LOLP standard.

And the remaining columns show the summer and winter projected reserve margins which meet, and all years but one where we meet the 15% reserve margin we easily exceed the reserve margin standard of 15%.

So based on our reliability studies for the FPL system, we project it to be very reliable. And, Tom Ballinger, this is the point we were discussing a little bit earlier.

As part of our planning work last year which led to the resource plan that we show in the 1999 Site Plan, we undertook on our own an independent analysis of LOLP for different types of utility systems. And the objective was to try to evaluate how reasonable the recent LOLP projections for both FPL and for Peninsular Florida were because there were a lot of questions about particularly Peninsular Florida when we first saw them.

We were able to closely approximate both the FPL projections and the FRCC projections. And we concluded from this that the current projections are reasonable and, in fact, should be expected for systems of those types. And that they should reflect a higher level of reliability for both types of systems in regard to LOLP.

Moving to the third item of the four, this was one of the two items that Staff asked us to present which is not traditionally shown in a Ten Year Site Plan filing. It was for a projection of unserved demand for the winter of 2000 and the winter of 2001 based on winter temperatures experienced on nine dates that Staff selected for the period 1970 through 1989.

Our approach to this was, rather than go through each one of those nine dates, we'd look at the

worst situation and see what that showed. So in Step 1 we selected the worst winter condition experienced by FPL from these range of dates. And we developed a new winter load forecast based on the temperature which was derived on that date, and we plugged this into our current reserve margin projection to develop a revised winter reserve margin projection. And this would tell us whether or not, based on the temperature alone, we had unserved load.

In Step 2, we took it one more step out where we went back and we looked at recent historical unavailability at peak values for generation for purchases, et cetera, to determine if we applied these reasonable outage factors, would we then have unserved load.

And then finally, we threw in the operational measures that are traditionally not counted in reserve margin analysis to see how that would affect the picture of unserved load.

Now, the range of dates or range of years that Staff had requested that we look at, we experienced our coldest winter conditions on December 24, 1989. So we used the temperature experienced on that date and we developed a new load forecast for the winter of 2001.

Now, Staff had asked us to look at winter of 2000 and 2001, but I elected to use just the winter of 2000 because our reserve margin is projected to be lower -- excuse me -- for 2001 than it is for the year 2000. So, again, I'm looking at the worst case.

Now, this new load forecast we plugged in and got a new current reserve projection for the winter of 2001, and it showed that our reserves at that point, based on the new load forecast, would be about 640 megawatts. So based on that change alone, no unserved demand was projected.

And, naturally, the projection would be significantly better for the other eight dates that Staff selected because the winter temperatures were not as cold as they were for this selected date.

Now, in this step we started with 640 megawatts of capacity that was still available and we then went back since the '93 time frame and we tried to select what we thought were representative values for unavailable at the peak hour for FPL generation, for QFs and for net imports. And we also used the most recent value for the confidence level in load management that our folks had, based on their experience with it.

And we then subtracted those appropriate

amount of megawatts from our generation, from QFs, from net imports, and we lowered the load management capability that we were projecting in the reserve margin calculation. And where we were on the plus side of 640 megawatts of capacity still left to serve, we now dipped into a theoretical unserved load of 70 megawatts, so we'd be 70 megawatts below what we thought we would be able to serve at this point.

However, these 70 megawatts represent where FPL would be if they applied none of the operational measures that we have which are not traditionally calculated -- included in reserve margin calculations. And I'll show you that one next.

MR. HAFF: I got a question before you leave that slide. This is Michael Haff. Are the uncertainty factors -- I guess you used uncertainty factors to come up with these reductions due to unavailability of FPL generation QFs, et cetera. Are those uncertainty factors the same ones used by -- the same number that FRCC used or is that an FPL specific?

MR. SIM: These are the same FPL values that fed into the FRCC analysis.

MR. HAFF: But they're not the same exact FRCC -- you haven't taken FRCC's value and applied it to FPL?

MR. SIM: No, because it wouldn't be appropriate. We took the FPL values that -- on which the FRCC total was built and we extracted the FPL values and applied them here.

MR. HAFF: All right. Okay.

MR. SIM: Now, looking at this, the Rows 1, 2 and 3 are what I showed you on the previous page, where if we applied none of FPL's operational measures, in theory we'd have unserved load of 70 megawatts.

However, FPL's projecting, in its operational measures, appeals to conserve about 400 megawatts which we actually think is a bit conservative. Let's get the footnote in here.

Residential load control SCRAM in the winter, about 1,600 megawatts. And voltage reduction, another 400 megawatts. So we have approximately 2,400 megawatts of operational measures that are not accounted for in reserve margin projections.

When you apply that, on Line 5 we're showing that we are projecting no unserved load based on those conditions. And, in fact, we'd have over 2,000 megawatts of capacity or resources available to serve additional load.

Now, the last of the four items that Staff

asked us to take a look at was the nonfirm load. And for FPL's system, our current capability for residential load control is about 700 megawatts summer, and almost 1,300 megawatts winter, while our commercial industrial load control is a little over 400 megawatts, summer and winter rating.

The notice provision, pretty typical I would say for these two types of nonfirm load. One week for residential and five years for commercial industrial.

Exit fees, none for residential. And yes, there is an exit fee for commercial industrial load control if a customer desires to leave earlier than the five year exit period unless certain conditions are met.

There was a question Staff asked about, are these counted in spending or supplemental reserves. They're both counted in our supplemental reserves.

And regarding the annual times we've exercised load control either in full or in part, what this shows is for residential load control, since 1992 it's ranged from zero to nine times; commercial industrial load control from zero to three times.

In regard to nonfirm load, we view it as a very reliable resource. It's operated very well every time we've pushed the button. We are not concerned

overly regarding dropout rates. Even with residential load control with customers able to leave after one week, we estimate that we have at least as many eligible residential load control potential customers as we have currently signed up. We also have a number of customers on the waiting list for commercial industrial load control.

CHAIRMAN GARCIA: What do you mean by residential customers signed up as those waiting to sign up? You're not allowing anymore to sign up?

MR. SIM: I wouldn't term it, Mr. Chairman, as not allowing them to sign up. It's simply allocating the resources to the contractors that do the installations.

CHAIRMAN GARCIA: Got you.

MR. SIM: So it's more like turning a spigot on and off. In regard to the actual --

COMMISSIONER JACOBS: One brief question. In the -- I'm sorry, but this is FRCC's load management and interruptible dispatchable table. In 2000/2001 they show not only maintaining the existing level, but increases. I guess it's 78 megawatts in one and 73 in the other.

What that says is -- and what I'm trying to do is put it in context of what you're saying. Even

if they were to lose some customer that would take them below that threshold, that 2,750 line, you -- there was collective interest in DSM that would not only take them back up to that level but even increase it above to the extra megawatts that's indicated there?

MR. SIM: Yes, Commissioner, I believe that's true.

COMMISSIONER JACOBS: Okay.

MR. SIM: I think all utilities, certainly FPL, attempt to only sign up for load control that level of customers that is cost-effective.

COMMISSIONER JACOBS: Okay.

MR. SIM: But there are additional customers that are -- at least at FPL, there are in the wings that would like to get on the program.

COMMISSIONER JACOBS: Do you anticipate there would be any impact -- I think I heard today, I know I've heard it in other instances, that the cost-effectiveness is being impacted by the cost curve of building new generation? Would that mean that, to the extent that more gas capacity comes on line, the rebate amounts are going to be impacted downwards? And do you think that would have an impact on your enrollment?

MR. SIM: I think the answer to that is yes for two reasons. No. 1 is the cost of generation drops. That's what load control is competing with; the avoided cost of new units. So certainly you're able to pay less in terms of incentives which shrinks your potential market.

COMMISSIONER JACOBS: So if that happens midstream here, what we'd expect to see would be additional capacity build as opposed to reliance on the DSM?

MR. SIM: And I would say yes, and I believe you're seeing that in some of the new DSM goals numbers. I think you're seeing less DSM. Certainly less load control being signed up by FPL in the coming ten years than what we projected the last time we sat down and came up with new goals, in large part due to the reduced costs of competing generation options.

COMMISSIONER JACOBS: Thank you.

MR. SIM: I think the last point I wanted to make sure was in regard to the actual dropout rates FPL is seeing. We traditionally have seen about 1% or less per year for all of the years up there. For example, if you look for residential load control in 1997, we never exercised it during the year and we saw roughly 1% dropout rate that year.

The next year, 1998 the frequency of use jumped to eight times per year, and I think the dropout rate only rose to about 1.5% per year. So we are not seeing any threat of any significant dropout from residential load control. And again, in concluding this slide, we view it as a very reliable resource.

MR. FLOYD: Steve, this is Roland Floyd with Staff. You say here that your load control, residential and commercial, are not used -- are not counted towards spinning reserves. I'm just curious whether, according to FRCC guidelines, could they qualify for spinning reserve? Are they wired in such that they can respond quick enough to be called spinning reserves or do you know?

MR. SIM: My understanding of spinning reserve means it has to be on line now, which means you'd have to have your finger on the load control button and be reducing load now. So, therefore, I don't think it would qualify as spinning reserve.

MR. FLOYD: Okay.

MR. SIM: And the last slide I've got is a summary slide. We project our system to be very reliable, again, from both an LOLP and a reserve margin perspective. Our projections are significantly

better than both respective standards for LOLP and for reserve margin.

And contributing to this projection of a reliable system are two fairly recent, back in 1997, changes that we've made to our planning process where we introduced a 15% winter reserve margin standard, and we've also, based on the winter of 1996, we've lowered our load forecast temperature, as Leo Green mentioned earlier, from about 37.5 degrees to about 34.5 degrees; both of which have contributed a bit to the increase in capacity additions that I showed you on the first slide over those that we were projecting back, say, in 1996. And that concludes my presentation.

MR. HAFF: Questions for Florida Power & Light? Mr. Wright.

MR. WRIGHT: Steve, right behind you. Schef Wright. I'm representing Duke/New Smyrna. I have two questions. Does the 2,400 megawatts of operational measures shown on your Page 11 correspond to the 3,800 megawatts that Mr. Villar mentioned for the FRCC total operational measures?

MR. SIM: Yes. That's the FPL contribution to the 3,800 that Mario mentioned earlier.

MR. WRIGHT: Thanks. And the other question

is, did FPL implement operational measures during the June '98 hot spell?

MR. SIM: Not to my knowledge, but I'm not 100% sure if we did.

MR. WRIGHT: Thanks.

MR. MOYLE: I had two quick questions. Jon Moyle. This is with respect to Sanford and Fort Myers, I guess, that are coming on in 02 and 03. Do you anticipate putting the capacity represented by those out for bid?

MR. DENIS: Jon, my name is Roberto Denis, and the answer is no.

MR. MOYLE: As to the cost-effectiveness of that, is that going to come through to the Commission under a need determination petition?

MR. DENIS: It is not required to come to the Commission for that purpose, but the management is quite confident that the cost of those units plus all of the associated benefits of reducing and doing away with existing sources of pollution within the state, air pollution primarily, more than outweigh any benefits -- when put together more than outweigh any -- are much better than a new combined cycle facility.

MR. MOYLE: And that's because you're

displacing older, inefficient plants with newer combined cycle units; is that right?

MR. DENIS: That's correct. Using existing infrastructure, existing disturbed environmental land, et cetera.

MR. MOYLE: Thank you.

MR. HAFF: Any more questions? Seeing none, let's continue with the presentation by Florida Power Corporation.

MR. CRISP: Good afternoon. My name is Ben Crisp. I'm with Florida Power Corporation. On behalf of Florida Power Corp. I will be presenting our Ten Year Site Plan summary and addressing the questions that were listed on the agenda for the Commission workshop.

We'll be addressing, first of all, the overview of the Ten Year Site Plan. And second, we'll be talking about the historical and projected reserves.

Third, we'll talk about the question on estimate for unserved demand based on specific winter conditions.

And fourth of all, we'll discuss FPC's nonfirm load capability.

Step off first with the planned summary and

the overall historical and projected reserves. FPC utilizes a minimum reserve margin criteria of 15% firm peak load. In addition, we utilize a loss of load probability for less than .1 days per year.

Next, we'll take a look at our peak demand. Right here you notice that's actual; actual demand served and that's for the history. That's this line. And you see, as you start off on the projection --

CHAIRMAN GARCIA: You know what? If you turn off the lights there, the little florescent lights, we'll be able to see it a little better.

MR. CRISP: How about that? Okay. This line depicts actuals, peak demand, and this line depicts the total demand that's from the Ten Year Site Plan.

The downward trend in between 2001 and 2003 reflects wholesale contracts with Seminole Electric Coop that are going away. And then as you see the trend continues along a fairly straight slope.

Summer peak demand, same format. Actual demand served on the left; Ten Year Site Plan total demand on the right. There's a slight dip in between 19 or -- let's see -- 1999 and 2000 where MEAG contracts and Southern Company contracts for the summertime go away. There's an increase, and then the

wholesale contracts from Seminole go away.

Reserve margin summary. Make a few highlights. As the 15% reserve margin was established as a planning criteria it took us about two to three years before we were up to a point to where we had passed the 15% criteria. At the 33%, that was the addition of the Debary and Intercession City units. You see a trend right in here from 2000 to 2003. That is the Seminole peaking contracts as they phase out. You see a drop from 25% to 21%. That is drop due to retirements. And then an increase to 23%, the addition of Hines Unit 2. And from 19% to 22% is the addition of Hines Unit 3.

Addressing demand side management resources. FPC has exceeded the 1994 Commission approved DSM goals in 1998. We have included the newly establish DSM goals for future years 2000 through 2009 in the plan. We recognize a reduction in nonfirm load as a part of our plan.

Generation additions. As I described for you in the 15% trend, Hines Energy Complex Combined Cycle Unit 1 became operational in April of 1999.

Intercession City, we're adding three units to 297 megawatts in December of 2000.

Capacity upgrades at Crystal River, our coal

units, we'll increase our capacity by 75 megawatts in December of 2001, and Hines Unit 2, November of 2004; Unit 3 in November of 2006.

CHAIRMAN GARCIA: Is that the only addition from your last submission?

MR. CRISP: That is correct.

This slide depicts the net energy requirements for the system and how its broken out by a fuel driver. As you see, natural gas, we're focusing on dual fuel contracts; dual fuel development within our fleet. Coal, natural gas, make up the bulk of our fleet.

The QFs are at 14% of energy service. Nuclear is at 13%, purchases at 7% and oil at 8%. Once again, this is energy, not capacity.

Now, I'm going to address Agenda Item No. 3, which is the estimated unserved firm demand based on historical weather.

We took a look at two scenarios. The first was a good operating condition scenario, and that includes 100% unit availability; normal wholesale demand and no operational resources. Under those conditions FPC would not expect any loss of firm load.

We looked at a bad operating condition scenario in which we had average unit availability and

we saw or we included a significant increase in wholesale demand, and we included no operational resources. And in that instance FPC would expect the loss of firm load between zero and 10%. I want to point out, significantly less then the 20% experienced in the December '89 freeze.

Well, one further point there. From the basis on the FRCC, that would not be an inconsistent finding. FRCC, looking at the total system, could very well wind up with a 0% loss of firm load. Us being in the stand alone analysis, that could wind up with zero to 10% and that makes perfect sense.

Nonfirm load will be the next issue we'll address. This graph shows an overall history for years 1990 through 1998 and then a projection from the Ten Year Site Plan for 1999 through 2007.

As you see we do have a reduction in the program in the Ten Year Site Plan. Most of that is coming out of our load management area. We went -- started off at 911 megawatts and went up to 1,300 megawatts of total nonfirm load, and in the Ten Year Site Plan we're dropping it down about anywhere from 12 to 30 megawatts a year.

The overall nonfirm load scenario has been very, very useful product for Florida Power

Corporation and --

MR. BALLINGER: Excuse me. Would you go back to your previous slide?

MR. CRISP: Yes. Sure.

MR. BALLINGER: I've got one question on this slide. How do you propose to reduce the load management amount? Are you going to start closing your residential load management tariff?

MR. CRISP: We will not close the tariff itself. We just will not advertise the tariff. We have had some cancellations. We are learning more about the system as we go on. We have had some cancellations based on our utilization of the load management program.

We've utilized the load management program as has been needed and has been required and to the best service of our native load customers.

MR. BALLINGER: Do you know if in your -- you'll be filing new programs soon to meet your new goals. Do you know if you'll be revising the credit in the residential load management program to lower it?

MR. CRISP: I'm not sure on that, but I can find that out.

MR. BALLINGER: Okay.

MR. FLOYD: This is Roland Floyd with Staff. Just to be sure on this voltage reduction, and maybe I should have asked FRCC the same name. Just to be clear, the Commission has standards on voltage quality. There's a nominal voltage and you cannot exceed that by plus or minus 5%, I think. I may be wrong on the percentages.

But when you say voltage reduction, you will still stay within the Commission rules on -- in other words, you bring the voltage down but no lower than what's required by our rules? I'm assuming that.

MR. CRISP: And I am assuming that that is correct, Roland.

MR. FLOYD: Okay. It just will go maybe from 110 volts to 107 or 106 or whatever; still within our criteria?

MR. CRISP: I believe that's correct.

MR. FLOYD: Okay.

MR. CRISP: Consistent with the voltage reduction program, you see that we have taken it out of our summer months. The reason for that being that the summer months you see a peak that's much broader than the winter months. The voltage reduction program is not considered as effective from the summer months standpoint so we've taken it out. You see the

continued reductions in the total nonfirm load program.

In summary, we believe the FPC plan is suitable based upon exceeding the 15% minimum reserve margin criteria and the loss of load probability of less than .1 days per year.

Any additional questions?

MR. BALLINGER: I've got a couple questions for you, and I will probably pose them to the other utilities as they come up as well.

We saw an FPL presentation that showed the number of times they utilized load management and interruptible load. Are you aware of any time during those instances that Florida Power Corporation was selling power outside of the state?

MR. CRISP: If power was -- Florida Power Corp. was selling outside of the state, it was a function of a long-term contract or a term contract that was made on the basis of 15% reserve margin criteria or above.

Now, the contract could very well have been made to bring down or create the best possible economics by bringing down reserve margins to 15% and then something happened during that period of time where the sale was actually being executed on a

day-to-day basis. And then you could have gone back in and used load management to satisfy a criteria where you lost a plant, but you continued your wholesale contract outside of the state.

MR. BALLINGER: Okay. And the converse of that, are you aware of any instances where Florida Power was interrupting its interruptible customers or load management, sought to buy from other utilities within the state and they were selling outside the state? In other words, it was unavailable and that forced you to interrupt your interruptible customers?

MR. CRISP: Come again.

MR. BALLINGER: Are you aware of any instances where Florida Power was in a situation where they were getting ready to interrupt their interruptible customers, looked around within Florida for power, and it was unavailable because other utilities were selling outside the state?

MR. CRISP: I'm not aware of that situation.

MR. BALLINGER: Okay. Thank you.

MR. CRISP: Any additional questions?

MR. HAFF: Mr. Wright. Behind you.

MR. WRIGHT: I have a similar question to the one I asked Mr. Sim.

MR. HAFF: Turn your microphone on, please.

MR. WRIGHT: This is Schef Wright representing Duke/New Smyrna. I have a similar question to the one I asked Dr. Sim. That is, do you have a number of megawatts of operational measures that FPC uses in its planning that would be comparable to the 3,800 that FRCC uses, or as Dr. Sim put it, FPC's contribution to that 3,800 megawatts?

MR. CRISP: Those under -- items are under consideration right now by FPC. I'll have to get back with you on that one.

MR. WRIGHT: You don't have a number today?

MR. CRISP: No, I don't.

MR. WRIGHT: Okay. Thank you.

MR. CRISP: Any additional questions? Thank you.

MR. HAFF: Okay. Next we're going to hear from a presentation by Gulf Power Company.

MR. MARLAR: My name is Mike Marlar. I'm the chief forecaster for Gulf Power Company. I'll be addressing the forecast related questions, and my colleague, Mr. Pope, will address the resource plan.

This is our '99 Ten Year Site Plan of our summer peak demand projections. Historically over the last ten years we have experienced a 2.7% compound average annual growth rate of summer peak demand and

our projected demand growth with the impact of conservation programs is at 1.4%. Historically it would have been 3% absent such programs, and our projected growth would be 2% absent such programs.

The winter peak demand forecast is a little more volatile. Historically, and this is an end-point-to-end-point calculation of 0.9% compound average annual growth rate. That's 9 more than normalized. The projected growth rate is 2.9% under normal weather conditions. Historically absent are our conservation programs and we would have experienced 1.3% and a 3.7% projected growth rate.

Our annual net energy for load projections indicate historical growth rate of 2.4% without conservation programs. 2% projected -- excuse me -- with our conservation programs. And without those programs we would have seen a 2.5 historical growth and a 2.1% projected growth rate.

This concludes my forecast presentation. If there is any questions I'd be happy to address them.

COMMISSIONER DEASON: One quick question.

MR. MARLAR: Yes, sir.

COMMISSIONER DEASON: Why the decline in the growth rate of summer peak demand?

MR. MARLAR: You talking about the '99 Ten

Year Site Plan projection, the 1.4% --

COMMISSIONER DEASON: Yes.

MR. MARLAR: -- versus 2.7 historical?

COMMISSIONER DEASON: Yes.

MR. MARLAR: Well, that's primarily due to impacts of our conservation programs in the residential sector. We're coming out with a new program that will significantly impact a lot of the energy consumption and the demand as well, and we also have a significant demand reductions that we were able to achieve under a realtime pricing program.

COMMISSIONER DEASON: Is your realtime pricing part of DSM?

MR. MARLAR: Yes, sir. It's part of our demand reduction programs.

COMMISSIONER DEASON: Well, then even if you're comparing -- if you compare your projections then without DSM you're still going from a 3% to a 2%.

MR. MARLAR: Yes, sir, and those projections without DSM reflect some of the national standards and improvements and supply sufficiencies and things of that nature, and increases saturation of higher efficient heat pumps. Those percentages, the 3% and 2%, reflects things that are absent our efforts that would occur. Any further questions?

MR. POPE: I'd like to briefly go over -- I'm Bill Pope with Gulf Power Company. Briefly go over our basic key assumptions. Mike's already covered the 1999 load forecast and we used as candid a technology for our plan, the combined cycles and the combustion turbines for the F class which is your nominal 180 megawatt combustion turbines, and we continued to put in a conventional pulverized coal unit which is important when you consider fuel price sensitivities in our plan.

Our fuel came from our 1999 budget year fuel panel. That fuel panel convenes in June of every year, so they actually met over a year ago.

Reserve margin for the Southern Electric System is 13.5% planning reserve margin, which is three years out and beyond. Our mixed technology that we use is PROVIEW. We used to use another mixed program, but it has long since been replaced by PROVIEW, a better model.

Each go around of the mix process identifies megawatts of needs in 300 megawatt blocks for all of the Southern Electric System. As a Southern System as a whole, these are allocated back to the operating companies of which Gulf is one, and then the individual operating company makes a selection based

on what best suits their needs from an economic standpoint. So there's another process that goes into the Southern Electric System resource plan where we get to select what is best for us.

We also go through a market test for our selection, our resource selection, which we've done recently and have been approved on our need determination back in June.

And what that plan revealed in our Ten Year Site Plan for 1999 through the planning horizon, the first column being the year, of course, and then the summer peak demand which is what we planned to. Where our starting capacity resources are is the next column. Then we have power purchases. Next column, capacity additions, which is actually machines on the ground. And ending capacity, which we can calculate our percent reserve margin.

And this particular reserve margin is Gulf Power Company's individual reserve margin, which contributes to the Southern Electric System reserve margin of 13.5% target.

You'll see that Gulf falls below the 13.5% percent reserve margin until 2002 where our contracts -- our firm contracts expire and we add a 574 megawatt combined cycle unit. That brings our

reserves to 19%, 19.1% above the 13% on until we get to the year 2006.

In 2007 we've got a repowering of one -- three of our plants in Pensacola. Brings our reserve margin above 13.5% again.

MR. FLOYD: Bill, this is Roland Floyd of the Staff. Just to put it on a table so to speak, I know Southern Company has lowered their standard, I guess you'd say, as far as reserve margin goes from 15 to 13.5. You know we've been going over that same type question with Peninsular Florida and we'll also be looking at it, you know, from Gulf's standpoint, its relationship with Southern Company, too. So it's -- I mean, I didn't want that to slip by.

Also, we have forecasting people who will be looking at this. The point that Commissioner Deason pointed out about the change in the load forecast where the future looks like has declined for other reasons, whether it's national standards or whatever is out there and we haven't completed the analysis of the plans yet and don't have a specific question to ask you right now. I just wanted to kind of put that out there that we are looking at Gulf as well as the Peninsular Florida.

If you want to say anything about how the --

why you went from 15% to 13.5%, that would be -- you can -- you might want to tell us why you did that.

MR. POPE: Roland, without getting into a whole lot of detail, and to summarize that, we have performed reliability studies from time to time and we did an update back in March of 1977. And considering factors at that time which drive our need to -- or our selection of reserve margin, it was appropriate at that time to select 13.5% from an economic standpoint as a minimum target. That's not to say that we can't have more than that as reserves, but our planning reserve target is 13.5%.

And as mentioned earlier this year, we're continuing to evaluate that in looking at current trends and market price which will drive that curve one way or another. So we're still looking at that. Indications are with what happened in the summer of 1998, the 13.5% from an economic and reliability standpoint, may not be appropriate, but we have not reached a conclusion at this time. So that in a nutshell.

One of the other differences, I believe, between Peninsular Florida and we're not a party -- a direct interested party in that, but we are monitoring that. One of the differences, we have more tie-line

assistance to rely on than Peninsular Florida and that's one of the things. We can kind of look at our reliability a little differently. And you're going to continue to study it, right?

MR. FLOYD: Yep.

COMMISSIONER JACOBS: Can I ask a question? Looking at the year 2001, that looks like you have about 22 megawatts. I suspect that -- you could lose pretty much any one -- any plant in that fleet and that would cause you to have problems there?

MR. POPE: It would make our reserves -- actual operating reserves at the time drop to a negative number; I believe a negative number. But, as part of the operating -- the Southern operating system, Southern Electric System, a lot of our year to year operating dependence is on the Southern Electric pool, and dropping one of our units is in our planning criteria and we're still solvent. We're not going to lose firm load because of that.

COMMISSIONER JACOBS: Okay.

COMMISSIONER DEASON: Your column entitled Power Purchases, is that the Southern System pool?

MR. POPE: No, sir. Those are outside the Southern Electric System pool. Those are firm contracts outside Southern.

COMMISSIONER DEASON: So those are your wholesale contracts?

MR. POPE: These are -- yes. Firm purchases from outside utilities. These are the ones that we know at this time to be firm. We are looking at now next year, just for next summer, to see if there's anything we need to supplement that with, but these are the firm ones that we have in place long-term, more than a year out.

COMMISSIONER DEASON: How do you factor in your wholesale contract with Florida Public Utilities? Do you get a demand forecast from them and factor that into your wholesale requirements or how is that done?

MR. POPE: Yes, we do. That's what we do, as well as delivery points for Alabama Electric Corp.

Okay. I've got one other slide. We were asked to put up a history of reserves and I guess of note here is the year 1995 and 1997 where our actual operating reserves at the time of summer peak were negative. This just highlights once again our reliance, our ability to rely on the Southern Electric System for meeting firm demand.

CHAIRMAN GARCIA: Let me ask you. Are just the realities of the Southern System so much different? I mean, do you have larger margins than

the rest of the Southern System? Is that why you don't need to worry about them in your --

MR. POPE: Besides the Southern, this is one of the benefits that Gulf derives from being a member of a large system is that a lot of things can happen to Gulf or other units on the Southern Electric System and because of size and resources we can pretty well just --

CHAIRMAN GARCIA: Find it.

MR. POPE: Yes. It's a benefit for being in the pool.

And other than that, as you can see, our reserves and our reliance on Southern make our plan suitable and economical as we've demonstrated in the recent need determination. And I'll answer any questions if anybody's got any.

MR. HAFF: I'd just like to request that if we can get a copy of these slides, a copy of those.

MR. POPE: I apologize, Michael. And I will send a copy. As you know, I was out of town last week.

MR. HAFF: That's right. Any questions for Gulf Power? Like to thank you -- we're going to continue on with TECO, but I'd like to take this point to announce, I guess we're going to be --

Mr. Chairman, we'll be finishing up today about 4:00. I'd appreciate everyone's brevity in their presentations and I'd like to get everyone in today, but just keep that 4:00 time in mind when you're presenting.

MR. WARD: Good afternoon. My name is Mark Ward. I'm representing Tampa Electric and I'll be reviewing our '99 Ten Year Site Plan, as well as a brief overview of our 2000 plan that we're currently wrapping up.

Real quickly, this is the outline that I'll be addressing today and I'll hit each one of these points as I go through my presentation.

I'd first like to talk about our projected demand forecast. This is our '99 Ten Year Site Plan forecast. We are looking at about a 2.8% average annual growth rate for the summer. Roughly 2.9 for -- excuse me. 2.9 for the summer and 2.8 for the winter. And it equals about 100 megawatts per season in firm demand growth. Our projected 2000 plan also has a forecast very similar to this.

Next slide is a comparison and overview of our '99 Ten Year Resource Plan, as well as our 2000 Ten Year Resource Plan. We've added a unit and a purchase in our 2000 plan and this is due to the

additional reserve margin criteria that we're adopting as part of our planning next year. It's a 7% minimum supply side reserve margin for the summer and that requires us to add an additional CT as well as a 90 megawatt purchase.

Also like to point out that 2005 we're going to be building out our Polk site. The site is currently permitted for 1,150 megawatts.

MR. BALLINGER: Mark, I'm sorry.

MR. WARD: Yes.

MR. BALLINGER: Go ahead.

MR. WARD: The CTs that we're proposing to build are also dual fuel, gas and oil.

MR. BALLINGER: You mentioned that you gave us a preview to the 2000 plan. Does this reflect the recent option that TECO exercised with the Hardee Power Station?

MR. WARD: Yes, it does.

MR. BALLINGER: I have that build out. And that's from -- I understand from the letter I saw from Mr. Hernandez, that's due in service year 2000?

MR. WARD: Yes, it is. Summer of 2000.

MR. BALLINGER: And have they started construction on that?

MR. WARD: Yes, they have.

MR. BALLINGER: Okay. If I understand it that's going to be -- you have a -- it will be owned by Hardee Power Partners. I think that's their name.

MR. WARD: Yes.

MR. BALLINGER: So they have a purchase agreement with TECO.

MR. WARD: Yes.

MR. BALLINGER: And that hasn't come before the Commission yet for cost recovery approval?

MR. WARD: That's correct.

MR. BALLINGER: Okay.

MR. WARD: Real quickly, I'd like to just compare our criteria. '99 we had a 15% minimum firm reserve margin criteria, as well as a 1% EUE per net energy for load. We've gone to a year round 15% firm reserve margin criteria for summer and winter, as well as the 7% minimum supply side reserve margin for the summer.

MR. FLOYD: Let me ask you one question about this. I don't know if I ever really got a good answer on this and maybe you don't know historically. But when I first stared working here TECO had a 25% reserve margin standard. A few years later they went to 20%. And now last year or year before, I don't remember which, now it's down to 15%.

MR. WARD: Yes. We went to that in the summer of '96, I think. Or sorry. Fall of '96.

MR. FLOYD: Okay. I just wondered, without getting into too much detail, if you can explain why in such a short time you go from 25 to 15. I mean, you got about -- you know, well, half almost of what it used to be.

MR. WARD: I think we've answered that in some of the interrogatories and I'd kind to like to leave that to the reserve margin docket.

MR. FLOYD: Okay.

MR. WARD: Having a hard time getting this slide on here. But this is a comparison of our '99 plan, reserve margins winter versus what we're proposing in 2000. The bottom part of each bar is the nonfirm load contribution to reserves. The top portion is the supply side contribution. You can see an increase in our supply side reserves with our proposed 2000 plan.

MR. BALLINGER: Mark, one more question. I'm sorry. Now, TECO hasn't filed a revised Ten Year Site Plan.

MR. WARD: That's correct.

MR. BALLINGER: So Staff is still reviewing and our comments will be focused on the '99 plan as

filed.

MR. WARD: All right.

MR. BALLINGER: Which would be the top graph you've got there.

MR. WARD: Okay.

MR. BALLINGER: Is that --

MR. WARD: That's fine.

MR. BALLINGER: Okay.

MR. WARD: Again, this is a comparison of the '99 Ten Year Site Plan for the summer reserve margins as well as our proposed 2000 resource plan. Same as the previous chart, we have on the bottom part of the bar the nonfirm load contribution, and the top part is our supply side.

To address the question about demands dealing with temperature extremes, Tampa Electric went back and looked at 50 years of data in the Tampa region; those temperatures occurring at the time of our winter and summer peaks. And then we calculated a reserve margin based on those loads and that's what we're showing here.

MR. BALLINGER: So if I understand this correctly, if it got to 25 degrees, I guess, in Tampa --

MR. WARD: Yes.

MR. BALLINGER: -- you'd have about a 4% reserve margin maybe?

MR. WARD: That's a 4% reserve margin without operational measures.

MR. BALLINGER: Okay. Basically, it could get down to 20%. Then you wouldn't lose any firm load and wouldn't have to use voltage reduction or SCRAM or anything like that?

MR. WARD: Ask that question again, Tom.

MR. BALLINGER: If it got down to 20 degrees, to me it looks like you still have some reserve, and you're saying you could serve that and not institute operational things such as --

MR. WARD: No. We would have to do that. This is assuming that we would have 100% availability of our supply side resources. So I would expect we'd have to institute some operational measures.

MR. BALLINGER: Okay.

MR. WARD: This is our projected -- our historical and projected nonfirm load. It includes interruptible and load management contributions. These are what we count in our reserves. It's fairly flat through time.

We wanted to try to address the correlation between reserve margin and load controls. What I'm

using as a proxy today is EUE, which is unserved energy, expected unserved energy.

Tampa Electric believes that it's a very difficult thing to do because of the multiple variables that affect the relationship that either -- any of those variables that you see in the dark purple could affect the correlation between reserve margin and EUE.

For instance, you could have relatively low reserves, very high unit availability and not institute controls or vice versa. And that's just one variable that would affect that. You have unit size, number of units and unplanned outages as well.

The items in the center there in the shaded box, those are the items that are in common with both expected unserved energy reserve margins. Any questions?

MR. BALLINGER: I will ask the same question I asked the FPC presenter. Are you aware over the last couple of years any time that TECO has been in a position, they were getting ready to interrupt their interruptible customers and looked for power from other Florida utilities, but found it unavailable because it was being sold out of state?

MR. WARD: Not to my knowledge.

MR. BALLINGER: Okay. I'd like to ask a favor, I guess, of TECO and Florida Power and Florida Power & Light. If you all could get together and look at instances you did this and corroborate those responses to see if, in fact, this ever happened and get back to Staff with that.

MR. WARD: We will. Thank you.

MR. HAFF: Question, Mr. Wright?

COMMISSIONER CLARK: Would Staff refresh my memory on the basis on which customers get interrupted, because we changed it. At one time it was that you could get --

MR. BALLINGER: As a priority?

COMMISSIONER CLARK: Right. You get interrupted if power is needed to firm customers on another utility's --

MR. BALLINGER: Yes. That's correct.

COMMISSIONER CLARK: For their firm customers.

MR. BALLINGER: Our rules read now, and I think all the tariffs are corrected, that if a company needs power to serve its firm load, another company must interrupt its nonfirm load to serve that load.

COMMISSIONER CLARK: Okay.

MR. BALLINGER: In other words, to help out;

to use it as an actual generator. But you're correct in that.

CHAIRMAN GARCIA: So that shouldn't be happening.

MR. BALLINGER: Well, it depends on the timing, I think, as Florida Power mentioned or other people, of when that contract was signed. It may have been a long-term contract signed a month or two ago and then you get into the situation; well, you've got a firm wholesale agreement. You've got to oblige by it. But then we get a heat wave come down here, you're stuck with operating reserves. But that's a firm commitment you made a couple months ago maybe. We're not sure if that's the situation or if it's a nonfirm transaction going on.

MR. HAFF: Mr. Wright, did you have a question?

MR. WRIGHT: Yes, Mr. Haff, thank you. Mr. Ward, I have a couple of questions about operational measures like I asked FPL and FPC's representatives. Do you have a number of megawatts that Tampa Electric uses as operational measures analogous to those represented by Dr. Sim for FPL?

MR. WARD: I believe what we provided FPL in that analysis was 70 megawatts and that was tied to

voltage control.

MR. WRIGHT: Okay. And as far as you know is that all then?

MR. WARD: That is all I'm aware of.

MR. WRIGHT: Okay. Did you all implement voltage control either in June of 1998 during the hot spell or during the constrained event you had in April of this year?

MR. WARD: I can't answer that. I don't know.

MR. WRIGHT: Thank you.

COMMISSIONER CLARK: I have a question. I don't know if you can clarify it or Staff. Is there an obligation on the part of a utility that has capacity, to sell that capacity to another utility so that they do not interrupt their demand side management customers? Are they obligated to sell it?

MR. BALLINGER: Are you asking me?

COMMISSIONER CLARK: I don't care who answers it really.

MR. BALLINGER: My view of it is, if they have it yes, they have to. But if they prearranged a sale, let's say --

COMMISSIONER CLARK: Why are they -- do the tariffs obligate them to do that? Do you know if you

are obligated to sell power to a sister company to avoid them interrupting their demand side management customers?

MR. WARD: Only if it's a firm contract.

MR. BALLINGER: Right. I don't think they're obligated for nonfirm for buy-through, that type of thing.

COMMISSIONER CLARK: And it would be appropriate that they would not be if it's supposed to act like a generating unit, right?

MR. BALLINGER: Correct.

COMMISSIONER CLARK: Okay.

MR. HAFF: Are there any more questions for Tampa Electric?

All right. Next we'll here from the munis. FMPA is next and we're coming up on 3:00. We need to wrap it up by 4:00, so make brief presentations or if you just want to answer questions, I guess, that would be fine. Yeah, Rick, that's for you too.

MR. CASEY: That extends to me as well?

MR. HAFF: Yes. Trying to move this along.

MR. CASEY: Rick Casey with FMPA. I will be as brief as I can. Let me switch gears here. Just to give you an idea, we've got currently 28 members as of last Friday. City of Quincy joined FMPA as a member

and so we have representatives all over the state.

We're organized a little bit differently. We're a wholesale power supplier. I apologize for the slide. We've got five power supply projects. The St. Lucie project has a partial ownership in the FPL. We've got 15 members that participate in that project.

Stanton project we have 64 megawatts out of the OUC Stanton 1 Unit of which six members are participating in that project.

Tri-City, again, is in OUC Stanton 1 coal power plant. Three separate members have participated in that project.

Stanton II, 100 megawatts of that in the OUC. Seven members participate there.

All-requirements project is where we spend most of our time. Pardon me. We have ten members now of that project. We supply all their power supply needs and that's where I spend most of my time planning.

We anticipate the City of Lakeworth coming in in the next year or so and so we may instead have 11 members there in the not too distant future.

MR. HAFF: Rick, is the light coming through the bottom of that projector or is it coming through the top?

MR. CASEY: That's the top. I want to try that one.

MR. HAFF: Turn the bottom on only.

MR. CASEY: Thank you. Just as a matter of information, the ten cities had hit -- had a new peak this summer. We were anticipating a peak of 940 megawatts. They instead hit 900 megawatts on August 2nd of this year which is over 4% higher than we expected.

The only significant change in this year's Ten Year Site Plan compared to last year is that our 2000 summer peak is higher than last year's projection of 2.6%.

Let me go ahead and cut through some of the other slides and just show you some of our historical reserve margins.

This is our historical summer peak reserve margins. As actually experienced, as you can see, up until about two years ago we were planning for about 20% reserves and we were close to that in most cases on an actual basis. Got a little higher in '96 and '97 but that's what we experienced on an actual basis in the summer.

Winter peaks being a little more spiky, not too prolonged are a little more difficult to project

but here's what we look like historically on our winter peaks. They can get real high and they can be real low when it gets real cold, so that's what that looks like.

On a planning basis we now plan for a 20% summer -- 18% summer reserve margin and a 15% winter reserve margin and we have a little excess in next year but coming down if things go as planned.

In terms of anticipated, what we can and can't serve in the future winters, we don't have a lot of history to go back and look at. The project was formed in May of '86. We did experience the December of '89 winter peak and we did serve all of our load that particular winter. Didn't have any fuel rotations or blackouts.

We don't have any formal studies to try to anticipate what we could or couldn't serve, but in view of the fact that we did serve our load in one of the most extreme winters that's been experienced we feel fairly confident that we can probably do so again should that occur.

And in terms of nonfirm load we don't have any except to speak of two of the cities, Ocala and Leesburg, do have residential load management and right now in the summer that represents about four

megawatts and in the winter six, and we expect that to grow a little bit by 2008 to five in the summer and nine megawatts in the winter. We don't operate it real frequently, only infrequently, and as needed for state capacity emergencies.

Any questions?

MR. HAFF: Any questions for FMPA? I'd like to thank you for your brevity in your presentation.

Next let's hear from Gainesville Regional Utilities if they have a presentation.

MR. KAMHOOT: My name is Todd Kamhoot. I've put together a very short handout that addresses basically the questions in Staff's outline.

First, I'd like to show a table, and this is going to be hard to see on the overhead. Your handout will be easier. These are our generating resources. And our current system total is 550 megawatts.

Next fall we are planning to repower our Kelly Unit 8 from a 50 megawatt steam unit to a 110 megawatt combined cycle, so we'll have a new net 60 megawatts for a total of 610. We expect that to be in service for the winter peak of 2001.

The table and graph on the next page show our capacity and demand at time of winter peak. You can probably surmise from this graph that GRU is a

summer peaking utility and we have a good bit of excess capacity in the winter time. The dark line at the top represents available capacity and the bars represent our peak demand plus 15%.

There's a similar table and graph, the fourth page of your handout, for our summer peak demand.

Try to hit some of the high points. Staff has identified some historical dates in which extreme winter weather contributed to extraordinary high winter loads. I selected what I viewed a worst case example to discuss today, and on Page 10 of Staff's handout, if you refer to that, I selected the January 21, 1985 date.

You can see on there for Jacksonville it was 7 degrees Fahrenheit. It was about 10 degrees in Gainesville at that time and that happened to be a date that we experienced the highest winter demand per customer that we ever have. On that date we had a 253 megawatt peak.

The following day the temperature increased a little bit and our peak increased as well. So it leads that there are probably some factors beyond temperature that are contributing to the peak.

The 255 megawatt peak on January 22nd was

31% higher than 1984's Ten Year Site Plan's forecast. So what I did for this example was apply that forecast error to the winter peak of 2000/2001 because we would have a lower reserve margin in that year than we would this coming winter. And with all available capacity, GRU would still expect to have a reserve margin of 39% under that scenario.

If our repower of Kelly Unit 8 is not complete and neither the original steam unit nor the new combined cycle are available, we would still have a reserve margin of approximately 14% so we would still be able to meet a winter demand under a scenario such as one where our peak exceeded forecast by 31%.

GRU has curtailable load agreements with two customers for a total of approximately two megawatts. These are new agreements we just entered into this year. Verification testing was conducted this summer. These were discussed in the interrogatories in more detail.

And in response to Staff's question, curtailment alone in this situation is not necessarily correlated to GRUs reserve margin because there is adequate capacity without curtailment. However, curtailment of load is valuable to us for other reasons. For example, this summer it helped relieve a

heavily loaded circuit.

That's pretty much all I have in the way of a presentation, if anyone has any questions.

MR. HAFF: Any questions for Gainesville Regional Utilities? Thank you.

Next presentation is from Jacksonville Electric Authority if they're here.

MR. BOSWELL: I'll be brief, Michael. Randy Boswell. And I'll correct you. It is no longer Jacksonville Electric Authority. It is officially JEA. We changed our name.

MR. HAFF: Okay.

MR. BOSWELL: I'll use about five slides out of the package and you can ask questions.

There's our current capacity, 2,700 megawatts. We have a one firm sale and a couple of purchases that are included in that number.

Just quickly, our forecast demand and energy growth rates are exceeding 3% for summer, winter and energy which was fairly aggressive, but it mirrors the Jacksonville economy.

Our expansion plan, as listed in our Ten Year Site Plan, you'll see first we do have some seasonal purchases in the near term until our capacity gets built for 2000, 2002, 2008. In 2000 we add our

first combustion turbine. Three more units in 2001, and one unit in 2007. The first four turbines are purchased. One has been delivered. The other three are on order and in the pipeline.

As part of our plan we are shutting down some oil-fired units; replacing them with the turbine gas capacity.

Part of our plan includes repowering Northside 1 and 2 which are large steam turbines currently. They will be repowered with petroleum coke fuel at our Northside power plant, but we will lower emissions out of that plant site in that effort.

Going to skip a couple of pages in the interest of time and go to our nonfirm load. We do have some nonfirm resources. These are our interruptible curtailment contract amounts by year. We purposefully limited the amount of interruptible on our system. Less than 50% of the reserves we carry are in interruptibles. One customer accounts for about 50 megawatts of that. It's a steel mill and current practice is the rate has a two rate option. When we're in a high cost day, they get price signal. They typically self-interrupt. They self-interrupted numerous times this summer on price, and they're happy.

You had some questions on on-site generation and so forth and the data is in the pack. There it is. Notice provisions on the interruptible are a three year notice or enter into a five year contract. We do not use it as spinning or supplemental. And we've only experienced one interruption to date, and there was when there was an airplane crashed into 500 lines in Florida and reduced the total import into the state. That's been our only interruption.

I think that covers all I intended to say and I will entertain questions.

COMMISSIONER JACOBS: On your '98 reserve, it was fairly thin, and coming into your projections, what's going to be the major factor in turning that around?

MR. BOSWELL: I'm sorry. On our '98 reserves?

COMMISSIONER JACOBS: Yes. I'm on -- it doesn't have a page. It's the table that has all the reserve margins here.

MR. BOSWELL: Talking about this table?

COMMISSIONER JACOBS: Yes.

MR. BOSWELL: Those are actual experience numbers, not planning numbers. And that was requested by Staff.

COMMISSIONER JACOBS: Okay. And what accounts for the projection for '99 going from a negative 11 to 15%.

MR. BOSWELL: Well, it's easier to say what happened in '98. We had a large unit trip at time of summer peak and that gave you the negative number. That's what our reserves are for, to account for that, and we certainly had no problem, but our projections are 15% or higher moving forward.

COMMISSIONER JACOBS: Okay.

MR. HAFF: Since you brought this rain with you, would you take it home with you?

MR. BOSWELL: I sure will.

MR. HAFF: Thanks.

Next presentation on the list is Kissimmee Utility Authority. Are they still here?

MR. ROLLINS: I'm Myron Rollins. Robert Miller had to leave for some PROSIM training this afternoon so he asked if I would make the presentation for him. He left me an hour's worth of slides, I think, but I can pick two or three of them out. But I think I can summarize it pretty quickly.

Kissimmee uses a 15% reserve margin. As a comment, I think we might be making too much out of a strict analytical application of reserve margins. The

important thing is the reliability of the system and whatever it takes to provide accurate reliability.

They need capacity in 2001 which would be met by Cane Island 3, and they will need some more capacity by 2004.

I looked at the issue of what would happen on the cold days in our system, and it will be nip and tuck if they would be able to serve all their loads and we don't really have -- they don't really have the data to do a detail model to try to do that.

But a couple of things that nobody's mentioned about that is, especially when it gets cold, all the combustion turbine capacity in the state will produce quite a few more megawatts than is in the winter capacity ratings. And also load management, which Kissimmee has about 12 megawatts of currently, you'll get a lot more load reduction from your load management than you will out of a normal winter situation.

And I've got plenty of slides if anybody has any questions, but since we're trying to run short on time, I'll quit.

COMMISSIONER DEASON: Can you explain to me what you mean by the fact that there's going to be capacity for combustion turbines which are not

accounted for on an extremely cold day?

MR. ROLLINS: Right. In general, the colder it gets, the more output you'll get from combustion turbines.

COMMISSIONER DEASON: Oh, you're talking about the efficiency of the plant?

MR. ROLLINS: Right. The plant will put out more so people will rate their turbines at a standard, you know, winter temperature or whatever probably, and then on these very severe days it will be colder than that and there will be more output come out of those units than what is shown on the capacity tables. Thank you.

MR. HAFF: Thank you, Myron.

Next I have the City of Lakeland with a presentation.

MR. ELWING: Good afternoon, Commissioners. Paul Elwing representing the City of Lakeland Electric. I'll try and keep my presentation very brief in the interest of time.

Just a few highlights on the load forecasting process. Lakeland has been gathering Lakeland specific weather data; temperature, rainfall, humidity data among other things, for over 25 years. Supplementing that with weather service data for the

area gives us a database that stretches in excess of 30 years.

We are a winter peaking utility and forecast ourselves to continue being that for quite some time. Over our history our average minimum temperature has been 38.6 degrees in winter with standard deviation of about 6 degrees. We've only had three years in the past 25 to 30 years where we've been below what would be about 24 degrees. Our lowest temperature at peak of all time has been 19 degrees which occurred Christmas of '89, and we're currently using 15% reserve margin with a 30 degree minimum temperature for winter for our planning purposes.

Just real quickly. Lakeland continues to maintain its efforts in DSM and conservation. On the residential side we have our SMART load management program, along with loans for thermal efficiency upgrades. On the commercial side, we've got commercial lighting program, thermal energy storage and high pressure sodium outdoor lighting program.

In an effort to address some of the Staff's questions regarding nonfirm load, Lakeland does have five interruptible customers that have been on tariff since 1996, I believe. And they make up a total of 5 megawatts. However, Lakeland has never had the

occasion to need to interrupt them. Those customers do have a 60 month notice in order to leave that tariff.

We do not have any curtailable customer as defined by curtailable rates. Load management, we've got a little over 27,000 customers. Almost all of those are made up as residential. In today's numbers that equates to about 52 megawatts of reduction in winter; about 22 megawatts in summer, and we're expecting that to grow to 63 megawatts in winter, 27 in summer by the end of the planning horizon, 2008.

I might note that over the past two years, we have not had to implement load management at time of summer or winter peak. We've had sufficient resources to serve all of our load. We have, however, used the program in both 1998 and 1999 calendar years. I believe '98 we used it 18 times and this calendar year we've used it 19 times for other reasons.

Lakeland continues to remain active in other renewable programs; solar street lighting program, and two other pilot programs that we're looking at; distributed generation via solar thermal collectors and residential photovoltaic systems.

MR. BALLINGER: Paul, can I interrupt real quick?

MR. ELWING: Yes.

MR. BALLINGER: You use DSM, you said load management 19 times in '99 --

MR. ELWING: That's correct, Tom.

MR. BALLINGER: -- but not at peak. What were some of the other reasons? Did you interrupt to sell to other utilities?

MR. ELWING: I don't know for sure on that. We did have some instances other times of the year where weather was warmer than what we had expected, unit tripped, and so just as a precautionary measure, we implemented load management, and I know it was primarily in the afternoons, warm summer days, just to make sure that we were whole.

MR. BALLINGER: Does Lakeland have the ability to use load management as a dispatchable resource? And in that I mean, can you us dispatch it like a unit and then make an all systems sale as long as you stay within your tariff?

MR. ELWING: I believe we could do that within the confines of our tariff. I don't know as we do that on a regular basis, Tom. I think we have made our load management available to others when others have been in trouble.

Just real quickly, just a little synopsis of

where we stand on fuel mix. I got about 205 megawatts that are solid fuel, coal based. We got two small diesel units that are captive to a single liquid fuel No. 2 oil, and then the remainder of our capacity is dual fuel capability, natural gas or oil. 190 megawatts of that is steam. 249 megawatts of CTs or CCs, combined cycle.

I'm going to skip over the next couple tables. They're just summary tables of our customers; our summer and winter demand, unless someone has a specific question on those.

Commissioners, I'm going to jump to Page 10 year, again, to attempt to answer a few of the questions that staff had asked for today.

Forecasted reserve margin. This is looking out over the next ten-year period. The red line is 15% reserve margin level which is what Lakeland has been using at present. As you can see our forecasted reserve margin for both summer and winter is either right at or above the 15%.

Historical reserve margin over the past ten years, again the red line, there's a 15%. We have been above the 15% in all but one year. The winter of '96 we experienced some colder than expected weather. I think we had temperatures in the 25, 26 degree range

and so our reserves dipped down below 10%. However, all of the load was served.

I'm going to jump ahead again here for time's sake. Jump to Page 16. The other pages in between are just some updates; where we are with current capacity projects. I think they are fairly self-explanatory.

Page 16, here again, attempts to answer some of Staff's questions. What would our load look like had we had temperatures, weather conditions based on a specific set of dates. The legend is over there on the right-hand side with the different dates. The red line on top is where our available capacity is based on our current plan. And so even if we experience weather based on those historical dates, forecasted to the '99/2000 winter peak, we have sufficient capacity to serve all of that load.

Page 17 is just the extension of that, looking at the 2002-2001 time frame. And, again, we have sufficient capacity to meet those loads.

That's all I have, if anyone has any questions.

MR. HAFF: Any questions for Lakeland?

(No response.)

Thank you, Paul.

Orlando Utilities Commission is the next presentation.

MR. BLANKNER: Good afternoon. My name is Matt Blankner. I'm with the Orlando Utilities Commission.

I apologize I don't have any handouts. I will forward a copy of the overheads to you, though, so you'll have those.

This is just a layout of the generation facilities for Orlando Utilities Commission. I highlight the ones in gray. Those are the steam units at the Indian River plant. There's a pending possibility of a sale of those units. That has not been finalized so I really don't have any more information on that. What I might add --

CHAIRMAN GARCIA: It's a sale with a contract with that, right? Sold with a contract for OUC to purchase back --

MR. BLANKNER: Right. There would be a Purchase Power Agreement with that.

So that's the layout of our generation facilities. And I might add, too, that there hasn't been any change of that since last year so those are the same.

This is just a review of our generation mix,

our fuel mix. As you can see it's fairly well diversified with coal, steam, oil and gas combustion turbines and nuclear.

These are projections of our reserve margins as we go out, and we don't foresee any problems with meeting the 15% reserve margin which we do go by; the red line at the bottom.

We don't have any generation planned out to 2008 right now. (Indicating) The indication of our summer capacity reserve margin is to the far right. And the winter capacity.

MR. HAFF: I have a question. A couple of slides back the reserve margins where you had the duel summer and winter.

MR. BLANKNER: Sure.

MR. HAFF: You're building no capacity but the reserve margins seem to be ramping up over time. Is that because you have firm contracts that are backing down during that period?

MR. BLANKNER: Yes, we do. Yes.

I'm going to skip along to the list of requested topics from the Staff. And I'd like to show that based on temperatures experienced on or around the different dates as indicated, that OUC basically has a -- we ran a native load at low temperatures with

different ranges.

At 22 degrees and below we reach a saturation point with our load. We also have ranges from 24 to 26 degrees and 27 to 30 degrees. And all of those loads indicate in those different years, especially in 2002-2001, that we're not going to have any problem meeting those loads. In 1989, which was the worst year we had as far as temperatures goes and loads, we were able to meet all loads at that time.

We do not have any nonfirm load situations except for one curtailable customer that's one megawatt. And in the interrogatories for the reserve margin we did list in there the times we've curtailed that customer.

I don't have anything else if you have any questions.

MR. HAFF: Any questions?

(No response.)

Okay. Thank you.

The next presentation is going to be the City of Tallahassee.

MR. FRAZIER: Hello. My name is Edwin Frazier. I'm with the City of Tallahassee, and here with me is David Byrne. He will assist me during this presentation. He's also with the City of Tallahassee.

And this is a brief Ten Year Site Plan presentation.

Okay. Here we have our demand forecast. We're a summer peaking system. We use a linear regression model and we include DSM impact. Our winter 1999-2000 forecast is 485 megawatts and our summer 2000 forecast is 522 megawatts.

Our projected reserve margins as shown here are for the years 1999 through 2008. That's based on current resources that are available. But we're currently evaluating other supply-side plans for the years 2006 through 2008 where you see the shortage appears.

This is our projected winter reserve margins for the same period,and as you see we have no problem, even based on our current resources, of meeting the 15% reserve margin criteria.

Our projected resource requirements. We, at the City of Tallahassee, actually target a reserve margin of 17%. And in October '99 we're going to retire two 23-megawatt steam units. And we plan on having a combined cycle addition in the month, May 2000, Year 2000. And as I said before, we're currently reviewing options for the years 2006 and through 2008 where we show shortfalls.

The issues that the Commission was concerned

with the extreme winter forecast. Our forecast model is temperature driven. The dates that the Commission Staff reference, our record load appeared for -- the historical record low for Tallahassee was on January 21st, 1985, which is one of the dates that was mentioned. And what we did was put the -- it was at 6 degrees Fahrenheit and we put that in our load forecast model based on today, and we came up with a forecast of 589 megawatts for the winter 1999-2000. And if that was to occur, we would have existing resources of 570 megawatts, which would, in turn, have a deficit of 19 megawatts. And in the year 2000-2001 we put in the 6 degree Fahrenheit load temperature in our forecast model and we came up with the demand of 609 megawatts and resources available, 730 megawatts and no deficit.

MR. BYRNE: I just wanted to mention one other thing. Edwin indicated in the extreme temperature case that there might be a deficit for the upcoming winter.

We do have one new unit coming on line subsequent to this winter, so the timing is a little bit behind there but this does represent a worst-case scenario. And we think if an indication of extreme cold weather like that was coming in, we have

sufficient operating actions that we can take that would avoid us getting into a problem situation. And if there was such a case, we would probably have to consider a load-shed action if we couldn't call on reserves from other utilities at that time. Also, about 11 degrees is what we calculate would be the -- kind of the break-even temperature; where we would have about a 570 megawatt load.

MR. HAFF: Is your portion of the intertie with Southern fully subscribed with firm capacity at this point or during these two winter seasons?

MR. BYRNE: No, it's not by Tallahassee, and we don't currently have any firm reservations for that tie line in that period of time.

MR. HAFF: So that would be available at those --

MR. BYRNE: It could potentially be available at that time.

MR. FRAZIER: Nonfirm load. We currently have two interruptible customers: Florida State University Magnetic Lab, which is 42 megawatts; Hermitage Place, which is .63 megawatts, and we have one current curtailable customer, which is Tallahassee Memorial Hospital at .6 megawatts.

MR. BYRNE: I'll just mention that the large

interruptible customer is one that we don't include towards our demand forecast. It's considered to be operating during off-peak periods only. We generally call them in advance if we feel like there's going to be a need for them to curtail their operation. And to this date we've never had on situation where we had to actually interrupt them on a short notice. So we basically don't consider them as part of our load. The other two customers we do. Although they are a small quantity, they can be interrupted but never have been. And that concludes our presentation.

Are there any questions?

MR. HAFF: Any questions for the City of Tallahassee?

(No response.)

Thank you. I've get two more. Hear from Seminole Electric Cooperative, and following them will be Duke Energy New Smyrna Beach who filed a plan this year.

MR. ZIMMERMAN: Good afternoon. I'm Garl Zimmerman from Seminole Electric Cooperative. I thought I was going to have a full 20 minutes, but since there's somebody else to go, I'll be brief.

MR. WRIGHT: You can have all my time. I need one minute.

MR. ZIMMERMAN: This illustrates the history and forecast of Seminole's demand and resources. This top line is Seminole's total peak demand; this bottom line with the -- (Adjust projection machine.)

We'll just have to make due with what we have here.

This bottom line is Seminole's obligation. The rest of the total peak load being handled by partial requirements and full requirements contracts. As you can see, the partial requirements contracts are diminishing over time and are projected to be a very small percent of Seminole's resource mix, with the green area being additional resources that Seminole will be adding.

A similar chart for winter. And this just shows that we had winter peak demand in the 3100-megawatt range and projected to increase over the planning horizon to about 4200 or 4300 megawatts.

Historical and projected reserve margins. Historically, we had some fairly high reserve margins because we were planning to -- a 1% EUE, which was the driver in our planning criterion. As we've added new resources and diversified some, expected unserved energy is no longer the driving force. In the future we'll be planning the 15% reserves. And we're showing

to be well above that for -- and in the 20% range for most of the planning horizon.

New facilities that are in our plan. We have our Payne Creek combined cycle unit coming on in January of 2002. That is well along with engineering and ground will be broken very shortly on that facility.

We had a couple of units in here which caused a little concern, I think, with Staff, where we had some CTs shown being in service by January of 2000. We have delayed those two CTs a year, with a combination of a seasonal and year-around purchases, and subsequent to that, have signed a contract to have those two units in service in December of 2001 with an independent power producer.

(Inaudible comment.)

MR. ZIMMERMAN: No. It's rely and energy.

The next four units that are shown on there, we're currently in negotiations and we will fill those needs probably with a combination of additional purchases and/or self-build units. We should have those next four units firmed up by the time we file our next Ten Year Site Plan.

Load management and interruptible. We've broken it out a little more than possibly we needed

to, but we have a certain amount of load management and interruptible that's in the Florida Power Corporation control area which only affects our partial requirements purchases. The load management and interruptible that's in the FPL control area or the Seminole direct-serve area, it directly affects Seminole's obligation and the amount of resources we have to have.

And what we have shown here, the interruptible is really not -- the interruptible, as you may think about it, it's actually self-serve diesel generation, and then the DSM is the residential and light commercial DSM programs.

And finally, load that would be unserved -- I need to go back the other way here. Load that would be unserved on the various dates in the winter of '99-2000 and 2000-2001. By 2001, with the additional resources, we'll have adequate capacity to serve all of the load on each of those dates. This coming winter we had, for one of the occurrences, about a 3% unserved demand; a couple other times where it was almost in the noise level, one of them less than half a percent.

One comment, we think that our load model is overforecasting our winter peaks on those extreme low

temperatures. It appeared to have a linear relationship rather than indicating the type of saturation that we've seen in some of the other presentations as the temperatures start to bottom out. So that coupled with operating measures and the ability to import from our interchange partners, we would hope the amount of load that we serve -- that would be unserved would be zero.

And that concludes my presentation.

MR. HAFF: Any questions for Seminole?

(No response.)

Thank you. Mr. Wright, I guess, next, and last but not least is Duke Energy New Smyrna Beach.

MR. WRIGHT: Thank you. I'm Schef Wright here on behalf of Duke Energy New Smyrna Beach Power Company. I'll be very brief.

Duke's plan is to construct the 514 megawatt ISO-rated New Smyrna Beach Power Project and to operate it as efficiently as possible. We expect to sell around 4 million megawatt-hours per year to other utilities in Peninsular Florida. At the time of winter and summer peaks we expect to be selling the full available capacity of the unit to other utilities in Peninsular Florida; that's estimated to be 548 megawatts winter and 476 summer. The only change from

our filed plan is that due to unanticipated delays in the permitting process at the cabinet level, we're now projecting an in-service date for the project of June 2002. Thanks.

MR. BALLINGER: Schef, I've got one question. Did you file your plan with the FRCC?

MR. WRIGHT: I'm sure we sent it to them, Tom. I don't --

MR. BALLINGER: Do you know if and how they incorporate it in the aggregate plan?

MR. WRIGHT: I don't think they did but I don't know.

MR. BALLINGER: Okay.

MR. HAFF: Any comments?

(No response.)

Well, we'd like to thank you all for your brevity and your comments and thank you for your participation today.

Is there any final comments from the Commission? Thank you all for coming. We'll see you soon.

(Thereupon, the hearing concluded at 3:50 p.m.)

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTERS
COUNTY OF LEON)

We, JOY KELLY, CSR, RPR, Chief, Bureau of Reporting, Florida Public Service Commission, and KIMBERLY K. BERENS, CSR, RPR, Official Commission Reporters

DO HEREBY CERTIFY that the Workshop was heard by the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed by us; and that this transcript, consisting of 212 pages, constitutes a true transcription of our notes of said proceedings

DATED this 4th day of October, 1999.

JOY KELLY, CSR, RPR
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