BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	:	**UNDOCKETED**
Commission review of electric utility ten-year site plans.	:	

PROCEEDINGS: **WORKSHOP**

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

DATE: **Friday, September 11, 1998**

TIME: Commenced at 10:40 a.m.
Concluded at 3:40 p.m.

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

REPORTED BY: H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter

IN ATTENDANCE:

LESLIE PAUGH, Division of Legal Services, Florida Public Service Commission.

TOM BALLINGER, Division of Electric & Gas, Florida Public Service Commission.

MICHAEL HAFF, Division of Electric & Gas, Florida Public Service Commission.

BOB TRAPP, Division of Electric & Gas, Florida Public Service Commission.

KENNETH DUDLEY, Division of Electric & Gas, Florida Public Service Commission.

JOHN McWHIRTER, Florida Industrial Power Users Group.

JOE McGLOTHLIN, Florida Industrial Power Users Group.

KEN WILEY, Florida Reliability Coordinating Council.

BOB ADJEMIAN, Florida Reliability Coordinating Council.

STEVE DAVIS, IMC-AGRICO.

ROCKFORD MYER, Florida Gas Transmission.

MICHAEL RIB, Florida Power Corporation.

VINNIE DOLAN, Florida Power Corporation.

MARIO VILLAR, Florida Power & Light Company.

ROBERTO DENIS, Florida Power & Light Company.

BILL POPE, Gulf Power Company.

CARL ZIMMERMAN, Seminole Electric Cooperative.

RICHARD CASEY, Florida Municipal Power Agency.

ROGER WESTPHAL, Gainesville Regional Utilities.

RANDY BOSWELL, Jacksonville Electric Authority.

ROBERT MILLER, Kissimmee Utility Authority.

PAUL ELWING, City of Lakeland.

MATT BLANKNER, Orlando Utilities Commission.

EDWIN FRAZIER, City of Tallahassee.

DAVID BYRNE, City of Tallahassee.

JOHN CURRIER, Tampa Electric Company.

MARK WARD, Tampa Electric Company.

JON MOYLE, U.S. Generating Company.

MARCIA ELDER, American Planning Association.

DEB SWIM, Legal Environmental Assistance Foundation.

I N D E X

MISCELLANEOUS

P R O C E E D I N G S

(Workshop convened at 10:40 a.m.)

CHAIRMAN JOHNSON: Ladies and gentlemen, if everyone can be seated, we'll go ahead and begin the workshop today.

Today's workshop is to inform and educate the Commissioners regarding individual utilities' ten-year site plans, as well as an overview of Peninsular Florida reliability from the Florida Reliability Coordinating Council. The Commissioners will be seated in the audience or here in the front row. Commissioner Clark will be joining us soon.

For those of you who have not participated in the process in the past, remember that comments and questions are welcomed from interested persons, and we will just proceed in a very orderly manner. To the extent that you do want to make comments, we will have a time and a place for that. We will generally begin with Commissioners' comments and questions, but we will entertain questions from interested persons.

I understand that Mr. McGlothlin and perhaps Ms. Swim may want to address the individual utilities after they make their presentation. Is Ms. Swim here? I haven't seen her. I understand that there are -- oh. I just wanted to make sure you were here. I didn't see you.

Staff has put together an agenda as well as a packet of tables containing a summary of each utility's ten-year site plan, and it contains Staff's concerns regarding the FRCC reliability assessment and individual utility plans and information requested from individual utilities.

The information that is missing from the tables that was requested at the August 25th workshop should be filed by the end of today's workshop. I understand that Staff has received a few of the responses and that most of their questions from the individual utilities will be directed towards getting the rest of the information.

With that, I don't believe we have any other preliminary announcements. There is a schedule that I think you've all been provided with. Have they all been provided with the schedules?

MR. HAFF: Yes.

CHAIRMAN JOHNSON: Is the mike system on? (Pause) Is it on now?

MR. BALLINGER: There you go. All the utilities were provided with those tables, at least the 12 utilities who filed ten-year site plans.

CHAIRMAN JOHNSON: Very well. Then with that, I'll then turn it back over to Staff to walk us through the individual presentations.

MR. HAFF: This is Michael Haff on Commission Staff. Am I on? Okay.

I'm going to pass around a sign-in sheet for everyone who is present to sign your name, your company and your phone number. I'd also like to note that when anyone is giving a presentation or addressing the Staff or Commission to please state your name and who you're with so the court reporter can make a record of it.

And I guess first on our list is the presentation by the FRCC on the load and resource plan and the reliability assessment, and they can sit at the end of the table down there and use that overhead projector if necessary.

MR. WILEY: I'm Ken Wiley. I'm with the Florida Reliability Coordinating Council, and I'm the staff member, and with me today is Henry Southwick. Henry is the chairman of our engineering committee and our reliability assessment group, which is the major group that determines reliability policy for our region.

Also with me is Bob Adjemian. Bobby is the chairman of our study group that performed the reliability study this year, and he'll be presenting that in a few moments. And also today Rock Myers, president of the Florida Gas Transmission, will be making a short presentation, since our reliability plans in the future include gas; and for the recent pipeline considerations we had, we thought it would be nice for Mr. Myers to talk to us today.

I wanted to make a few introductory remarks before Bobby discusses the reliability study that we made and try to put the reason why we're here today into perspective.

I know that t' e Staff has communicated to the Commission some of their concerns about the reliability studies, and I wanted to address that with some of these remarks.

CHAIRMAN JOHNSON: Let me pause for a second. I'm going to have someone check the mike system.

UNIDENTIFIED SPEAKER: We cannot hear in the back. It's not working.

MR. WILEY: How about now? Is that better?

UNIDENTIFIED SPEAKER: No.

CHAIRMAN JOHNSON: I'm going to have someone check the mike system. It's not --

(Pause in proceedings.)

MR. WILEY: In order to put today's discussion in perspective, I just wanted to review why I think that we're here.

Last year when we went through the review of the electric utilities' ten-year site plans to produce this document, we in the staff got concerned early on, and they asked us to run some reliability studies; and we did that. And, as you recall, we had discussions in November and December trying to resolve some of the questions that that reliability study put forth last year.

And out of that entire process, the Commission asked the FRCC to go back and assess the criteria or the tools that it uses to determine whether or not the generation resources in the Peninsula are adequate or not.

And just a little historical perspective on what those tools that are available are: In the '80s when we were going through annual planning hearings, the industry used what we called a loss of load probability study technique, and this was a mathematical probability model. And it allowed us to analyze how reliable the generation supply was to meet the projected loads into the future, and we measured that in terms of how many days per year or days per 10 years that we would expect loss of firm customer load.

And it was a statistical mathematical tool, and being a mathematical tool it has a lot of input data into it. And one of those input data was how reliable are each individual generating units that were in the state; what was their individual reliability. The words that we used, technical word, was what were their "availabilities."

And during that period in time, availabilities of our generating units in total were approximately 80%. Well, the economics of the past decade have caused utilities to look at that, and economics say that they needed to improve that reliability in order to not build as much new generation; and that was one of the factors.

So what we have seen over the past decade is the availability of all the generation in the state as a whole go from a roughly 80% level to around 90%, a very significant increase.

So last year and this year when we ran our studies using this loss of load probability technique, because the availability had significantly increased, the answers that came out of that study were not what we were used to seeing back when the availability of our generation was at the 80% level; and we all weren't exactly sure what it was telling us because of the numbers.

And, therefore, we started looking at the other factor that we have historically used of installed reserve margins; how much more generation do you have to -- you know, available to meet the load. And historically we had used, as a guideline, between 15 and 20% during the 1980s and the early '90s.

And so all of a sudden these two tools were a little -- well, they were in a new era because of these increased availabilities. And you, the Commission, asked us is there another tool that you can go out there and find to analyze this.

And so that was our job this past year. And Bobby is going to present to you a study in a moment that we came up with to try to answer that question. And the net effect of what that study was, to try to determine was, what level of installed reserves should we have in order to ensure that our generation is adequate; and so that was the answer that we were trying to seek.

Based upon the results of that study, the FRCC just this week adopted a reliability standard for this purpose of 15% installed reserve margin as its minimum over the peak periods.

When you look at our existing ten-year plan that was presented to the Commission this year, the FRCC's installed reserve margin over every one of the peak periods, the 20 peak periods for the next 10 years, is at or greater than 15%. As a matter of fact, there are only two of those peak periods, which are two winter peaks, that are at 15%. Everything else is above it. And based upon the study that Bobby will be discussing with you, and based upon the history, and based upon looking around the country, that is why we adopted that as our standard today.

We understand that -- Staff has pointed out to us and we understand that this was not a rigorous mathematical model that we utilized to come up with this. We feel that we need to continue to look at this as we go through next year and the year thereafter.

The Staff has proposed a proposed probabilistic technique using the same data base we had, and at this time we don't feel completely comfortable with using that particular method on the data that we have at hand. We feel that over the next year we do need to work with Staff to see if probabilistic techniques can be factored into the study that Bobby is going to be talking about. But until such time, we have certain things to go on, and that is the LOLP study he's going to talk about and its reserve margin analysis.

When we looked around the rest of the country at some of the other reliability regions to see what they have been doing, we find that there are at least three other regions that utilize a 15% reserve margin as their planning guidelines, and we find there's still a couple of regions in the country that use this one day and 10 years loss of load probability as its measure.

And one of these regions, which is Texas, the Electric Reliability Council of Texas, is a region that is somewhat similar to FRCC in that they're isolated electrically over there just as we are here in Peninsular Florida, and they're using this 15%.

So based upon all of these factors, the Reliability Council definitely feels that the council as a whole, its generation plans are adequate over the next 10 years; and we feel that that constitutes a suitable regional plan in the ten-year site plan parlance. And with that, I turn this over to Bobby for him to discuss our studies.

MR. ADJEMIAN: I hope I can live up to the expectations here. But as you'll see -- I think it was -- I like to call it kind of an elegant study, in one sense, but also based on intuition.

But let me start here at the beginning. Here's the two things that I really expect to address: The load and resource plan of the FRCC for the 10-year period of 1998 through 2007, and then the reliability assessment study, which took the bulk of the activity this year for the FRCC study group, which also includes the reserve margin standard.

So starting with the load and resource plan, I will take you through a series of slides that summarize -- and I realize this is not very easy to see, but I'll describe them -- summarize the key components of the plan.

Starting with demand, these numbers are in the order of starting around 35,000 megawatts, the top line, all the way out to 43,000 megawatts. What you see is the winter peak demand is the top line. The red line is the summer peak demand that's projected. As you'll see, winter is projected to be higher -- to have higher demand than the summer.

The level that you see here, let's say compared to last year's load and resource plan, is slightly higher in the out years, about 600 megawatts higher than last year's load and resource plan.

Next I'll discuss the generation capacity that's in place and expected to be in place towards meeting this demand. The green bars is where the capacity is today, and the number off to the right is in 35,290 megawatts, and then the light blue shades is the net capacity additions that are being -- going to -- are projected to come into place between now and the 2007 period. And the last year cumulative is 7,800 megawatts. So we are starting from 35,000 and we're adding a net almost close to 8,000 megawatts of capacity in summer demand terms. Summer rating. Sorry.

Also comparing to 1997 what I think is pretty relevant is 8,000 megawatts compared -- for the '98 plant compared to only about 2,800, megawatts in the '97 plan. So it's significantly additional generating capacity that utilities have -- (pause) -- trying to focus this a little better.

Winter we're adding nearly 8,700 megawatts over the 10-year period as it compares to a little over 4,000 in last year's plan, almost twice the amount of generating capacity.

The next two slides deal with dispatchable DSM load management interruptible. For the summer period looking at the out year, we have a total of close to 3,300 megs of total dispatchable DSM being available towards meeting load, and in the winter that number is about 4,300 megs towards meeting load. These numbers are very similar to what were in the plan, in last year's plan. (Pause)

This table discusses the available uncommitted transfer capability into the state over our transmission tie lines. It's also referred to as the tie line assistance. It's in the box, and as you see, it's a number ranges close to 1,000 megawatts. That's about the same amount that was assumed last year.

The fuel mix, projected fuel mix under this -- the composite of these plans of the utilities in the state is for 2007 versus actual 1997. You notice there's not really a big difference. The gray and darker shades of gray are basically all fossil fuels; gas, oil and coal. And coal is expected to remain the predominant source of fuel followed by gas and oil.

And the last graphic I have for the load and resource plan is the resulting reserve margin. It's a little hard to see. But reserve margin, as Ken defined it, is the excess resource available to meet load. And basically if you have a reserve margin of zero, that means you have just enough resources to meet your expected load.

So typically a planner would want to have some reserve margin, more than zero, so that any contingencies to the generation or additional load, unexpected load increases could be in place, be able to supply it.

And what we have here is the dark bars are the summer reserve margins, and the white bars are the winter reserve margins, as Ken mentioned. In the summer, the reserve margins range between 17 and 20%. In the winter they range between 15 and 19%.

Now I'll turn it over to reliability assessment study. And here's what this piece of the presentation is going to cover. Focused in three areas; a reserve margin analysis, loss of load probability analysis, and then we have a section on natural gas transmission which, as Ken mentioned, Mr. Rock Myer from the FGT is here, and he's going to address that. He's going to immediately follow my presentation.

The reserve margin analysis had really two tasks. One was to develop a standard for reserve margins, and then the second one was to take the resulting reserve margins from the 1998 load and resource plan that I just showed you earlier and compare it to the standard to see how well they measure up to make a determination of resource adequacy.

So let me go to Number 1: How do we develop a reserve margin standard. As I said, I thought our approach was actually fairly intuitive. We asked ourselves why do you need that reserve margin. And clearly we need the reserve margin to cover unforeseen events, such as unit outages and load increases, for instance, beyond what's expected.

Well, so that means that we develop a system, we design a system to meet certain expectations. If those expectations are not met because of we didn't do our planning right, that means maybe our forecasting is in error in some fashion, that we're not doing the right -- we're not capable to be very accurate in predicting what's going to happen in the future.

So keeping that in mind, going back to history, we said, let's look at the history, 1993 from 1997, and look at the relevant components that enter the calculation or reserve margin, which is shown right here -- primarily installed generation and load, of course, the two biggest ones, but there's also purchases and imports and load management -- and find out how the forecast for a given year compared to the actual for that year.

So as we identify this area in our ability to predict accurately, that composite of those errors becomes, in essence, the required reserve margin, minimum reserve margin. So that study concluded that a reserve margin of 13% would be adequate to cover the historical inaccuracies in our forecasts, both for summer and winter.

However, the study group recommended a 15% standard as that was a level of reserve margin that, as Ken mentioned, several intuits have been using already and they felt comfortable with that level of reliability, as well as we know that other reliability councils have adopted, and furthermore to just give us some additional margin for -- of safety. I'm glad to hear the executive committee has adopted it.

So the standard of 15% was what was utilized to measure the adequacy of the load and resource plan. And you'll recall from the bar charts that you saw that at no time we had reserve margin that we're dipping below 15% percent. So we felt that from a reserve margin perspective, the resource plan is adequate.

However, traditionally we've been utilizing another method, which is the loss of load probability approach. And why would we want to look at a loss of load probability is because a reserve margin looks at basically two instances in a year; a summer peak and a winter peak. And yes, we can meet those adequately, we feel, with 15%, but there's an awful lot of time between two peak periods in a year where we don't know what happens, and we need to take care that the plan is reliable and can meet all the needs throughout the course of a year.

That's where loss of load probability comes in, which basically measures your ability to meet, on a daily basis, the expected demand, and it calculates that as an expected value of number of days in a year that you cannot meet that demand. The accepted standard in the industry is one day in 10 years, or since this is done on a year-by-year basis, .1 days per year.

Let's go straight to the summary of the results of the loss of load probability analysis. The reference case showed no violations in the 10-year period. In other words, we have never exceeded the .1 day per year criterion. But we decided to also run a series of tests on the LOLP method to see how robust our system is, and we tried several sensitivities.

One had to do with the load management interruptible. Of course, that's nonfirm load, and utilities can choose to disconnect that load at times of peak demand or other stress conditions. But we wanted to see to what extent we need to rely on this. So we tried a case where none of the interruptible load was going to be affected or, in other words, exercised, and we found just like in the reference case that there were no violations of the LOLP.

Next we tested the totality of the DSM, dispatchable DSM, both residential and industrial/commercial load management fully. As you probably know, companies have the ability to use these measures fractionally as well, in fact, focus it by appliance as well; and most likely you would not fully commit all of the DSM. But in any event, that's what we decided to do here to try and stress against conditions, and we did find that there would be two violations.

Next we turn to EFOR, which stands for equivalent forced outage rate. Forced outage rate is a significant measure of availability of generation. And, as Ken mentioned, there has been a steady improvement in generating unit availability in the state of Florida in the FRCC over the last 10 years, but we wanted to test to see how well the system can withstand increases in forced outage rates.

The embedded reference case does include a certain level of forced outage rates. It's around 5%. So what we did is we went back to the '93-97 average, which was about 7 and a half percent. So we added the 2.7 to the 5. So basically we increased the forced outage by 50%, and we found out that there still were no violations. Of course, we did this for every generating unit in the state, so it's a pretty severe contingency.

And then we went further to see how it would look if we were tc revert back to the 10-year average rather than a 5-year average, which in essence doubled the forced outage rate that's in the reference case, and then several violations popped up. Obviously these forced outage rate improvements that have been achieved over the years have not been just a random outcome. It's a result of processes the utilities have undertaken through preventive maintenance, through weatherization of plants to try and improve. And those are in place, and I wouldn't expect that they will unravel suddenly. But in any event, we wanted to test the system's robustness in forced outage rate increases.

Finally we looked at -- well, I guess two more cases. We looked at the load forecast contingency, if you will. And what we tried to do there is a load forecast increase of starting at 2% in the early years and increasing to 10% in the out years, because basically that's what we found from analyses that we've done in the past, that typically we're better in forecasting near term than long term.

And when we did that we found that there were some violations showed up in the 2005 and on period, which is by then you're probably about 7 to 8% over your forecast. Of course, the assumption here is that we're just looking at loss of load probability. And, as we mentioned earlier, we're also going to be looking at reserve margins.

If I were to increase the peak load by 7 or 8%, my reserve margin will drop well below 15%, and clearly utilities would respond to that. Here we're just assuming that we're blinded to that effect, and we just wanted to see how bad things can get. And actually 2005 is not so bad. We could really react well before then if loads start picking up.

And the final case we looked at was at the tie line assistance. We wanted to see for purely isolated from available transmission that we have, and it was not available anymore, what effect that would have and, in essence, there was no effect. There was no violations as in LOLP, from an LOLP perspective.

So in summary, there were three items that basically I covered here. One was that our load and resource plan showed that we're maintaining at or better 15% summer and winter reserve margins through the addition primarily of between 8,000 and 9,000 megawatts, summer/winter of new generating capacity; a big increase over last year's plan.

Secondly, we performed a study, the FRCC performed a study, that established a 15% as a standard to measure resource adequacy as a reserve margin, from a reserve margin perspective, which we have adopted now to -- compliment the LOLP criteria. I'm sure LOLP is indebted to reserve margin from -- complimentary of it. I think we meant "compliment" there, but --.

And finally, the LOLP analysis indicated that under a certain -- quite a range of contingencies of key assumptions of load forecast, unit availability and, let's say, reduced tie line assistance, the system is strong enough, or designed to be strong enough to be able to withstand those contingencies;

and for those cases that we cannot, we feel that there are adequate processes in place that will be able to respond in time to be able to account for these situations.

With that, I will turn it over to Mr. Rock Myer from the FGT. He's the president of FGT, and he's going to address some gas issues on gas supply, gas pipeline expansion, and gas pipeline reliability. And I think after that, of course, we'll be open to answer any questions that you might have.

MR. BALLINGER: Bobby, did you ask for questions on your presentation before the FGT goes, or do you want to wait?

MR. ADJEMIAN: We can do it either way.

MR. BALLINGER: Okay. I've got a few questions for you, if you could, and perhaps it may be a bit --.

You mentioned the FRCC adopting the 15% reserve margin, but you didn't go into any explanation of how they came up with that number. I wonder if you could give us a brief synopsis of how you arrived at that number. I think you probably had the spreadsheet that shows all the contingency factors.

MR. ADJEMIAN: Tom, I don't have the spreadsheet with me. I'm sorry. But as I said earlier, though, we looked at the various components that go into the reserve margin calculation, the installed generation, the load forecast and load management purchases and imports, and we went back to history and found out how good we were in predicting them.

And when we determined that, let's say, in the case of generation we found out that we seemed to be missing available generation on peak by about 6 to 7%, which means that instead of assuming it in a reserve margin calculation that the generation is going to be there 100% available, that I put my formula to calculate reserve margin, and we said, well, it's only 93 point so percent of that that's going to be available.

So we basically calculated reserve margins using those factors, those uncertainty factors, and then determined what the resulting reserve margin would be when you account for those inaccuracies. And when we found that -- then at that point we determined that there is -- well, as long as there's a positive reserve margin left at the end of that, that means we have enough reserves accounting for the uncertainties to still leave you with a reserve margin.

And in essence what we did is that we took that remaining amount, compared it to what the projected amount -- well, the difference is really the amount that you have to have in place to account for the uncertainties, and that's how the reserve margin came about.

And it was a number that started fairly low in the near term years, as you'd expect, because uncertainties are lessened in the early term, and it was like 6 to 7% in the near years. In the out years it grew to about 13%. But we decided to adopt a 15%, as I said, and we kept it for every year, even though our ability to forecast in the near term is better than the long term for simplicity and other reasons and for more conservatism.

So, really, I mean, I'm not sure that the spreadsheet was showing anything else than what I just went over, but that's really the method that we followed.

MR. BALLINGER: That's fine. I was just looking for a little explanation of how you got the number.

MR. ADJEMIAN: I hope I --

MR. BALLINGER: That's find. And the difference that the FRCC and Staff took on this -- and I think you mentioned this -- is the FRCC looked at, I'll call it, a simple numerical average of error rates for these components, and Staff took for a probabilistic approach to those error rates looking basically at the same thing of what can you cover with contingencies.

Does that sound about right of where we --

MR. ADJEMIAN: Well, I guess I can make a comment on that. As Ken said, this is not something that we really studied very carefully -- I'm talking about the Staff's method -- and maybe we'll have ample time to look into it maybe next year or later this year.

But from the perspective of the way the Staff has analyzed it, we are looking at five data points, 1993 through 1997. And as I understand, the Staff did random draws of potential of 5,000 events occurring out of these five numbers.

You can create distributions from five numbers, and I'm just a little concerned that maybe reading too much into distribution projections out of just five numbers. It's not big a sample enough of a computation basis.

The second thing that I have a concern with is that, as I mentioned several times in my presentation, let's take one of the key variables, which is generation availability. I mean, that -- you look back in five years -- and Ken mentioned this, too -- availability of generation has been improving, and there's a reason for it.

The reason has to do with the processes that companies have put into place to keep units available at time of peak. And when we do a random draw of data, we'd be picking maybe the first years of the -- of my sample date, my sample database, availability of unit, which is something that happened maybe five years ago, unraveling all the systems that have been in place and all the processes that were put in place to keep generation on line and treating it as an random event.

It's not a random event. I happen to have with me, just to show how it's not random, a -- (pause) -- this actually shows you how the generation -- this is the forced outage rate for generating units for the last five years.

I mean, it consists in a steady improvement. And for me to go back and say, now I'm going to do random picks here, and I'm going to pick the numbers that happened in '93-94, it's a little unlikely that will occur, because I have already put systems in place that will make sure that I'm going to get closer to the events that occurred in the '94-95 -- or '95, '96, '97 time frame.

And so I don't view this as a random process. A random process would have numbers going up and down, and the Staff's method assumes that all these variables -- this is just one example. The load forecast, the same way -- are random. And they're just not random. There's human intervention that takes place and rrects conditions, and that's a key concern that I have with it, but we've not really spent too much time with it; and perhaps we can, like I said, or Ken said, we can work on it later.

MR. BALLINGER: I think I understand it. And I think what Staff was trying to do is just to show that probably neither method is perfect and may need some future work over the next year or two.

Both methods had their shortcomings. I think you pointed out one with the random numbers that may not recognize trends that are going on, whereas the FRCC method did not look at other concerns that could be like operating capabilities or some sort of distribution of events.

So I think it would be fair to say that both methods need some work, that we need to look at the coming years going on.

Do you know what the FRCC will do if the Peninsula does fall below 15% now that it's been established as a standard? And probably Ken should be the one to address that.

MR. WILEY: The standard that the executive board adopted this had week states that we will be reviewing this on an annual basis, and when we see any of our seasonal peaks fall below the 15% minimum standard, that we will make a thorough analysis of the facts concerning that, and we will make that review available to our executive board and to this Commission simultaneously to point out all the facts involving that.

And just to elaborate on -- which I know is going to be your next question, Tom -- is that the FRCC, it does not feel that it is in the position to go out and prescribe to whomever it feels might be deficient that it must build generation. It will be our job to point out where the deficiencies exist in the state, and then perhaps our board and this Commission will go from there.

MR. BALLINGER: Okay. I understand that, Ken. We've had this discussion before. While you're there, though, you mentioned something this morning about how you looked at other regions and that 15% was used in other regions; and I'd like to explore a little bit with -- you mentioned ERCOT, which is basically Texas, I believe, uses a 15% reserve margin. But we're unsure how do they compare in terms of the FRCC as far as percent of nonfirm load as a reserve margin. Are they in a similar situation as the FRCC?

MR. WILEY: I don't know, but I doubt if they have as much nonfirm load in the reserves as we have.

MR. BALLINGER: Do you know if they're a winter or summer peaking system?

MR. WILEY: Tom, I don't know that. I feel that the summer peaking system that we're in right now -- or excuse me -- I feel that our summer peaks that we have are our most important peaks in terms of having reserve margins over them.

MR. BALLINGER: And I guess my question goes to maybe -- I don't know -- if they're a winter peaking system, they typically probably have more gas heat. I mean, they're probably a summer peaking system -- I'm sorry -- because they have winter -- they have natural gas for heating for the winter, unlike Florida who has a limited amount, and we tend to see winter can sometimes exceed our summer peaks.

MR. WILEY: Yeah. And I must say we did not go out and look at a rigid analysis of the three or four regions that still utilize this as a guideline, but -- because we were just interested, you know, has anybody pulled back from this. And I think that's where we were really coming from, and we haven't seen that there's been a great pullback from 15%.

Had there been -- you know, and everybody is using 20% or 25%, I think that would have influenced our decision a little bit, but -- so that's the kind of thing that we were looking at, not the micro details.

MR. BALLINGER: Okay. Back to Bobby. In the Staff's concerns in that one table that we submitted to everybody and passed around, the one concern was the percentage of nonfirm load that's the reserve margin in Peninsula. And I think currently we're looking at roughly 58% of our reserve margin in the winter is made up of nonfirm load.

Do you see that as a potential problem in the Peninsula? Or has it improved? Has it gotten worse over the past couple years? And when I say improved or gotten worse, have we had more generation as a percent of reserve margin?

MR. ADJEMIAN: Okay. Well, let me take the last one first. It's improved.

But back to some of the slides that we're showing. You'll remember that dispatchable DSM made up between three and 4,000 megawatts of total resource. In a pool of resources it's about 40-some thousand megawatts. I think it adds a nice diversity of resource.

It's obviously a pretty successful program, because customers elect to use it, and it has -- you know, from my personal experience, I think it has worked pretty well. I think we're learning how to use it still, perhaps, and it would probably be appropriate to ask some of the specific utilities the question as to how they've used it.

But is it too much in the pool of resources that we're dealing with, I'm not really sure that I can answer that. I do know that it's gotten better from last year. I mean, I don't think I would like to see reserves that more than 100% of your reserves consist of, let's say, nonfirm load. That may not be right. But is having a mix of generation and nonfirm load making part of your reserves as well as some other resources, I'm not sure that that's so bad.

MR. BALLINGER: Okay.

MR. WILEY: I would like to add to that just to say to say that obviously the events of June, which this Commission has been getting into and will continue to look at, you know, is something that the FRCC is going to look at from a policy point of view just to see what implications that it might have on how we look at that. So, yes, we're going to be looking at that.

MR. BALLINGER: I think, Commissioner Clark, you had a question, or you looked like you wanted to jump in with a question. I'm not sure.

COMMISSIONER CLARK: Yes. I want to be clear. Where is there a showing of how much of reserve margin is dispatchable DSM? Which slide is that, or is it on a slide?

MR. WILEY: We did not have one.

MR. ADJEMIAN: It's not on a slide. It's in the load and resource report.

MR. HAFF: I thought you had a slide which showed the resources, dispatchable DSM resources.

COMMISSIONER CLARK: I was asking for what percentage of the reserve margin is -- did they make up for each year.

MR. HAFF: It varies by year, but in the early years it's about 50% summer, and it looks like about roughly 40% winter.

COMMISSIONER CLARK: Okay. But last year, last ten-year site plan, wasn't there one year when it was 100% of it?

MR. HAFF: Yes; in the -- especially in the outer years when the utilities weren't planning as much generation as they have in this year's plan.

COMMISSIONER CLARK: And Florida is a winter peaking system; is that correct?

MR. BALLINGER: It vacillates back and forth.

COMMISSIONER CLARK: Okay. Thank you.

MR. BALLINGER: Bobby, one more question, and this wasn't touched on at all in your presentation.

At the August 25th workshop, Staff had a thing that we did a quick calculation about a recreation of the Christmas of '89 freeze to kind of get a feel for if certain events happened, you know, would we be worse or better off than we were in Christmas of '89.

Most of the parties here probably still have that. I've got extra copies if we go into detail. I wanted to ask you your opinion. Did what Staff did seem like a reasonable look at it that we may be the same, we might be worse off, we might be better?

MR. ADJEMIAN: Just to recap it, I think what the Staff had looked at is taking almost like a back-cast; looked at the 1989 conditions and tried to apply the experience that we had in terms of load increase and generation unavailability to 1998 or '99 conditions; and if I remember, it was 17% demand in excess of what was expected and 23% of generation unavailable.

And when you apply those two similar factors to 1980 -- I'm sorry -- 1998 conditions, we found that -- at least the analogy showed that the load interrupted -- I mean, a real worse condition.

However, the Staff, I felt appropriately, also went ahead and utilized an availability of generation reflecting closer to what has been the more recent history of availability of generation that we've talked already about a few times here. And under that condition, I think the finding was that it was going to be a better -- in the sense that not as much load was going to be disconnected as before.

So I think there's good reasons why we would want to utilize or consider the better availability of generation condition, as we said earlier.

In addition to that, there are some operational measures now, like scram load management, that was not in existence then that could be utilized as well.

But generally I would say I think that was the finding of the Staff, and I don't disagree with it, and I don't think that I feel bad. I mean, it tells me that we're improved from then if that event were to occur again. How likely is it to occur, I'm not sure.

MR. BALLINGER: Okay. That concludes my questions for at least the FRCC. I've got one or two maybe after the FGT is done.

COMMISSIONER CLARK: I have a question. You said there are three regions that use the 15%?

MR. WILEY: Yes, ma'am.

COMMISSIONER CLARK: And then Texas used the -- uses the one day and 10 years LOLP; is that correct?

MR. WILEY: Texas, SERC and MAPP.

COMMISSIONER CLARK: Well, all right. SERC is --

MR. WILEY: -- or 15 --

COMMISSIONER CLARK: -- the southeast?

MR. WILEY: Southeast, yes.

COMMISSIONER CLARK: And MAPP --

MR. WILEY: -- is the --

COMMISSIONER CLARK: -- mid America?

MR. WILEY: Mid America. They all use 15% as one of their criteria guidelines, whatever you want to call it.

COMMISSIONER CLARK: I'm sorry.

MR. WILEY: 15 percent.

COMMISSIONER CLARK: Who uses the 15%? SERC, MAPP and --

MR. WILEY: MAPP and us -- oh, I'm sorry -- ERCOT, which is Texas, and now us, which is FRCC.

COMMISSIONER CLARK: What do the others use?

MR. WILEY: The ECAR, which is, you know, the American Electric Power Area, and MAIN, they use loss of load probability, one day and 10 years, those two; and then the other ones are varied. NPCC uses loss of load probability, Bobby's --

COMMISSIONER CLARK: MDCC --

MR. WILEY: Yes -- Northeast Power & Coordinating Council; New England.

COMMISSIONER CLARK: Okay. What's ECAR? Where is that again?

MR. WILEY: East Central -- Ohio and that area. East Central -- something like that; Ohio and then that around it.

COMMISSIONER CLARK: Am I am mistaken, but it was in the MAPP area and ECAR area that there were problems this summer with availability?

MR. WILEY: MAPP and MAIN had it, had the problems.

COMMISSIONER CLARK: Okay. MAIN is next to MAPP?

MR. WILEY: Yes, it is.

COMMISSIONER CLARK: And that's up in Wisconsin and --

MR. WILEY: Yes.

COMMISSIONER CLARK: And they had problems with meeting load during some peak periods, but I understand some transmission was down.

MR. WILEY: That was a combination of generation and transmission concerns. A lot of transmission problems constituted that.

COMMISSIONER CLARK: But our ten-year site plan doesn't deal with transmission problems other than the import capability; is that right?

MR. WILEY: That's correct.

COMMISSIONER CLARK: So we would not infer any concern that they're using the 15% or the one day in 10 LOLP? We wouldn't infer any concern that they've had problems this summer because it was compounded by the transmission?

MR. WILEY: I think there were compounding factors in that, yes.

COMMISSIONER CLARK: Okay.

COMMISSIONER JACOBS: I have a question on that. It's my understanding -- and please correct me if I'm wrong -- that the compounding effect of the transmission restrictions occurred as attempts were made to overcome some of the nonfirm problems that they were having as the load restrictions became more clear.

In other words, as they began to see that some of the futures contracts were not going to be relied upon and people tried to go out and buy outside the region, that's when those transmission restrictions really began to become a factor? Is that true?

MR. WILEY: I do not recall all of the details of the problems up in Wisconsin, but my recollection -- if there's somebody here that would like to grab this, I'll be glad to -- Roberta or anybody -- but my recollection is that there was some generation capacity, there was some nuclear concerns up there, and that they caused a capacity shortfall, and then trying to get capacity into that region over the transmission system from other regions was where the transmission bottlenecks came in. So there was perhaps -- it was a combination of those factors that caused the concerns up in that area.

COMMISSIONER CLARK: Commissioner Jacobs, I thought there was problems with a specific transmission line not being available, and then there were problems as far as identifying how much available transmission there was to import capacity; and I think they were unable to get capacity they thought they were going to get from the PJM area, which is Pennsylvania --

UNIDENTIFIED SPEAKER: That's the one that's --

COMMISSIONER CLARK: -- New Jersey. What I was asking about was I thought some specific transmission lines were just not available, that they were down.

UNIDENTIFIED SPEAKER: Do you recall that?

MR. WILEY: I believe it was a limit between that area and surrounding regions, Commissioner Clark. And I might add, in our analysis we've assumed for all these study purposes of zero assistance from -- generation-wise from Southern.

And in terms of -- and within the region we run transmission studies to ensure that generation can flow around the state in case there is a large outage one place, that there is transmission capability to come in and take care of that from other parts the state.

So intrastate we do run studies to ensure we have transmission capability to overcome that.

COMMISSIONER JACOBS: I note that you don't show any availability concerns surrounding the winter 1999-2000 time frame. That's not a guarantee that none of the year 2000 type computer problems are going to have an impact, is there?

MR. WILEY: No, sir, Commissioner Jacobs. This does not have any implications on that question, and as you know, we're working very hard on that issue within the region with the national people and with your Staff on it. So this has no comments on Y2K involved in this particular study.

COMMISSIONER JACOBS: My concern is that I noticed that the demand over that time frame is a significant increase. That winter's demand appears to be one of the larger increases on the demand table. Do you follow me? On your --

MR. WILEY: I didn't realize it.

COMMISSIONER JACOBS: -- slide; the third slide. That span from 1999 to 2000 is one of your larger demand increases, winter demand increases. So if there were some concerns to arise as resulting from that, what would be the impact?

MR. WILEY: Well, there's a lot of --

COMMISSIONER JACOBS: And I understand --

MR. WILEY: Yeah. I'm not really sure I know exactly what the answer is, but I think some of the concerns, to partially answer it, is that our industry is not going to be the only one that's impacted by Y2K if there's any real problems, and we just wonder if -- how much load is going to be out there, because you have air conditioners and a lot of large load consuming -- electrical consuming devices that also could experience Y2K.

So whether or not that demand is going appear as we forecast is probably a good Y2K question also. There's a lot of uncertainty surrounding that right now. I'm not sure how that answered your question.

MR. ADJEMIAN: Commissioner, as a clarification, I just put the slide up. I think you're referring to 1997, which is actual, to 1998 change, not '99 change; right? I mean, 1997 is what actually we -- we had summer peak that exceeded the winter peak. So now we're forecasting that we're going to hit a new peak in the winter.

COMMISSIONER JACOBS: Correct.

MR. ADJEMIAN: And that's where you see the big change. It's the forecast which is actual --

COMMISSIONER JACOBS: I'm sorry. It's --

MR. ADJEMIAN: Year to year --

COMMISSIONER JACOBS: Wasn't the largest, it was the --

MR. ADJEMIAN: -- the change is about the --

COMMISSIONER JACOBS: -- second. So it will probably be one of the second largest. But I'm speaking of that -- the period where it goes from 36 -- I can't quite -- 36, 4 something to 37, 3 something, which that is -- as I look down the line from the other winter peaks, that is one of the more larger increases over that winter.

So my conclusion is that winter appears to be imposing a fairly significant surge in demand, and if there were unforeseen availability problems arising out of the year 2000 types of concerns, it would appear to me to present a particular critical situation.

And my only concern is -- and I'll take that a little further. In prior discussions that I've heard from people in Washington, particularly -- and this is very preliminary because I know NERC is coming out with this, with its report sometime next week -- but one of the contingency options that I've heard is that in an effort to forego major implications of the year 2000 problems, there will be a heavier reliance on analog type generating facilities.

And I know that -- I'm not asking you to comment on that, but if that were a real contingency procedure, that in my mind would even have a further restriction on available generation to meet what we're saying is a pretty important increase in demand over that time. And if I'm off base, I'd be very happy to hear how I'm off base.

MR. WILEY: I would say, given what you just said, then yes, you would want to be concerned. I guess I hadn't looked at that particular demand or made a distinction that that was a truly significant change in that particular year. But, you know, as you know on this year 2000 thing, we're still working on that. That's truly a work in progress for our industry, even though we've done a lot of work already. And I guess all I can say is that on some of these uncertainties, part of the plan that we're developing for year 2000 will include strategies to mitigate these things if, in fact, they happen.

And your discussion about analog generation is running all that you have over those periods is probably going to be one of the mitigating strategies that we come up with when we develop it next year.

COMMISSIONER DEASON: I have a question. What caused the significant increase in the winter peak demand from '97 to '98, and is that something that could reoccur?

MR. ADJEMIAN: Commissioner, all that chart tells me is that we really didn't have a winter peak in 1997. It was a very mild winter. So the forecast, being the first year we still expect that given the right weather conditions, you could hit a peak of that magnitude.

In reality in the FRCC what we find is that summer is much more consistent in terms of growing, and winter has this errant shape to it that every couple of winters you hit a cold winter, and then you have two or three winters that are very mild; and '97 happened to be one of those mild winters.

UNIDENTIFIED SPEAKER: Are those actual numbers?

MR. ADJEMIAN: Yeah, it's an actual number, right.

COMMISSIONER DEASON: Thank you.

COMMISSIONER JACOBS: A couple final

questions, one to kind of follow up on that second question I asked.

If you were to -- kind of hammering on this year 2000 issue -- if you were to go to the contingency of looking at analog generation, would that have an impact on your forced outage numbers? I guess that wouldn't be a forced outage, would it? That's a preferred, just a chosen --

MR. WILEY: I don't think it would. I mean, that would be for such a short period of time that we'd revert back to that older generation, that I don't think that would be a factor.

COMMISSIONER JACOBS: Okay. And then the last thing is not so much a question as a clarification. I'm looking at your reliability assessment, and it's the Load and Resource Plan, FRCC region summer of capacity and demand reserve margin. It's near the end of the report. It's a table. Are you familiar with it?

MR. WILEY: I'm going to get my copy.

(Pause)

COMMISSIONER JACOBS: This kind of goes back to a question that we were going over earlier about the nonfirm issue. And the clarification is, I'm wondering does this tell us, does this give us some guidance on the answer that to that question about the percentages of nonfirm over a course of time?

MR. WILEY: I'm sorry, Commissioner Jacobs. What page were you on.

COMMISSIONER JACOBS: It's labeled Page 10, but I know it's not Page 10. It's near the end of the document. It's a table near the end of the document. It's called "1998 Load and Resource Plan, summer capacity demand and reserve margin at time of winter peak."

MR. WILEY: Okay. I have that now.

COMMISSIONER JACOBS: Goes back to the questions we were going over regarding firm and nonfirm. And at peak -- and I'm wondering; this appears to give us the reserve margins and it also appears to give us firm at peak, firm load at peak.

And the question I have is, can we derive from that the nonfirm, because it would appear that it would be easier to calculate that out of that; is that correct?

MR. WILEY: The nonfirm load?

COMMISSIONER JACOBS: I don't see a column on here, but I'm assuming I could go --

MR. WILEY: Yes, you can.

COMMISSIONER JACOBS: Just simply derive this from that?

MR. WILEY: That's correct.

COMMISSIONER JACOBS: Okay.

MR. WILEY: If you take that column "megawatts" under that Column 10, the difference between that and the corresponding number in Column 7 is the amount of interruptible and load management load that is available.

COMMISSIONER JACOBS: All right. Thank you.

MR. DAVIS: Can I ask my question now?

CHAIRMAN JOHNSON: Yes, sir. If you could state your name.

MR. DAVIS: Steve Davis from IMC-AGRICO. We're a large interruptible customer. I just wanted to see if I understand Page 17, the loss of load probability analysis, which I would basically consider to be a sensitivity analysis that was done.

Item 2(A) shows no violations without interruptible. Would I be correct in interpreting that to mean that when you ran your model, you showed that interruptible customers would never be interrupted if your model is performing correctly?

In light of our experiences this summer, we're very concerned with our reliability. We were interrupted approximately 10 times in June and twice within the last two weeks.

MR. ADJEMIAN: I can answer how the LOLP study was done with regard to the interruptible, but I think you probably want to address that question to the utility that supplies you. FRCC has not looked at specific customers' patterns of interruptions.

But in this study we basically blocked, if you will, the use of interruptible and ran it that way to see whether the loss of load probability reliability criterion was going to be affected by not exercising it; and given the assumptions in the study, said that it would not be affected and it would meet the criteria. That's correct.

MR. DAVIS: So you're saying that if the -- the model would say that interruptible customers would not be interrupted during the study period; is that correct? Because it's my understanding that the other demand side customers are exercised for load shedding first before interruptible on a normal situation.

MR. ADJEMIAN: I think that is a decision case by case by whatever utility you want to talk about. They may have a different procedure.

But I just wanted to clarify that it's not that the study says interruptible customers are not going to be interrupted. It's an assumption that we made.

We forced the assumption, if customers were not to be interrupted, what effect would that have on reliability; and it tells us that it wouldn't have a negative -- a large enough negative effect. That's all it said. It's not that -- take away from this, so therefore interruptible customers are not going to be interrupted.

You know, given the assumption of the study, loads may exceed what we've assumed here, in which case companies may decide to exercise their option. I don't know if I've answered your question.

MR. DAVIS: Well, I guess maybe it's -- it's definitely a question, but it's also a statement. It seems to be inconsistent with the experiences we've had this summer and my understanding of basically how load shedding would work with interruptibles basically being among th _ast to come off line before firm customers.

So maybe there's not an answer, but I was hoping to get some comfort that in the future we wouldn't experience what we had experienced this summer.

COMMISSIONER CLARK: I would like to follow up on that. Does the one day and 10 years mean accumulative amount of 24 hours in 10 years?

MR. ADJEMIAN: The one day and 10 years is -- first, we're not doing it on an hourly base, we're going to daily base it.

So we look at 365 peak days in a year, and we look at during the course of a year for each of those 365 days will we have enough generation during the peak of each day to meet that, and at the end of the year we calculate what the expected value of meeting that was. In other words, having every day generation to cover the peak load of the day.

And if that number in its sum for the year exceeds .1, then we have violated our criterion. That's all it is. And over a 10-year period you can call it one day in 10 years, but it's done on a year-by-year basis. It's not a one 10-year snapshot.

COMMISSIONER CLARK: Okay. So in one year, you won't have more than .1% interruptions?

MR. ADJEMIAN: It's .1 days.

COMMISSIONER CLARK: .1 days.

MR. ADJEMIAN: Not percent.

COMMISSIONER CLARK: So you could have several interruptions that don't amount to that amount?

MR. ADJEMIAN: That's correct.

COMMISSIONER CLARK: So even though it says "without interruptible," and it says, "no violations," you could be interrupting interruptible customers for brief periods.

MR. ADJEMIAN: Yes, you could.

COMMISSIONER CLARK: But it wouldn't amount to --

MR. ADJEMIAN: It wouldn't be large enough that it would violate the criteria. Exactly.

MR. DAVIS: Well, I'd say we've been violating the criteria this summer.

MR. BALLINGER: Perhaps I can -- this ties into Staff's concern as to the LOLP values being so low due to the high availability of units.

If you look on Page 10 of the Load and Resource Plan, which shows reserve margin with and without nonfirm load basically, you'll see that in time of winter, if load management and interruptible load were not exercised, we have reserve margins of 3% in some years, but the LOLP still showed very reliable system. And that's what gave Staff -- it's not really concern, but it shows that reserve margin is what's driving the liability needs now of capacity, not LOLP.

So I think to say that because LOLP says there's no violations means there won't be any interruptions, I don't think that's true. You have to look at reserve margin also, and that shows that we only have a 3% reserve margin to cover any contingencies that may happen; and that's why Staff was concerned that the LOLP values are nice, but they're not indicative of what's really driving the need for generation. It's reserve margin, and that's what we need to look at.

COMMISSIONER CLARK: Well, wait a minute. Tom, why do you say it's not really indicative of what's driving the reserve margin? You could decide that LOLP is the appropriate --

MR. BALLINGER: And I think it's because of this, because of the LOLP value in, let's say, the year 2000 might be .0006, very reliable, if you will, but then you look at reserve margin that corresponds to it, using nonfirm load you get to 15%.

If you didn't use nonfirm load, you'd only have 3%. So obviously they're going to be used as part of your reserve margin to cover contingencies. That's what our concern -- I mean, you went to --

COMMISSIONER CLARK: I see. You're going to be using lot of interruptible to meet your LOLP.

MR. BALLINGER: Yes.

COMMISSIONER CLARK: Okay.

MR. BALLINGER: And I think the study that Bobby did with not using nonfirm load at all just showed that the magnitude of it from LOLP perspective is not great.

From a reserve margin perspective, it's very great. And it's just saying that now we're in a different time period where reserve margin is what's driving the need to add capacity, not LOLP.

They still, I think, are both very important data to have. They tell you two different stories, but the leading one in today's day and age is reserve margin.

MR. ADJEMIAN: Just wanted to -- not anything that you've that said that I disagree with, but I think it just needs some additional to -- some additions to it.

For instance, we shouldn't be making the assumption that -- and I stated that in my presentation -- that all of the dispatchable DSM goes at once. I mean, there is in the residential load management we have different appliances. Many times we'll interrupt pool pumps and water heaters, and we get very beneficial megawatts out of that towards meeting demand; and customers don't even know this.

And to the extent that that can be done, it doesn't mean that we will automatically go to the interruptible load and exercise it every time because this thing said there was only 3% of generation.

So just keep that in mind. I'm not saying we're not going to get to it, but I wouldn't necessarily pull away from that, that so -- every day, you know, so many times it's going to happen.

MR. BALLINGER: I think that's it. I think we can go on the with FGT presentation.

MR. MYER: Thank you. My name is Rockford Myer. I'm president of Florida Gas Transmission. I appreciate the opportunity to be here this morning.

I believe we handed out -- handed out a copy of our slide presentation. There's also a map in the back of that booklet which may be helpful to look at during some portions of the presentation.

The topics which I intend to cover this morning include gas supply availability on the Florida gas system, the expansion capability which we have, FGT system reliability, and enhancing system reliability after the incident which we had at Compressor Station 15 last month.

Looking first at gas supply on the Florida system, the Florida Gas Transmission system, if you look at the map, is strategically located. It extends from Texas to the state of Florida and accesses significant gas supply on shore as well as offshore from the Gulf of Mexico. This diversity of supply is a significant benefit which our system offers to the Florida marketplace.

On shore we have direct connect access to gas supplies as well as interconnects with intrastate and interstate pipelines, including SONAT, Columbia Gulf, Texas, Eastern, Tennessee, ANR, Natural and others. It is even possible to access Canadian gas supplies through our interstate pipeline and interconnects, and that could be important, given the incremental Canadian gas supplies being brought into the United States.

We do have access to storage in all three zones on the Florida system in the most westerly zone. We have access to the Bamel Storage Field and the Spindletop Storage Field in Zone 2, which is in Louisiana. We have access to Napoleonville. And in Zone 3 in Alabama we have access to storage at Bay Gas Facilities.

The offshore gas supply, again, given the location of our pipeline as it extends from Texas to Florida, we have access to all of the -- essentially all of the prolific gas supplies which are being produced in the Gulf of Mexico.

Estimates of total Gulf supplies range from 155 TCF to 162 TCF, and production increases from 5 TCF per year today to 6.8 TCF per year in the year 2010, and 7.8 TCF per year in the year 2020.

We have major interconnects for offshore production with Mobile Bay at 320,000 a day; the new Destin pipeline interconnect, which went into service this summer, at 500,000 per day. We have an interconnect with the MAPP system in Texas at 220,000 per day. We also have access to the Dauphin Island gathering system production behind or through the Mobile Bay pipeline system.

Overall, we have total receipt point capacity on the Florida system which exceeds 4.5 BCF per day.

Looking at the expansion capability which we have on the Florida gas system, given the infrastructure which we have in place, we're able to expand our system through the addition of pipeline looping of our existing system and with the addition of compression.

Comparatively, this is a very economical way to bring incremental gas capacity to the state of Florida and minimizes the impact on land use and the impact on the environment.

We are also able to tailor the size of our expansions to meet market demands and timetables. For example, we can expand our system anywhere from 25 to 50 to 100, 500,000 to a BCF a day. It just depends on market demand and what market timetables require.

We're currently negotiating with a number of customers in the Florida market for our proposed Phase IV expansion. We expect to file our application with the FERC by December of this year. We expect to have a certificate issued by the FERC within the next 12 months after that filing; have the facilities available for testing in the fourth quarter of the year 2000, and in service in the second quarter of the year 2001, again depending upon market requirements.

Looking at system reliability, the incident at Compressor Station 15 notwithstanding, which I'll talk about in just a bit, we do have an excellent reliability record here on the Florida gas system. We've had only one other main line outage, and that was 1967 at a time when we had only one 24-inch line serving the state of Florida. We lost our main line after it was hit by a third-party contractor, and the line was repaired and placed back into service in 16 hours.

If you look at the map that we have, you can see that essentially we have two pipelines which run from western Louisiana to Miami, Florida, and in many areas we have three pipelines. With the addition of our Phase III expansion in 1995, we built our 36-inch line from Citronelle, Alabama, to Tampa, Florida, and the 36-inch line also runs intermittently westward to Louisiana and intermittently again as far southward as West Palm Beach.

Of the over 4,800 miles of pipeline which we have, over 90% of that pipeline is buried. At the compressor stations, we have multiple compressors, and what this does is allow us to take compressors in and out of service as needed for maintenance or down time without affecting our ability to meet market load requirements.

Again, if you look at the map, you'll see that the -- will look at the design of the FGT system in Florida which provides a market area grid which, again, increases our overall system reliability. The 30-inch west leg, which was installed as a part of our Phase III expansion project, provides a separate route to central Florida as an alternative to the two main lines which run through the center of the Florida Peninsula. That's the green area noted on the map, the North Central Florida network.

We also have three other smaller market area grade -- grids which improve reliability in the marketplace; the Gainesville/Ocala grid, the Orlando/Cape Canaveral/Melbourne grid, which is light blue, and the Southwest Polk grid, which is noted in purple. Again, what these do is provide alternative delivery routes in the marketplace in the event that we do an have an emergency or an incident on one of these lines.

We do have 1.7 BCF of line pack, which is in the market area here in Florida, which is available in the event of an outage or loss of capacity. I think as was demonstrated during the Compressor Station 15 outage, we do have strategically located inventory in the event of an outage.

We have the capability, with our own special response teams and with our relationships with our contractors, to quickly bring our system back on line in the event of an outage. At Station 15 we had 55% of our capacity back in service within 48 hours. We had 82% of that capacity within 72 hours, and 90% of the capacity was back within 96 hours, and we were able to continue to serve our priority end use customers, gas customers, in the state of Florida from line pack during this outage period.

The primary exposure which we have to hurricanes on the Florida system is really in our gas control and scheduling groups back in Houston with a loss of power, people unable to get to work, that sort of thing. However, we have the capability to move our gas control and scheduling groups to Omaha, Nebraska. We can do that on a 24-hour notice basis. That system is in place and tested, and essentially is transparent to our customers as they schedule their gas to move to the marketplace.

With respect to the incident at Station 15, in spite of the reliability which we have built into the Florida system today, we did experience what we believe was an unprecedented incident, not only on FGT, but in the industry. We take very seriously our commitment to provide gas supply to the state of Florida, and what we are doing is learning from that incident at Station 15. We are taking steps at this time to significantly improve the reliability of our service to Florida, and we'll talk about those next.

Immediately after the incident at 15, we commenced an inspection and assessment of all of our emergency shutdown and mainline valves to assure proper operation. We're looking at the configuration and design and location of those valves on our system.

Since it appears that lightning was the precipitating cause of the incident at Compressor Station 15, and we recently had an incident at Station 20 related to lightning, we have commenced a major effort to review our lightning protection procedures on the system. We have subscribed to the services of a firm which is able to notify us in the event of approaching lightning storms to our critical locations.

At that time if we do not have operations personnel on site, we're going to dispatch operations personnel to the location. We're going to place the compressor station on manual operation, although our emergency shutdown facilities will remain in place. What this will do is eliminate the possibility of a lightning strike which will disable our electronic instrumentation causing a shutdown of the compressor station and a potential lightning strike of the gas related to that emergency shutdown.

We've retained two firms who specialize -- two firms from Florida who specialize in protecting facilities from damages caused by lighting. They are conducting an independent review of all of our critical locations in the state of Florida and across the Gulf to look at our lightning protection procedures in place.

We're consulting with electric generators here the state of Florida for their expertise in lightning protection. We've retained the services of a lightning scientist from here in Florida to help us to devise a final action plan to protect our facilities from significant damage associated with lightning. That group met this week in Florida for three days, and they're in the process of putting together our action plan in response to lightning protection on the Florida system.

The second major effort which we are pursuing in response to the incident at 15 is an in-depth review of our pipeline system and compressor stations. We've retained the services of an independent engineering firm to conduct a review of our system drawings and to conduct on-site inspections of our system.

Among the things we're looking at, we're looking at facilities which should perhaps be physically separated. We're looking at all of our bypass capabilities at our facilities. We're looking at sequential failure possibilities and remedies. We're looking at the location and operation of valves in the station yards. We're reviewing our most critical locations first, and we expect to begin devising our final action plan for those locations on November 1.

The remainder of the facilities, we expect to commence work on devising our action plan for those facilities on December 1 of this year. To the extent that we see situations which require immediate action as we're going through this process, we'll take those actions as required.

We have what we call a LIC computer software model which gives us the ability to see the operation of our pipeline system on a realtime basis. What we're doing is completing a study right now to determine where we can place additional sensors on the system in order to more quickly detect pressure drops along the pipeline, and what that will do is give us the capability to more quickly react in the event that there is an incident out there on the pipeline system.

We are strengthening our inventory to assure continued quick response in the event of an emergency. And finally, not unlike other industries, both in the gas industry and the power industry and across the nation, we're in the midst of an aggressive Y2K compliance program, including the coordination of that program with our producers and with our customers here in the market area.

To conclude, the FGT system is strategically located to access both onshore and offshore gas supplies, including expanding access to storage. We have the capability to quickly and economically expand our system to meet market demand as it arises. We have an excellent reliability record, but we are determined to significantly enhance that reliability through better lightning protection procedures and through improvements in the design of the critical points on our pipeline system.

MR. TRAPP: Mr. Myer, Hi. I'm Bob Trapp with the Public Service Commission Staff.

Having had the privilege of serving in the emergency operating center during the weekend of the Station 15 incident, I personally would like to thank you for the company's efforts to restore that line in the quick and efficient manner that you did, and also to thank you for the cooperation and communications with the emergency operating people. I think it was essential that we stayed right on top of that, and you helped very much in doing that.

I only have one question, if I could. In these studies that you're doing with respect to enhancing the reliability of the pipeline or evaluating that, I'm given to understand that the FRCC will be participating, or at least monitoring that or have a member participating. And my question is, would there be any problem with perhaps a member of the Public Service Commission Staff monitoring those activities?

MR. MYER: No. I think as we develop -- as we do the study of our system and develop our plan to enhance the reliability of the Florida system, I think it would be most appropriate for us to share with not only the FRCC, but the PSC, how we are improving reliability; because, again, we take our responsibility very seriously and want to assure the PSC and the customers in the state of Florida that we will have the capability to reliably meet their gas supply needs today and into the future.

MR. TRAPP: Thank you.

MR. BALLINGER: Hello, Mr. Myer. My name is Tom Ballinger with the Staff. I have a question. I don't know if it would be more appropriate for you or for Mr. Adjemian, but it goes to the response that FGT gave to the FRCC about the ability to supply gas to the Peninsular expansion needs.

In other words, the FRCC submitted saying, we're planning on building so many megawatts of gas capacity, can you meet these needs. The response back was that the incremental gas required to serve Florida's needs was about 550 BCF a day incrementally, which the FGT said could be done through compression; in other words, that could be done in a short time line and be able to meet the needs of this installed generation capacity.

What my concern was, though, is buried in that was the assumption that some of the already committed gas to existing units that may be less efficient than new generation capacity would be diverted to the new generation capacity to conserve their load. That's how the 550 number was developed.

And my question is, the FGT did not look at the economics of doing that. That would be an individual utility decision obviously. But does that lend itself to -- I don't want to say racing to get gas, because you will get the -- I'll call it the "compression transportation rate" as opposed to "if a new line has to be installed" transportation rate.

That was a pretty long-winded question, but that's my basic concern that the assumption of diverting existing gas to new units creates an economic question to be addressed by individual utilities, and are we setting up a race to gas.

MR. ADJEMIAN: Let me see if I can address that, Tom. The FGT at our request, at the study group's request of the FRCC, gave us what I would consider a way of meeting the generation expansion needs of the FRCC.

As you stated, economics really didn't play any role in it, and it may be that it makes more sense for us to retain some of the gas -- or individual utilities, I should say -- to retain the gas for dual fuel units and not divert all to new combined cycles. But, I mean, those decisions will be done, I think, on a case-by-case basis, on a bilateral basis probably between the utility and the FGT or whoever, if you can provide transportation needs for the companies.

So, again, I think the FGT basically provided us with, if you will, a feasibility answer that yes, what you need can be done, provided you take all these other steps; and it could be done primarily through compression. But, you know, that's not necessarily the specific plan that would actually develop when companies sit down and lay out their individual needs before the FGT or whoever else they work with, and what the final expansion is could be a combination of compression and new pipelines.

I'm not sure if I'm answering your question, but, I mean, is there going to be a rush to gas, I don't really know how to address that.

MR. BALLINGER: Maybe not a rush to gas, but the first signatories to gas who fill up the 550 that can be done through compression may get it a little cheaper than the last 450 who have to get it with a new pipeline or -- it's going to go on a piecemeal fashion, and as we approach the limit of compression, a new pipeline may have to be built, and it may change the economics, or affect the economics.

MR. ADJEMIAN: I'm not an expert on tariff matters for pipelines.

MR. MYER: I think clearly there's a very real built-in advantage today in the Florida system in that we're able to add capacity through compression and/or looping, and that's very economical as compared to building a brand new pipeline into the whole system, and there is some fairly significant capabilities still within the Florida system.

I think at some point -- and I'm not an engineer -- at some point it may become -- that capacity that -- the incremental capacity may become more expensive than the existing capacity today, or these incremental -- this incremental capacity which is built today; but where that point is I can't tell you.

I guess we could do a study, and if you look at particulars on what kind of load over what time frame you would add and how we would meet that load -- and, of course, it depends on location to a certain degree, as well.

But I think you're right. At some point down the road you may end up in that situation where the incremental capacity is more expensive than what we had today, but where that point is, I can't tell you right now, although we could certainly get back to you with that answer.

MR. BALLINGER: No. That won't be necessary. I just wanted to make sure I understood what potentially could be out there. Thank you.

I guess with this, we're done with the FRCC presentation. And I know the agenda shows Staff giving a brief presentation about that, but we had a request from Mr. McWhirter, who needs to catch a plane. He has a very short presentation he'd like to make, and then we will go on to Staff's presentation, individual utilities.

Commissioners, I don't know if you want to entertain a half-hour lunch after Mr. McWhirter.

(Discussion off the record.)

MR. BALLINGER: Okay, Mr. McWhirter; I guess you're on.

MR. McWHIRTER: This is a wonderful machine. I'm not sure I can figure it out. My name is John McWhirter, and I represent nonfirm industrial customers.

You've heard a generic presentation from the utilities' viewpoint. Well, I'm going to give you somewhat of a generic presentation from the consumers' side of the issue; and of course I don't represent all consumers, only a limited number, but there are consumers who are quite concerned about the circumstances.

Quickly I'm going to tell you where we are today, briefly how we got there and, three, I'm going to be presumptuous enough to recommend to you some governmental policies that might be worthy of consideration.

Where we are today is demonstrated on this page that has already been discussed previously, and this is extracted from the FRCC report, and that page is summer demand. I'm going to go down to winter demand where Staff says the crisis is potentially the greatest.

If you will look at Column 11, Column 11 is the presentation that was made by FRCC which indicates using a 15% reserve margin, that everything is hunky-dory for the next nine years. However, if you look at Column 9 and you look at the percentage of peak that is met by the installed capacity of the utilities, you'll see that it comes nowhere near the 15% reserve margin.

And the difference, as has already been pointed out to you, is the fact that load management and interruptible customers who are nonfirm load management customers now become part of the reserve load margin.

There has been a very significant change in the last six or seven years of the definition of reserve margin. The people who were served from the reserve margin previously, which was machinery, have now become the reserve margin.

As is pointed out, we're up to 58% of the utilities' reserve margin is met now by people rather than by machines. That is not the deal that was entered into at the time that the nonfirm customers signed up.

The second question is -- well, there's another little problem in the first thing. This reserve margin, even if we're dealing with the availability of machines which is the 2, 5, 3, 6, 7% in Column 8, those machines to get those numbers, you were told by the previous presentation, that the machines are going to be operating better in the future than they have operated in the past. That's an interesting proposition.

The machines today that are meeting that reserve margin are approaching the final trimester of their life. They're 25, 23, 28 years old. They're nuclear plants that are coming up for relicensing, and those machines are expected to operate at a 92 or 93% operating capacity, which is most intriguing when you realize that you presently pay a reward to utilities which operate their base load units at somewhere around a 75% operating capacity factor.

So I would suggest to you that you might want to carefully examine the idea that the older machines are going to be operating more efficiently in the future during the last trimester of their life than they operated heretofore.

How did we get into a circumstance in which people rather than machine became the reserve margin? This subject is actually -- I think, would be an interesting topic for a doctoral thesis, and I won't present the full thesis with you today, but there are several basic underlying factors, and I'll give you a few of them.

One is that larger power plants were built to gain economies of scale, and when they go off line, you've got a more serious problem than if you had four or five generating plants meeting the demand of what an 800-megawatt plant meets today.

Secondly, most of the coal and nuclear plants are aging, as I've mentioned before. Third, the investor-owned utilities have forestalled construction of new power plants by municipal utilities and REAs. Once the wholesale market became competitive, they can go in and bid to supply power to those municipalities and REAs at a cost less than those people would pay to build their own plant.

There was a disincentive for them to build new plants because it was met by wholesale sales from the retail plants that were needed for the retail sector. These contracts with the wholesale customers have become firm contracts, and they come ahead even of a utility's firm customers.

Those are some of the reasons. Probably the biggest reason that people instead of machines have become the reserve margin is the conservation programs that have been endorsed by this Commission, and the biggest conservation program of all, of all the utilities in Peninsular Florida, is the demand side management program called Load Management in which people are paid money that's collected from them and other customers in order to be interrupted during times of critical times.

And, as has been pointed out, if you're only cutting off your pool pump and you're cutting off somebody's water heater, there's no really loss in sales to the utility, and the customer shouldn't feel it. But I think in your further studies you're going to find that maybe the customers this summer felt it a little bit more than usual and may in the future summers face it more even more seriously.

The Staff has concluded that we don't have a problem in the summertime, the problem lies in the wintertime; but the records demonstrate that in the month of June of this year, Florida Power Corporation was unable to meet its nonfirm load 11 of 30 days. 11 of 30 days it was not able to meet it. On three of those days it was able to meet it by purchasing power. On the other eight days the customers were interrupted.

The interruptions in the summer are not

peaking interruptions that occur for a short period of time and can -- or at least the peak is not composed of a short term where plants can be run harder for a short period of time in excess of their installed capacity. They run for 20 and 30 hours at a time, which puts a real strain on older units.

So we think we have a problem. I have a client that's in the mining industry, and I pointed out some of these things to him, and he said, my God, we are the canary that's going into the mine. And when something is happening to the interruptible and the load management customers, it's kind of like the canary beginning to flutter and gag.

And Mr. Davis explained to you what's happened to his company this summer, and I've just pointed out to you --

COMMISSIONER GARCIA: Mr. McWhirter, I thought the canary began to sing in a mine when there was a problem.

MR. McWHIRTER: Say that again.

COMMISSIONER GARCIA: I thought the canary began to sing in a mine when there was a problem, not gag.

MR. McWHIRTER: Well, it's a --

COMMISSIONER GARCIA: I was -- I thought you were the canary. That was -- that you were here singing the problems that your client is having.

MR. McWHIRTER: Well, I am the singing canary, but the other canary is dying.

So what do you do about all of this? And from a customer's viewpoint -- and you have the very difficult assignment of trying to protect utilities as well as protect the customers and trying to draw a bright line to protect both of those interests, and the consumers' interest is somewhat different.

We're interested in reliable service, and we're interested in economically priced service; and I'm up here all the time crying about economics, not so much about reliability.

But I would suggest to you a short 11-point program that you might consider. First is to encourage independent power producers to come into the state of Florida and build plants, because that power doesn't go into the rate base; and if they're not technically more proficient than the other plants, then their power isn't sold.

Secondly, and I think this is something you should do immediately, is to ensure that economic interruptions don't occur. Now, last summer in Wisconsin people were paying $7,500 a megawatt for power.

The price for firm industrial power in the state of Florida is somewhere in the range of 45 to $50 a megawatt hour. So there would be a great incentive for a utility, if it could, to sell to that higher priced market. You want to be sure, I would think, as regulators, that utilities don't take advantage of that circumstance.

I would think that another big aspect is Florida is known throughout the nation as a sunshine state, not only from its sun, but from the open government. And I would suggest to you that the Florida Reliability Coordinating Council is an excellent organization. Obviously its reports are truthful. And that organization, however, is composed primarily of utilities.

Their operations are not open to the public, and I would suggest to you that you require, since it's a matter of such great public interest, that they give notice to their meetings and that the public be given the opportunity to attend those meetings. I can't see any legitimate reason why that couldn't happen.

I would also suggest to you that the opportunity is there with the Internet that we have today for a bulletin board, a bulletin board that would demonstrate the cost of power and the available reliable capacity that's in the state; where it is and what it costs. That would be a very interesting thing to track.

Today if a customer is given an opportunity to buy through rather than be interrupted, he doesn't know what that price is going to be and doesn't get the bill for two or three months later after all the accounting is done. If we could look on the Internet and make that choice, perhaps we wouldn't do the buy-through.

I know that you have statutory responsibility over the transmission grid. FERC is exercising ratemaking authority over it, but I would suggest to you that as part of the your operations, you should study the capabilities of our state's transmission grid and whether improvements need to be done.

I would strongly recommend to you that you ensure that the power plants siting act is not utilized to create a closed shop to keep technologically superior and more economical power plants from being built in the state.

I would recommend to you, number 8, that you promote local land use and zoning which favors distributive generation. Distributive generation is on the horizon and may be the answer to some commercial and even residential people that would like to get the benefit of it. It would enhance green power.

I would suggest to you that you don't load obsolete high heat rate plants with additional costly improvements that will create stranded investment.

With respect to the customers who have to buy through from time to time, their agent for the purchase power is the utility company. If the utility is not obligated to serve those customers, it would seem to me that it would follow that those customers should have had the opportunity to select the persons from whom they're going to buy their buy-through power to see if they can't get a better price; permit customers to engage in hedge contracts to purchase power when utilities can't serve them, irrespective of the source.

And finally and most importantly, I would recommend to you that you do exactly what you're doing today, and that is try to deal with this problem before a serious crisis arises. Deal with it now in a logical methodical and appropriate way. Give publicity to the problem. Invite university type people to participate in the discussion. Invite the environmentalists to participate in the discussion in a colloquial group so that we can come up with good solutions for the state before we have to deal with a serious dramatic problem that price is not a problem, only reliability.

Thank you for letting me interrupt your scheduled agenda to present a stumbling presentation on behalf of consumers.

CHAIRMAN JOHNSON: We're going to take a short break, a 15-minute break.

(Brief recess.)

CHAIRMAN JOHNSON: If everyone could settle in, we're going to go back on the record. Staff, I believe we're ready for the next presentation.

MR. BALLINGER: Mr. Dudley is going to give a presentation.

MR. DUDLEY: My name is Kenneth Dudley. I'm with the Commission Staff. This has been talked about pretty extensively and prerebutted, so maybe I can get through this a little bit quicker than I had originally anticipated.

The reason for this is merely to present an alternative view of looking at reserve margin calculations. So far in the past we've done a traditional method. The FRCC has shown us another method in which they have accounted for some of the historical errors. We took another viewpoint and entered in some probability into that calculation, and I'll go through each of these fairly quickly.

Mr. Adjemian described the reserve, the fundamentals of reserve capacity, and that being the amount that your capacity of resources exceeds your firm load. The mechanics of that is that you have these five variables, which are generation import, the QF, which makes up your capacity resource; and each of those is used to serve your peak load, which is further -- which is reduced any direct load control which you may have, such as load management.

A concern with some of this -- with reserve margin calculation is that each of these five variables are assumed to be forecasted with 100% accuracy. The theory is that in any particular circumstance or an event -- were an event to occur, that the reserve margin would be large enough in order to keep the lights going.

To address the concern of this 100% forecasted accuracy, the FRCC undertook an analysis which Mr. Adjemian and Mr. Wiley discussed earlier this morning in which they took and looked back at the historical forecast error in each of the five reserve margin components, and took an average of those and incorporated that into the reserve margin calculation.

The Staff, we took -- and instead of looking at the viewpoint of FRCC on taking the average, we decided that within the data range, that we would allow any error within that time frame to occur and not merely take the average of that.

This is just a sample here of the FRCC method that Mr. Adjemian presented earlier this morning, and it just shows that the top table -- this is a smaller sample than the total state -- but for the utilities' forecasted generation levels, you would take and make a comparison of what the utility had forecasted to occur versus what actually -- the generation that was actually available, and then you would take that number for each of the five years and obtain an average at the end of that, obtain an average for those five years.

You take then and sum those -- in this instance, the column on the far right -- and then you would compare that with the projected total, and in making that comparison you would determine that there was a certainty factor or uncertainty factor -- I think I may have printed the wrong slides here -- that you would take to reduce each of the components or increase each of the components.

It's hard to see here. But for this particular instance where you have a forecasted generation of 38,000 megawatts, once you incorporate your historical errors in your generation availability forecast, you would reduce that to a level that is only 92.6% of what you had forecasted, and that should allow to you account for any -- that would account for the historical error you've seen over the past five-year period.

And you make a similar calculation for the remaining variables to then take and arrive at an adjusted reserve margin, whereas if you recall in the first slide, without taking any historical uncertainties into account, you would think for that year you may have a 20% reserve margin, but then after accounting for this five-year average historical uncertainties, that 20% may reduce down to a little less than 7%.

The PSC method -- or I guess more so the Division of Electric and Gas method -- we took the same fundamental data that the FRCC used, and instead of taking and looking at each of the five years and arriving at an average, we said that for -- in the instance we have in the top table of generation, we would say that we'll do one calculation and allow that calculation to assume that FPL's 1993 error may occur, and then for the next utility, Power Corp, it may be their 1995 error, and JEA could be '94 or '96; TECO and Tallahassee may be different years.

So instead of taking a mere average of each of the five years and summing that amount, we will take and randomly select any particular year's error for each utility and sum that amount. In this instance it was 3,500 megawatts. And then just like the FRCC, we would take and incorporate that into the reserve margin calculation, whereby a generation of 38,000 instead of reducing that down to a 90-some odd percent level, we reduced it by 3,589 megawatts. And you make a similar calculation for each of the remaining variables; the imports, QF, peak load and load management.

And you see that for this particular run, the reserve margin level, which initially started at 20%, and then using an average method may have been a little less than 7%, well, now under this method for this particular run, the reserve margin may be determined to be 5.3%.

This is really hard to see. (Indicating) But in order to remove any bias or to try and avoid distorting any of the results, we wanted to make a sufficient number of calculations because of the probability that for that particular run you may have actually selected some of the best or perhaps even some of the worst errors for each utility in any particular year. So we performed the calculations 5,000 times, and it provides a distribution very similar to the one shown here in which we plotted the particular reserve margin levels according to the frequency of occurrence.

And what was important to us, by looking at this graph, was that as you can see on your handouts, there is a portion that lies less than zero. And less than zero in this instance indicates that you would have inadequate reserve to serve your load, and as you can see in the top right-hand corner, there was -- for this particular year there was 400 occurrences, which in looking at the area under the curve less than zero, that may have equated to roughly 900 megawatts of capacity shortfalls.

We made these calculations for each of the seasonal periods, both the winter and the summer, for each of the years covered within the 1998 ten-year site plan. And here I show a table comparing the original reserve margins projected in the 1998 site plans, as well as the FRCC results, after accounting for the averages of the historical uncertainties, and compare those with the results that the Staff obtained by using the probabilistic method.

And overall for the summer period, there was very little concern with respect to shortfalls, even using the FPSC probabilistic method and, in fact, using the FRCC method they never fell below 5% after accounting for historical uncertainty. So we drew away any concern that we had from the summer.

The winter results were a little bit more extreme than the summer. As we show on the second column, the original reserve margins were projected in two of the year years at 15%, and then in other years it reached up to a 19% level. After accounting for some average errors, the FRCC method of using the average historical uncertainties ranged anywhere from a 15% down to a 2%.

Well, in looking at this they concluded that reserves could be maintained and reliability could be maintained with roughly a 13% reserve margin. Well, in using the FPSC -- or the probabilistic method, we saw that in the year -- the winter periods of 1999, 2000 and 2001, it started to get a greater percentage of shortfalls to the extent that the shortfalls started becoming -- represented 6% and 8.3% of the probability, which in turn equated to roughly 1,000 megawatts of shortfall.

But the real question is now that we've seen these potential shortfalls and potential inadequacies, what do we do? Do we require additional capacity resources? Are there mitigating factors out there, such as improving availability; the cold weather benefits, not only in generation but DSM? Public appeals is one response, as well as scram load management that Mr. Adjemian spoke about earlier.

And it's these types of questions that we hope that in working with the FRCC and in the upcoming years, that we can take the benefits of both this method as well as the averaging method and address these in the future analyses.

At this time I'll take any questions with respect to the method was employed, and Joe Jenkins will address any questions regarding the concerns with load and reliability.

MR. BALLINGER: I'll fill in for Joe on those.

CHAIRMAN JOHNSON: Any questions from the audience?

(No response.)

CHAIRMAN JOHNSON: No. Commissioners?

(No response.)

CHAIRMAN JOHNSON: Thank you.

MR. BALLINGER: I guess from there, I guess we can go to the individual utilities, and we've left it to their discretion if they want to give a presentation or not of their individual plans.

The only list we could find as far as an ordering list was on the heading of the official notice of this proceeding, and we've followed it so far. We had the FRCC going first. The next utility on the list would be Florida Power Corporation. So if they'd want to step up and -- if they want to go through their presentation or not.

Let me also, before we get into this, I've gotten some responses to the information we requested regarding low temperature, purchase power, things of that nature. So if you provided it to Staff, you don't need to go through that. I don't know that we'll have any real questions at this time. We will look at that and hopefully discuss it in our write-up of this review.

There was a little bit of confusion with the things; so they should be prepared to address those.

MR. RIB: Thank you. We will try to keep our comments brief, since I know we have a lot to cover today. I am Michael Rib with Florida Power Corporation. I am honored to be first this year to go through it, and I know we've gone through some of this material in the Commission workshops, so we'll try to move through most of these issues more quickly endeavoring to touch on the specific questions that Staff has asked us to address.

Just a quick update. We have continued in our 1998 plan to apply a 15% reserve margin on firm peak load for a reliability criteria, and we also test that for LOLP, which we call .1 days per year equivalent to one day in 10. The other constraint that we analyze is SO2 emissions requirements starting in year 2000 to meet the prescribed limits that the EPA has assigned us.

Okay. Talk about winter first. What we're showing here is our forecast for the winter going forward from '99, the winter of '99, forward again. You can see the actuals in the earlier years going up and down as they did in the FRCC, '97 being a fairly mild winter; '99 going forward back on a trend forecast that we feel we are not planning it purely for that mild winter of '97.

Some of the questions that were asked of us in the exchange dialogue this summer of Commission Staff, one of which was in our weather history what -- how many years do we look at in terms of determining planning weather that we're designing our system for.

Florida Power looks back at 23 years of weather history and looks at the temperatures that occur over the peak periods -- and this applies really for summer and winter -- as well in the winter as looking at the prior 24-hour period to see how that impacts.

We've discovered in our research that generally for the cold temperatures we experience, we also need to look at a 24-hour period in advance of the morning peak we hit on those cold winters and see how that affects it, because there's a build effect in the prior 24 hours.

The two-hour average temperature basis we're using is 34.2 degrees, and that's based on a weighted average between temperatures collected in St. Petersburg, Orlando and Tallahassee, and those are weighted in a representative fashion of the amount of load that we serve in each of those regions.

Another question we had been asked by Staff was for the '99 winter forecast, what temperature would our reserves be depleted; and we addressed that, 286.8 degrees two-hour averages, roughly the point at which our reported reserves would be depleted.

A couple comments to add on summer. We're showing the forecast table from our ten-year site plan. You can see the history, the trend. The growth trend is much more visible and consistent in the summer graph, and that's the same comment Mr. Adjemian added to his.

In this you see a noticeable dip out in 2002-2003 period, and what we're showing there is anticipated changes in wholesale requirements. I would characterize the retail service area growth as being pretty consistent, much like you see in the trend of the actuals in the prior years.

Now, we did have -- every utility in Florida went through some difficulties this summer. We had record high demands in June, and I think we set a lot of temperature records in that month for all history. I would comment that the direct load control program that we have, which includes our load market customers and our interruptible customers, was there as planned to meet the requirements and maintain reliability of the system even through very difficult times in terms of the demands on the system from temperature as well as some of the experiences that we had with our generating equipment.

We managed to serve continuously firm load throughout the summer and have not had to interrupt firm load at any time this summer. So our system has worked as we would like it to.

I think we would always hope to do better, but the combination of issues we were dealing with this summer, we're very glad that we were able to serve as well as we did.

Some of the customers that were load management participants dropped off. In June we had a fairly substantial drop-off. I think most of the folks in the Commission are aware of that. Roughly 40,000 of our load management participants dropped off either in a partial way, in other words, they may have kept one appliance on and dropped another appliance, or some of them dropped completely.

By July that had tapered off to what we consider a normal level. I think in the first week of July there were about 5,000, and after that it tapered off to a very normal exchange level of new customers coming on and attrition of customers moving out of the area or dropping off the program.

So it was a very short-term effect. And I think in June with the fact that we were depending on those folks, we found out that maybe some of the folks -- not a lot of them, but out of a total program of about 550,000 customers, we might have found some of the folks who really weren't the best applied to these load management programs to begin with.

We were asked about cogeneration performance through the summer, and we reported roughly at 92% on-peak availability of our cogeneration suppliers, which we consider adequate.

We were also asked some specific questions on power purchases and sales during the quote "summer '98 heat wave". We had some purchases and sales at very high prices, I would say. That's not the type of hourly prices we anticipate on a daily basis, but more in unusual situations like we had this June.

We reported our highest sold power, at the request of Staff, somewhere between $2,000 and $4,000 a megawatt hour for 87 megawatts over a six-hour period; and I think that's been submitted to Mr. Ballinger for his compilation.

He also requested the highest price paid for purchased power, and that was somewhere between 2 and $400 per megawatt hours for a total of 48 megawatt hours. So it was a very small amount. During that period of that purchase we were purchasing to support firm load, and during that period we were also operating load management and our ISCS program. So I think that was the request Mr. Ballinger had for us.

COMMISSIONER GARCIA: Before you move off, you had 45,000 customers drop off your program?

MR. RIB: Yes, we did. I'm sorry. The megawatt -- rough megawatt equivalents for that -- for the drop-off is there. I neglected to mention that. That's about 50 megawatts of summer interruptible capability and translates to a little bit more in the winter, about --

COMMISSIONER GARCIA: And this is just because they were bothered by being cut off?

MR. RIB: Yeah, they -- primarily I think that was the complaint, that they were being used frequently, and I guess they weren't adapting to it.

MR. HAFF: But the interruptions didn't exceed the limits established in the tariff, did they? I mean, you didn't interrupt them longer than 15 minutes every hour?

MR. RIB: No.

MR. HAFF: Okay.

MR. RIB: I guess I would comment that the tariff includes provisions for operating them beyond those time periods and capacity emergencies, but to my knowledge, we weren't doing that.

I think I've covered most of these. In our ten-year site plan we are continuing to show expectation to meet the DSM goals growth that had been established in the '93 Commission goals docket. In terms of new participants, we exceeded those goals' requirements for '97. DSM programs are open to all customers and -- trying to find the appropriate customers for the programs.

And after the drop-offs, we still have roughly a half a million of our customers on residential load management. So it's a very high participation rate.

MS. SWIM: May I ask a question? This is Deb Swim for LEAF. I'm wondering -- you say there that you include DSM goals for future years in the plan. I'm wondering how you do that.

MR. RIB: Well, the DSM goals, it's actually outlined in our ten-year site plan. The DSM goals for megawatts and megawatt hours, both for load and conservation, we read upon are -- are included as assumed resources for -- up until 2003. At that point -- which is the end of the goals period -- at which point we keep that consistent thereafter.

MS. SWIM: So what you're saying is after 2003 you assume no incremental DSM?

MR. RIB: That's correct.

MS. SWIM: Okay.

MR. RIB: I wanted to just touch on very briefly some of the things we are doing in terms of improving the economy of our mix and some of the capacity being added to the state, which I think is a positive note for today's conversation.

We've done several peaker conversions to burn natural gas and/or distillate oil, and we're continuing on the program. We recently completed another peaker at Suwannee plant, which is in north Florida, and we attempted to endeavor to pursue dual fuel capability where we can.

Also, are still on track in our Anclote gas conversion for supplemental gas-firing. Unit 2, as I understand, is still scheduled in service this fall.

Hines Energy Complex is in construction and start-up at this time. That 470-megawatt unit is coming along quite well, and we have an expected commercial in-service date in November.

We've also included in our plan some capacity upgrades at Crystal River, which are turbine enhancements, to allow increased capacity at that site, and at very attractive rates.

In future expansion, we've shown Unit 2 and Unit 3 being added at the Hines Energy Complex as our next economic unit addition starting November 2004. Both of those current -- plan natural gas supply from FGT pipeline, and those units at that site all include distillate backup fuel.

Touching briefly on Hines 1, Westinghouse is the major equipment supplier for that unit. Power block construction is almost complete, and we did first fires of our combustion turbines beginning in July. So things are coming along nicely.

What I've shown here is a capacity resource mix for the year 2000. It's based on winter capacity, and there's a couple of take-aways we can get from this. This represents in total capacity just over 12,000 megawatts of capacity, including supply resources and demand side resources. You can see that DSM is included in the resource mix.

One of the questions we were asked is how much of our capacity does not have backup -- how much of our gas-fired capacity does not have backup distillate capability. And out of this roughly 12,000 megawatts, we have about 400 megawatts of gas-fired capability without backup. However, those are all firm gas customers -- I'm sorry -- firm gas allocation to those units.

In the IPP cogens there may be some issues that we need to look into, but they're not of a significant magnitude when you look at the total resource mix.

Another question that was asked that we comment on is the appeals for public assistance in the pipeline incident. And we've talked to the folks in our operations group. I can't give you an exact number to determine how effective that was, but their comment was it was effective in helping us manage the capacity situation. I apologize that I don't have the specific number for that.

And one last question related to qualifying facilities was, do we have a standard off . contract. We do not have a unit specifically identified as an avoided unit at this point in time, so our company does not have a current standard offer contract.

(Pause)

Now, this shows the corresponding energy mix, forecast for 2006, a growing addition of natural gas; still coal and nuclear, key supplier is. (Indicating) And also showing purchased capacity as well.

Okay. Last page. We have shown our summer and winter reserve margins. One of the questions I was asked by Staff references winter 2000-2001 showing 13%.

We have some uncertainty in our load forecast in that period depending on some of our wholesale contracts, and we're nearing a point, I think, where we'll find out if those folks are making a choice to another supplier or whether they're going to depend on us. So if we -- we intend to make short-term capacity purchase if necessary to cover that and meet that reserve minimum of 15%, but we didn't want to show that since it hadn't been consummated in the load -- the wholesale contract question was still open at the time that we put the plan together. So that seemed to be an answer to the question, I think.

And that's the end of the presentation I had planned.

CHAIRMAN JOHNSON: Any questions, Commissioners? Staff?

COMMISSIONER DEASON: I have a question. Who are you going to buy from in the year 2002, 2001 if you do not lose those contracts?

MR. RIB: That hasn't been identified yet. I think probably October, November this year we'll need to pursue that.

COMMISSIONER DEASON: Well, what is the reserve margin for the state of Florida as a whole for the 2000-2001 time frame?

MR. RIB: I think the state as a whole is at 15%.

COMMISSIONER DEASON: It doesn't show a lot of excess capacity then, does it?

MR. RIB: No, it doesn't. I think if we are going to have trouble meeting that, I think we will advise accordingly. I think we can meet that.

MR. McGLOTHLIN: Leslie, I've got some questions, if you want me to go next.

COMMISSIONER JACOBS: I have a brief question. I noticed that -- and I don't know if it was in this or in FRCC's document. Your winter peak awards particularly depended on nonfirm low. Is there a particular strategy that goes along with that, or is it simply a falling out of the process that you've outlined here?

MR. RIB: Well, first I'd say I think it falls out of the process of the way we calculate this. I think on a percentage basis we do have the largest load management program in terms of total resources in the state. So when you do the calculation it shows that a large part of our winter reserves are in -- are characterized as nonfirm capability. So, I mean, doing the calculations as is, that's what it shows.

COMMISSIONER JACOBS: Thank you.

MR. HAFF: Go ahead, Joe. I'll go after you're done.

MR. McGLOTHLIN: Okay. I don't know if anyone needs me to step over to the other table.

Commissioners, I'd like to give a very brief preface to my questions. I'm Joe McGlothlin. I'm with John McWhirter. I'm here on behalf of the industrial interruptible customers.

There are two aspects of the interruptions that were experienced during the June-July time frame that warrant some analyses.

The first is whether we were witnessing an aberration of weather, or whether instead we were seeing evidence of inadequate capacity for the systems of those utilities and for Florida as a whole.

As John said earlier, the expectation of interruptible customers who entered their deal with the utility was that there would be capacity adequate to serve the firm customers' needs with the reserves and that those reserves would be adequate to satisfy their inferior but -- service quality, but in a way that would meet their needs.

But the second aspect is, were interruptions even of nonfirm customers necessary under the circumstances that governed in June or July. And with respect to the first question, we commend Staff for probing that issue and for gathering the information.

With respect to the second, following the Staff workshop we asked the Staff to include in the informal data requests some questions that we posed to Florida Power Corporation and Tampa Electric regarding the particulars of those interruptions.

We believe that under the terms and conditions of service, there were some things that the utility can and must try to do to keep even nonfirm customers on the system whenever possible.

First of all, the utility should suspend any discretionary off-system sales so that it can continue to serve nonfirm customers. We've seen some documentation that refers to something called recallable and nonrecallable sales, and we wanted to know the definitions of those so that we can determine whether the sales that occurred during that time were truly firm nonrecallable sales.

The second thing that the utility should have to do is limit any genuinely needed interruptions to the minimum amount of capacity needed to serve firm customers; and what we don't know without more information is whether the utilities have a practice of trying to tailor the interruption, or whether they simply knock off the class of interruptible customers when if a mechanism for rotating the burden were implemented, it could be done successfully.

We've asked whether the utilities are tapping all available resources, including QFs, and we notice what appears to be a disconnect between the way the utilities price as-available purchases from QFs on the one hand and what they're willing to pay for different types of purchases to other utilities on the other hand; and if there is a rational way of enabling QFs to go full out by offering a more compensatory rate that is consistent with the definition of as-available --

COMMISSIONER GARCIA: What do you mean, Mr. McGlothlin? Could you explain that more?

MR. McGLOTHLIN: Yes. I think you'll find the prices paid to QFs for as-available energy would be in the range of -- oh, I don't know -- 28 to $30 per megawatt hour at the same time utilities during the capacity shortfalls are paying in the range of several hundreds of dollars per megawatt hour.

That seems to be a discrepancy that invites at least some analysis as to whether there's something amiss in the way that the as-available purchases are being pushed through the formula for pricing. And our thought is that there may be an additional resource in the form of QFs who can and would generate more power during these capacity shortfalls if the price were more compensatory and that would alleviate in the shortfall during those circumstances.

We ask that utilities provide the information that would enable the Commission to assess the reliability of the residential load management programs, both from the aspect of whether the mechanisms in place to remove them from the system work fully, and also as to the numbers of customers who left the system during the most recent experience.

It could be that the utilities are tending to overstate the reliability of the system by counting too much on what may be a very vulnerable resource in the form of residential load management.

Finally, we saw some documentation called capacity assessments, which are projections of the next day's available capacity compared with load whenever certain temperature criteria are triggered and various reasons of the state.

Again, those are projections, and it appeared to us that if we could add to that a follow-up report that would show what actually transpired, that that may be an additional and valuable tool for assessing the conditions of the system around the state.

Now, I haven't received any responses to our written requests for information. Mr. McGee advised me that Florida Power Corporation intends to provide us with a written response sometime next week. I hope and trust that TECO is working on that as well.

But to the extent that a more general way the witnesses -- or the presenters -- excuse me -- can describe the way they approach these subjects, whether they tailor the size of the interruption, how thoroughly they try to identify and negotiate with potential buy-through sources of power, and their practices with respect to the relationship between nonfirm customers on their own system on one hand and sales they're making to other utilities at the same time they're interrupting native customers on the other hand, I think it would be very valuable information to hear from them today as well.

I'd also like to give you a copy of the letter and data request that we submitted to them before we leave today.

UNIDENTIFIED SPEAKER: Tom, do you want me to address those or --

MR. BALLINGER: Yes, go ahead.

MR. DOLAN: Okay. Vinnie Dolan with Florida Power Corporation. And, as Mr. McGlothlin indicated, we will be filing -- or submitting written responses to these questions sometime early next week.

But just taking them in order, I think one of the issues regarded what Mr. McGlothlin calls discretionary off-system sales, and our answer will indicate that during any of the periods of interruptions, we were not making any discretionary off-system sales.

As a matter of fact, I think his terminology is "recallable" and "nonrecallable." Maybe the better terminology is nonfirm sales that we tend to make day to day. We recalled all of those when we had capacity emergencies for our native customers.

With respect to the amount of capacity that we interrupt during critical time periods, we have approximately 300 megawatts of interruptible capability, and the majority of the times that we needed to interrupt in June, we needed all of that capacity. That is and has been our practice during periods of interruption for a number of years.

It's our understanding that others may be doing that differently, and we would certainly be willing to talk about that, changes to that, that are technically feasible so that if there is a way, if we only needed, say, 100 megawatts, that we could rotate, we're certainly amenable to that and be happy to talk with our interruptible customers about that.

With respect to the purchased power, Florida Power recently entered into an alliance with Dynergy Corporation, and I think we've expanded our reach, and I will assure you that we made every effort during these capacity emergency situations to find all available power for both our firm and nonfirm customers.

As to the difference in pricing as-available for QFs versus the way the market works, I think -- I certainly don't profess to be an expert about that, but we have contracts and tariffs that govern our relationships with our QFs, and I think we follow those contracts and tariffs in terms of the pricing of that power.

With respect to residential load management, I think Mike earlier addressed, I think essentially our customers responded to the extreme heat in June, and we had a reasonably high number of customers that decided to leave the program decided that the economic value of the credit was not worth, I guess, the inconvenience of the interruption.

But by the same token, we still have half a million of our customers, or roughly about 50%, that still think there is good value for the credit versus the amount of interruptions that they have to tolerate; and we think that's an important part of our generation mix.

And I think the last question was one that was directed at FRCC, if I'm not mistaken.

MR. McGLOTHLIN: Brief response. And I look forward to seeing the detailed written responses to the questions that asked for some backed up information.

But the one thing that occurred to me is that I'm sure Florida Power Corporation followed its tariff with respect to the pricing of QF power. Each utility has to have a methodology in place that describes the formula for calculating as-available pricing.

My point was that there may be something deficient with the methodology in place if it results in the type of discrepancy and disparity that I've described to you. And you'll see in your rule governing as-available energy, that among the factors that go into it is the avoided cost associated with purchased power.

So it seems to me that there may be an avenue there that the utilities could avail themselves of and need to, if they are to fully extract --

COMMISSIONER GARCIA: Give me an example of what you'd want, Mr. McGlothlin.

MR. McGLOTHLIN: Well, I'm not prepared to make the full proposal, but I'm making the observation that the as-available prices paid to QFs are orders of magnitude lower than prices being paid to utilities from whom the utility purchases during these type periods of tight capacity at the same time that the Commission's rules governing as-available seem to have room within the parameters for recognizing the cost of purchased power and the formulation of the as-available price. And I'm suggesting that's something worth exploring.

COMMISSIONER CLARK: So you're saying QFs should get market price when capacity is constrained?

MR. McGLOTHLIN: Well, that wouldn't be market pricing, because the definition is in terms of the utilities' avoided costs. But that definition does incorporate a reference to whether the power is being generated by the utility or being purchased by the utility.

So to the extent that those purchase prices are based upon the selling utility's costs, it would be something other than pure market pricing.

COMMISSIONER DEASON: Mr. McGlothlin, when payments are made for as-available, those are costs which are then passed through the fuel adjustment clause; is that correct?

MR. McGLOTHLIN: Yes.

COMMISSIONER DEASON: So you're proposing, then, that all customers pay a higher price so that you don't get interrupted. Am I looking at it too simplistically?

MR. McGLOTHLIN: Well, that wasn't the intent of my suggestion. Maybe that's another possible source of buy-through power in that event. This could be something that could be an exception for tight situations and for buy-through pricing.

CHAIRMAN JOHNSON: Staff?

UNIDENTIFIED SPEAKER: Tom, probably one other point that needs to be made here is I know part of your data requests got to highest sales prices and highest purchase prices, and I think we need to keep in perspective that, you know, those -- the kind of prices we're looking at are very short duration under extreme conditions.

And I think what we'll find, and I think what Mr. McGlothlin will see when we submit our information next week is that forecasted as-available prices by and large throughout the course of the year tend to match up very nicely with the actual prices paid.

So I think we need to keep in perspective -- you know, we had a series of days in June where we had hot weather that some folks clarify as rivaling, you know, hottest summer month that we've ever had here in Florida for the last 30 years or whatever.

So I think we need to be mindful that we don't, you know, take one instance and manage this whole issue by exception as opposed to looking at it in total and making sure we're doing the right thing.

MR. BALLINGER: I agree, and I think some of the utilities' as-available methodologies account for purchased power in emergency situations such as this. I also believe that I think only Florida Power was the utility with the highest purchase price that was buying it for firm power. Many of the other utilities were buying it and reselling it back out of state. So it wasn't needed for their own native load, it was just a strictly marketing tool.

That's basically what I have on that situation. I think that's it, as far as Staff goes. I think Mike may have a question.

MR. HAFF: My question was already answered. Thanks.

CHAIRMAN JOHNSON: Thank you.

MR. BALLINGER: Joe, would you want to stay there and hear TECO, and then that would finish you up as well, I presume?

MR. McGLOTHLIN: All right.

MR. CURRIER: Good afternoon. My name is John Currier, director of planning at Tampa Electric Company. What we'd like to do this morning is present our revised ten-year site plan as it relates to our new business forecast for 1999.

As it relates to going to an annual business cycle, our full business cycle actually moved up two to three months here at Tampa Electric Company this year, and with that we've been able to capture out the newest assumptions, including the weather and strong economic growth of our service territory that we've been experiencing, particularly this summer.

As it relates to loads and demands, we actually saw a 7% increase in peak demand this summer on our system, not once, but we actually saw four or five different occasions, including the month of August, which was more of a typical summer weather pattern.

With a 7% increase, we've revised and looked at our forecasting techniques and tools, and with that we have not only a different load forecast this year, but also a different schedule for our expansion plan.

Mark Ward, who is our manager in our resource planning department is going to actually present our revised ten-year site plan, and Mark compares that against what was filed in the month of April, which was the original site plan; and we're going to present that in a moment.

First of all I want to make a few comments, though, as it relates to the month of June on our system. Tampa Electric actually interrupted its interruptible class of customers one time, and that was on June 22nd, and that was clearly when there was a -- purchase power available for the buy-through provision.

This year we have exercised load management seven times in the month of June and six times in the month of July. We've actually had less customers leave our system this year than we had the previous year; 1,000 of our 80,000 customers, which is barely over 1% that have left our system.

During the FGT occurrence, or event, that occurred, Tampa Electric actually experienced its summer peak that Monday right after that experience for the year. And although we don't have a significant amount of natural gas generation, we do buy from the Hardee Power Partners through an IPP contract, and that station actually switched over from gas to oil without actually -- without losing generation. So we were able to carry that day very well.

As it relates to Mr. McGlothlin's comments or questions, we have submitted our response to those questions this morning through Mark Futrell on Staff; and I've got a few comments I'd like to mention as it relates to your questions.

First of all, Tampa Electric does have a sequencing of -- arrangement as it relates to how we prioritize the interruptible class of customers. And it does go through a rotation based on last one interrupted will go to the bottom of the list for the next occurrence.

This June 22nd was a substantial operation, and we actually had to exercise the full class, the interruptible class, which was approximately 200 megawatts --

COMMISSIONER JACOBS: Excuse me. I had a question there. You interrupted -- that there was no available purchased power that day?

MR. CURRIER: No available for the buy-through. We were able to carry it for the emergency K for four hours. So we bought emergency power for the firm class of customers.

COMMISSIONER JACOBS: Is it possible that that mark or condition was related to the midwest events? In other words, there was so much purchasing going on up there that it --

MR. CURRIER: I believe it was related. It occurred in the same time frame of June 22nd, and there was a -- you know, substantial power needs throughout the eastern United States.

COMMISSIONER JACOBS: Thank you.

MR. CURRIER: Also, the fact of just the extreme weather conditions here in Florida made a challenge for all the utilities.

As it relates to recallable wholesale

transactions, all our recallable sales were recalled during that day, including the wholesale transaction through Seminole's system to one of the IMC customers. That's in the PRECO service territory that we serve. So that one was also recalled.

Joe, is there any other questions you want to ask me at this time at this point before we go to Mark's presentation as it relates to your questions?

MR. McGLOTHLIN: You might just spend a moment defining what you mean by recallable; what type of sale would be recallable; what type of sale would take precedence over your native customers.

MR. CURRIER: Recallable sales are nonfirm transactions, economy broker sales, and then transactions that are actually contracted as a recallable case, and that's in the case before you get to native load, firm native load, customer interruptions. Certainly those are recallable.

MR. McGLOTHLIN: Where you do have a buy-through opportunity, is it your practice to try to price that power and notify the customers ahead of times, or is that after the fact?

MR. CURRIER: Yes. You'll see in our response, in the case where you can have a significant amount of time to actually shop for the purchased power -- often we'll start early in the morning when we know we're in situations we may be looking later in the afternoon for peak, we have those opportunities to shop, and there's enough of a notice, we will contact interruptible customers and give them an opportunity to look at that price as it relates to that buy-through option.

When you're in a situation where you're down to less than an hour and system dynamics have suggested now we have to look at buy-through or actually have to exercise that, there's just not enough of a window of time to actually be able to find a price and communicate; often because of what your purchasing may or may not be priced at that point anyhow.

Often you just take the transaction that you have available. So there is -- that response is also in our submittal to you.

MR. McGLOTHLIN: Thank you. I don't want to belabor that and impose on the Commissioners' time anymore, but I would look forward to seeing written responses.

MR. CURRIER: Okay. In addition to that was it relates to our QF pricing. Tampa Electric in its tariff does price purchased power a component of the full QF price in that given hour. So you can take a look at our tariffs, and that's our practice, too.

And with that, I'd like to turn over our presentation to Mark Ward.

MR. WARD: Good afternoon. My name is Mark Ward. I work for Tampa Electric. I'd like to show a comparison of our demand in energy forecast for the -- as compared to the ten-year site plan that we filed in April this year versus the amended plan that we filed in August this year as a result of our early planning process.

The winter total peaks and the summer total peaks both show increases as well as the net energy for load.

The next chart looks at the makeup for our demand side resources. We have included conservation, interruptible, self-serve cogen and load management, and over the planning period we increase during the winter about 300 megawatts. The overall contribution of each component, each resources -- stays about the same through the planning period.

And then I'm showing on the next chart demand side resources for the summer over the planning period. And again, same type of resources, and the contribution of each resource pretty much stays the same over that planning period.

The next chart I'd like to show is our expansion plan that we are proposing with our amended ten-year site plan and the summer and winter reserve margins with the exercising of load management and interruptible. I'd like to use this chart to respond to a few of the statements that were made earlier today by Mr. Davis and Mr. McWhirter.

Three points concerning LOLP. The 0.1 LOLP guideline concerns only the firm customer. It does not indicate the magnitude nor the frequency that a particular interruptible customer may be exercised.

Concerning the interruptible customers, interruptible customers provide a method for utilities to defer generation in exchange for significantly lower rates as compared to the firm customer.

And then the final statement is on load management. Load management programs also serve to defer expansion requirements. Customers receive a credit on their monthly bill. The credit amount is based on the level of involvement in the program. The value of that credit is based on the avoided unit concept.

Operationally, if load management resources are used prior to interruptible customers, this has approximately the same effect as if the unit was, in fact, built in lieu of the load management resource. Frequency of use of the load management is subject to a theoretical maximum of the projected capacity factor of the avoided unit.

The next chart shows our incremental resources. Over the next 10 years we plan to add roughly 75% in generating capacity and a 25% demand reduction resources. The makeup of our overall resource mix through time stays about the same, if you include future capacity along with existing capacity.

My final chart shows the generation mix by fuel type. Going through time with the addition of our planned generation, you'll see a decrease in the reliance on coal and a heavier increase on the reliance of natural gas.

Are there any questions?

MR. HAFF: Yes. These charts, I understand, are based on your revised ten-year site plan that we received about two weeks ago?

MR. WARD: That's correct.

MR. HAFF: I'd like to make note that there's not enough time left to send this plan out for review agency comments as the statute mandates for our review. So our review will focus on the plan that was filed in April of this year.

MR. WARD: I understand.

MR. HAFF: Okay. We appreciate you keeping us updated with the latest information. Because of the late time it was filed, we can't get review agency comments in time to meet our deadline for our report.

MR. WARD: We just felt that it was incumbent that we inform the Staff and Commission of our change in plan.

MR. HAFF: Okay. Thank you.

MR. CURRIER: Any other questions?

(No response.)

MR. CURRIER: Thank you.

CHAIRMAN JOHNSON: Thank you.

MR. BALLINGER: The next utility will be Florida Power & Light.

MR. VILLAR: Good afternoon, Commissioners. My name is Mario Villar. I'm manager of resource planning for Florida Power & Light Company.

At the August 25th workshop Staff asked a number of questions of all the utilities. We have provided our response in writing to the Staff. They do have that now, so in the interests of time, I'm not going to cover those questions nor am I going to go into a formal presentation. I'll just take you to the chase on our 1998 ten-year site plan and how it differs from the 1997 site plan, and what we did as a result of some comments we received, et cetera.

When FPL filed its 1997 ten-year site plan, we had a couple of unspecified resources that we had identified as filling our needs in the years 2002 and 2003. People raised some questions, including this Commission's Staff, as to what the source of those unspecified capacity purchases might be.

There were also some questions raised as to the winter reserve margin that FPL might have. We have taken those comments into account in developing our 1998 plan and have addressed those issues in the plan that we now have.

On the left you see the 1997 ten-year site plan as filed by FPL. All I have included in there is the generating capacity additions. I have deleted a number of capacity enhancements and minor changes to our QF purchases, et cetera.

As you see, the two unspecified capacity purchases that we had identified in the 1997 plan are shown there on the left, followed by the Martin Combined Cycle Units No. 5 and 6, and an unsited combined cycle in 2006.

The 1997 plan did not go out to 2007, and that's a feature of the 1998 plan. For comparicon purposes, I dropped off the early years also.

The 1998 plan identifies our Fort Myers repowering as a preferred alternative for FPL in the year 2002. The need date did not change from the 1997 plan to the 1998 plan.

We also have identified the repowering of Sanford in 2004 as meeting our needs, followed by Martin Combined Cycles No. 5 and 6. And as you see, the number of megawatts being added to the system is significantly increased from the one in the 1997 plan, almost twice the number of megawatts that we had projected originally.

There is significant benefits associated with the repowering of the Sanford and the Fort Myers facilities because they bring benefits not only in terms of capacity, but they improve the efficiency of the existing system.

The resulting winter reserve margins are shown in this graph. As you see, we meet the 15% reserve margin throughout the period of the study. The lowest time is the winter of 2000, 2001.

Summer reserve margins are shown on this bar graph, and they are higher than the winter reserve margin. The lowest ones we show there is 17% in the

2001.

That concludes my presentation. I'll open it for questions.

COMMISSIONER JACOBS: I saw in the load and resistance plan that you guys have plans for a 500 kv line in 2005, 2006. Are you familiar with that?

MR. VILLAR: That we have plans for a 500 kv line in 2005 and 2006?

COMMISSIONER JACOBS: Yes. I believe -- let me go to the page. I had it and I lost it.

UNIDENTIFIED SPEAKER: Commissioner Jacobs, I think you may be addressing there's an Andytown to Orange River 500 kv line, which in the plan is currently scheduled in 2005, 2006. That's a line that has been needed, would have been needed in the 2002 time frame, but it's being delayed as a result of the repowering of Fort Myers.

COMMISSIONER JACOBS: You answered my question; that was, which was going to be where.

UNIDENTIFIED SPEAKER: Yes. It's a line which originally was intended to be sited on the existing corridor of an existing 500 kv line that runs from Andytown, which is just west of Fort Lauderdale, Florida, to Orange River, which is just east of Fort Myers.

COMMISSIONER JACOBS: Okay. Thank you.

MR. DUDLEY: I'm Ken Dudley with the Commission Staff. We recently got an e-mail with regards to FPL advancing the construction of the Fort Myers repowering. Could you discuss that?

MR. DENIS: Yes. By the way, my name is Roberto Denis, and I'm the director of resource planning, Florida Power & Light.

Just this week we announced that we had accelerated our plans to build a generating capacity at both Fort Myers and at our Sanford repowering from that which was just shown and included in the filed ten-year site plan that Mr. Villar just showed.

This acceleration or this decision to accelerate the construction of these two facilities, which is a phasing-in since this is modular technology and we can phase in different aspects or different components, takes into account the recent unusual weather patterns that have included one of the hottest summers ever experienced in Florida.

Florid Power & Light exceeded its 1997 summer peak 43 times this summer. We do not know at this point in time whether this load increase that we have experienced is an anomaly being created by some global changes, such as El Nino, or it is the beginning of a trend in weather patterns. But out of an abundance of caution and to be able to give us the flexibility to meet those loads, we've opted to accelerate the construction of those facilities.

The benefit of this type of construction on the repowering, which involves the adding of combustion turbines to the existing site, one of the advantages is that it does allow one to accelerate components. It's not an all or nothing with the capacity, with respects to the capacity addition, but allows us to accelerate as well as delay construction in the future, should some of this load that we have experienced not continue to form part of a trend or materialize in the future.

I guess Mr. Villar has put up a chart which is a modified, an updated chart from that which he just presented. My understanding is, as Mr. Haff just mentioned, that this will not be part of a -- the review process of the ten-year site plans, because the review limits itself to that which was filed already.

But for information purposes, this slide shows what the impact on the plan from that which was filed to that which we are currently on, the accelerated schedule. The resulting reserve margins from such an acceleration also change, as you saw before.

Assuming no load changes, the reserve margins will change, and in the next planning cycle we will be analyzing -- and as we get some additional load research data, we will be analyzing and trying to determine the reasons for the load increases that we saw this summer.

MR. VILLAR: Going back to that previous slide that you had accelerating the Fort Myers expansion to 2001 and you show winter capacity ratings there in 2001 and 2002 with a total of 640, and in the plan that you filed, the Fort Myers expansion was expected to increase capacity by 1,000. Is there something --

MR. DENIS: Well, again -- no --

MR. VILLAR: -- not included there?

MR. DENIS: No. This is again what I'd refer to as the benefits of the type of technology that we're putting in on the repowering.

At Fort Myers we have had an existing -- two existing steam boilers and turbines and electrical generators. The first one is around 400 megawatts, and the second one is about 150. In the repowering process what we are doing is we are adding six combustion turbines, each nominally rated about 160 megawatts, which will provide the heat exhaust to be able to run those steam boilers or the revamped steam boilers.

What we expect because of the phasing in of the construction is that we will have two of those combustion turbines installed and operating in the winter of 2001 and we will sequentially add one combustion turbine essentially per month until we get to the summer period, at which time we will have essentially 900 megawatts of additional capacity at the site, complimented by the additional 550 or so that are already there.

Then what we have to do is we have to take down the existing units during that summer period to be able to do the crossover. So we lose -- although for summer purposes, which is not shown here, we add 900 megawatts, but we lose 500 of existing capacity.

So the net result is that the sequencing throughout the years, we'll have 320 megawatts in the wintertime of 2001; we'll have approximately a net 400 additional in the summertime with the full 1000-megawatt increment by the end of the year.

MR. HAFF: The end of 2002?

MR. DENIS: End of 2001.

MR. HAFF: These two CTs are coming in the winter of 2000, 2001, at the two --

MR. DENIS: Yes.

MR. HAFF: -- CTs at Fort Myers? Okay. With that acceleration, I understand that gas, the earliest gas can get to that site is March of 2001. Are you going to burn these on oil? And that's assuming you have a contract, I guess, with FGT, which is another question.

What's the status of the fuel supply at Fort Myers?

MR. DENIS: When we were here, I guess a couple weeks ago, I expressed to you my wish that I could tell you that we had selected a gas transporter to supply these needs, and I did not want to comment at the time any more because of the sensitive nature of the negotiations.

My hopes have not been -- have not come true. We are still in very active and sensitive stages of negotiations with the gas transporters. We have issued another press release yesterday, I believe in the Fort Myers area, that talks about our selection, or our termination -- or our conclusion of those discussions by the end of this month. At this time I cannot really comment because of the sensitive nature of the discussion.

MR. HAFF: The end result is you'll probabl, be burning these on oil, these two CTs at Fort Myers, the first winter that they're operating?

MR. DENIS: That's part of the discussions that are taking place. Our hope would be not.

MR. BALLINGER: I think that's it from Staff. Are there any other interested persons?

CHAIRMAN JOHNSON: Commissioners?

(No response.)

CHAIRMAN JOHNSON: That's it.

MR. DENIS: Thank you.

MR. HAFF: Next is Gulf Power company.

MR. POPE: My name is Bill Pope with Gulf Power Company. We didn't plan on giving a formal presentation or summary of our ten-year site plan, but we'll be available to answer questions if anybody has got any.

CHAIRMAN JOHNSON: Any questions of Gulf?

MR. BALLINGER: I have one. I haven't got a response yet, and my only question goes to your -- are you going to issue a standard offer contract for your combined cycle you're planning to build, or are you going to seek a waiver of the standard offer rule?

MR. POPE: We will be filing a petition for standard offer contract approval within the next week or two.

MR. BALLINGER: Will it be based on the combined cycle unit?

MR. POPE: It will be based on the next unit, which would be another combined cycle for the year 2006.

MR. BALLINGER: Okay. Thank you.

CHAIRMAN JOHNSON: Thank you very much.

MR. HAFF: Following the order on the official notice, next I have Seminole Electric Cooperative.

MR. POPE: This is Bill Pope again. I erred in my answer. It's a 2006 CT.

MR. HAFF: Thank you.

MR. ZIMMERMAN: I'm Carl Zimmerman, manager of planning at Seminole Electric Cooperative. We have just a very brief presentation that we're handing out. I'm not going to go through all of those slides.

I just wanted to make a couple comments. And my first comment is that old habits are hard to break, and we still called our presentation to the annual planning workshop. The chart that -- one of the comments that I wanted to make -- well, that doesn't work on there. (Indicating) The chart that was handed out this morning that had the summary of the ten-year site plans indicated that Seminole's next need was 650-megawatt CTs.

Actually, our proposed additions -- (pause) -- we actually have a combined cycle, gas-fired combined cycle unit scheduled to be in service January 1, 2002, and that particular unit has already been through the need determination process; and then that will be followed the following year. (Pause)

So I just wanted to make that one correction, that we do have the combined cycle unit scheduled in service January 2002; then followed by a group of CTs that will be -- and that's our back-stop plan. We will be issuing all source RFPs to determine exactly how we'll meet those future requirements.

And we did file our answers to -- or provide our answers to the questions this morning to Staff. So other than that, if there's any questions, that's the only comments that I have.

MR. BALLINGER: I'll just point out I believe that summary chart where it had the six CTs, that was because we recognized that Hardee 3 had already been certified as needed. That's why it went to the next units.

MR. ZIMMERMAN: Okay.

MR. HAFF: Are there any questions for Mr. Zimmerman?

(No response.)

MR. HAFF: Excellent. Thank you. Next on our list is the Florida Municipal Power Agency.

MR. CASEY: I am Richard Casey with FMPA. In the interests of time, I'm going to forego giving a detailed presentation of our ten-year site plan. I did give to Staff just a few minutes ago the other details which were requested regarding winter temperature data and sales data and experience during the FGT explosion. I would be open to any questions on that information.

Let me give you a couple of quick comments, though. Our all-requirements project is where we spend all of our time planning to serve the full requirements of 10 cities currently, and that project began in May of '86, and so we've only been in operation in that mode for 12 years, and, therefore, our database is somewhat limited in terms of doing detailed studies of load variation versus temperature.

The other consideration is, we have just added four new cities over the last two years, and yet we haven't had a cold winter.

So, again, our database is fairly new, in an infant stage. As time goes on, we will be looking more intensely and getting a better understanding of those relationships.

The other point I would make is that FMPA is one of four members in the Florida Municipal Power Pool along with KUA, OUC, and Lakeland, and, therefore since we're in the pool, all of our sales were on a nonfirm basis as the pool; and so the pricing information that we've supplied to you would be the same for all four entities.

I guess generically I would just offer you this: We are in the process, as I'm sure you're aware, of planning to construct and have an operation for the summer of 2001, a 250-megawatt nominal combined cycle unit at Cane Island. It will be Cane Island 3. We're going to share that 50/50 with Kissimmee Utility Authority. And so that's well into the process.

That's all I've got to offer to you.

MR. HAFF: Any questions for Mr. Casey?

(No response.)

MR. HAFF: Thank you, sir. Next I have on the list, Gainesville Regional Utilities.

MR. WESTPHAL: My name is Roger Westphal, Gainesville Regional Utilities. I have no formal presentation. We've filed our answers to your questions yesterday in a fax. If there's any questions, I'll entertain them now.

MR. HAFF: Who did you fax them to?

MR. WESTPHAL: To Mr. Ballinger.

MR. HAFF: I should know that. Thank you. I've got to say something. (Laughter)

MR. WESTPHAL: Okay. Any further questions?

(No response.)

MR. HAFF: No. Thank you. Thanks for making the trip.

Next on our agenda is Jacksonville Electric Authority.

MR. BOSWELL: I'm Randy Boswell, Jacksonville Electric Authority. We had planned no presentation either, unless you have some questions. We did send up yesterday the information that was requested.

MR. HAFF: Could you explain briefly, I guess -- I know you don't have slides. But last year one of our major concerns, as you know, was the unspecified purchases that made up a large part of your expansion plan. Could you briefly explain how those may have been mitigated and what the status is of that as of this year?

MR. BOSWELL: I do have couple slides, so let me use those to talk from on that.

This is our current plan as filed, at least the major additions for the next 10 years. From last year we've added 700 megawatts of combustion turbines as well as repowering of our Northside 1 and 2 units. We do have some seasonal purchases, particularly 1999 and 2000, that we will have to make prior to implementation of those purchases.

We already have made the purchases necessary to meet our winter of '99 obligation, and we're working on summer of '99 currently. As you know, we have significant tie capacity to the southern subregion, and we don't believe we'll have any problem making those purchases for those periods of time.

MR. HAFF: Any concern about the cost of those purchases?

MR. BOSWELL: Yes. (Laughter)

MR. HAFF: I'm sure. But what -- I guess you're looking at a pretty short time frame for determining when your -- or from whom you'll be purchasing from to meet these short-term needs.

MR. BOSWELL: Yes. As I mentioned, we've already made the winter of '99 purchase that we need this fall. We hope the pricing for the summer of '99 will be better than it has been this summer, and we'll make those purchases.

We took some bids during the summer, but the pricing -- there was available capacity, but we didn't like the prices, so we're going to go back to that market. We don't believe we'll have a problem for 2000.

MR. HAFF: And these purchases, I guess, would be a short-term firm --

MR. BOSWELL: Yes.

MR. HAFF: -- contract?

MR. BOSWELL: Yes.

MR. HAFF: It's not nonfirm, then.

MR. BOSWELL: It is not nonfirm.

MR. HAFF: Okay. Does anyone have any questions for Mr. Boswell?

(No response.)

MR. HAFF: Thank you. Next I have Kissimmee Utility Authority. Welcome back.

MR. MILLER: Good afternoon. My name is Robert Miller. I am from Kissimmee Utility Authority. I don't have a presentation today. And Rick Casey from FMPA presented most of the information that was requested, or at least some of the information that was requested, by Staff.

With regard to the database, we also have problems with our data base. We have temperatures going back to probably 1970, but they're not correlated with the peak. We just have maximum and minimum temperatures for each day, so we're not able to come up with statistical analyses that would give us information on megawatts per degree. We are currently putting that database together so that we will be able to answer that question in the future.

MR. HAFF: Okay.

MR. MILLER: With regard to the questions relating to the FGT explosion, currently all of KUA's generation, gas generation, have oil backup. So I can answer that question, and all the others relating to price were already answered by Mr. Casey. So if there are any further questions?

MR. HAFF: I understand there's firm gas transportation or firm gas capacity into the Cane Island site?

MR. MILLER: Yes.

MR. HAFF: And that this FGT event was the first time that gas supply had ever been interrupted to that site?

MR. MILLER: Yes, it was. We hope it's the last.

MR. HAFF: Any other questions for Mr. Miller?

(No response.)

MR. HAFF: Thank you. Next up is the City of Lakeland.

MR. ELWING: Good afternoon. My name is Paul Elwing, City of Lakeland.

In the interests of time, I don't have anything add to our ten-year site plan. We'd like to just leave it as it stands as filed with you all.

Lakeland did file comments and responses to questions from the August 25th workshop. We hope that they suffice in answering. If you have any questions, I'm here to respond.

MR. HAFF: Anyone, any questions for Mr. Elwing?

(No response.)

MR. HAFF: Okay. Thanks. I like how this is proceeding. (Laughter) I'm sorry.

Orlando Utilities Commission is next.

MR. BLANKNER: Good afternoon. Matt Blankner with Orlando Utilities Commission. And also in the interests of time, I didn't have a full presentation planned.

I wanted to mention briefly that we don't have any planned capacity additions for the ten-year site plan horizon.

The response to the questions regarding the winter temperature, I haven't submitted those to you. If you would like, I could give those to you now, or I could submit them to you before I leave today.

MR. HAFF: That will be fine. You can just give them to me after we're done.

MR. BLANKNER: We certainly feel we're going to meet our reserve margins by a significant amount through the ten-year site plan for the horizon, so, therefore, I'll leave it open for any questions anybody may have.

MR. HAFF: Any questions?

(No response.)

MR. HAFF: Okay. Thank you. Our last Utility on our list is the City of Tallahassee.

MR. FRAZIER: Good afternoon. My name is Edwin Frazier. I'm an engineer with the City of Tallahassee Electric Department, and due to the interests of time, we are not going to do a full presentation, but highlight on the main capacity addition as planned during the ten-year period.

Okay. We have a proposed power plant that's a 250-megawatt combined cycle, and has a 39% better heat rate than our system average and also improve the environmental profile and scheduled to go on line May 2000. And the plant site is one of our existing sites at St. Marks. And we're going to replace the 75-megawatt purchase contract currently with Southern Company.

The current status of the proposed plant, we have met major milestones, such as the needs order was received in June '97, the siting approval in April '98, and the final authorization to proceed was in July '98, and the future targets to be met are construction mobilization in January of '99 and in-service date target for May 2000.

That's it. If you have any questions, I'd be glad to respond.

MR. TRAPP: Can you tell us just out of curiosity how the -- I'm Bob Trapp from Staff. Can you tell us how the site fared during the hurricane? Did you have flooding down there or --

MR. FRAZIER: I'll let -- .

MR. BYRNE: I'm David Byrne. I'm chief planning engineer for Tallahassee, and we didn't run into any troubles down at the St. Marks site during this hurricane. Apparently the bulk of the rain passed to the west of Tallahassee and then north from there. They were concerned and had the -- did shut down the units early that evening, just in the event that there was -- might be a flooding problem. But no, there weren't.

MR. HAFF: Are there any questions for City of Tallahassee?

(No response.)

MR. HAFF: Thank you.

MR. FRAZIER: I would just like to add that I will respond to the questions about the winter temperature after the workshop.

MR. HAFF: Is that in writing to present to us?

MR. FRAZIER: Yes.

MR. HAFF: Okay. Thanks. That's all for the utility presentations.

I understand we have some interested parties who would like to make some comments on the plans, and right now we'd like to entertain those comments.

In case I neglected to mention, once again I'd like to make sure everyone has signed the sign-in sheets at the back door on my side of the room in blue paper. Make sure everyone is signed in, if you would.

MS. SWIM: Hi. I'm Deb Swim and here for LEAF, Legal Environmental Assistance Foundation, and appreciate your attention. It's quite a long and grueling day.

We're here today because we want to give some input on your decision as to whether utility plans for the next decade are suitable or unsuitable, which is what the statute for ten-year plans requires you to do.

The utilities are proposing to add 8,000 megawatts in new capacity, and we believe that part of that capacity can and should be postponed by cost effective investments in DSM, but that that is not reflected in the plans.

We have the following concerns which we believe should justify a finding of unsuitability:

First, Staff and the industrial customers have stated their concerns about how Florida is relying too much on load management and interruptible resources to keep the lights on.

We share those concerns and especially because our heavy focus in Florida on load management has actually resulted in increased energy consumption. So we have a situation where what we're supposedly doing for conservation increases consumption.

It's not that it's a bad thing to try and level the load curve out, but there's a lot more that can be done. And we believe that rather than allowing utility plans to focus almost entirely on reducing peaks, which is what the plans before you now do in the area of DSM, that you should take this opportunity to encourage utilities to also plan to lower the entire energy consumption curve.

And yesterday in the playground I made a chart to help illustrate this point. You probably already know this. This is just a picture of a load curve. (Indicating) It's not any particular utility or time; it's just to show that overtime load increases and decreases.

The blue hatched area here and here generally depicts the effects of current utility DSM efforts. They reduce the usage at peak and increase the usage in the valleys.

This white striped line shows what would happen if the Commission were to encourage utilities to lower the entire energy consumption curve, which is something we strongly urge you to do so. Lowering the energy assumption curve as we're suggesting would address both the liability concerns that we're facing as a state and conform to legal requirements that govern this proceeding.

In this proceeding you are to review plans in light of the state comprehensive plan, and the state comprehensive plan has a specific part that directs a decrease in per capita energy use consumption.

That's just what this white line is, and something we think is very important to the state. And we would go so far as to, you know, recommend that you find the plans unsuitable because of the focus right now on load management rather than per capita energy use consumption reduction.

We also have some kind of more utility specific concerns where we believe that utility plans have underestimated or ignored contributions from DSM. It varies for each utility, so you'll have to bear with me a little bit.

Florida Power Corporation and Florida Power & Light both plan no incremental DSM after the year 2003. That's even RIM based DSM. It's as if they were going to stop doing DSM after 2003. That's clearly not an accurate assumption.

FPL and FPC are legally obligated to do DSM. It's required by the Commission's rule and FECA, the Florida Energy and Conservation Act, and we don't think it's right for the plans to assume that there will not be DSM after that time period.

TECO didn't assume no incremental DSM after the goals period of year 2003, but they do plan less DSM than the Commission's conservation goals that were set in the last goals proceeding would require.

When the goals were set, the Commission in its order stated that the goals were intended to be minimum pass-fail goals which must be met to avoid penalties. And we think a plan that plans to do less DSM than the Commission's goals require has to by nature be unsuitable.

So those are some concerns we have specifically about TECO, FPL and Power Corp's plans.

We also have, you know, a general concern which we've expressed a lot to you in the past about the level of DSM that's going on in the state.

In the last goals proceeding you adopted a policy -- it's in the order -- that you set RIM based goals and then encouraged utilities to implement TRC passing DSM that offered high energy savings and low rate impacts.

The utilities have stated that their planning processes are purely based on RIM. They don't consider TRC based DSM at all, and so we have a Commission policy --

MS. PAUGH: Excuse me, Ms. Swim. The

subject of this discussion has moved very quickly into subject matter that is within a docketed or for docketed proceeding. This is not a matter that we can discuss at this time. We can take it up within those dockets, but not in this forum.

MS. SWIM: Well, I feel kind of constrained, because to me it's part of the ruling on suitability, which is what's before the Commission here, so I'm not really sure how to handle it. It's certainly, to me, relevant in both proceedings.

MS. PAUGH: Commissioners, I recommend that we not take any testimony to this effect.

COMMISSIONER DEASON: As I understand it, this is a subject matter of a docketed proceeding which will be coming before the Commission shortly.

MR. BALLINGER: Yes, sir. Specifically, the issue of should the utility screen on issues of TRC or RIM is coming before the Commission in the DSM goals dockets.

MS. PAUGH: Our recommendation will be filed on that very issue based on seven pleadings in the goals dockets. The rec will be filed for the next recommendation period. So this is currently pending before the Commission.

COMMISSIONER DEASON: What is the time frame for that matter to be heard and the time frame for determining suitability of the ten-year site plans?

MS. PAUGH: The goals proceeding is set for May of '99.

MR. HAFF: We're due to make an ultimate determination at Internal Affairs on the suitability of these plans. It's currently scheduled for November 30th of this year.

COMMISSIONER DEASON: Ms. Swim, it seems that the timing of these matters is such that if we were to determine plans plan unsuitable based upon matters which we've not determined yet, it would be construed as prejudging issues which are going to be coming before the Commission at a later time. And if you disagree with that, let me know.

MS. SWIM: Well, you know, I do disagree. I mean, if it's your pleasure not to hear what I have to say, I'll, you know, certainly stop speaking about this. But I believe right now you're supposed to be looking at whether or not the plans are suitable or unsuitable, and to me that brings up, you know, looking at this issue.

You know, yes, you do get goals, too, but you can't just say, oh, well, because we set goals, we can't determine suitability. There's an overlap in issues, that's true, but, I mean, there's overlap in other areas that have to do with, you know, whether a plant is needed. I mean, those kind of arguments can come up too.

COMMISSIONER DEASON: I understand, but --

MS. SWIM: I'm not pushing this. If you don't want to hear it, that's okay. I just wanted to let you know why I felt, you know, it was relevant here.

COMMISSIONER DEASON: And I understand that. But in an abundance of caution so that we do not perhaps violate procedure in the other dockets, I'm going to ask you not to go further with that particular --

MS. SWIM: Okay. I can respect that.

So for the reasons I stated before about the concern with focus on load management rather than reducing per capita energy use consumption, the concern about how FPL and FPC have excluded incremental DSM after the year 2003, and how TECO has excluded goals level DSM from their planning process, we think their -- you have in effect an overstatement of capacity needs because of an exclusion of -- an underuse of DSM.

We also have two additional concerns. One is a concern that you've heard me express before; that the plans reflect virtually no investment in solar energy, and I won't go into any further detail about that because we've talked about it before.

And, second, we're concerned because new capacity seems to be being added without any apparent consideration of the aging fleet of existing plants. There are potentially increased maintenance costs, and there are considerable current and future environmental costs.

Ms. Kamaras is handing out a sheet which compiles information about the age of the units that are being -- that are in existence now.

You heard today Mr. Wiley for FRCC claim that the availability of existing units is increasing, but that's not really true, or certainly is probably not true for the older units; and this is something I think you all heard FIPUG's representative discuss.

You know, as any machine ages, and of course as we -- as humans know, as all humans age, we require more maintenance. And many of the plants that were built in the 1940s, '50s and '60s, and '70s even, were originally designed for a 25 to 30-year life. And as the charts we handed out show you, Florida has a significant amount of aging capacity, and only a very small fraction of that is proposed for retirement during the 100-year planning period.

So these plants are going to require more maintenance at a time when utilities are cutting their costs, including plant and staffing levels. They're also among the most inefficient and most polluting in the fleet. And those are some concerns that, you know, in your review of the state comprehensive plan, which is, again, required under the ten-year site plan statute, should be looked at in this proceeding.

They cost ratepayers a lot more because they're fuel inefficient, and they cost Floridians in direct health and environmental damage, and we'd like to see some recognition of the need to retire these plants.

COMMISSIONER JACOBS: How would you replace that low?

MS. SWIM: How would I what?

COMMISSIONER JACOBS: As I understand what you're saying is that you anticipate that would be a higher retirement of older plants over the planning cycle than anticipated. How would you would replace the low that they represent?

MS. SWIM: Well, we would replace it first with cost effective, least cost DSM to be followed by least cost supply option, which I think most folks thinks these days would be a natural gas unit. Whether it's combined cycle or CTU would depend on whether it was a base load or a peaking kind of need. But I think that would probably be the -- you know, I'd like to throw in some solar, too.

But the newer natural gas plants, and the newer plants generally, even a newer coal plant, they meet much more stringent emission standards than the older plants. These older plants, when the air pollution laws were adopted, they got exempted with the idea that they were going to retire in 25 or 30 years; and it's been 25 or 30 years and they haven't retired, and they're still clunking along with the larger, much larger emissions that are permitted under the federal Clean Air Act.

COMMISSIONER DEASON: Does that conclude your comments?

MS. SWIM: Yes.

COMMISSIONER DEASON: Questions?

(No response.)

COMMISSIONER DEASON: Thank you.

(Brief recess.)

CHAIRMAN JOHNSON: If everyone could be seated, we're going to continue the workshop.

Ms. Elder?

MS. ELDER: Thank you, and good afternoon. For the record, my name is Marcia Elder and I'm representing the American Planning Association, Florida Chapter, and the Project for an Energy Efficient Florida.

In addition, I have been asked to present comments on behalf of a range of other organizations whose members also care about these issues in the context of Florida's energy future. We and they appreciate the opportunity to offer our conclusions and recommendations for your consideration.

I'll begin with the group statement, which is presented on behalf of the League of Women Voters of Florida, the American Lung Association of Florida, the Florida Consumer Action Network, Common Cause of Florida, the League of Conservation Voters, Florida Legal Services, the Cross Creek Initiative, the Florida Catholic Conference, the Presbyterian Caring for Creation Coalition, the Florida Public Interest Research Group and the Sierra Club, Florida Chapter, in addition to our organizations and the Legal Environmental Assistance Foundation.

The statement reads: "The planning process for meeting Florida's energy needs has substantial bearing on the energy sources that we use, how much that energy costs, the siting of energy facilities, and reliability of energy services. As such, it impacts the environment, public health, the economy, and the disposable income of consumers, and it thereby affects all Floridians.

The undersigned organizations, representing thousands of Floridians who care about the future of our state, want that process to provide for clean and safe alternative energy sources.

Absent a timely transition to renewable energy, Florida cannot be sustainable for the long term, yet the proposed ten-year site plans for electric utilities reflect no plans for renewable energy sources and a limited role for energy efficiency.

This concerns us greatly, and we are troubled that despite many compelling reasons for change, Florida continues an almost exclusive reliance on fossil fuels and nuclear power. We do not object to building new power plants where they are needed. To the contrary, we all enjoy the benefits of electric power and appreciate the importance of electric utilities in our society.

However, as the consumers who pay for

whatever plants are built, we worry about proposals to significantly increase utility generating capacity, and particularly when demand side management alternatives that cost less than building new power plants are readily available.

Conservation and efficiency are also a way to avoid pollution, which is vitally important from the standpoint of human health and the health of our ecosystems. The use of such practices and technologies is good for the economy as well.

We are pleased that the utility plans as a whole emphasize natural gas as a fuel choice over other conventional energy options that are far more polluting and less efficient. We further believe that a capacity additions utilizing natural gas should replace dirty and inefficient plants that are aging and warrant retirement.

Floridians want clean, sustainable energy for our future and that of generations to come. We are entering a new millennium, and energy decision making that affects the public and our quality of life must keep pace with changing times. Towards that end, we urge that the Florida Public Service Commission call on Florida utilities to amend their plans in accordance with these needs and concerns. The future of all us and those we care about depends upon your action.

We have written statements, which we'll provide to you, and we have some additional comments as well, but that concludes the group statement. And I do want to mention that one of the groups that I listed verbally was inadvertently not listed on the written copy, so you'll notice that.

As you know, since you had a representative on their energy advisory committee, the Governor's Commission for a Sustainable South Florida, which was a very diverse group of leaders and experts from the public and private sectors, devoted better than a year and a half to examining energy issues of importance to our state.

The committee concluded from the onset that the issues they would be addressing and the recommendations they were to develop would not only be pertinent to south Florida, but instead to all of Florida. Their findings and recommendations were wide ranging, two of which have special relevance here.

First, they concluded that Florida is not energy sustainable on our current path, and that we cannot be sustainable without making the transition to renewable energy resources.

They further concluded that the Public Service Commission has a critical role to play in assuring that this transition occurs, and they acknowledge that it takes years to make the shift in facilities, equipment, procedures, consumer habits and so forth, so we need to start now.

For these reasons and given the many benefits of renewables, as we have testified on before this body on numerous occasions, we are especially disappointed to see no plans for renewable technologies via the 10-year utility plans.

Secondly, the Governor's commission stressed the importance of energy planning as being the pivotal ingredient to achieving desired outcomes for our state. As part thereof, their number one recommendation called for the development of a state energy plan to map out where Florida wants and needs to be energy wise, in addition to strategies and priorities for getting there.

As they found in their deliberations, energy decision making is currently fragmented and piecemeal, and absent a clear decisive path for our energy future, the path we take is random, and the potential consequences are substantial.

Unfortunately, funding for that plan was killed in the last legislative session, and no offense intended to participants here today, but it was killed due to the intense opposition of the utility industry lobbyists who said that they were comfortable with the status quo and did not want to see any changes that might occur as a result of a plan.

But the fact is that we are in a time of incredible change where a fundamental ability important for decision makers at all levels, both public sector and private sector, is adaptability coupled with the courage to risk taking a new discretion.

To walk a steady path in the face of changing ground and to have the vision and foresight to do so well is, in our view, an integral part of what leadership is all about.

To pretend that the times are not 'achanging, as some have when red flags abound, is akin to presuming an endless ascent into the stock market, even though signals were many and varied that 9300 points on the Dow was pushing the heads of -- the edge of the proverbial envelope, and just like the influence there of the Asian crisis, the Russian ruble, and so forth.

The Parade Magazine front page feature this summer, that hopefully all of you saw, spotlighted one of the major -- one of the many red flags in the energy market versus the stock market pointing in that case to what has become the unthinkable to the vast majority of people; that being the prospects for serious oil crises in the not too distant future, complete with gas lines, price spikes and an array of other disruptive impacts.

It's unthinkable, because energy is off the radar screen for the general public. But regardless, as the writers of this article observed, the problems are nonetheless real and growing, which to use another current metaphor, like the Titanic, it makes the situation all the more dangerous, whether due to foreign oil politics or due to growing energy demand of developing countries or the miniscule alternative energy infrastructure now in place and being planned for.

So it's time for us to pay attention to the signals and to begin the capital and time intensive process, including the significant lead time required, of positioning our state for the future and a future where the environment, the economy and our quality of life are sustainable.

We do appreciate the focus of Staff.

Indeed, it is your statutory responsibility to provide for system reliability, but you can't have reliability over the long haul without renewable energy.

Speaking of the law, the Florida Statutes compel state policy makers and policy implementers to make that shift. Citing several examples under Chapter 186, Section 186.801, the Commission is called upon to review possible alternatives to the proposed plans, the relationship of the plans to energy availability and consumption and, as Ms. Swim indicated, the extent to which the plans are consistent with the state comprehensive plan.

But when you look at the state comprehensive plan, the singular goal under energy is to reduce energy requirements through enhanced conservation and efficiency while at the same time increasing the use of renewable energy resources. That's the singular energy goal in the state comprehensive plan.

The policies call for continuing to reduce the per capita energy consumption in the utility sector, to reduce the need for new power plants, and to promote solar technologies and other renewables. So it goes without saying that these plans are not consistent with the state comprehensive plan as required by the law.

Chapter 366, as governing the PSC concerns, specifically calls -- or says that reduction in the growth rates of the electric consumption and weather sensitive peak demand are of particular importance to our state, and it goes on to say that the Legislature intends that the use of solar energy and renewable energy will be encouraged for Florida.

The state energy policy under Chapter 377 says that the state will discourage all forms of energy waste, that we will encourage alternative energy sources, and particularly renewable energy resources, and that we will consider -- or that the state will consider in its decision making the social, economic, and environmental impacts of energy related activities so that the detrimental effects of these activities are understood and minimized. These policies were set to be observed by all state agencies in their decision making processes.

In addition to the statutes, the public opinion polls also compel such action. And from the standpoint of a growing number of religious institutions, since I mentioned those in our group statement, they have over recent years taken a strong interest in the environment and earth stewardship because they view it as an ethical responsibility toward all of us here and toward generations to come.

But regardless of any of our personal or business perspectives or motivations, the reasons for taken a new path are many, and the benefits of doing so accrue to all of us, including the utilities, which leads us to the solid conclusion that it's time to challenge the utilities as the Governor's commission did; to step up to the plate and be a part of the solution for the good of the whole.

As always, we very much appreciate the opportunity to appear before you and we urge your favorable consideration of these concerns. Thank you.

CHAIRMAN JOHNSON: Any questions?

(No response.)

CHAIRMAN JOHNSON: Thank you, Ms. Elder. Mr. Moyle?

MR. MOYLE: Thank you, Chairman Johnson. For the record, my name is Jon Moyle with the law firm of Moyle, Flanigan, and I appear before you today on behalf of U.S. Generating Company.

I know the hour is getting late, and I have a few brief remarks that I'd like to share with you and read a statement to you on behalf of the company.

There's been much discussion recently in the state of Florida about the state experiencing a robust competitive wholesale market for electric energy and capacity. Gulf Power recently indicated that it intends to issue a request for proposals pursuant to a PSC rule, Rule 25-22.082, for competitive bids to meet Gulf's next plan generating requirements.

Remarkably it should be noted that this is the first time that this rule, commonly referred to as the competitive bidding rule, has been used since it was adopted by the Commission in 1994.

U.S. Generating is of the belief that a truly robust competitive market cannot be achieved unless all electric energy providers, investor-owned utilities, municipalities, cooperative, and independent power producers can compete on a level playing field.

This will not happen until and unless restructuring or reregulation is implemented in Florida; that is until wholesale energy providers can compete head to head on a market priced basis.

I would note that the Commission by its adoption of the so-called competitive bid rule has expressed support for competition in the wholesale electric marketplace, allowing independent power producers such as my client, U.S. Generating, to competitively bid projects apparently not covered by the competitive bidding rule, will further the goal of a competitive wholesale market in the state.

For instance, it's unclear whether the present rule applies to quote, unquote, "repowering projects," such as the one that FPL is proposing for its two existing steam units in Fort Myers.

FP&L's ten-year site plan states that approximately, and I quote, "837 megawatts of new generating capacity will result from this project," end quote. Rather than just accepting that these repowering projects will give ratepayers the best deal, until such time as competitive reregulation comes to Florida, the competitive bid rule should be employed as the already approved mechanism of assuring ratepayers the least cost alternative.

U.S. Generating looks forward to discussing this and other issues with the Commission so as to ensure the existence and furtherance of a truly robust, competitive wholesale market in Florida.

That concludes the prepared statement. I do have a couple of thoughts, that if you would bear with me just for a couple of minutes, I'd like to share with you.

This forum, as I understand it, is pursuant to statute called a ten-year site plan, and it's a time when we look sort of in the future, and utilities come forward with their plans, and just by the very nature, I think it's sort of expansive of, you know, what does the future hold.

We all know that things are changing in the electric industry, and this forum, which is charged with looking 10 years out, I think is a good time for folks like U.S. Generating to come forward and to talk about the changes in how we believe things can be better by instilling some additional competition.

I found it interesting that, you know, you had a large consumer of electricity, a customer, and a large employer of a number of Floridians here today tell you that their business operations were interrupted 10 or 11 times in one month and that that was a hardship on them, and they were asking, as I thought I understood it, for some kind of relief.

I think that we need some additional capacity in Florida and that folks like my client ought to be able to step up to the plate and to provide that capacity in a way that doesn't put ratepayer dollars at risk. If we can finance it and we can build it and whatnot, I think we ought to be given that opportunity.

Just concluding, it struck me after hearing the comment from the gentleman from IMC-AGRICO that, you know, Florida is a great state, and we've done well throughout the years because of our location, our geography, the sunshine of attracting a lot of people here and a lot of businesses; but it's becoming more and more competitive in that regard.

The Mercedes-Benz plant, a couple years ago there was a lot of Competition as to where to locate that plant, and I think South Carolina won. But in the south, you know, industry is sought after. I would think that if an industry today is looking around as to where to locate, that if they were here today and heard the comments from a large electric user that they did not enjoy a steady, dependable source of energy, that that would be of concern to them.

And as Ms. Elder pointed out, you have the Sustainable South Florida Commission and they've kind of charged you all with setting forth the policy, the energy policy for the state. And we would urge you as you go forward and as the electric market changes, to look at these things and to be progressive in your thoughts and your actions as we go forward.

And we look forward to continuing this dialogue, and thank you for bearing with me at the end of a long day. Thank you.

CHAIRMAN JOHNSON: Thank you, Mr. Moyle. Any questions?

(No response.)

CHAIRMAN JOHNSON: Thank you for your presentations. Staff?

MR. HAFF: I just wanted to give a summary of the time lines we have for the review of the ten-year site plans.

As I answered Commissioner Deason before, we're currently set to have this review -- I guess it will be a draft -- for consideration at the Internal Affairs on November 30th.

Statutory requirements call for this report to be sent to DEP by December 31st. So that's the last activity I guess we have on this case until we go to Internal Affairs.

MR. BALLINGER: I'd like to add to that, too, for Ms. Swim, Ms. Elder and Mr. Moyle, if you have written comments you want to submit to Staff, get them to us as soon as you can so we can include them in the report; because even though Internal Affairs is November 30th, that probably means end of September we have to file it, by the time we get copies. I'm not sure, but we have quite a bit of time in there that we need to file it ahead of that, so we need those as soon as possible.

CHAIRMAN JOHNSON: Is that it?

MR. HAFF: Yes.

CHAIRMAN JOHNSON: With that, this workshop is adjourned. Thank you.

Staff, as usual, excellent job.

(Thereupon, the workshop adjourned at 3:40 p.m.)

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, H. RUTHE POTAMI, CSR, RPR Official Commission Reporter,

DO HEREBY CERTIFY that the Ten-Year Site Plan Workshop, undocketed, was heard by the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 173 pages, constitutes a true transcription of my notes of said proceedings.

DATED this 24th day of September, 1998.

H. RUTHE POTAMI, CSR, RPR
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