BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION WORKSHOP

UNDOCKETED

In re: Commission Review of Electric Utility Ten-year Site Plans.

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COMMISSION WORKSHOP

The above-entitled matter came on to be heard before the Florida Public Service Commission, Honorable SUSAN CLARK presiding as Chairman, at Room 148, the Betty Easley Conference Center, 4075 Esplanade Way, Tallahassee, Florida, on the 16th day of August, 1996, commencing at approximately 9:40 a.m.

Reported by:
RAY D. CONVERY
Court Reporter

P R E S E N T

SUSAN CLARK, Chairman

JOE GARCIA, Commissioner

JULIA JOHNSON, Commissioner

TERRY DEASON, Commissioner

DIANE KIESLING, Commissioner

P R O C E E D I N G S

COMMISSIONER DEASON: If I can have everyone's attention, please, we'll call the workshop to order and ask you to take your places. We will begin by having the notice read.

MS. ERSLING: This time and place was noticed for the Commission workshop on the ten -- electric utility ten-year site plan. The purpose is the Florida Public Service Commission has jurisdiction over the determination of overall suitability of ten-year site plans pursuant to Chapter 95-328, 1995 Laws of Florida, effective July 1, 1995. The purpose of this workshop is to afford an opportunity for public comments on the ten-year site plans submitted by Florida's electric utilities. At the workshop, the utilities will describe their plans, the key assumptions underlying the plans, and the impact of demand side management goals on the plans.

COMMISSIONER DEASON: Okay. Thank you.

I'd like to take this opportunity to welcome everyone to the workshop today. There is an agenda that has been prepared. Obviously, I am not Chairman Clark. She is not with us at the moment. She does plan to join us a little bit later. She did recognize she had 15 minutes on the agenda. So she gave me a speech to read, but she told me I could dispense with it if I wanted to, so I will. I'm just kidding. She really did not have any formal comments, and neither do I other than to welcome you to this workshop today.

We are not going to take appearances, but this workshop is being recorded by a court reporter. Therefore, it is necessary for you to identify yourself. If you make a presentation, please identify yourself before you make a presentation. If anyone has any questions, please identify yourself before you ask your question. There is a remote microphone that is available for those who are seated in the audience who wish to avail themselves of that, and there are plenty of empty seats and microphones available at the front as well.

We certainly are glad that you are here and encourage your participation. That is what this workshop is all about. We have had a few logistic problems as far as some of the equipment with the presentations and overheads. It may be necessary at some point to take a break and allow some of those problems to be addressed, but I think basically we are ready to begin, and with that, I'm going to turn it over to staff to take it from this point.

MR. HAFF: Thank you. I'm Michael Haff. I'm with the Commission's staff, and today we will be hearing brief presentations from each of the utilities that filed ten-year site plans.

The first presentation we'll hear is from the Florida Coordinating Group, and Tom Hernandez, who is the manager of the Generating Task Force of the FCG will be giving that presentation; but before we begin, I just want to ask that, if there are questions that are specific to a particular utility's plan, then we will have an opportunity after each utility has given their brief presentation to ask those questions. Otherwise we have reserved time this afternoon for comments of a general nature.

Before we start, I just wanted to -- Todd Borman is passing out something that the staff has put together just to aide the Commissioners in understanding the presentations you're going to hear today, and it relates to the fuel prices. Fuel prices are the single most important factor that affects the type of unit that a utility builds in their plan, and as I said, to assist you with understanding why utilities have certain units in their ten-year site plan, this will just assist you to give you kind of an overview of the fuel price and how that drives the unit choice.

And with that, I guess we can start with Mr. Hernandez.

MR. HERNANDEZ: Good morning, Commissioners. My name is Thomas Hernandez. I'm the Director of Resource Planning at Tampa Electric Company, but this morning I'm going to represent the Generating Task Force of the Florida Coordinating Group.

I'm going to present a very brief overview of the 1996 FCG ten-year plan that was prepared earlier this year. I've left copies of the presentation on either side of the room, and I believe each of the Commissioners should have a copy as well. I'm not going to go through all the pages that are in the handout, just to be brief. I'll try to hit the highlights.

This is a graphic illustrating the projects for firm peak for peninsular Florida, and so it accounts for all the conservation and load management and interruptible customer load reductions, and this is the basis for planning new resource in Florida. And what we're showing here is very similar to what we showed last year for both the winter and summer firm peak. We're still indicating that we are a winter-peaking system for peninsular Florida, but we can have excursions, as shown in the history. You can note the excursion in the 1989 winter, the Christmas freeze, the high increase in the winter peak. We do not forecast weather excursions. We do that on a normalized weather basis. This is very consistent to what you saw last year.

As -- excuse me. As I just mentioned, the conservation and load management self-service cogeneration qualifying facilities have a significant impact in terms of reducing the total demand for peninsular Florida, showing the values expected for this upcoming '96-'97 winter, and out after ten years what we expect to see, almost a 50 percent increase in the curtailable load or interruptible load; and, again, that helps to defer the addition of new generating plant in the state.

A similar story for the energy reduction in peninsular Florida, primarily driven by the self-service cogeneration, as well as the conservation effort. There is very little energy reduction associated with interruptible load and load management.

Just a quick look at where the generating -- installed generating capacity is in the state. The three investor-owned utilities for peninsular Florida comprise approximately 78 percent with the balance with municipal systems, cooperatives and other smaller utilities.

A quick look at the resource mix for peninsular Florida. This includes firm purchased power as available power. Again, the conservation effects, the load management, interruptible load, and the firm purchases from non-utility generators. We're showing that approximately 83, 84 percent of the generation or energy sources will be provided by self-owned/installed generating capacity in peninsular Florida.

This next graphic is generation by fuel type on a gigawatt-hour basis. Looking at it in 1996, we see the emergence of a new fuel type, petroleum coke, and going out looking at in ten years the impact of petroleum coke and orimulsion, primarily on the Tampa Electric and the Florida Power & Light systems, but contributing close to six and a half percent of the energy needs for peninsular Florida.

COMMISSIONER DEASON: Let me ask you a question. The orimulsion percentage for 2005, is that -- was that projection made before or after the decision recently made by the Governor and Cabinet?

MR. HERNANDEZ: It was made before. I believe Florida Power & Light's planning process was -- occurred well before the April, 1996, filing of the ten-year site plan. So in their ten-year site plan that was filed, that was included as projected fuel.

This next chart is a graphic illustrating the incremental resource mix over the next ten years for peninsular Florida, showing about 43 percent of combined cycle capacity, most of that fired by natural gas or syngas, as well as distillate oil as a backup fuel. You see a fairly good contribution for the conservation, about 27 percent, on load management, interruptible load and the balance of conservation programs.

A quick look at the projected firm peak, winter reserve margins for peninsular Florida. We see a decline in the reserve margin over time but we're still at or above 15 percent on a firm basis. And, again, looking at the planned capacity additions of combustion turbines and combined cycle units, those have relatively short lead times for construction and for planning purposes, and there is significant siting capacity that's already been developed or under way. So we feel like, from a reserve-margin standpoint, that we're in good shape for peninsular Florida.

And the last graph I'll show is the relative change in the firm peak winter reserve margin compared to last year's ten-year site plan to this year's ten-year plan aggregate, and we see a slight decrease in the 1996 plan that was compiled, but, however, as I just stated, we're still at or well above the 15 percent planning margin criteria, and that's not the planning margin criteria for each of the utilities, but that is a benchmark that SERC and other reliability regions have looked at.

And that's the end of my presentation, if you have any questions.

COMMISSIONER DEASON: Questions for Mr. Hernandez?

MR. HERNANDEZ: Thank you.

COMMISSIONER DEASON: Okay. Thank you.

MR. HAFF: Okay. We can go ahead and start with the individual utilities' presentations of their ten-year site plan, and first we'll hear from Florida Power & Light Company.

MR. ADJEMIAN: Good morning. My name is Bobby Adjemian. I am the Manager of Resource Planning for FPL, and my presentation this morning will cover briefly the 1996 ten-year site plan. I'd like to add here that the presentation you're seeing and the elements of this plan are the results of studies that were conducted about a year ago. Tom alluded to that, following up to your question. So those types of studies are currently under way, and some of these elements may be modified depending on what the conclusion of the studies will show.

I'll skip to page 2. The 1995 site plan had presented a need for new capacity in the year 2004, but there have been several key assumption changes. Our load forecast came in slightly higher. The availability -- which caused the need to move up in time. The availability of our units through better management of scheduled outages was able to push the need back a little bit, and finally, in trying to reflect in a more conservative manner the increased accessibility of the transmission system, we decided to restrict the amount of transmission capacity, and that tended to move the need up again. The net effect of all these changes has been to move the capacity need for Florida Power & Light to 2005.

COMMISSIONER DEASON: I'm sorry, what was it before?

MR. ADJEMIAN: 2004.

The major elements of the resource plan over the next ten years as presented in that report is -- consists of supply-side additions totalling 1690 megawatts and then demand side management additions totalling 1225 megawatts.

On the next page you see a distribution of the

1690 megawatts of supply-side additions over the next ten years. You see 2003 being the new need date, and at this point we're showing that that need will be met with a capacity purchase -- a short-term purchase. Following that, we're showing the proposed construction of the two combined cycle units in our Martin plant.

The 1225 megawatts of DSM is the amount that was ordered -- as ordered by the Commission to Florida Power & Light to achieve for DSM programs and as was filed and approved by the Commission, is -- are the targets that you see here on the cumulative basis, on a year-by-year basis.

The resulting plan produces a fuel mix that -- about the only thing here I could point out is that we are achieving an increased diversification -- we're hoping to -- and reducing reliance on oil primarily by committing into the orimulsion fuel.

COMMISSIONER DEASON: I'm going to ask you the same question. I mean, I know it's early in the process after the decision. Do you have any preliminary estimates of what the fuel mix is going to be, assuming orimulsion is not available?

MR. ADJEMIAN: Commissioner, you can assume that all that would come from oil if orimulsion is not approved. FPL, however, is still optimistic that that would be a project that will eventually be approved, we think, you know, as to the best interests of our customers.

The resulting reserve margin for the summer shows a declining trend but still above the 15-percent level, which is one of our reliability criteria for the summer.

This concludes my presentation, if you have any questions.

COMMISSIONER DEASON: What about the winter margins?

MR. ADJEMIAN: The winter reserve margin comes in a little lower. It is a -- long term, about 12 percent. That is not one of our criteria. Florida Power & Light -- the Florida Power & Light system is stressed primarily in the summer, and that's due to the long, extended peak duration, as opposed to the winter when we usually experience a peak demand that lasts maybe two hours and -- which is usually the result of a cold front as well, and allows for interchange power to take place and be able to share into reserves of other utilities and helps meet that demand.

Additionally, in the winter, our power plants have typically exhibited higher capabilities because of the ambient temperatures, and that's another way of meeting the winter. So even though the reserve margin appears numerically to be somewhat low, it's not a significant issue for FPL as compared to the summer.

MR. HAFF: Before we leave that point, I have a question about that graph you just had up there. Now, in one of the ways you addressed the concern of the low winter reserve margin in the out years was by relying more on interchange, is that correct?

MR. ADJEMIAN: Somewhat, yes, yes.

MR. HAFF: I guess -- help us with -- I have this concern that, if you're relying on interchange at a time, due to cold weather, that every other utility in the state will also be relying on interchange, and further, I guess you'd be buying from Southern, they would not -- if they're having a cold front, would they have the excess capacity to sell you during those critical times?

MR. ADJEMIAN: Yeah. What we have found in the past -- because that has happened several times in the winter -- we do experience -- although not year in, year out, but we do get some cold, like this last winter that we had. Typically it is a -- it's a cold front, and the cold front is not that -- geographically speaking, it doesn't cover a very large region. So typically what happens is we -- as the cold front comes down into the state, we end up -- the pattern is we end up selling power early to the north, like, for example, places like maybe Tampa Corporation or even Southern Companies, and then later on turn around and we buy it back from them because we experience the cold. So that seems to be -- it has worked in the past pretty well. So hopefully we'll continue doing that and -- unless we get some massive cold that covers everything, but that has not really happened. I mean, if it has happened, maybe it was in 1989. It's not something that happens maybe more than once in a long, long period of time.

MR. HAFF: Thank you.

MR. ADJEMIAN: Sure. Any other questions?

COMMISSIONER DEASON: The firm capacity purchases which are shown for 1996, 456 megawatts --

MR. ADJEMIAN: Yes.

COMMISSIONER DEASON: -- what does that represent?

MR. ADJEMIAN: The 456 megawatts consists of three QF contracts, the Indiantown contract, which is a 330-megawatt coal-fired unit. That's already in operation. So that 300 is part of the 456. The remaining amount consists of two contracts. One is in Ocuola (phonetic) -- I'm sorry -- Okeelanta and the

Osceola facilities of -- consisting of -- summing up to about 120 megawatts, and those are currently in test operation, and by contract they are supposed to be on line by January 1st of '97. So -- but we expect they'll probably be on line before then for commercial operation.

COMMISSIONER DEASON: You do expect them to meet those dates?

MR. ADJEMIAN: Right, yes, we are. They've been in commercial test -- in test mode since November of last year, so --

COMMISSIONER DEASON: Further questions?

MR. WRIGHT: I have a few.

COMMISSIONER DEASON: Please identify yourself.

MR. WRIGHT: Sheff Wright with the Landers & Parson law firm, appearing on behalf of Lee County, Florida.

Mr. Adjemian, it's Lee County's understanding that FPL has not evaluated the cost effectiveness of its DSM program since 1993. If this is correct, I'd appreciate your confirming it, and if it's not, I'd appreciate being straightened out; and then if it is correct, I'd ask when FPL plans to reevaluate the programs based on current avoided costs?

MR. ADJEMIAN: Yeah, you're understanding is correct. It's a 1993-'94 -- just prior to the goals docket was the last time that we analyzed the cost effectiveness in full detail. Of course, following that, what happened is we had -- you know, we were waiting for the Commission to review the entire and complete the entire docket proceedings and issue an order, which I think was at the end of -- close to the end of 1994, and then in 1995, FPL, pursuant to the order and the targets, filed for specific programs to meet those targets. Those were -- those were finally approved late last year, I think around November. So this year we basically started rolling out the programs and we're beginning to put them in place.

So the next time -- to answer your second part as to why or when we're going to reevaluate those, currently we're taking a look at the -- at those DSM programs and -- but, as to whether we're going to and what extent we're going to do the review, that's not yet decided because, as I said, the process is somewhat -- as you've heard, the process is somewhat lengthy, and to try to change and stop and change and reanalyze and start again may not be really a practical thing to do. So we need to -- we'll have to decide -- we'll have to see how far we can -- or how long we'll have to wait before we complete the study or the reevaluation of the cost effectiveness of these programs.

MR. WRIGHT: I have a second question relating to FPL's evaluation of potential purchased power options. It has been my understanding that FPL, in its planning processes with regard to unspecified future purchases, generally evaluates such purchases based on avoided costs of FPL's best self-build option. Is that still correct?

MR. ADJEMIAN: The unspecified purchase that I'm showing in this resource plan is based on specific offers that were provided to FPL by power suppliers which indicated that, for that time frame, there would be capacity that would be available to FPL that -- at terms that would be favorable to FPL. Specifically the purchase that we're showing here is what we would call a seasonal purchase. We would buy maybe one or two months in the winter and then again maybe three or four months during the summer period, and apparently the suppliers feel that that's available. The costs seem to be in line. We have not done and we will not do that type of an analysis until we're ready to commit to a purchase, which we're not ready yet, but we have to compare that against the construction of a plant that would carry a cost, of course, year round.

So -- I mean, giving you a lengthy answer here, but eventually we'll be -- I'm not sure -- there would be an economic evaluation performed to find out which particular short-term purchase we'd commit to, but right now we feel comfortable that that level of purchased capacity will be available in the time frame.

MR. WRIGHT: Thank you.

Does FPL evaluate long-term purchase opportunities in its planning and, if so, on what avoided cost basis?

MR. ADJEMIAN: Well, we're showing here -- we're showing here that our proposed plan shows construction of combined cycle units. Of course, with the advent of the bidding rule that's -- it may or may not happen, and at that time there would be an evaluation of what power suppliers would provide in lieu of this capacity, which could be viewed as the avoided capacity, and that's when the evaluation would take place of long-term contracts or short-term contracts, however we package the power supply deal to offset or avoid this capacity, if that is a more economic thing to do.

We may end up building our own plant is what I'm saying, maybe. It's one possible outcome.

MR. WRIGHT: Yeah. If it's the most cost effective option, that's exactly what you ought to do.

Thank you.

COMMISSIONER DEASON: Further questions?

MR. McNULTY: I have a question. My name is Bill McNulty. I'm with the Commission staff.

My question has to do with the energy forecast, and specifically on page 1 of 3 of Form 2 in the ten-year site plan, the average kWh consumption per customer for the residential class increases 16 and a half percent over the historical period of the last ten years but increases six and a half percent over the ten-year forecast period.

I was wondering if you would give us some indication as to the reasons for that declining increase in use per customer?

MR. ADJEMIAN: Well, I guess I will give you what I think is part of the reason and we'll see if we can get you a little more detailed reason, but -- later on, but I think part of the -- part of what's reflected in there is the effect of the load management programs that are going into place, the conservation programs that are going into place, as well as the assumption that we make that the increased appliance saturation in homes consists of more efficient appliances as time goes on. So the incremental change may be not as large as it was in the past, and those may be some reasons why that would happen, but I'd have to get back to you with a more detailed response from our load forecaster as to what the specifics is behind that.

MR. McNULTY: So that would be both increasing appliance efficiencies as well as appliance saturations as two separate reasons for this apparent trend?

MR. ADJEMIAN: I don't know.

MR. McNULTY: Thank you.

COMMISSIONER DEASON: Further questions? Thank you.

MR. HAFF: Okay. Our next summary of the plans will be from Florida Power Corporati n.

COMMISSIONER GARCIA: Does Florida Power Corp. have a handout by any chance?

MR. RIB: Yes, we do.

Good morning. My name is Mike Rib. I'm with Florida Power Corporation. I'm the Manager of Generation Planning, and good morning, Commissioners, good morning staff. I want to very briefly present some of the highlights from our 1996 ten-year site plan.

Florida Power Corporation's planning criteria in the 1996 planning horizon remains the same as it has in the past. We're including both the 15-percent reserve margin on seasonal firm peaks, and those firm peaks historically have occurred in the winter, as well as a loss of load probability limit of .1 days per year. In our planning we also constrain operation scenarios to meet the EPA total SO2 limit for the year 19 -- or for the year 2000 for clean air.

This shows the total summer peak demand. We show it growing at a moderate rate somewhere in the neighborhood of two percent, and these are our system peak demands. You see that the historical and the forecasted trend weld together.

This was the winter system peak demand. Of course, as we've seen in the state summary and also the Power & Light summary, the winter peaks are a lot more sensitive, but you can see that our forecast trends nicely with our historical experience.

One of the items we show in the new forecast where the forecast drops off in the year 2002 demonstrates some anticipation of reduced wholesale sales. So that is something that we are taking into account is forecasting retail and wholesale.

The retail growth rates are pretty consistent throughout the planning period. The wholesale is a little more volatile, as I think we've seen in our experience.

Net energy for load also trends at about two percent, and you can see a very similar pattern.

This is looking at 2004, the end of the ten-year planning period, looking at our capacity resource mix, fossil steam remaining roughly the same, increasing slightly, qualifying facilities showing full participation from the contracts that we have, the -- demonstrating the increase in DSM we anticipate having on line at that time, as well as continuing the purchased power agreements that we currently have.

Now at the end of the planning period on an energy basis, you can see the predominant fuel consumption is coal. This has changed a little bit since 1995 in that, with a slight reduction in our energy forecast over this period from what we had last year, the natural gas additions to the system have been deferred a few years, and that causes a slight shift in terms of the oil and natural gas ratios from what we had last year.

The DSM cumulative capacity reductions are noted here for both summer and winter, representing the goals from the Commission's goals hearings, and that's what's included in our plan. This is incremental above what's currently in place.

A couple of other changes to note between the '95 and the '96 ten-year plans. Intercession City is a peaker site in central Florida. Last year we converted two of those units to dual fuel capability, and this year we've converted an additional two. That allows us to operate on natural gas when it's available. It's less expensive and it's a very attractive dual fuel choice location.

We increased our partial requirements contract with Seminole Electric for a three-year period, '99 through 2001, by 455 megawatts, and that wholesale power sale is just a short duration.

We've also shown -- as a result of the load forecast change, we've included Turner and Higgins repowering, but they've shifted back. That's the -- those were the natural gas generation choices that were in the '95 plan. I think, Commissioners, you'd note that that -- or your staff may have mentioned to you that the Turner and Higgins plants have been retired very recently, just in the last couple of months. That does not preclude them from repowering in the future. They still represent a choice for us. At the same time, they may very well be competing with Greenfield natural gas combined cycle plants, and with all the information we're getting in as we've purchased our new units, it gets more and more competitive every year as the prices of the new combined-cycles come down. So that's a very close call, but it's still an option that's available to us.

One other note I might add that's off the sheet is that the Polk County unit was originally two individual 235 megawatt single combined units. As we evaluated that project and looked at the cost of having two separate units rather than having a single unit built in '98, the economics were overwhelming in terms of the less expensive equipment, the less expensive construction cycles, to go ahead and install that plant as a two-by-one combined cycle and bring it into service in 1998.

There are some generating capability changes that are driving the plan. There is just a minor adjustment in capability at the nuclear plant, and then the fuel conversion. One of the other drivers towards the back end of the plan is some retirements are anticipated, and these are directly from our current -- currently-filed plant retirement study. One of the things that we have to do is revisit that study, I believe, in 1997, and we'll determine if all of these facilities will, in actuality, be retired at their proposed retirement dates. Most of these are peakers, or they're all peakers, as you can see.

The new power plant capability that's in the 1995 plan includes Intercession City P-11, which is currently in service; Polk County Unit 1, coming in service, November, '98; and then beyond that, a combustion turbine in the fall of 2003, followed by repowering of Turner and Higgins, and then topped out with a combustion turbine project in the fall of '95. So that keeps us as at our 15 percent reserve margin criteria, as well as loss of load probability.

A brief update on the Siemens 84.3 combustion turbine. That is a brand-new technology, a combustion turbine at our Intercession City cite. We had some trouble with it this spring that some folks in the room are probably aware of, some firing problems with the oil burners on that unit. It's Serial No. 2, so sometimes that can be expected. Those problems, to the best of our knowledge, have been resolved and the unit's operating reliably this summer in a test and start-up mode. So the test and start-up actually began the 29th of July. That's moved our official acceptance back to November for a commercial operation, but we feel very comfortable with those target dates.

On our Polk County project, we began site development November, '94, and site development at the time of writing of this contract or -- I'm sorry -- of this report was 80 percent complete. It's -- site development is currently substantially complete absent pouring foundations for the power blocks. So the site development, the cooling ponds and a lot of the environmental mitigation work has been done, and they're currently filling cooling ponds at this time. The power plant equipment contracts for the combined cycle have been awarded to Westinghouse, and natural gas transportation has been secured for the project through both permanently released capacity and any required pipeline expansion that FGT needs to supply. I think FGT makes the final determination of how to bring that capacity to us, but we do have the necessary capacity under contract.

Finally, just a quick look at reserve margin summary. You can see they are dropping towards the outer period, but they are shown to maintain the 15 percent reserves based on our winter criteria. I think enough comments have been made this morning about shorter lead times on equipment and so forth, so we're not as concerned about the outer year periods in terms of meeting the resource requirements.

Those are all my comments, but I'm available for questions.

COMMISSIONER DEASON: Questions?

MR. GING: I'm David Ging with staff. I have a question about the capacity you say is under contract with FGT. Would that include the Phase 4 expansion?

MR. RIB: That's something -- I'm not the expert on that, but that's something that's recently negotiated with Citrus, and I believe that Citrus will make the final determination whether Phase 4 is required, and I guess that will come before this commission. I don't know if that's going to be required or whether they'll be able to go back into the market and get adequate release capacity and allow them to defer that expansion.

It may be that some folks on staff here know more about that than I do, though. If you'd like, I'll follow that up and get more clarification.

MR. GING: Okay.

MR. BALLINGER: Tom Ballinger with the staff. Do you have any preliminary results of your reverse RFP to the cogenerators that you sent out?

MR. RIB: I'm sorry, I don't. That area is in a different area of the company, and I didn't come prepared to speak about that. If you'd like, I'll have somebody from our company contact you.

MR. BALLINGER: That's okay. I've seen some correspondence back. I can check with that or I can check with Robert Dolan at the company.

MR. RIB: Either Robert Dolan or Sam Nixon would be fine, yes.

MR. BALLINGER: Okay. Thank you.

COMMISSIONER DEASON: Tom, did you say "reverse RFP"? What did you say?

MR. BALLINGER: Reverse RFP. There are -- several of FPC's co-gen contracts are higher than today's avoided costs, and FPC has gone and tried to buy back or buy down some of those contracts to see if there's any interest.

MR. RIB: Yeah, that's essentially correct.

MR. McNULTY: I have a question. Again, Bill McNulty, Commission staff.

A similar sort of question to that which we asked to Florida Power & Light regarding Form 2 energy consumption. The average kWh per customer increased in the historical period 18 percent over the last ten years and is increasing eight and a half percent in the forecast horizon.

Can you give an indication why there's this change in the rate in increase in usage per customer?

MR. RIB: I don't think I could give you a better answer than Mr. Adjemian did. The forecasting area is not my expertise, but I think -- I've heard a lot of the same discussions in terms of appliance saturation and impacts of load management. So it very well could be the issues at hand, but I would be happy to follow that up, if you'd like.

MR. McNULTY: Thank you.

MR. WRIGHT: Thank you, Commissioner Deason. Again, Sheff Wright, representing Lee County. Just a couple of questions, Mr. Rib.

MR. RIB: Sure.

MR. WRIGHT: I'm looking at your chart that describes your integrated resource planning process, which is the second page in your package.

MR. RIB: Okay.

MR. WRIGHT: I just want to understand how FPC treats DSM programs in developing its integrated optimal plan, then I'll get to the real point. Do y'all reevaluate DSM programs based on current avoided costs in each annual planning process?

MR. RIB: Typically we don't do that in each annual planning process. Every few years we'll go through a more rigorous exercise. In recent years we've been through the same proceedings in terms of setting the goals for the Commission for DSM targets as well as having gone through that in terms of costs -- cost adjustments that were necessary for that rate. I think we've done quite a bit of work on that.

But in this 1995 plan, we did not go through a future evaluation. We simply integrated the DSM targets and looked at primarily the supply side.

MR. WRIGHT: But am I correct that you did evaluate specifically the load management program? And I may be -- I think load management you did reevaluate and modify based on the fact that it wasn't cost effective, is that right?

MR. RIB: Well, that was what went into the rate adjustments that were proposed and didn't go into effect last year. They did not affect the targets for capacity and energy reduction, but they did affect the pricing signals in terms of our customer rates. So you are correct.

MR. WRIGHT: If you have a plan as to when you intend to reevaluate your DSM programs based on whatever the current avoided costs are at the time, when would that be?

MR. RIB: I can't say that for sure. I imagine, since that we're at that level of depth in terms of looking at those programs every few years, I'd anticipate that coming up probably in '97, possibly in '98.

MR. WRIGHT: Thank you.

Does FPC evaluate unspecified purchased power options as part of its integrated resource planning process?

MR. RIB: We really didn't in the '95 planning process. We've started to bring more of that information up to the surface and look at it in our current planning processes. I think that it's clear that, in the wholesale power markets, there are going to be market-based products that are available that are alternatives to new construction, and those will be looked at as the needs arise. So we are looking at them more and more.

We talk to the suppliers directly to see what type of options are available. We communicate with the suppliers we're currently contracting with to make sure we're up to date on what options are available from them. So I do believe that, going forward, the market will offer opportunities that we will certainly consider as we evaluate our needs.

MR. WRIGHT: Okay. Thank you. Just one more question.

To what extent, if at all, does your plan reflect consideration of the possibility of federal legislation affecting competition in the electric industry, say the Schaffer Bill or the Markie Bill?

MR. RIB: Well, I'd say that the '95 planning process probably was not as sensitive to that as some of the work we've begun to do more recently. We try to anticipate that, although a lot of the regulatory issues are really here in Tallahassee. So that would need to be dealt with appropriately.

The most important thing you can do is just try to anticipate different types of market conditions and different types of market structures and try to make sure that your planning is robust and not necessarily particularly tied to a particular scenario. So I think we're doing more of that, but that's something we're learning. I don't really think it's reflected much in the '95 plan.

MR. WRIGHT: Thank you.

COMMISSIONER DEASON: Further questions?

MR. RIB: Thank you.

COMMISSIONER DEASON: Thank you, Mr. Rib.

MR. HAFF: Our next presentation will be from Tampa Electric Company.

MR. GATES: My name is Paul Gates. I'm the Manager of Generation Planning within the Resource Planning Section of Tampa Electric Company, and I'm here representing Tampa Electric Company.

Starting off with the demand and energy forecast, which is a primary driver to the ten-year site plan effort, I've shown a comparison of winter and summer firm peak as well as net energy for load as it relates to last year's ten-year site plan relative to this year's.

As you can see on the overall change between the two ten-year site plans, there is a nominal difference between these two forecasts. We are projecting effectively the same type growth rate as well as outlook for our area in the peak demand area.

Net energy for load in 1996, we have changed that energy down by 63 gigawatt hours. That is primarily driven by specific customer activities within our service territory, notably Florida Steel leaving our service area throughout the years 1994 and '95, and those have been captured in the 1996 ten-year site plan.

Long-term we're going to have a little bit stronger growth in our net energy for load, and that is going to put us back on track with what we were projecting last year.

MR. HAFF: Mr. Gates, we're having trouble hearing you over on this side of the room. I was jut wondering if you could speak up a little. Thank you.

MR. GATES: Okay. Looking at existing generating capacity owned by Tampa Electric Company, we currently have 3404 megawatts of capacity. 86 percent of that is coal. Seven percent is No. 6 oil, as represented by our Hooker's Point Philips Station, and on the No. 2 oil, which is represented by our CTs at the Big Bend and Gannon Stations. This does not include the Polk unit as this was relative to January of '96.

Serving -- the energy generated by Tampa Electric Company in 1996, we expect 92 percent of that energy to come from coal-fired resources, one percent from oil, two percent from purchases, approximately three percent from cogeneration, and we currently expect approximately two percent of that generation to come from petroleum coke, which is currently being burned at our Big Bend Station.

In the year 2005 we'll expect that pet-coke generation to increase to 9.5 percent, and that is associated with the Polk Unit 1 petroleum-coke blend at that station, and that will reduce our coal generation down to 83.7 percent versus the 92.

Demand reduction alternatives: Currently we have a pretty even balance between dispatchable demand side management on the load management and interruptible. Conservation is representing approximately 31 percent of those demand reduction alternatives. We're expecting that to grow by up to 42 percent as per the conservation goals that will be taking effect.

Looking at the summer demand reduction alternatives on our system, we currently have a much smaller percentage of the conservation type activity. Given that it's a smaller base of overall demand reduction in terms of megawatts, that is going to take on a greater percentage of our overall mix associated with this area.

Tampa Electric currently has a dual reliability criteria, .1 net assisted loss of load probability, or one day in ten years, a minimum 20 percent firm winter reserve margin that we will meet through this process.

Our expansion plan and capacity additions that we expect, we've shown a comparison here between 1996 and 1995 ten-year site plans. Given the slightly lower energy forecast as well as the slightly lower demand, firm peak demand forecasts, primarily driven by the conservation efforts, we will be able to push the previous 2001 CT to the year 2002. We are assuming the Hardee Power Station Unit 2 build-out and at the same time we will be retiring Hooker's Point for the purposes of this study.

Looking at the specifics of how this system reliability criteria plays out with these capacity additions, you can see that we have met all the criteria that we have laid out in our dual reliability criteria with the first CT, again, being added in the year 2002.

Looking at it from an overall integrated resource perspective, we're looking at a total demand requirement on our system of almost approximately 4900 megawatts, increasing by approximately 1,000 megawatts to the year 2005. The capacity mix between these two is approximately the same, 69 percent in 1996, a total of 65 percent out in the year 2005, demand reduction alternatives increasing coincident with that, and purchases specifically related to firm contracts and the Hardee Station build-out climbing to 10.2 percent.

Looking specifically at the incremental additions to our system associated with that resource expansion, 40 percent of that additional demand will be met through generating capacity additions, 42 percent associated with demand reduction alternatives, and 17 percent of that met by new purchases.

I have one additional slide here that is not in the packet, and it's just a quick update on the Polk power station recent accomplishments and where we are to date on that.

The combustion turbine was fired on No. 2 oil April 20th of this year. The combined cycle exceeded the guarantee on number oil -- on capacity by four percent. The heat rate was 2.5 percent better than the guarantees.

We made our first syngas on July 19, '96, as per the schedule, and the initial gasifier run was approximately 22 hours, which was one of the longest first runs of the Texaco technology, and syngas to the combustion turbine is expected sometime early next week.

That concludes my presentation.

COMMISSIONER DEASON: Mr. Gates, I have a question concerning your reliability criteria and the minimum 20 percent firm winter reserve margin. Why is your target 20 percent as compared to some of the other utilities which are having a target of 15? Is it because your winter peaking as opposed to Power & Light being basically summer driven, or is it the big difference is in the size of the utilities? What causes that?

MR. GATES: I think one of the drivers is that we are winter peaking. We are a little more volatile to those weather conditions coming in.

Also, our generation mix are very large units, and to the extent that we can lose a very large unit can have an impact on our sensitivity to that.

COMMISSIONER DEASON: Okay. Thank you.

Further questions?

Mr. Wright?

MR. WRIGHT: Thank you, Commissioner Deason.

Mr. Gates, I want to ask you a couple of the same questions I've asked the FPL and FPC representatives. Has Tampa Electric reevaluated its DSM programs based on current projected avoided costs since the goals hearing?

MR. GATES: Our last evaluation I believe was the '93-'94 time period, and as it stands today, we are currently in the process of evaluating those.

MR. WRIGHT: Based on current avoided costs?

MR. GATES: Yes, sir.

MR. WRIGHT: And that's for your '96-'97 planning cycle?

MR. GATES: That has yet to be determined whether or not that will be complete at that time.

MR. WRIGHT: Thank you.

And I noticed -- or on page 10 of -- the last page, in fact, of your handout, that Tampa Electric is projecting 17.5 percent of its incremental resources between now and 2005 as being purchases. I guess that calculates out to about 210, 220 megawatts?

MR. GATES: Approximately. I'm not sure of that number.

MR. WRIGHT: I did not notice that in the projected resource table. Is that just an unspecified future purchase at this point?

MR. GATES: No, sir. That is actually associated with the Hardee Power Station build-out, which is our most cost effective alternative overall.

MR. WRIGHT: Okay. Thank you.

And, lastly, I would ask what if any consideration Tampa Electric's planning process gives to the federal legislative initiatives regarding the electric industry, say the Schaffer Bill or the Markie Bill?

MR. GATES: All of those considerations are done at a different level, but they are taken into account from a risk and strategic position.

MR. WRIGHT: Thank you.

COMMISSIONER DEASON: Okay. Further questions?

Thank you, Mr. Gates.

MR. GATES: Thank you.

MR. HAFF: Thank you.

Okay. Next on our agenda is a presentation by Gulf Power Company, or presentations by Gulf Power Company.

MR. MARLER: Good afternoon, Commissioners.

COMMISSIONER DEASON: I believe it's good morning.

MR. MARLER: Good morning, I'm sorry. My name is Mike Marler. I'm with Gulf Power Company. I am their principal load forecaster. I'll be presenting the company's forecast that went into the '96 ten-year site plan, and my colleague, Bill Pope, will present the resource plan to meet those needs.

COMMISSIONER KIESLING: Excuse me. You need to give a copy to the court reporter.

MR. MARLER: The major assumption changes that are incorporated into this forecast include involving the recent Base Realignment and Closure Commission decisions. Additionally, we incorporated the latest demand side management plan approved by the Commission. Our previous ten-year site plan did not incorporate the goals that were approved in '94. This one does.

Currently Gulf's makeup between the classes, the residential energy share represents approximately 43 percent of our total net energy for load. Commercial is approximately 29 percent, industrial 19 percent. Street lighting is very small at two tenths of a percent. Losses and company use represent about 5.2 percent, and our wholesale sales represent 3.6 percent in 1995. So we're primarily a residential company.

Our customer growth expectation in the '96 ten-year site plan reflect a 2.2 percent compound average annual growth rate expected over the next ten-year period as compared to 2.4 percent historical growth.

Our summer peak demand projections -- this reflects with and without the demand side management programs. Historically, without the DSM programs, we would have seen approximately 2.6 percent compound average annual growth, and 1.6 percent in the forecast horizon. With the demand side management programs, we realized a 2.2 percent growth rate and we're expecting a 1.2 percent growth rate with our new DSM programs.

A similar but slightly more dramatic effect on the winter peak demand. Historically we would have seen 2.8 percent, and projected -- expected a 2.2 percent, and we realized a 2.3 percent historical growth and we anticipate a 0.3 percent growth rate in the winter, and that's due to the more heavy impact of the goals on winter peak demand than on summer.

Our net energy for load results reflect a 2.8 percent historical growth rate without DSM programs, 2.7 percent with, and a projected growth rate of 1.8 percent without, and 1.7 percent with DSM programs over the next ten years.

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(Whereupon, Chairman Clark joined the proceedings at 10:45 a.m.)

MR. MARLER: This depicts the resultant energy by class so you can get a feel for the impact on net energy for load by the various growth rates among the classes, residential, commercial, industrial, street lighting, losses and wholesale.

And that concludes my portion of the presentation.

MR. POPE: As Mike described, our forecast is summer peak demand, which is our basis for planning the resource additions for Gulf Power Company system.

This slide depicts how Gulf plans to meet those demand growth needs over the planning horizon. First, starting with a purchased power of 180 megawatts in 1999, which will be sought from the open market, going on down to a 200 megawatt combustion turbine plant in 2003, and then an additional purchased power in 2005, a reduction of some of that purchased power in 2006 with another combustion turbine addition. Over on the right-hand side you'll see Gulf's summer peak reserve margin, and if anybody's got any questions, I'll be glad to address them.

My name is Bill Pope with Gulf Power.

MR. HAFF: Yes, I have a question, Bill. Last year's plan showed your next unit addition as being the Shoals A., correct, at 1998? And this year's plan has been pushed five years into the future to 2003. So, I was wondering if you could explain why that was done and what -- I see the capacity purchase, but try to, you know, give some insight as to why that was done.

MR POPE: Well, as noted in the ten-year site plan, yes, the 1998 and 1999 combustion turbine additions at the Shoals Plant has been replaced with 100 megawatts of short-term/near-term capacity purchases; and the main factor here was that we felt and still feel confident that the purchased power -- short-term purchased power option is, one, less costly and, two, more flexible for the utility at this time when there is some degree of uncertainty in the near term.

MR. HAFF: Have you signed a contract for that capacity yet?

MR. POPE: No, we have not, but we're in the process of preparing an RFP for the market.

MR. HAFF: Okay. I guess my next question is, you haven't identified a specific potential seller of that capacity, if you're going to go through the RFP.

MR. POPE: No, but we have seen others who have gone to the market for very similar type of stuff, and there's plenty out there at this time, we feel confident. We just want to make sure we get out there before everybody else does.

COMMISSIONER DEASON: I have a question. The reserve margins for the years '96, '97 and '98 appear low. Is that -- first of all, why is it that low, and what is the impact of the interchange agreement with Southern Company? Does that remedy this situation?

MR POPE: The reason that the reserve margins for Gulf Power Company are low is because there have been -- with the Olympics and Georgia Power, there are going to be some slight temporary surpluses on the southern electric system, which we're a part of and plan with, and we're allowed and take the benefi_ of allowing that to happen without having to commit to other resource because of these temporary surpluses and deficiencies. The Southern Electric System plans on a 15 percent target reserve margin overall. The smaller companies do get the benefit of not having to add big chunks of power and paying that by leaning on the system slightly.

As far as I see, it comes and goes, and I couldn't tell you if it's positive or negative.

MR. HAFF: Is that -- to follow up on Mr. Deason's question, the winter peak doesn't seem to have as much of a -- pose as much of a problem to your reserve margin. Is that because you, along with the other members of Southern Company, are all summer-peaking utilities?

MR. POPE: We are summer-peaking, and there's quite a bit of natural gas in Alabama and Georgia, which frees up generating capacity during the winter period.

MR. HAFF: All right. Thank you.

MR. McNULTY: I have a question similar to what was asked to Florida Power & Light and Florida Power Corp. Essentially the growth rate in the average use per customer for the residential class, we see that between '86 and '95 it's -- the growth is 11 percent over that entire ten-year time period, and in the future ten-year time period, through 2005, that rate goes negative. It goes to negative one percent. Could you give us some indication as to why you see a negative growth rate here?

MR MARLER: I'll try.

This is graph of what he's talking about right here, and basically what it depicts -- historically we've seen a 1.2 percent growth rate of energy per customer in the residential class. We're projecting approximately a negative .1 percent growth with the DSM programs. Without it it would be slight positive, and the reason for that is primarily driven by, historically we've had an increase in the saturations in residential central air-conditioning. They're reaching the point of saturation. They cannot continue increasing forever, and our residential end-use energy planning model, REEPS, which is an EPRI model, actually simulates things like that. It also incorporates the 1993 appliance efficiency standards and shows those rolling in over the near horizon, where older units become defunct, they get replaced by newer super-efficient units, and the end result of in all this is the residential energy per customer basically holding its own.

There are some increases that are occurring in the other categories, not central air-conditioning or heating, but, rather, other home end-use energy consumption, and this just depicts the net result in that.

MR. McNULTY: Thank you.

MR. HAFF: Are there any other questions for Gulf?

Okay. Thank you.

Next on our agenda is the Alabama Electric Cooperative, and --

CHAIRMAN CLARK: Have you taken a break? Mr. Haff, don't you think we should take a break?

MR. HAFF: Sure, we can take a break at --

CHAIRMAN CLARK: Why don't we do that and break until :05 after 11:00 and we'll start with Alabama Co-op.

(Whereupon, a recess was had in the proceeding.)

CHAIRMAN CLARK: Let's call the workshop back to order.

I was just trying to get some sense of what time is remaining for us to cover what we have on the agenda, and I wanted to get a sense of the next presentations and then the municipal utilities. I'll tell you, quite frankly, what we're doing is contemplating going through lunch and finishing up.

Let me ask you, Alabama Power -- Alabama Co-op, how long --

UNIDENTIFIED SPEAKER: Less than five minutes.

CHAIRMAN CLARK: Seminole?

UNIDENTIFIED SPEAKER: About the same.

CHAIRMAN CLARK: FMPA, Mr. Bryant, what do you think?

UNIDENTIFIED SPEAKER It will be about the same.

CHAIRMAN CLARK: Okay. Gainesville Regional Utilities?

UNIDENTIFIED SPEAKER: (inaudible).

THE COURT REPORTER: I'm sorry. Ma'am, I couldn't hear.

CHAIRMAN CLARK: Someone in the audience said 12 or 15 minutes. I'll just -- I'll repeat what they said. How about that?

Jacksonville Authority?

UNIDENTIFIED SPEAKER: About 15 minutes.

CHAIRMAN CLARK: Fifteen minutes for Jacksonville.

Lakeland?

UNIDENTIFIED SPEAKER: Ten to 15 minutes.

CHAIRMAN CLARK: Ten to 15 minutes.

City of Tallahassee?

UNIDENTIFIED SPEAKER: About 15 minutes.

CHAIRMAN CLARK: About 15 minutes.

Okay. I'm sorry. I skipped over Orlando.

UNIDENTIFIED SPEAKER: About five minutes.

CHAIRMAN CLARK: Five minutes for Orlando.

I know there are other parties here that may want to comment on this. Could you raise your hand and give me some idea if you do have prepared comments and how long you think they would take? Ms. Kamaras?

MS. KAMARAS: About five minutes.

CHAIRMAN CLARK: Okay. About five minutes. Is that for LEAF?

MS. KAMARAS: Yes, ma'am.

CHAIRMAN CLARK: Okay. Mr. Wright?

MR. WRIGHT: One or two minutes.

CHAIRMAN CLARK: And one or two minutes, and you are representing --

MR. WRIGHT: Lee County.

CHAIRMAN CLARK: Given that time schedule and it being Friday, I think I would like to go ahead and work through lunch and complete the presentations. It looks to me like maybe an hour and a half to two hours. So let's continue on and work through lunch, and if it gets to be too late, we'll take a break, but otherwise it's my plan to work through lunch and break when we hear from Ms. Kamaras and Mr. Wright and anyone else who is interested in commenting at this time. Go ahead.

MR. SCHUSSLER: My name is Russ Schussler. I'm from Alabama Electric Cooperative.

The first chart, I'm not really trying to show any more than where we are. We serve 16 distribution cooperatives, four of which are in the state of Florida in the Panhandle. The Florida utility -- the Florida distribution cooperatives make up around 17 percent of our end-use load customers.

Our energy is overwhelmingly coal and we make a lot of purchases. We have right now just a very small amount of gas and oil.

At the end of the site plan our percentage made up of natural gas should increase to approximately eight percent of energy. This is largely due to our new additions being combustion turbine or combined cycle.

Currently this shows our existing generation. The only generation located in Florida is the Portland CT, which is ten megawatts. This is primarily backup for a military installation to provide reliability.

Our current addition, we are completing repowering of a coal plant, making it a combined cycle, a gas combined cycle plant. That will be just up the road from us in Andalusia, Alabama. Our next generation addition after that will be in 1998 when we add two 113-megawatt combustion turbines up in Macintosh, Alabama. We also have a couple of purchases coming in 1998. Beyond that, we plan CT additions in 2001 and 2003.

That completes my prepared presentation. If there is any questions.

MR. HAFF: None of the proposed unit additions are in Florida, is that correct?

MR. SCHUSSLER: No. We have not sited the 2001 and 2003. At this time I would not say that Florida is a primary site for any, but it does receive some consideration.

MR. HAFF: Okay. Thank you.

Any other questions?

Thank you.

Okay. Our next presentation will be from Seminole Electric Cooperative.

COMMISSIONER KIESLING: Are you going to hand any of those out to us?

MR. TWITCHELL: My name is John Twitchell. I'm Director of Operations --

COMMISSIONER KIESLING: You're not on.

MR. TWITCHELL My name is John Twitchell. I'm Director of Operations for Seminole Electric Cooperative, and I'll summarize our 1996 ten-year site plan in just a few slides.

Seminole's 11 distribution cooperative members predominantly serve residential load scattered fairly well across the state. As you can see from this slide, we are predominantly a winter peaker. Our winter peak demand is quite a bit larger than our summer demand, and we expect that to continue.

Our energy requirements are expected to grow at approximately the same rate as our demand growth for the upcoming period of the study. Our energy requirements are supplied primarily by a coal-fired unit that we own in Palatka, Florida. It's a little over 1200 megawatts. We are also a very small minority owner of the Crystal River 3 Nuclear Unit along with Florida Power Corporation.

In addition to those owned resources, we have various firm power purchase contracts with a number of utilities and with an independent power producer, TECO Power Services.

Our capacity needs in addition to this are purchases from Florida Power & Light and Florida Power Corporation through partial requirements purchases.

I have one unit to report on that is not constructed. Our Hardee Unit 3, which is to be located at our Hardee Power Station site is a gas-fired combined cycle unit that has received regulatory approval as well as financing approval from RUS. We have entered into a short-term purchase contract with Florida Power Corporation, which the Florida Power Corporation presenter discussed, that has allowed us to extend the commercial operation of that unit from 1999 until 2002.

We use a two-pronged reliability criteria that is a little different than most Florida utilities. We use the unexpected -- pardon me -- the expected unserved energy concept, which, because of the nature of our system, it's similar to LOLP but not quite the same. In addition to that we use the 15 percent reserve margin criteria, whichever is more restrictive. In the near term the EUE criteria is more restrictive. Eventually the reserve margin criteria will be.

As you can see from this chart, our reserve margin will be dwindling as the percent reserve becomes more important to us than EUE and as our generation mix changes in the future.

We are currently evaluating our future power supply. We are a proponent of competitive bidding, and we presently have an RFP out on the street for about 1,000 megawatts total. Their -- the RFP is soliciting purchases from utilities, qualifying facilities, marketers, independent power producers. We should be opening bids late this fall and doing our evaluation well into the spring of next year.

That concludes my prepared presentation, if there are any questions.

MR. HAFF: Staff has one question. Did you want to -- okay.

Did you happen to pick up the three handouts that we had given out at the beginning that listed every utility's base case forecast of the fuels?

MR. TWITCHELL: I have not seen that.

MR. HAFF: Okay. Oh, thank you. I have it now. Particularly, I'm looking at coal and distillate oil, and that would be on the second page -- Seminole will be on the second page. One thing is particularly striking as we received the supplemental data or the fuel forecasts for the ten-year site plans, is that your projections for these two fuels start off, you know, the lowest and escalate almost not at all, and I just -- I mean, without judging it, it just seems kind of optimistic, and I was just wondering, you know, what is your opinion of how this will pan out?

MR. TWITCHELL: This is always a difficult call. If you recall last year in our ten-year site plan, in the supplemental information that we filed, our fuel forecast was probably in the middle if not slightly higher than the average fuel forecast.

We've recently done a reevaluation of our fuel forecast, and looking at historical trends and the way we think things are going in the future, we're projecting fuel cost growth at less than IPD --

MR. HAFF Less than --

MR. TWITCHELL: Implicit price deflator, and it does show up here. It does now make us -- appears to make us probably the -- well, it does seem to be the lowest reporting growth rate of any of the reporting utilities.

MR. HAFF: Okay. Okay. Thank.

Are there any other questions for Seminole?

Thank you.

Our next presentation is from the Florida Municipal Power Agency.

MR. CASEY: Good morning, Commissioners and staff. I'm Richard Casey, an assistant planning manager with the Florida Municipal Power Agency.

I want to give you a quick overview of our ten-year site plan this year. One thing you may notice as we go through this, there are a lot of similarities to last year. Part of the reason is, our planning cycle was -- has been a little different and we are currently in a very intensive cycle due to some significant changes that we talked about last year by doubling our load growth, and I'll explain that in just a minute -- doubling our load, excuse me.

For those folks who didn't get to look at our ten-year site plan or review or see what was done last year, let me explain, since our structure is somewhat different. FMPA is a nonprofit agency. We were formed in '78 under the Florida Constitution and Joint Power Act. Its primary function is to do joint financing and construction, acquisition, manage, operate, utilize and own electric power generation and transmission facilities. We currently have 26 member municipals across the state. You can see we're quite diverse, from the Panhandle all the way down to Key West, and several of those members do participate in various projects that we do have.

Our current five generation projects are the St. Lucie project, which we participate in with FPL, St. Lucie 2. The 15 members are allocated to 74 megawatts of that unit. The Stanton project is -- and Tri-City both are projects involving Stanton Unit 1 of OUC. The Stanton project has 64 megawatts for the six members. Tri-City has 23 for the three members. Stanton 2 project, we have seven members participating, of which they are allocated 98 megawatts of the 420. The project that I spend most of my time in primarily is the All-Requirements project, where we're the whole -- full-requirement supplier to six cities currently.

As of right now, '96, those six cities are Ocala, Leesburg, Bushnell, Jacksonville Beach, Green Cove Springs and Clewiston, and their total summer coincident peak load is about 523 megawatts.

One item of significance that was not reflected in the ten-year site plan in April of '96, we did enter into an agreement with FPL for network transmission service and, of course, that was before the FERC Order 888 open-access transmission tariffs were filed in July.

In '97, based on our ability now to get network transmission service, we will be forming or implementing what we call our integrated dispatch and operation project, IDO project, where we bring in four additional cities, each of which has generation to add to the All-Requirements project, those cities being Ft. Pierce, Vero Beach, Lake Worth and Key West. Our total '97 summer coincident peak should then be about 961 megawatts.

This graph gives you a visual feel for what change we're fixing to see in the project. As you can see, we've got FMPA generation, and then we're going to pick up the four generating cities' generation as well, and then we have purchases on top of that, and we've got our projected reserve margin being roughly 20 percent for the out years.

To compare this year's ten-year site plan to last year's, the siginficant changes, because we have seen significant growth in some of our All-Requirements member cities in '95 and '94, we've upped our projection for '97 over last year with the IDO cities in place by almost five percent. The 1998 NEL, compared to last year's '98 projection, is up three percent, and also Cane Island 1 and 2, which we jointly own with Kissimmee, are now in service, and to add, Stanton Unit 2 did go commercial in June of '96, this year, and that, of course, was not in the ten-year site plan.

If I may digress for just a second, I forgot to mention one item of interest. Back to this graph. The plan -- our plan does have three 80 megawatt combustion turbines planned in the out years. Those are still on a tentative basis, however. They're not firmly in place on a planning basis, and I'll mention in a little bit the fact that we're going to be going out for a long-term RFP to compare what the market may offer against building those units.

On a tabular basis, here's another comparison of this year's ten-year site plan compared to last, and as I mentioned, you can see the increased anticipated summer peak demand in 1987, again with the four generating cities. Looking at the out years and then looking at the annual growth rate, we're about -- we're using about the same annual growth rate as we did last year. The NEL basis, '98 is the first full calendar year of operation under IDO. So that is shown as the first year of comparison, and again we're looking for a little more load than we anticipated in last year's forecast.

And just to briefly run through other important aspects of our plan, we have maintained several conservation programs at Ocala and Leesburg, as well as others. We do have the demand side management program in place. We also have residential, commercial and industrial energy audits among other programs in those cities.

MR. HAFF: I've got a question while you're talking about the demand side management. Is that dispatched from -- by y'all or by the individual member utilities?

MR. CASEY: We're set up to operate both. Leesburg and Ocala can operate them independently, but we also normally operate them out of the Orlando dispatch center, and they also dispatch our generation for the project.

MR. HAFF: Okay. Thanks.

MR. CASEY: Sure.

In terms of renewable options, we did consider waste burning at Stanton 2, but it was determined to be not cost effective. We do currently participate in the Utility Photovoltaic Group and keep up with the solar technology.

As far as other supply-side alternatives, we currently support APPA and the fuel cell commercialization, and we are in line to purchase one of the first commercial units once they achieve that point. We do have two cogenerators located at two of our members, the Coca-Cola plant at Leesburg and U.S. Sugar -- excuse me -- at Clewiston. U.S. Sugar is about to add a second generator to go into service this fall, which will add an additional 21 megawatts in their generation output.

As I mentioned earlier, we have just -- we are just wrapping up a short-term RFP process to look at our needs over the next four years, and we will be assembling and putting out a long-term RFP this winter to look at our long-term needs as compared to the build option at probably Cane Island or whatever other site may be economical.

COMMISSIONER GARCIA: Let me ask you a question on the U.S. Sugar plant.

MR. CASEY: Sure.

COMMISSIONER GARCIA: That's not on line yet, correct?

MR. CASEY: Yes, sir. They've been in service for several years.

COMMISSIONER GARCIA: I'm thinking of another one.

MR. CASEY: They are basically nested in our service area, but they either consume their own output and what they don't consume is sold to Florida Power & Light.

COMMISSIONER GARCIA: And it's already been on line for a few years?

MR. CASEY: Oh, yes, sir. I'm not sure for how long, but they've been there for quite some time. It's a sugar processing plant.

COMMISSIONER GARCIA: Right.

MR. CASEY: One other dimension of FMPA's All-Requirements project is the participation in the Florida Municipal Power Pool, along with Orlando Utility Commission, Lakeland, and now Kissimmee. The Kissimmee Utility Authority became a participant in January of this year. The pool's been operating since '88. It's a share-of-the-benefits energy pool, an economy pool, if you will, and we average benefits of about nine million dollars a year which are spread among the participants.

COMMISSIONER GARCIA: I just want to make sure, it's the Okeelanta then that I'm thinking of that isn't on line yet, correct?

MR. CASEY: I'm not familiar with that.

MR. ADJEMIAN: That's correct (inaudible).

COMMISSIONER KIESLING: You can't talk from out there because he can't write it down.

COMMISSIONER GARCIA: Scream or come up to a microphone. I just want to --

MR. ADJEMIAN: The Okeelanta and the Osceola cogenerating facilities, those are the ones that are under contract with Florida Power & Light, and they are currently undergoing the test mode, test operation, and we expect it to be on line before the end of this year for commercial operation.

COMMISSIONER GARCIA: I'm sorry about that. I was just confused.

MR. CASEY: So just to wrap up FMPA's ten-year site plan, we use reasonable load and fuel forecasts and we consider all reasonable demand side and supply side alternatives, and we are sensitive to our environmental responsibilities, and we provide needed power to an increasing number of municipal electric utilities.

And that's the end of my presentation, if there are any questions.

MR. HAFF: Are there any questions for FMPA?

All right. Thank you.

Continuing on, our next presentation is going to be from -- made by Gainesville Regional Utilities.

MR. KAMHOOT: Good morning. My name is Todd Kamhoot. I'm a utility analyst representing Gainsville Regional Utilities. I'm responsible for preparing the customer energy sales and power demand forecasts included in the ten-year site plan. I'd like to give a brief summary of GRU's 1996 ten-year site plan through the portion of the plan covering the forecast. Following the discussion of the forecast, Mark Spiller will present demand side management and generation planning highlights and conclude the presentation.

This slide shows an overview of general characteristics of Gainesville Regional Utilities' electric system. GRU's a municipally-owned electric, natural gas, water and wastewater utility. Its electric service area encompasses approximately 100 square miles of the Gainesville urban area within Alachua County. GRU serves approximately 150,000 persons representing three-fourths of the population of Alachua County.

GRU has two generating sites, the Deerhaven site and the J.R. Kelly site, with a generating capacity of 512 megawatts from four steam units and six gas turbines, plus an 11-megawatt share of Crystal River 3.

1995 system loads, our summer peak demand was 361 megawatts. Our net energy for load was 1,648 gigawatt hours. GRU serves approximately 62,000 residential customers, 7300 non-residential customers, wholesale service to the City of Alachua and Clay Electric Cooperative and firm interchange service to the City of Starke and Florida Municipal Power Agency.

This graphic shows GRU's summer generation capacity, which I stated was 523 megawatts, by unit type. This chart shows the source of fuels used to generate electricity for 1995. Net generation was 1,866 gigawatt hours, 70 percent of which was produced by Deerhaven Unit 2, utilizing low-sulfur coal.

This is a summary of forecast assumptions, data sources used. GRU uses least squares regression analysis for each customer class to develop customer forecasts and usage per customer forecast. Separate forecasts are developed for the City of Alachua and Clay Electric.

Analyses are conducted using calendar-year data from 1970 through 1995. GRU assumes normal weather conditions. Heating degree data and cooling degree data is obtained from two area weather stations which report to NOAA. One is operated by the University of Florida, and the other by the municipal airport.

All economic and demographic data used in our models comes from the Bureau of Economic and Business Research at the University of Florida. That includes population projections, income, employment, household-size type of data. Income and electric price are adjusted for inflation, and we assume an average of 4.0 percent per year in our forecast horizon.

Estimates of energy and demand reductions resulting from demand side management programs have been incorporated into all retail forecasts. Total energy sales are adjusted for losses which average almost six percent to derive our forecasted energy for load.

And we have included in the '96 plan high and low band forecasts which were based on alternative population projections which, in turn, yield alternate sets of independent variables, such as incomes and employment figures used in the models.

This table summarizes some economic and demographic characteristics of residents of Alachua County versus the state of Florida. You can see that Alachua County residents are on average younger than residents of the state of Florida and less affluent. Alachua County residents are more service and trade employment based than industrial than are residents of the state, and the household sizes on average are smaller. These factors contribute to lower energy uses for all retail classes and equivalent -- if they were compared with equivalent retail classes among other areas of the state.

This chart shows our forecast of net energy for load, also historical data. I've also included the high band and low band projection on the graph. Historically, in the last ten years net energy for load has increased at an average annual rate of four and a half percent a year. It's projected to increase at 2.3 percent a year.

This chart shows seasonal peak demands for GRU. The red line represents summer peak demand. That's the higher line. We are a summer peaking utility. We have been in each of the last 25 years. The blue line, lower line represents winter peak demand. The lighter lines above and below represent the high band scenario for the summer peak and the low band scenario for the lower peak. That sort of gives you the full range of the seasonal demands that we look at.

Historically our summer peak demand has increased at 4.2 percent a year, and our forecast has it increasing at 2.3 percent per year.

That's all I have on the forecast. I'd like to turn it over to Mark Spiller now.

MR. SPILLER: My name is Mark Spiller. I'm responsible for demand side management planning for Gainesville Regional Utilities, and I'd like to discuss our resource plan and the impacts of demand side management programs upon that plan.

Our plan is based upon a least-cost integrated resource planning process and our needs are based upon a 20-year load forecast that Mr. Kamhoot has just described and the equipment of our generation, transmission and distribution equipment. We performed a dynamic optimization of the generation needs using the EPRI-developed GS software.

This graph shows you the summer peak demand, the historical and the projected on the green line. The blue line just above shows you the available capacity in the system, and the vertical bars represent 115 percent of peak demand, which gives you an idea of what a 15 percent reserve margin would be in our system. Notice we came pretty close in 1995 to that 15 percent reserve margin, and the increase that you see represents the addition of Deerhaven Combustion Turbine 3, which came on line in January of this year.

This graph shows the winter peak demands, and you can see capacity is not an issue in the Gainesville Regional Utilities system. This is largely driven by the prevalence of natural gas within our service area.

The conclusion that we reached in our '96 ten-year site plan is that no additional generating units will be needed within the planning horizon of that ten-year site plan.

GRU plans to remain aggressive with demand side management programs despite the deregulation of smaller utilities for DSM programs. We will maintain our existing programs and, in fact, we plan to add a number of new programs, including incentives for thermal energy storage, gas cooling and quite a number of other areas.

This graph shows you the energy impacts of our projected programs, the estimated savings in green of the programs that we plan within this horizon, and the red line shows you what the PSC approved goal was for Gainesville Regional Utilities. You can see that our planned programs we estimate will exceed the PSC approved goals by a substantial margin.

This graph shows you the summer demand impacts of our planned programs versus the PSC approved goal, and again, you can see that there is a substantial increase in our estimated savings versus the PSC mandated goal.

This graph shows you the winter demand impacts, power demand impacts versus the PSC approved goals, and you can see there is even a greater increase or difference between the estimated savings of these programs and the PSC approved goal, and that's due to our natural gas incentive programs.

In conclusion, GRU plans to be even more aggressive than they have in the past with DSM programs in order to better serve our customers and to meet our resource needs. The net effect of our proposed DSM programs at this point are to delay the addition of the next generating unit about one year, out to 2006. Without these programs, and in fact, if we were to only meet the PSC approved goal, that unit would be moved up to one year within this planning horizon of this ten-year site plan to 2005. And, last, GRU does not require additional generation within the horizon dictated in the 1996 ten-year site plan.

Any questions?

MR. HAFF: Are there any questions for Gainesville Regional Utilities?

Thank you.

MR. SPILLER: Okay. Thank you.

MR. HAFF: Our next presentation is going to be made by the Jacksonville Electric Authority.

MR. MEYERS: I'm Jim Meyers. I work in the fuels management area of the Jacksonville Electric Authority. I appreciate the opportunity of going over our ten-year site plan with you today.

The first slide I want to put up just lists our planned changes to generating capacity contained in the ten-year site plan. The first project is our Girvin Road Landfill project, which will add three megawatts. In this project, we're using the methane gas at the City's Girvin Road Landfill to power four internal combustion engines, providing the three megawatts of capacity. In the ten-year site plan, this was listed to have a commercial date of November, '96, and the latest information I have is that this has slid to January of '97.

The next capacity change is with Northside Unit 1. This unit has been derated 11 megawatts, and it is being restored to its full load of 262 megawatts by 1997.

One of the bug assumptions in the '96 ten-year site plan is the addition of 100 megawatts of interruptible load by 1997. The Jacksonville Electric Authority has proposed a tariff that is currently being reviewed by the Commission, and we're anticipating by October of this year having that tariff in place and having our about 100 megawatts of interruptible load by '97.

We also include in this ten-year site plan the purchase of peaking capacity from PECO energy. This is a done deal for firm capacity, 40 megawatts for the summer of 1998, 50 megawatts for the summer of 1999. The plan then shows the repowering of Southside Unit 3, which is currently in cold storage. We'll be adding a combustion turbine to repower Southside 3 as a combined cycle unit. This will take place by the summer of 2000.

In the last four years of the ten-year site plan, we show the addition of combustion turbine units to maintain our 15 percent reserve margin.

How does this compare with last year's ten-year site plan? The similarities are that the repowering of Southside 3 was shown in our last plan as was the Girvin Road Landfill and the return to 262 megawatts of Northside 1.

Okay. As I mentioned, the interruptible load is a major difference. Also the contract that we have with PECO Energy is new for this ten-year site plan. We also show Kennedy 10 being derated 24 megawatts. The unit's about 25 years old and we're operating it at lower pressures. So that unit has dropped in capacity from 129 net megawatts to 105 megawatts.

The other change is that the combustion turbine units that we show in the last four years were not shown in the last ten-year site plan. Last year we showed our reserve margin dropping below 15 percent but did not identify any unit additions.

The demand and energy forecast I think is one of the key assumptions in the ten-year site plan. What this shows is the summer and the winter peak forecasts and the net energy for load forecasts for the '95 ten-year site plan and this year's ten-year site plan. So one thing that you'll note is that our forecast is higher for the summer and winter peaks in the net energy for load than it was last year, and also our winter peak is growing faster relative to the summer peak in the '96 ten-year site plan. We're growing at 2.2 percent in the winter, 1.9 percent in the summer. In 1996, we're starting out essentially the same in terms of summer and winter peak, but by the end of the ten-year period, we anticipate being a winter-peaking utility.

Still, the summer peak is more critical for planning purposes because we have higher capacity ratings in the winter than in the summer. So what this graph shows here is summer peak demand versus capacity.

The blue line represents our peak. The red line has been increased by 15 percent, and the white bars represent our installed capacity and firm purchases. And as you see, this ten-year site plan is based on maintaining 15 percent reserve margin.

The last slide I want to show describes our fuel mix. Fuel flexibility is critical to the Jacksonville Electric Authority. As recently at 1980, we were essentially 100 percent oil-fired. Since that time, we added coal-based purchases from Southern. We added gas capability at our oil-fired units. We've constructed St. Johns River Power Park with Florida Power & Light and purchased a portion of Sharer 4 in Georgia.

Let's see. It's kind of difficult to see, so you may need to look on your handouts, but the top shows 1995. That's actual, and then the bottom two pies show 2005 capacity and energy. In 1995, about 60 percent of our capacity is oil and gas fired, but when it is -- as far as producing energy, we're producing about a quarter of our energy with oil and gas. The remainder is coal -- basically coal-based, although some of this pink pie -- you can't really see that, but that is pink -- but a portion of that is coal-based as well, because that's the other category, and most of that is economy transactions.

By 2005 we anticipate our energy mix to be similar. We see oil and gas going up to about 28 percent, the remainder being essentially coal-fired. We show the other category dropping, but that may in fact increase and take away some of the oil and gas as purchased power begins to be more plentiful with the increased marketing in the electricity field.

So that concludes my presentation. If you have any questions, I'll be he happy to answer them.

MR. HAFF: Are there any questions for JEA?

Okay. Thank you.

Our next presentation is going to be made by the City of Lakeland, and will you make sure the Commissioners get those as well? Thank you.

MR. ELWING: Good morning, Commissioners. It just barely is morning yet. Let me give you a brief overview of the City of Lakeland this morning. My name is Paul Elwing. I'm Manager of System Planning with the City of Lakeland. Lakeland did not file a ten-year site plan this year as our forecast did not come out until after the filing deadline. So we did not have any new information or new plan to file at the filing date, but we do have a new forecast that has come out since then, and our plans are beginning to gel as we speak, and so I'm going to give you a brief overview of our new forecast and what our long-range plan looks like.

Just real briefly, a little bit about who we are and where we are. We are the third largest municipal system in the state of Florida. We're about a 680 megawatt system today, which is made up of about 450 megawatts of natural gas capacity, 250 megawatts of coal capacity, and 30 megawatts of firm purchases at this time.

The planning criteria that we use is based on reserve margin, and we use a 15 percent minimum reserve margin at time of system peak. We do use an integrated resource planning process to integrate both demand and supply side alternatives, and we use a minimum revenue requirement, economics-based analysis to make sure that we have the lowest-cost alternatives available for our customers. We do also take into account all environmental needs so that we are in compliance and acceptable.

Other planning issues that many utilities are addressing today, as competition looms, we are shifting from more long-range planning to shorter-range planning. We see the market being very volatile today, and so we need to pay close attention to what's happening in the near term. We are also seeing that demand side management worth is diminishing as energy prices drop. The marketplace is expanding with many new players and opportunities for utilities, and so investments must have shorter paybacks, and energy prices must be competitive for all of our customers, not select groups.

Our first graph here on page 4 is just a comparison of the 1995 forecast which was in our '95 ten-year site plan, with our latest forecast, and as you can see, we are projecting customer growth to be in excess or -- I'm sorry -- slightly less than the '95 forecast. So a slight moderation in total customer growth. We are projecting about 1.8 percent customer growth for our system.

Comparing net energy for load in the same manner, we are seeing our net energy for load increase over previous forecasts, about a 2.3 percent growth rate. This is due -- in fact what we are seeing is increased all-electric homes on our system and so our per customer consumption is increasing.

Winter peak demand forecast is probably the most significant change in our forecast over past years. We are showing a significant increase in winter peak demand. That is due in part to changing our forecasting methodology to account for slightly cooler temperatures, but we also had a number of large industrial customers who are doubling the size of their operations, and that alone has put or added between a 15 and 20 megawatt impact on our system, and so that is being represented here.

The growth rate for winter peak, if I didn't mention it, was about 2.8 percent.

Summer peak demand, our '96 forecast is indicating a slightly slower rate of growth over the previous forecast, about a 1.9 percent growth in demand.

MR. HAFF: Why is there such a substantial difference between the winter and the summer?

MR. ELWING: Again, most of that has been the slight change in forecast methodology. I believe our forecasters had been forecasting for minimum temperatures of around 32 agrees in winter, whereas, in the new forecast, they're using 30 degrees. So that does add at least to our size system what looks like a significant chunk of demand. Our summer forecasting methodology has not changed that much. We're remaining at approximately a 97-degree summer peak temperature during forecasts.

MR. HAFF: Thank you.

MR. ELWING: Lakeland does have DSM on its system. Load management is our primary program, and as you can see here, we are continuing to forecast summer demand reductions. Right now we're slightly above 30 megawatts of summer demand reduction, forecasting that to go up in the neighborhood of about 55 megawatts of demand reduction by the end of the ten-year period.

Winter demand reduction, we're continuing to see increases there. This past winter we had a little over 40 megawatts of reduction and we're forecasting that to increase to slightly over 100 megawatts of on-peak reduction by the year 2006.

This next graph gives you an idea of how we stack up on resources meeting the load. The dashed line, "Reliability Target," that is our forecast line plus our 15 percent reserve margin. And so as you can see, throughout time, we meet the 15 percent reserve margin criteria based on the reserve rule, and we are forecasting some capacity additions out after the year 2000, which I'm going to speak about in a few moments, and that's the rise in the capacity block that you see in your chart.

Likewise, for winter, we see the need for capacity almost immediately, and we have noted that for the past few years, and that was in our 1995 ten-year site plan, and our plans for meeting short-term capacity needs are going to be through purchases. We see the market being very fluid right now and very good for short-term purchases, and so the short-term needs are going to be met through those.

Again, we are planning for a sufficient combination of built resources and purchased resources to meet all reliability needs throughout the planning horizon.

So again, in very brief summary, how we're going to meet those future needs: Short-term needs for the one to five years will be met through firm purchase contracts. Longer-term needs will be met by a economic base mix of demand side management, purchases and self-build options.

I'd like to talk to you for just a moment about one of those self-build options that we have on the drawing board, if you will. Lakeland has been approached with a unique opportunity to perhaps participate in one of DOE's clean-coal-technology projects. We have been selected as a potential site, and so we do have a project being submitted before the DOE, and it is currently at DOE for their review and approval. If approved, this project would be a pressurized circulating fluidized bed project, which is, as I said, one of DOE's new clean-coal-technology projects.

The basic concept is to burn coal in a pressurized boiler using some new technologies to get very high efficiencies out of burning coal, very attractive prices, very environmentally good.

Just a few brief project highlights, the project as we are envisioning it at this point is a little over 200 megawatts of capacity. The net heat rate would be under 9,000 Btu per kilowatt hour. The net cost to Lakeland's customers would be less than $500 a kW. We're envisioning this as a two-phased project: Four years of permitting and engineering, procurement and construction; and then there's a four-year demonstration phase that DOE requires on these types of projects.

The DOE would cost-share in the project, which results in the low cost to Lakeland customers, and Lakeland is currently working with DOE to try to get up to 50 percent cost-sharing for the project, and that would include the four-year demonstration period.

Just a few more bullets here about the project. It would burn a wide variety of coal, petroleum coke, some of our lowest cost fuels. This technology is currently being used in Europe and to some extent in the United States, and so it is not a brand-new technology. It is one of our newer ones, but it would be constructed at our Macintosh plant, which is already a coal plant, and so we would be using a lot of existing facilities, also saving on the cost. As I said, it has an extremely low environmental impact, and it's similar to combined cycle technology, in that it uses a gas turbine to pressurize the boiler. The pressurized boiler is where the efficiencies come from in burning the coal.

As I said, we're attempting to get DOE approval for cost-sharing on the project to make it viable for our customers.

In summary then, the bottom line for Lakeland, at this point in time this would be the most economical alternative for Lakeland customers that we've evaluated. It would be one of the lowest net cost coal plants to build and operate in the state of Florida. It is environmentally friendly as compared to standard coal units, demonstrates new clean-coal technology and would return federal tax dollars back to the citizens of Polk County.

That concludes my presentation. Any questions?

MR. HAFF: Staff has a couple of questions.

What is the -- is there any certainty as to the status of when you're going to know if you have won this grant? If so, I guess, the next step would be to file a need determination with the Commission. How is that falling out?

MR. ELWING: Yes, sir; that is correct. As I said, the application is currently on DOE's desk. Of course, when dealing with the federal government, there are no absolute certainties. We are hoping to have some type of response from them prior to September 1st. We can't guarantee that. Our feeling is, if we don't have a response by September 1st, we probably won't hear anything until January because of the elections. I think that's just safe to say that.

MR. HAFF: I guess, you know, if that becomes the situation, ultimately you're going to be faced with a choice of whether to go ahead with this or to look at something else.

MR. ELWING: Yes, sir. We still feel that we have time, based on our '95 ten-year site plan we have submitted that we would not look at or would not consider self-build options until the year 2003, which is sort of our second year of need, if you will, that we would meet the need between now and then with purchases. So we feel like we still have sufficient time to have capacity or even to allow this project to flesh out a little bit better as far as the government is concerned on a yea or nay before we have to establish a drop-dead date.

Our analysis up to this point in time shows our next best alternative is gas-fired combined cycle, very similar to what many of the other utilities in the state of Florida are planning. We still feel that we have sufficient planning horizon to accomplish that prior to the 2002-2003 time frame of need.

Yes, once -- either way, once we get either an affirmative from the DOE that that project is go, we would be coming to this commission with a notice of need determination. In the event that project is canceled, then we resort back to other technologies. The capacity that we would propose building would more than likely be of sufficient size that would trigger a need hearing, and so we would be coming for that capacity as well.

MR. HAFF: Okay. Are there any other questions for the City of Lakeland?

Thank you.

Our next presentation will be made by the Orlando Utilities Commission.

MR. BROOKMAN: Since we don't have a proposed unit addition in the ten-year horizon, I'm just going to give you a brief overview since our last ten-year site plan filing.

Stanton 2 came on line, as they said originally, on June 1st, which is on time and well under budget. Stanton 2 is currently 57 million under budget, and when the final books are closed, we expect it to be -- that number to increase significantly. The total project took 39 months to complete and more than 70 percent of the work force came from central Florida.

As you know, Stanton 2 is a joint municipal project, and OUC owns 72 percent of the unit, and since the ten-year site plan filing, we have signed a UPS from Stanton 2, which is consistent with our need hearing and also our ten-year site plan filing.

On demand side, we will be issuing an RFP for hardware and software for our direct load control in a few weeks, and this program is expected to be in operation in March of 1997. That's all I have right now.

MR. HAFF: Are there any questions for Orlando Utilities Commission?

MR. BROOKMAN: Tom Brookman.

MR. HAFF: Thank you.

Okay. Our final prepared presentation from the utilities will be made by the City of Tallahassee.

MR. BRINKWORTH: Commissioners, my name is Gary Brinkworth. I'm the Electric Planning Administrator for the City of Tallahassee. I want to start kind of with a technology apology, sort of. We've got a different kind of presentation that we're going to do this morning with its computer-generated graphics. So I apologize to everybody that's sitting over there on that side of the room not going to be able to see that very well. I'm going to move this cart out of the way so that the Commissioners can see the rest of this.

I'd like to start with just a brief overview of the City of Tallahassee's electric system. We serve over 87,000 customers in a 221 square mile service territory in and around the capital city. We are the fourth largest municipal electric utility in Florida. We own and operate about 500 megawatts of generation. In addition, we have firm power contracts of about 100 megawatts. To date, our highest peak experienced on the system occurred in February of this year where we reached 533 megawatts.

Our system resource needs, as described in the ten-year site plan, you see here in the bar chart. We use a 20-year load forecast technique that utilizes a series of linear regression models that forecast each retail customer class by rate class. We also incorporate some econometric variables into that forecast. In addition, we apply a 17 percent reserve margin based on some of our reliability criterion studies to determine what our resource needs will be for each year.

Our summer peak demand growth rate in the 1996 ten-year site plan is about 2.12 percent. You see in this bar chart our shortfalls beginning in the year 2000 of about 88 megawatts, and by the year 2005, we're up to about 187 megawatts of need. Those needs do include capacity to meet our 17 percent reserve requirement.

What you see in this graphic is a little bit of a different perspective on our supply and demand requirements. You see the need shown in the yellow area there, but what you'll notice is our need is actually driven by a couple of things in the year 2000. First, we have a fairly significant drop in purchased power. Our contract with the Southern Company for unit power terminates in May of 2000. We also have a small contract with Entergy Power, Incorporated, that terminates in 2002. There is also some generation reductions that take place, some retirements in the City's generating stations in the out years of this ten-year site plan reporting period.

In order to determine what our resource needs would be, we've undertaken an integrated resource planning study, and in order to evaluate what possible resources we might use, we looked at a variety of scenarios or strategies which might be used to meet that need, and here you see the five basic strategies that we considered in the RFP process.

Conservation and energy efficiency programs was one of those strategies. We also looked at a series of purchased power kinds of strategies, both short-term purchases which would come off of the evolving open-access power markets, some longer-term firm power purchases. We also looked at a combination strategy that mated up these short-term purchased power with the deferral of possibly a unit addition, and lastly we also looked at building or buying some additional generation.

We identified in a previous IRP analysis that the maximum amount of supply side capacity we could take, if it were a unit construction or purchase, would be 250 megawatts because of the characteristics of our system.

One of the things that we did include in all of the analyses and turned out to be an economic choice in all cases was a DSM portfolio. This DSM portfolio includes both residential and commercial programs. Our portfolio is primarily -- addresses fuel substitution, because we are an electric and gas utility, and so we have a number of programs that move electric load to gas.

The contributions from that portfolio, although they're fairly significant for our system, were not enough to defer the need for another supply side resource in the period around the year 2000 because of the significant loss in our purchased-power contracts. This portfolio, which is shown in the ten-year site plan and did come in as cost effective in all of our IRP runs, is the one that the Public Service Commission recently approved in our DSM filing. We are looking at some further enhancements to our portfolio now, including some direct load control programs.

As the Commissioners may know, we just completed an RFP process for capacity. We issued the RFP in August of last year, received five external proposals in response to the RFP. The City also placed two options on the table for evaluation. Three of the five external proposals were retained for further evaluation.

Because the City put in its own options, we went to some length within the electric utility to separate the bid team that prepared those options from the evaluation team. We also undertook some other procedural adjustments in our normal city RFP process to recognize our exposure to public records requests under Chapter 119. We were able to successfully preserve the confidentiality of both the external proposals and our two internal alternatives.

We opened those proposals last November and completed our IRP analysis and screening in April of this year. The City Commission selected a -- the most cost effective resource plan for our future customer needs to be the one that includes the City's own internal project, and I'll tell you a little bit about that project in a minute.

Just briefly, on our IRP result, we ran a number of different kinds of studies in order to identify what our least-cost plan should be. We looked at a lot of base-case assumptions. We did some city project cost variation because our external bidders came in with guaranteed prices, and we wanted to test whether or not some of the costs that the City could not lock down and guarantee to itself might change our analysis. So we tested those.

We also looked as a set of risk scenarios. We created eight different future circumstances for the electric utility to operate in. Certain things were adjusted, and we tried to see if the plans would change, things like: We considered retail wheeling, we looked at higher load forecasts, we looked at higher prices of natural gas, we looked at limited imports of power into the state of Florida, tested all of our supply and demand side alternatives within those eight futures, and then tried to identify the resource plan or plans that performed best under all of those future conditions.

As it turned out, the plan with the City's proposed unit at the Purdom Station performed the best under all of those scenarios. What you see in the middle of this slide is two 20-year present worth revenue requirements plan costs, one for a plan that includes the City's project, one for a plan that includes a project offered by AES, who was the closest external proposal to the City. What you see there is a plan cost difference in PWRR over 20 years of a little over eight percent.

In addition, when you look at the specifics of how that plan with the City's project in it compares to our existing operations in Tallahassee, we find that we can improve our system efficiency by a little over 40 percent when the new combined cycle unit comes on line in the year 2000, and that, in addition to that, our operating savings on an annual basis are greater than the debt service required to fund that unit. So that helps to tremendously lower our operating costs as well as our fixed costs, and as a result of that, we looked very closely, not only at revenue requirements, but also at total system costs, which include all our debt and our fixed payments, and find that we can -- we would experience an 11-percent reduction in total system costs from the year before the unit comes on line until the year after it comes line.

Purdom Unit 8 is the combined cycle unit that forms the basis of this preferred 20-year resource plan. It is added at an existing site on the St. Marks River in St. Marks. It's a 250-megawatt class combined cycle unit. You see the statistics here. It's averaging a heat rate of a little under 7,000 Btu's per kilowatt hour. The capital cost of $110 million works out to about $440 a kW, and that capital cost does include an advanced zero-discharge water treatment system that's included in this plant in order to significantly reduce our impacts on the water table in St. Marks and our draws from the St. Marks River.

No new transmission facilities are required for this plant. We will be upgrading some of the existing transmission lines that currently connect the Purdom Station to the City's electrical grid.

COMMISSIONER DEASON: Let me ask a question on that slide. How is it that your mean heat rate is less than either the summer or the winter?

MR. BRINKWORTH The summer and winter heat rates are calculated at very specific ambient temperatures. I think the mean is a calculation based on some operating conditions that are statistically in between summer and winter operating conditions in Tallahassee. We expect the unit to operate somewhere between the 6900 and 7,000 Btu per kilowatt hour, and the summer and winter numbers are based on local Tallahassee ambient conditions for the winter and the summer, and the mean is a calculation I believe based on manufacturers' indexes.

Just to wrap up our milestones for this particular unit, the Commission will be seeing a need application in December of this year. We expect permitting for Unit No. 8 to be completed in the spring or early summer of 1998. Prior to our final decision to go forward with construction of this unit under the direction of our City Commission, we are going to issue an additional investigation, possibly an RFP or two to test the power market and be absolutely certain that this alternative provides our customers with the lowest power option to meet this new need.

That's the end of my prepared presentation. I'll be glad to answer any questions if you have them.

MR. HAFF: Yes. Staff has a question.

Did you happen to get a chance to review the forecast of the gas prices that we compiled that were passed out today?

MR. BRINKWORTH: No, I didn't see that. Do you want me to --

MR. HAFF: The munis are on the second page of that.

MR. BRINKWORTH: Yeah, okay, I see it.

MR. HAFF: I guess we're just -- you know, again, it's just a compilation of the supplemental data that the staff received in the ten-year site plan review, and the City's forecast stands alone as by far lower than any of the reporting utilities, and I guess it's just -- obviously, fuel forecast is the major driving factor behind your decision that Purdom 8 was the least-cost generating alternative, and I guess, in light of some of the other utilities' forecasts on here, I was just wondering if you could explain why, if you have a belief as to why yours is so much lower?

MR. BRINKWORTH: I suppose saying we do a better job is not the right answer.

MR. HAFF: Of course.

MR. BRINKWORTH: No, that's not really true. That forecast is actually the result of some fuel RFP bid responses that we actually have in hand for firm gas delivered to Tallahassee for fixed pricing and periods ranging from ten to 20 years, and so those contracts form the basis of this forecast; and because they're guaranteed and they're firm gas delivered to our area, we felt like we were fairly confident in those numbers. So it's not really a traditional forecast. It's more a response from fuel suppliers to our request for delivery of firm quantities of natural gas.

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

Thank you.

This concludes the utility presentations of their ten-year site plans, and next on our agenda is to receive any comments from the public or any other interested persons who may want to comment on the utilities' plans as they've been summarized today; and anybody that hasn't already identified themselves, when they make their presentations, please do so.

CHAIRMAN CLARK: Mr. Wright.

MR. WRIGHT: Thank you, Chairman Clark. Again, Sheff Wright, representing Lee County.

Commissioners, this morning you heard the representatives of the three major investor-owned utilities in Florida tell you that they have not reevaluated their DSM programs based on current costs, current avoided costs, at least not across the board since the 1993-1994 time frame.

During the same time frame, one utility, Florida Power Corporation, has reevaluated one of its major, probably its actual major DSM program, it's residential load management program, and determined that it was necessary to reduce some of the credits offered through that program and to restrict eligibility in order to assure continued cost effectiveness of that program. The same utility has seen market costs for new generation fall low enough that it deemed it appropriate to solicit buyouts and buydowns of its current power purchase contract obligations via a reverse option RFP. Another utility has petitioned the Commission to approve recovery of costs associated with buying out a previously approved standard offer contract, and FPL has recently submitted a revised proposal for a DSM program, it's Build-Smart program, based on much lower avoided costs than were contemplated in their 1993-1994 analyses.

The fact is, Commissioners, that the avoided costs of new generation spurred largely by competition at the supply level have declined significantly in the past two years or so, and, you know, we're not talking about two or three percent. We're talking about 20 to 50 percent reductions in avoided generation costs.

We have serious doubts as to whether planning processes that do not incorporate a level-playing-field, equal-footing evaluation of demand side and supply side options based on current and consistent planning assumptions and avoided-cost assumptions, will produce optimal, truly integrated resource plans; and, accordingly, we have serious doubts as to whether plans based on those processes can be considered to be suitable. Thank you.

CHAIRMAN CLARK: Mr. Wright, you're representing Lee County?

MR. WRIGHT: Yes, ma'am.

CHAIRMAN CLARK: And you're going to have to make the connection for me with your comments and the County -- and Lee County's interests. What I understand you saying is that we've got to somehow reevaluate DSM and avoided costs on an ongoing basis.

MR. WRIGHT: Yes, ma'am.

CHAIRMAN CLARK: And how would you propose doing that?

MR. WRIGHT: Well, using whatever process the utilities heretofore used to evaluate them on a level playing field using current avoided cost data for all purposes in each annual planning cycle.

CHAIRMAN CLARK: I guess -- let me be more specific, Mr. Wright, and I may be a little bit unfair with you because I expect you to be able to come up with answers for me.

It just seems to me that we could be in a constant state of analysis, and at some point you have to hold things constant and make some decisions in terms of planning, and I just am having difficulty as to -- I realize that the DSM programs were evaluated a while back, but that was a long, drawn out process, and I don't think we can go through that process continuously. So suggest for me a way to do it that sort of accomplishes what you're suggesting but doesn't have us continually analyzing things and making changes that leave us no time to implement the plans.

MR. WRIGHT: Well, what I'm suggesting to you is that I think that you don't have to go through 15 days of hearing and 5700 pages of transcripts to do the analyses. As you know, I was in the case, but what I am suggesting --

CHAIRMAN CLARK: Yeah. But, if we do that analysis and then someone thinks it's wrong, then what?

MR. WRIGHT: Well, what I would suggest is that the utility probably ought to be doing the analysis, and if they -- you know, if the analysis shows that things have changed -- that if the results of dramatic changes significantly change the cost effectiveness of some of their DSM programs, then something ought to happen, I think. I think either they ought to come in and say, "Y'all, we've got a problem," or y'all ought to say, you know, "We might have a problem here."

If the changes in the avoided costs from year to year are two or three percent, then it's no big deal. You could do the analyses or even not do them, but you probably ought to, just to make sure you're continually doing things right, and probably a change of two or three percent is not going to make any significant difference in the ultimate outcome.

I suggest probably --

MR. GARCIA: I happen to agree with you, and I think that sometimes we do these programs for the sake of doing them as opposed to checking. I'm not saying we have to have a full blown out proceeding, but certainly the company should be checking on the effectiveness of this program, if it's a significant percentage, because doing DSM for the sake of doing DSM is certainly not, I don't think, conducive, and I think Mr. Wright is correct on a limited basis. I agree with you, Madam Chairman, that we don't want to go through a full blown out thing when the percentages are relatively small, but certainly we should be checking to make certain that they're worthwhile doing at all at a certain level.

CHAIRMAN CLARK: So what percentage would be significant enough to suggest we do something and, if so, what should we do?

MR. WRIGHT: Well, I think the utilities ought to do what they heretofore did, and that is not take DSM as a given on a year-to-year basis, but do the evaluation on then current planning assumptions and then current avoided cost data each year as part of what they represent to be their integrated resource planning processes or their least-cost planning processes and leave it to them.

You know, if the results come out that there's no big change, then they can tell you the results came out, there's no big change and nothing should happen. If they do the analyses and the results indicate that there are big changes and that significant portions of programs or total programs are no longer cost effective, then somebody needs to be thinking about it, because obviously, you know, as I said earlier, you want to be doing what the most cost effective thing is, and if your analyses show that you're not doing the most cost effective thing, you need to think about it. I mean, probably you need to do something about it.

CHAIRMAN CLARK: Don't they do that when they file their programs? I mean, we've set their goals, and when they would file their programs, they'll be looking at whether it's cost effective.

MR. WRIGHT: My understanding and my understanding and interpretation of the responses given to you this morning was that they have not reevaluated -- that none of the three large IOUs in the state have reevaluated their programs since the 1993-1994 time frame analysis that was done for the goals dockets.

COMMISSIONER GARCIA: Can staff tell me where he's wrong?

MR. FLOYD: Yeah, I don't think Sheff's completely right. This is a complicate issue, but let's just go one by one here.

Number one, the utilities are constantly looking at their programs, I know, because I talk to them day in and day out, and they file modifications here and we bring them down for your approval. If staff looks at things and thinks they're getting out of line, we'll come down ourselves or talk to the utilities first and see if they can modify programs, or we'll put them on notice that we're looking at this. Of course, issues can be raised at any time at the annual cost recovery hearings that we have. If we hear from Sheff or anybody else that there's a problem with a particular program, we will look at it and we do look at it.

I will say this, just technically, just because avoided costs go down does not necessarily mean that programs will become non cost effective, because you might have moved closer to the unit and the installation that you're making are still cost effective. So it's not as simple as saying, "Avoided costs have gone down, we need to reevaluate all these programs."

There is a practical side to it that Commissioner Clark pointed out, when you gear up and advertise that you have a certain program, ceiling insulation or whatever, you can't just start and stop those things every six months or even every year, so you have to take the practicality into account, but I assure you, Commissioners, we're looking at this -- we have a conservation sub-unit, you might call it. We look at these numbers all the time, and if somebody has a program that they think is not cost effective, we would like to know about it and would bring it to your attention. We don't want to necessarily go in and set goals every year, but the programs, themselves -- the utilities may not have looked at it on a wholesale basis on all their programs as a package, but they do lcok at individual programs on an ongoing basis. At least that's my pretty well educated understanding of the situation.

MR. WRIGHT: That he may or may not be true, but that's not what I heard them say this morning, with the exception of Florida Power reevaluating the load management program, and I don't disagree with you, Roland, that just because avoided costs change -- you made the statement that just because avoided costs change doesn't mean cost effectiveness won't necessarily be affected. I don't disagree with that statement at all. I think when the avoided cost changes are dramatic, as they have been over the last two years, however, that the analyses ought to be done and the results looked at, and my understanding is that the analyses have not been done, and I think that's what you were told this morning.

MR. FLOYD: Well, I think that the Commission -- and the Commissioners will speak for themselves, but this commission, at least historically, has put the utilities on notice that they are under continual obligation to review their programs and bring them up here and get them modified if they're not cost effective, just as I know Florida Power did with its load management program. I can't think of other examples right off the top of my head, but I know there have been other modifications that we've brought down here in the last year on modifications of utility programs, plus new programs based on new avoided costs.

COMMISSIONER GARCIA: Mr. Wright, I think staff's issued a challenge, if you can find one that's not working.

MR. WRIGHT: That's all I had.

If you had some more questions, I'd be happy to address them.

CHAIRMAN CLARK: Well, I was just curious as to what Lee County -- are they concerned that the DSM programs that people in their county are required to implement are not cost effective or --

MR. WRIGHT: Yes. Lee County's concerned in two regards. One, they're concerned that programs that they, as a significant customer and that their citizens as customers are paying for are not cost effective. They also, frankly, have capacity at a 40 megawatt waste-to-energy facility that they would like to sell on a capacity basis, and they would like to be evaluated on a fair, consistent, current-avoided-cost basis against all options.

CHAIRMAN CLARK: Okay. Thanks.

Ms. Kamaras.

MS. KAMARAS: We're wrap-up batter. I handed out some materials to the Commissioners and the reporter. I apologize for not having extra copies. We're a low-budget operation, but if anybody wants what we handed out, if they'll give me their card, I'll make sure they get it.

I'd love to enter into the debate here with Sheff on this issue, but in the interests of time I will not, except to say that some of the avoided cost data that's been provided in some cases is low-ball. I think you saw some things on the fuel side this morning that suggest that there may be some overly optimistic estimations of what avoided cost really is.

Let me just say that our remarks focus on two things. One is the whole deregulation arena and the fact that we strongly believe that, even in a more competitive, less regulated scheme that we seem to be slowly slogging our way into, that there still is a need for planning and there will still be regulated entities that require resource planning and that will require, we believe, continued government oversight to ensure that that planning is done properly.

We, obviously, continue to have some problems with the ten-year site plan process as not being what we consider to be a real integrated resource planning process, and we believe that there needs to be some increased use of methodologies to look at both direct and indirect costs and benefits of resource options, such as renewable resources, the environmental costs of new and existing resources, risks related to changes in economic conditions or changes in future environmental regulation, and other means.

Planning methodologies have been one of the primary barriers to renewable resources. I think, as the presentations went forward this morning I did not once hear the word "renewable." If somebody said it and I missed it, I apologize, but we're sitting in a state that has a potential for solar energy and we just don't have any at this point, and we're not going to have a sustainable energy future as we're getting into more concerns about global warming and other issues, where we are so coal and petroleum based.

We've got to have an energy future that's based on sustainable resources, and we don't think that this is just a nice social policy. We think it's a hard-ball economic policy for Florida's future, both in terms of keeping our energy dollars in the state and increasing the number of jobs and economic development. I would note that the Florida Legislature this past session included as part of their economic development package a reinstitution of the tax exemption for solar components.

As I mentioned previously, we have some problems with the avoided cost data. Some of the forecasting models we see also are using some outdated data based on 1988 and 1990 information regarding residential appliance and forecast data, and we think that there are some problems with that as well.

We've included some other written comments, and in the interests of getting everybody out of here, I won't go into those, but I hope that the Commission has an opportunity to read those. I would also point out that some of the regional planning councils, from year to year, continue to have some concerns with this planning process and with the deficits in it. I have a copy here of the Treasure Coast Regional Planning Council letter; and again, I would just urge the Commission to look at what the planning councils are saying concerning the energy planning in the state of

Florida.

We -- I understand that the Commission is constrained by a weak statute, but I would certainly urge you to maximize the authority that you have under that statute to try to ensure that we're planning for a sustainable energy future in this state where we have such tremendous growth. Thank you.

CHAIRMAN CLARK: Thank you, Ms. Kamaras.

Anyone else have any comments they'd like to make at this time?

Staff, is there anything you want to say by way of closing remarks?

MR. HAFF: I just wanted to add that we -- if I there are any written comments, that we get a copy so we can incorporate it in our revie /, and, Mr. Wright, I don't know if you had anything written, but if you -- if not, if you're able to summarize it and present it to us, we can incorporate it in our final review.

I just wanted to note, I guess, in closing that we're in the process of writing the review of the plans. We plan to bring it to you in late November at internal affairs for your consideration at that time.

CHAIRMAN CLARK: Thank you.

Anything else, Commissioners?

I'd like to thank everyone for coming to the workshop and presenting their comments.

This workshop is adjourned.

(Whereupon, the proceedings were concluded at 12:45 p.m.)

CERTIFICATE

STATE OF FLORIDA)

COUNTY OF LEON)

I, RAY D. CONVERY, Court Reporter at Tallahassee, Florida, do hereby certify as follows:

THAT I correctly reported in shorthand the foregoing proceedings at the time and place stated in the caption hereof;

THAT I later reduced the shorthand notes to typewriting, or under my supervision, and that the foregoing pages 3 through 109 represent a true, correct, and complete transcript of said proceedings;

And I further certify that I am not of kin or counsel to the parties in the case; am not in the regular employ of counsel for any of said parties; nor am I in anywise interested in the result of said case.

Dated this 2?th day of August, 1996.

Ray D. Convery

RAY D. CONVERY
Court Reporter

AS TO SIGNATURE ONLY
OF THE COURT REPORTER

IN WITNESS WHEREOF, I have set my hand and affixed my seal this 29th day of August, 1996; said instrument was acknowledged before me by RAY D. CONVERY, Court Reporter, who is personally known to me.

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