BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070098-EI

In the Matter of:

PETITION FOR DETERMINATION OF NEED FOR GLADES POWER PARK UNITS 1 AND 2 ELECTRICAL POWER PLANTS IN GLADES COUNTY, BY FLORIDA POWER & LIGHT COMPANY.
_______________________________________/

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VOLUME 9

Pages 1195 through 1384

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LISA POLAK EDGAR
COMMISSIONER MATTHEW M. CARTER, II
COMMISSIONER KATRINA J. MCMURRIAN

DATE: Thursday, April 26, 2007

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

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APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

P R O C E E D I N G S

(Transcript continues in sequence from Volume 8.)

STEVEN R. SIM

continues his testimony under oath from Volume 8:

CONTINUED CROSS EXAMINATION

Q Exhibit 155, Page 2. And this is taken from FPL's response to Staff Interrogatory 82. I want you to have a chance to look at it, or if you are ready to answer questions, we will move on.

A I'm familiar with it.

Q Okay.

MR. GUEST: Madam Chairman, I think I may want to interpose an objection to the introduction of this exhibit.

MS. BRUBAKER: Madam Chairman, the exhibit has already been identified. I'm not seeking to move it into the record. It is used for the purpose of administrative ease in discussing information with the witness.

MR. GUEST: It looks to me like it's a summary exhibit.

MS. BRUBAKER: That's correct.

MR. GUEST: With summary exhibits you have to provide the underlying data and a reasonable opportunity to check it.

MS. BRUBAKER: And actually that information has been provided. The complete response is provided in staff's composite exhibit, which you have stipulated to.

MR. GUEST: Well, I guess my deeper objection, if I might be heard, is that this looks like advocacy of FPL's position. This looks like a repeat of what is in their petition itself. You had asked me before when -- the reason I am raising this is that I had sought to recross at one point in the past, and you had said that you don't generally do that.

CHAIRMAN EDGAR: But I allowed.

MR. GUEST: You did. And what you directed me to do was to articulate objections at the time of the questioning.

CHAIRMAN EDGAR: Yes, I did.

MR. GUEST: I'm doing that here. And what I had raised then at the time was that, well, it is not really cross-examination if what you are doing is bolstering or supporting the witness' testimony. And if you are doing something like that, it doesn't feel like cross, it feels like direct. And if it's direct, then we should get one shot at responding to every piece of the direct. And that was the question I raised with you. And your response was that I should really raise it at the time. Well, it's the time and I'm raising it.

CHAIRMAN EDGAR: I understand. Mr. Harris.

MR. HARRIS: My initial response is staff has never, to my knowledge and time at the Commission, been perceived as a party who would be asking questions to bolster the testimony of one side or the other. The purpose of staff's questions, as I understand them, is to clarify points in the record to allow staff to explore issues that either are raised by the parties and staff believes requires further fleshing out in order to draft the recommendation or to address areas that the parties have failed to bring up.

I suppose that we need to ask Ms. Brubaker if she intends for these questions to bolster FPL's case in chief. If her answer is no, that she needs it in order to obtain information that staff will use to prepare the recommendation to you, then I think that it is appropriate for you to allow that line of questioning. That is the role of your staff, which is to seek information that they believe is relevant in making a recommendation to you. So I believe the correct inquiry would be to ask Ms. Brubaker if she believes that she is attempting some kind of friendly support for a case, or if she is seeking information that staff will use to prepare a recommendation.

CHAIRMAN EDGAR: Ms. Brubaker, are your questions intended to advocate one position or another?

MS. BRUBAKER: They are certainly not. They are not meant to bolster any party's position. Staff always has its responsibility, in its professional judgment, to look at those issues that it believes needs clarification, or have not been explored previously. And honestly in light of the preceding cross-examination for Doctor Sim, I think pretty much that qualifies all of my questions.

MR. GUEST: May I have an opportunity to respond?

CHAIRMAN EDGAR: You may.

MR. GUEST: Well, I don't think that one person's perception or another should really control about what it is or what it isn't. I think that is a decision for the Chairperson. And, so, I think it is; staff doesn't think it is. I think that one can look objectively and make a decision. What is in play, one of the contests here is what is practical doing DSM.

CHAIRMAN EDGAR: I'm sorry.

MR. GUEST: Demand-side -- is there a way that you could enhance demand-side management. And as you know from the prefiled testimony, there are other places that have a much larger investment in DSM than Florida, dramatically larger investments that produce much higher yields, and that is the substance of our testimony. So what we have here is we have a summary exhibit that is basically taking the advocated position of FPL about how far they can go and what the maximums are and then saying that that's what it is. And that is as if we don't have a case here.

CHAIRMAN EDGAR: Okay. As you said, one sometimes can have different perceptions, and my perception is not as you have just described it. So, with that, I'm going to allow the questioning. I have no problem with you raising the objection, of course, and with you reminding me of my previous rulings.

However, I'm going to allow the questioning, and at the appropriate time we will take up whether the documents are to be entered or not.

MR. GUEST: Thank you.

CHAIRMAN EDGAR: Thank you.

BY MS. BRUBAKER:

Q Doctor Sim, if I could have you please refer to Exhibit 155, Page 2. This is taken from FPL's response to Interrogatory Number 82, and if you could look at that second table appearing on that page, the one titled information regarding firm purchased contracts with changes in this time period, please. Now, is it correct that this indicates that FPL currently has 1,087 megawatts of firm capacity contracts that are due to expire during the period of 2009 through 2012?

A That's correct.

Q And of this amount, 143 megawatts are from municipal solid waste facilities, is that correct?

A That's correct, the Broward South, Broward North, and Palm Beach Solid Waste is shown in this table.

Q And in FPL's response to Staff Interrogatory Number 82 -- and if you would like to look at that page, it appears on the Blue 156 Exhibit, hand-numbered Number 7. And my question is it is indicated in that response there that FPL has contacted, had contact discussions with representatives from the Palm Beach County Solid Waste Authority, is that correct?

A That's correct.

Q And that would be regarding a contract extension of their municipal solid waste energy project expiring in 2010?

A That's correct.

Q Were the other two MSW facilities not contacted regarding renewals of their contracts?

A I do not know.

Q Do you have any knowledge whether FPL intends to pursue renewing these types of contracts?

A I have no direct knowledge, but my understanding is that the parties would be approached and a potential new agreement may be discussed.

Q What avoided cost are you using to evaluate the cost-effectiveness of renewing these types of renewable contracts?

A At present, to my knowledge, we are not doing analysis on evaluating the cost-effectiveness of these contracts.

Q Is it correct that FPL has submitted a proposed standard offer contract that would be made available to these renewable waste-to-energy plants?

A That's my understanding, yes.

Q And in that standard offer contract filing, is it indicated that FPL would be willing to negotiate a coal-based contract with these renewable generators?

A I don't deal with the standard offer contract. I believe Mr. Silva, among our witnesses, would be the best one to ask that question of.

Q Okay, thank you. Now, FPL didn't issue an FPL for the Glades units, is that correct?

A Could you repeat the question, please.

Q Certainly. FPL did not issue an RFP, a request for proposal for the Glades units, is that correct?

A That is correct. We came before the Commission and requested a waiver versus an RFP, and it was granted by the Commission.

Q In brief, what was the reason for requesting the waiver?

A In brief, it was to facilitate the implementation of coal-based capacity and energy on our system to maintain and enhance system fuel diversity.

Q So fuel diversity was the primary driving factor?

A I would say the speed with which we could implement coal-based capacity in order to maintain system fuel diversity would be the reason, yes.

Q If I could again refer you, please, to Exhibit 155, Page 1 of that exhibit.

A Okay.

Q And specifically I'm going to be discussing the middle table that appears there, estimated impact on FPL's summer reserve margin due to purchased power contracts to expire. And then let me just kind of briefly walk you through that table. Some of that information is -- well, specifically it's the second table there, reserve margin without FGPP assuming purchased power contracts renewed. And there are some calculations there that I prepared, and let me just kind of walk you through how I got to those calculations. And in order to do that I would like to refer you, please, to your Prefiled Direct Exhibit SRS-1.

A Okay.

Q Now, on SRS-1, if you will look at the table -- there are two tables listed there, one says summer and one says winter, and it is a discussion of the projection of FPL's 2007 through 2015 capacity needs without new resource additions. That's the title of that exhibit. Specifically, I started with Column 7, and for summer of 2013, the forecast of summer reserves, that number is 3,421 megawatts, correct?

A Yes.

Q Now, I added in on a hypothetical the 1,087 megawatts of purchased power, which we previously discussed, to get a sum total of 4,508, and then I divided that amount by the firm peak forecast in Column 6, which for 2013 for summer is 23,074 megawatts. And I resulted in 19.5 percent and so on for years 2014 and 2015 as shown on Exhibit 155.

Now, we understand that it's a hypothetical of adding in the 1,087 megawatts, but would it be correct that the percentages that are shown on the reserve margin without FGPP assuming purchased power contracts renewed appearing in the center of Page 1 of Hearing Exhibit 155, is it correct that those would be the resulting reserve margins if the 187 megawatts of firm capacity contracts were extended through the year 2015?

A You mentioned 187; you mean 1,087?

Q I'm sorry, 1,087.

A Assuming your math is correct, yes, those would be the percent reserve margins.

Q Okay. If one were to accept what the numbers show here for the sake of argument, do the numbers also show or indicate that FPL's need might shift one year to 2014?

A I think I would have to say no, because I would disagree with the premise of the question for a couple of reasons. If I may?

Q Certainly.

A Turning back to Page 2, which has the table of the expiring contracts. There are two contracts there, the third and fourth labeled Progress Energy Ventures and Williams, which FPL attempted to extend beyond the current expiration date, but was unable to do so. The reason for that is these contracts are based on excess capacity for co-ops in Georgia for which that capacity bubble, so to speak, was ending near the term of these contracts, and the parties were unwilling to extend the contracts, therefore, beyond the time frame. So the 105 megawatts and 106 megawatts, or 211 megawatts would, therefore, not be available to FPL and, therefore, could not be counted even hypothetically in the calculation you did on Page 1.

Now, if we take that for a moment and go back to Page 1 and look at your first year of 2013, where you have calculated a 19.5 percent reserve margin. As a rule of thumb, FPL has about a 200-megawatt level which brings the reserve margin up or down about a percentage point. So, subject to check, this 19-1/2 would move down to about 18-1/2. So, therefore, physically we could not do this.

And I think there is a second reason why we couldn't do it, because we would then be at an 18-1/2 percent reserve margin. And I refer you to the Commission order in the Hines 3 case in 2003. And if I may, let me read the appropriate points. It's discussing the stipulation reached between the three IOUs back in 1999 regarding setting a 20 percent reserve margin. And I quote, "By approving the stipulation proposed by the IOUs and issuing the above order, we have already determined that 20 percent is the appropriate reserve margin criteria, and the IOUs are required to utilize this criteria unless modified in a subsequent proceeding."

It then goes on to say that, "The proper forum to address what minimum reserves are necessary should be in a generic docket as was previous done and not in a particular utility's power plant need determination docket." Therefore, based on that, FPL is required to use a 20 percent margin. Since the highest we could do, even assuming that you could sign up all of the rest of these parties other than Williams and Progress, the closest we could come is approximately 18-1/2 percent.

Now, if we move beyond the question of could we do this, I think the question is should we do this in regard to or in relation to comparing it to FGPP. And my answer would be no for a couple of reasons. If you go back to the table on Page 2 of Exhibit 155, you will see, as was pointed out, that there are 143 megawatts of the waste-to-energy facilities which will bring some fuel diversity to our system. Of the 1,087 megawatt total, that equates to roughly 13 percent of the total capacity would bring fuel diversity to our system, which means that the remaining 87 percent, even assuming you could get them, is fossil fuel, primarily combustion turbine and oil-fired units. Therefore, in comparison to FGPP, we would be bringing a very small amount of fuel diversity to our system, certainly much, much less than 2,000 megawatts of highly efficient coal technology.

The second question moving beyond fuel diversity is cost-effectiveness. These capacity contracts on Page 2, several of them, the Indian River, the second item, which makes up the bulk of the 1,087 megawatts of 576 megawatts to be specific, as well as the Progress Energy Venture and Williams were signed due to this 2005 very high load that I mentioned earlier. Therefore, they were economical as short-term stopgap measures, but may not and probably will not be cost-effective on a longer term basis compared to something like FGPP.

To showcase that a bit, I will take a look at Indian River, which as I mentioned makes up the bulk of the 1,087 megawatts. It is a short-term contract. It is an oil-fired unit, well over a 10,000 heat rate, and the capacity factor at which it was operated on in FPL's system last year was approximately 5 percent. So it operates like a combustion turbine. Oleander down below, a combustion turbine.

So what we are seeing is fairly inefficient, very low capacity, and nonfuel diversity options here that would not be cost-effective on FPL's system in the long-term in my opinion. So, in trying to sum up this lengthy answer, I would say that two of these projects simply are not available. The Commission order requires us to use a 20 percent reserve margin criteria in our planning, and without those two projects the closest we could get is 18-1/2, so we couldn't satisfy the Commission requirement.

These would do very little to bring any fuel diversity on our system. These would almost certainly not be cost-effective in the long-term. In fact, as an analogy the only thing I could think of that -- maybe not the only thing, but one of the things on a simplified example basis that might even be worse than this would be if we were to satisfy all of this with combustion turbine capacity, which would do nothing for our fuel diversity. It certainly would not be cost-effective on our system, and, therefore, would be something that would be analogous to this extension of -- hypothetical extension of the purchased power contracts.

Q And you referenced a 20 percent reserve margin that you use for your projected reserve margin, correct? And that is based on a Commission order for FPL, Progress, and TECO, if I remember correctly?

A That's correct.

Q And that was pursuant to a stipulation by various parties in that docket, the agreement to use the 20 percent, correct?

A And approved by the Commission.

Q And approved by the Commission, of course. Do you recall at your deposition we had some discussion about that order, and I had asked whether you were aware to your knowledge whether FPL or any other party involved in that docket had performed a report, or study, or cost analysis of the use of the 20 percent reserve margin value; do you recall that?

A Generally, yes.

Q And your answer at deposition was that to your knowledge no such study, or report, or analysis was done?

A I am certainly not aware of any that has been brought forward by the other utilities, that's correct.

Q Are you aware of any such studies being conducted or performed since the approval of that stipulation? In other words, since the time the stipulation has been approved, to your knowledge has FPL specifically made any assessment regarding cost-effectiveness or the effective reliability of using a 20 percent reserve margin?

A I'm sorry, what was the last part of your question?

Q I'm sorry. Actually let me back that up. Let me lay a little foundation for the question. FPL is a member of the FRCC, correct?

A Yes.

Q And what reserve margin do they use for their planning purposes?

A For planning purposes, the FRCC uses a 15 percent reserve margin.

Q With that in mind, since the time the 20 percent stipulation was approved by the Commission, has FPL to your knowledge done any analysis or study about the appropriateness of the 20 percent versus the 15 percent reserve margins?

A We have completed no such analyses.

Q Okay. Now, with regard to the FRCC reserve, if I could refer you, please, to Page 1 of Exhibit Number 155?

A I'm sorry, which page?

Q The first page. And if I could refer you, please, to the last table on that page, the one titled estimated impact on FRCC summer reserves. Now, the source for that information comes from FPL's response to Staff Interrogatory Number 9, and if you would like to refer to that, it's Attachment 1 to that response. It is the first two columns, summer reserve margin projection. If you are willing to take those numbers subject to check, I am happy to move on, or if you would like to see the source, I'm happy to --

A Subject to check, we will accept them, yes.

Q Very good. Now, is it correct that the information shown on this last table on Page 1 of Exhibit 155 shows that the projected reserves for the Florida Reliability Coordinating Council, FRCC, are at or above 20 percent during the period 2010 through 2013?

A That's what it shows. Again, pointing out that this does not reflect units that the utilities are committed to, it merely -- especially the longer one goes out in this time frame it reflects projections of the utilities that were circa about a year ago when the utilities did their planning and reported to the FRCC.

Q Now, you mentioned units in the FRCC region that are not committed to being built during this period. Could you identify for me, if you know, what units those are?

A I would say any unit that was identified in each individual utility's site plan or submittal to the FRCC which has not received a determination of need, those would be the units. They would be far too numerous to mention here.

Q Now, we have already discussed the FRCC uses a 15 percent reserve margin planning criteria, correct?

A Yes.

Q To your knowledge, do you know whether that 15 percent reserve margin was based on any study, report, or analyses performed either by or through the FRCC? In other words, how that number, 15 percent, was arrived at?

A The number has been in place for a fair number of years, and I don't recall exactly how it was created. I don't recall a specific study that was designed to create the 15 percent. There have been what I will say complementary analyses that the FRCC has done from time to time, both on loss-of-load probability as well as on what I will call an early warning system, or a trip wire to LOLP that looks annually at megawatt-weighted forced outage rates for the Peninsular Florida utilities, as well as megawatt-weighted availability. And what those have shown is from an LOLP basis and what these trip wire studies are designed to do is to show whether it may be necessary to do an LOLP study because it is so time-consuming and so exhaustive an exercise to do an LOLP study for the entire peninsula. Those have shown that from an LOLP or probabilistic basis that Peninsular Florida, as a whole, is reliable.

Q Let me ask one more question, if I could, about the units that aren't committed for the FRCC region up through the 2013 period. I'm going to name some units, and if you would, you say you don't know specifically, but if it rings any bells that these might be some of the noncommitted units, if you would let me know, please. Glades, the FGPP project?

A I would say FPL is committed to it, and upon approval by the Commission and site certification application will absolutely be a committed unit.

Q The Taylor County project that is co-sponsored by the City of Tallahassee, JEA, FMPA, and Reedy Creek?

A I think, in general, I would put in the same category as the Glades unit.

Q What about Gainesville's Deerhaven 3 Unit?

A Not familiar with the status of it.

Q TECO's IGCC?

A Not familiar with the status of it.

Q Progress' coal unit?

A Subject to check, I don't recall that unit showing up in this year's ten-year site plan for Progress, therefore, I would say that is definitely not a committed unit.

Q Thank you.

If I could refer you, again, to Exhibit Number 155, Page 3 of that exhibit. And the table there is titled comparison of FPL's generation alternatives. And I'll identify for you the source of that information. It comes from Appendix H of the need study. Specifically, Page H-1 of 1, and the second is FPL's response to Staff Interrogatory Number 94.

So if you're willing to look at those numbers subject to check, we will move on, or I would be happy to show you the source documents?

A I believe there's a couple of corrections that would need to be made. I looked at this before.

Q And certainly on the first day of the hearing I did mention that on the third column, 2012 gas CC, the 750 that is located there, it is the first number appearing on the right-hand side, should be 734. And if you are aware of others, please go ahead and identify them.

A On the third column, the 1,115 megawatt in the subtitle, I believe, should be 1,219 megawatts. And on the first row, the total installed cost without the AFUDC, I believe the 4,197 for IGCC is with AFUDC and not without. And I might note that the table does omit several important program costs or performance characteristics here, but, subject to check, the rest of it appears to be accurate.

Q Now, you mentioned the 4,197 number, that is without AFUDC. Do you happen to know the number with?

A No. I believe what I said is that number is with AFUDC, and I don't know off the top of my head what the AFUDC number is that you would need to subtract to get a without AFUDC number.

Q Okay. With regard to the number that appears in the column 2013 USCPC, the 2,796, can I get confirmation that is without AFUDC?

A You are correct, that is without AFUDC.

MS. BRUBAKER: If I could take just a second.

CHAIRMAN EDGAR: Ms. Brubaker and others, it is about that time. I would like a stretch. Let's take about a ten-minute break and then we will come back and proceed.

(Recess.)

CHAIRMAN EDGAR: Okay. We'll go back on the record.

Ms. Brubaker.

MS. BRUBAKER: I will do the best I can with this.

BY MS. BRUBAKER:

Q Doctor Sim, I'm referring to Interrogatory Number 94, FPL's response to that. If you could look in Exhibit 156, that's the hand-numbered Page 12.

A Okay.

Q And I'm looking specifically at the row titled construction grand total cost in-service year with AFUDC, and the number there, 4,197,440. Would it be possible to get as a late-filed exhibit what the appropriate number there would be without AFUDC?

A Yes.

MS. BRUBAKER: I would like to have that identified.

(Phone ringing.)

CHAIRMAN EDGAR: I would note for the record that was Mr. Harris and not my child. (Laughter.)

MS. BRUBAKER: Madam Chairman, I would move Mr. Harris out of order.

MR. HARRIS: Sustained.

CHAIRMAN EDGAR: Okay. So we will have 185, which will be a late-filed amendment to correct numbers contained within Exhibit 155.

MS. BRUBAKER: Well, if we could make it the Interrogatory Number 94.

CHAIRMAN EDGAR: Okay.

MS. BRUBAKER: That would be fine.

CHAIRMAN EDGAR: And, again, that would be 185.

MS. BRUBAKER: And that will be late-filed.

(Late-filed Exhibit 185 marked for identification.)

BY MS. BRUBAKER:

Q If I could next refer you, Doctor Sim, to Exhibit Number 155, again, Page 3.

A Okay.

Q Specifically, I'm looking at the emission rates that are indicated at the lower half of that table. Now, is it correct that the information indicates that SO2, NOx, and CO2 are comparable for the Glades project versus an IGCC plant?

A Yes, that is what the data on this page knows.

Q Were you present during Mr. Hicks' cross-examination?

A I was present during portions of it.

Q Do you recall he was asked some questions regarding SO2 and CO2 values that are shown here?

A I don't recall that discussion, no.

Q He indicated you might able to answer a question. It appears that those numbers are identical for the USCPC and IGCC. Can you explain to me why that's the case?

A In part, I'll try. The numbers were handed to us by FPL's engineering and construction group, and to my knowledge, the emission rate numbers for the ultra-supercritical were based on the numbers that were filed in our site certification application. In regard to the IGCC, my understanding is that those numbers were selected to be representative of IGCC filings or projections that were around the country, those units that have been projected, not currently built.

Q If I could refer you next, please, to Page 4 of Exhibit 155. And just for clarity sake, this has been excerpted from FPL's response to Staff Interrogatory Number 93, Attachment 1. And is it correct this table shows the total cost and total differentials for the 16 scenarios discussed in your testimony?

A That's correct. It shows those costs for the two resource plans. It does not include the cost for the plan without coal of the comparable LNG gas storage.

Q Now, this table indicates that FGPP is not always the most cost-effective option as compared to a plan without coal, is that correct?

A That's correct, and that was expected before we even started the analysis.

Q And why is that?

A Because when we're looking at different types of units, such as coal and gas-fired units that have significantly different capital costs, significantly different heat rates, and depend upon entirely different fuels, when you are looking at fuel forecasts over the time period, as well as environmental compliance costs forecasts over 16 scenarios, it would be very surprising, to say the least, where you have got one technology that was a winner in all of the scenarios. So it was expected that you would get some scenarios in which one resource plan won and some scenarios in which another resource plan won.

Q Now, the scenarios you discussed in your testimony, they offer a range of years. I think it is 2006 to 2054, is that correct?

A I believe that's is correct.

Q Forty years from basically the in-service date?

A Correct.

Q And the table here on Page 4, that indicates that there is a fair range of net savings, approximately 2.8 billion, or 1.7 percent of total system cost to a net cost of 4 billion, or 3.8 percent of total system cost, correct?

A That's what the table shows, yes.

Q Would you agree that in weighing and evaluating these 16 scenarios discussed in your testimony that a lot would depend on what one believes will happen regarding the price of fuel and environmental compliance costs?

A I'm sorry, can you repeat the first part of the question?

Q Certainly. When one is to weigh and evaluate the different 16 scenarios about what is likely to happen about what one might put forward as the most likely scenario?

A I would think one would view the total data involved and should recognize, as FPL did, that no one knows what the fuel forecasts are going to be over this time frame, and no one knows what the environmental compliance costs are going to be over this time frame. Furthermore, there is uncertainty as to how the environmental compliance costs will impact the fuel costs over the time period. So we have uncertainty in fuel, we have uncertainty in environmental compliance costs, and then we have the impact of the compliance costs on the fuel costs, and essentially uncertainty compounding upon itself.

And that's why FPL took the view that this was a scenario analysis. It wasn't the type of analysis where we said here is the most likely set of forecasts and we will work sensitivities off of that. FPL was very careful to say correctly that the correct way to look at this is through a scenario analysis.

Now, what this shows to me is you are getting roughly an even split of cases in which the case with coal is the economic winner versus the case without coal. And, again, these set of costs for the resource plan without coal do not account for the approximately 1.4 billion CPVRR cost of comparable gas storage which would allow these two plans to be truly comparable both in terms of reliability for reserve margin as well as reliability of fuel supply.

Another item I would mention is that -- well, before I leave that one, the addition of those costs as indicated in Mr. Silva's testimony would change it from a case of, I mentioned before, 7 out of 16 cases with coal being the economic winner to 10 out of 16 being the economic winner.

Furthermore, in those cases in which the plan without coal is the economic choice, you typically are looking at very low natural gas prices; and that is shown, Commissioners, in Columns 3 and 4 here. As you look at these in terms of, say, blocks of four rows each, you will see that the first set of costs start at 159 and 162 and then those are with the Fuel

Forecast 1, Scenario 1A, 1B, 1C, 1D. That is the high gas/coal differential forecast.

As you drop down -- well, let me back up. Before leaving this 1A, 1B in all of those cases coal was the winner, recognizing that with high gas costs, coal is clearly the economic choice. If you take the other extreme and go down to the bottom four rows, and take the lowest gas/coal differential case, the 4A, 4B through 4D, you see that the 159 and 160,000 numbers drop significantly to a total cost of 87 to, say, 110,000 in this view, which means that FPL's customers would be exceedingly better off in regard to total cost due to low gas costs.

So even with the FGPP units on its system, if you take the differential it is roughly on the order of $70 billion CPVRR moving from high gas forecasts to low gas forecasts, and yet the differential on Column 5, the highest penalty, so to speak, for the coal units is only on the order of $4 billion. So FPL's customers would receive the benefits of the low gas due to the significant number of gas units on our system on the order of $70 billion versus a $4 billion penalty. And we view that as showing that the coal units are a very effective economic hedge against gas prices, because FPL's customers will still be significantly well off due to -- well, benefit significantly from low gas prices if they were to occur.

Q In your direct testimony you state that FPL's plan with coal acts as a hedge or insurance against higher natural gas costs, correct?

A That is correct.

Q And would you agree that FGPP could be characterized as a capital intensive project?

A Yes. I would say any coal project, for that matter any nuclear project would be a capital intensive project compared to other generating alternatives such as combustion turbines or combined cycles.

Q Is it correct to say that over time FPL expects that there will be fuel savings associated with the FGPP project?

A Most definitely. Significant fuel savings.

Q And is it also correct to say that given a capital intensive project, like FGPP, that it may take a certain amount of time to allow those fuel savings to offset those increased capital costs?

A Yes, that's fair to say. And that is not unexpected. In fact, if you look at virtually any resource comparison you are going to see more often than not the more capital intensive projects take a number of years before the fuel savings kick in and result in a net cumulative savings. And we see that not only in power plants. We see delays in one project being more cost-effective than another on a rolling cumulative basis. For example, when we view DSM versus generating units, DSM must be signed up, for example, over a number of years before it can reach a stage where it is of a size to avoid or defer a block of capacity.

We are incurring costs for DSM in all of those early years and it is only after the avoided unit would have gone in service, and typically several years after that before the net savings from DSM overcome the initial upfront cost of it. So, it's not unusual. And, in fact, it's to be expected that it will take a number of years before one resource decision, especially a capital intensive one, the cost disadvantage is made up for with the fuel savings.

Q Now, if the fuel cost differential between natural gas and coal should become very small, or if environmental costs should become very high, is it correct or would you agree that fuel savings may never necessarily offset the capital cost of coal units?

A I view that as two questions. I would agree with the first and not the second. And let me try to explain. If natural gas prices compared to coal remain very low for an extended time period, then with perfect hindsight one can look back and say the coal unit was not the economic choice. However, we don't know that today.

The second part of your question is high environmental costs. It is FPL's contention, and I think those of several of our witnesses that the likelihood of high environmental compliance costs and low gas prices just isn't going to happen. That the higher the environmental compliance costs goes, the more demand there will be for natural gas and, therefore, the price of natural gas will be driven up.

For example, in this table I have in front of me, Page 4, I think what that would say is the last four rows, or at least several of the last four rows, the 4D, 4C, and 4B I would view as very unlikely to occur simply because they have the highest environmental compliance costs and yet assume low natural gas prices. I just don't think that's a likely occurrence.

Q Do you recall during your deposition we had a few questions regarding looking at the difference in CPVRR between the plan with coal and the plan without coal through the year 2027?

A Yes.

Q And is it correct that only two of the 16 scenarios explored show a positive net benefit for the FGPP through that period 2027?

A I think our discussion focused on the plan with coal and the plan without coal without adding the LNG natural gas storage. I think that analysis, which we would term a somewhat incomplete picture of the total cost, would show what you indicated. But I think as some of our later filed exhibits and interrogatory responses showed that when you include the LNG storage cost that the length of time it takes before, we will call it, crossover of the coal plan and the natural gas plan is shortened considerably.

Q By how much, do you know?

A I don't have the document in front of me. I think we filed that as a late-filed exhibit.

Q Okay. Those two scenarios I was referring to, to your memory are they Scenarios 1A and 1B?

A If you could show me the document, I would be happy to take a look at it.

Q Well, I can either refer you to your deposition transcript if you would like, or --

A I don't have my deposition transcript.

Q That's all right. I can refer you to the interrogatory.

MS. BRUBAKER: What I'm passing out is a copy, it is a full copy of FPL's response to Interrogatory Number 25. It is part of Staff's Composite 2.

MR. GUEST: Madam Chairwoman.

CHAIRMAN EDGAR: Mr. Guest.

MR. GUEST: I have seen Advil bottles with larger type than this. And maybe it's my age, but the top line appears to have writing on it.

CHAIRMAN EDGAR: The one that's darker?

MR. GUEST: Yes.

CHAIRMAN EDGAR: Let's see, fuel cost forecast.

MS. BRUBAKER: I can read that for you, Madam Chairman. It's Fuel Forecast 1, and that actually is the column I will be referring to.

CHAIRMAN EDGAR: So going across it's Fuel Cost Forecast 1, Fuel Cost Forecast 2, then 3, then 4.

MS. BRUBAKER: That is correct.

CHAIRMAN EDGAR: Does that help, Mr. Guest?

MS. BRUBAKER: It basically serves to cross-reference the four fuel scenarios with the four environmental scenarios. The columns are 1, 2, 3, and 4 for the fuel cost; and it is cross-referenced with the row below it, Environmental Compliance Scenarios A, B, C, D; A, B, C, D.

MR. GUEST: Is there a unit that is shown here for what these numbers are? I mean, are they -- oh, they are in millions of dollars.

MS. BRUBAKER: Yes.

CHAIRMAN EDGAR: 2006.

BY MS. BRUBAKER:

Q Doctor Sim, have you had a chance to review the interrogatory response?

A To the extent I could read it, yes.

Q My apologies for the eye strain. Again, I'm just looking for confirmation. This was something we had discussed in the deposition. Looking for the period 2006 through 2007, is it correct that -- or, I'm sorry, 2027 -- is it correct that the two scenarios, and the only two scenarios of the 16 listed here that show a positive benefit for the plan with coal are Scenarios 1A and 1B?

A I'm sorry, could you repeat the question?

Q Certainly. Looking at the various 16 scenarios listed here, is it correct that the two scenarios, and it is the only two scenarios for the period 2006 through 2027 that show a positive benefit for the plan with coal are Scenarios 1A and 1B?

A Subject to check, I'll accept that. I'm having a tough time reading it myself.

Q Again, my apologies. Is it correct that Scenarios 1A and 1B both represent a high fuel cost differential and low environmental costs?

A Yes, a high gas/coal differential and low net environmental compliance costs.

MS. BRUBAKER: Thank you.

If I may, I would like to go ahead and hand out two documents. I have the source documents if anybody wishes to refer them, but rather than put the entire Progress and TECO 2007 year site plan into the record, I was hoping that the parties would be willing to consider an excerpt. However, I do have those full documents available if that is the preference.

What they consist of is Schedule 6.2 from, again, Progress and TECO's 2007 year site plans. And the reason I'm passing them out is those items were not previously entered into the record through staff's composite exhibit, so I just wanted to make sure everybody had a clear source.

BY MS. BRUBAKER:

Q Now, Doctor Sim, if I could, please, refer you to Page 5 of Exhibit 155.

A Okay.

Q And this page we have captioned as system fuel mix projections, and the source for this information, again, comes from Schedule 6.2 for Progress Energy and TECO's Ten-Year Site Plan for 2007, and it is also pulled from information in your Exhibit SRS-15, Page 1 of 1. And, again, if you would like to look at those sources, that's fine, or if you are willing to take the numbers subject to check, we can move on with the question.

A We'll assume they are correct.

Q I'm sorry?

A We'll assume they are correct.

Q Thank you. Now, does this page indicate that FPL's fuel mixes is more heavily dependent on natural gas than either Progress or TECO?

A Yes, definitely.

Q And for the time frame that is represented here, 2012 through 2016, is there a substantial difference in FPL's relative fuel mix between coal and petcoke, natural gas, whether you are looking at FPL's plan with or without FGPP? In other words, looking at the first two tables, FPL with Glades plant, FPL without Glades plant, looking at the relative distribution between coal and petcoke and natural gas, is there a significant large difference in the percentages shown there in those two tables?

A Yes.

Q What I'm looking at is, for instance, the year 2012 and the coal/petcoke column. They both represent 11.5, so I see no difference there. And I'm looking at a maximum difference in 2016, 60.4 percent with natural gas, 71.1 percent with natural gas, and that is with Glades plant and without Glades plant. Do you consider that roughly 11 percent to be a substantial difference?

A On a system the size of FPL, absolutely. Both in terms of the energy that is produced and in terms of the system reliability that is engendered by the addition of coal on the system.

Q If I could refer you next, please, to Page 6 of Exhibit 155. And for the sake of reference, this is Attachment 1 from FPL's response to Staff Interrogatory Number 79. Now, this chart shows the average residential electric price versus the percentage of net energy load for natural gas, correct?

A That's correct.

Q Now, looking at the year 1990 when the percentage of

NEL from gas was around 18 percent, FPL's residential rate was approximately 8 cents per kilowatt hour, correct?

A That's what it shows, yes.

Q And if I could have you next look at the year 1995, and it looks like FPL's generation from gas was approximately 30 percent at that time, correct?

A Yes.

Q And the residential rate was still approximately 8 cents per hour, maybe just a tad less, correct?

A Yes, roughly equivalent.

Q Okay. Would you agree that according to this graph residential rates didn't really start to increase or climb until the percent of NEL from gas reached about the 40 percent mark?

A I would agree that's what the graph shows. I think there are two factors here. Number one is a greater reliance in terms of the percentage of energy supplied by natural gas as well as a significant run-up in the cost of natural gas during the same time period.

Q Doctor Sim, do you have a copy of the need study, and more specifically the appendices to the need study available to you?

A I have a copy of the need study itself. I do not have a copy of the appendix with me. I'm sure we could get one.

MS. BRUBAKER: With counsel's permission, I'm happy to pass out the single page I am interested in.

CHAIRMAN EDGAR: Okay.

MS. BRUBAKER: We will go ahead and do that then. What I am handing out is a page from Appendix M of the need study. Specifically, it's Page 1-13. I will go ahead and let everybody get a copy of that and, Doctor Sim, give you a chance to review.

BY MS. BRUBAKER:

Q Just so we are clear, this is a study performed by Black & Veatch comparing solid fuel technologies, correct?

A I believe it was performed by Black & Veatch in collaboration with FPL. And I might point out that I believe that Mr. Hicks is sponsoring the Appendix M in the need study and he might be a more appropriate person to ask these questions.

MS. BRUBAKER: With counsel's indulgence, the questions aren't so much on the particular information, but how these types of analyses are typically used.

THE WITNESS: Okay.

BY MS. BRUBAKER:

Q And if, as I question, it seems like it should be deferred, I am happy to accept that.

Now, the graph that is shown here is a typical screening curve used in electrical generation expansion plans, correct?

A I would clarify slightly not in terms of expansion plans. It's what's called a screening curve of resource options is more typically used, and it is typically used to screen out options that would operate in similar capacity factors on a utility's system by trying to clearly identify which units are the economic winners or losers within a select group of resource options.

Q Okay. Now, in your time and experience with FPL, have these types of screening curves been used for an appreciable length of time?

A They have been used since I have been in the planning department, probably 15 years or so off and on, yes.

Q And is it correct that this type of screening curve is commonly used by utilities to compare the like technologies before you perform a more detailed system revenue requirement analysis?

A Yes, that's generally how they are used.

Q And a similar screening process would be used, would be done for other types of technologies, such as gas-fired combined cycle or peaking capacity additions, correct?

A Yes. For example, we might look at different combined cycle units in which the turbines were supplied by GE, Mitsubishi, et cetera, in different configurations, and we would use a screening curve analysis to compare the competing combined cycle options or the similar peaking capacity options.

Q Does a base load unit typical run at full capacity whenever it's available to run?

A Yes. Generally to the extent of its availability it will typically run.

Q And does this mean that the capacity factor and availability factor for these units are similar?

A They are pretty close, if not identical, yes.

Q Is it correct looking at this, the graph that I provided you that it also shows that a USCPC unit is more cost-effective than IGCC?

A That's correct through all of the capacity factors shown on the graph.

Q And that is true then even at the lower availability and capacity factors levels, then?

A At the lower capacity factor levels, yes.

Q Lastly, I'm hoping you have this available to you. Do you have at your station, it's been identified as Exhibit 161? It's FPL's supplemental response to Staff's Fifth Set of Interrogatories, Number 112?

A Does it have a cover on it?

Q It is an odd lavenderish gray cover. We will provider an extra copy. And when you have had a chance to review, Doctor Sim, if I could refer you specifically to the last page of that. I believe it is numbered Page 11.

A Okay.

Q Now, I am looking at -- from going from Appendix M to this discovery response, can you explain for me what this discovery response, this page, Page 11 signifies, what it demonstrates?

A Yes. It's a screening curve analysis comparing the advanced technology coal, which is the lower line on the graph, to various perspectives of IGCC units. The 50/50 or 0/100 refers to the mix of fuel. The first number refers to the percentage of the fuel mix that is coal. The second number is that of petcoke, so the 50/50 is 50 percent coal, 50 percent petcoke. The 0/100 is 100 percent petcoke.

There are also variations in regard to emission rates, and those emission rates were examined, I believe, in regard to Mr. Hicks' deposition in which there was a question or two in regard to the emission rates chosen for the IGCC. So in response to a request for a late-filed exhibit, we went back and reexamined IGCC with several different emission rates and the different fuel forecasts or fuel mixes that you see here.

MS. BRUBAKER: Okay. And with that staff has no further questions.

CHAIRMAN EDGAR: Doctor Sim, earlier you answered some questions regarding the reserve margin. Has that 20 percent proven to be efficient?

THE WITNESS: It has certainly proven to be effective.

CHAIRMAN EDGAR: That was going to be my next question, actually.

THE WITNESS: Okay. And let me try to explain, Madam Chairman. FPL's system has certainly evolved from, say, ten years or so ago when we were operating at a 15 percent reserve margin. And I think there are two aspects of that that I could touch on. Number one is we have a much larger number of units on our system than we had before, and back about ten years or so ago we had, I think, four advanced combustion turbines on our system as part of a couple of combined cycle units at Martin and Fort Lauderdale. Excuse me, eight advanced combustion turbines. And those combustion turbines are different than the old traditional steam generating units in that they must come out for maintenance at very specific times. At a number of run hours you have to take them out or you will have catastrophic failures of the turbines.

Today, looking at where we will be at the end of even 2011 with the West County Units coming in, we will have shifted from eight of those advanced combustion turbines to 42 advance combustion turbines, which makes it much more difficult to schedule maintenance for those units due to the fact that there are very well-defined lines of running hours over which those units can only go before you have to take them out. So it is more difficult to schedule maintenance.

The 20 percent reserve margin has assisted us in finding time to do maintenance for those and other units. It has also allowed us to add more fuel efficient capacity on our system, which has allowed us to back off of some of our older conventional less efficient units and decrease their run times thus resulting in fuel savings.

CHAIRMAN EDGAR: I think in response to one of the questions from Ms. Brubaker you answered something along the lines of a comprehensive analysis on that 20 percent not having been done, and I guess that leads me to my next question. Realizing that that order approving the stipulation was issued prior to my being on the Commission, was there then or has there since been analysis, or thinking, or exploration -- let me begin again, I'm sorry.

Why 20 percent rather than 17 or 18 or 19 or some other number between 15 and 20 or between 15 and 25?

THE WITNESS: It's a question that I think it is safe to say FPL has considered. And let me go back to my earlier explanation of the very high load forecasts or load that we experienced in 2005. We have taken or had taken some steps to begin an analysis of reserve margin back in those time frames, but I guess the flow of our thinking and the flow of our analysis was kind of brought to a halt when we experienced that very significant load.

Frankly, we have only had one summer since then in which to look at an additional data point and try to see how much of an aberration that 2005 was. For us to feel comfortable in going forward with an analysis of what the appropriate reserve margin was, frankly, the most recent and significant data point is that 2005 load which showed how much uncertainty there was in our load forecast.

For that reason and for others, FPL believes it is certainly appropriate to hang onto the 20 percent reserve margin. In regard to analysis we have done, I believe Mr. Silva has introduced in his rebuttal testimony a simple but powerful example of why a 15 percent reserve margin simply does not work for FPL, and I will be happy to discuss that now if you would like.

CHAIRMAN EDGAR: Could you do it briefly?

THE WITNESS: We have an example on a handout. If we could show you that, I could walk through it pretty quickly, I believe.

MS. BRUBAKER: May I take advantage of the brief lull while we are putting up information? My apologies, Madam Chairman, I had meant to ask to have the Schedule 6.2 for Progress and TECO identified as Exhibit 186. May I do so at this time? My apologies for the interruption.

CHAIRMAN EDGAR: Let me get there. Okay. So that will be 186. And, I'm sorry, a title for me again, if you would?

MS. BRUBAKER: Certainly. Schedule 6.2, Progress and TECO's 2007 Ten-Year Site Plan.

CHAIRMAN EDGAR: Okay.

(Exhibit 186 marked for identification.)

THE WITNESS: I will try to walk through this quickly. What this document examines is going back as a starting point to my Exhibit SRS-1 where we looked at what would happen in 2013 in regard to our capacity needs and reserve margin if we did not add FGPP. The reserve margin I showed in that exhibit was a 14.8 percent reserve margin. So we are looking roughly at a 15 percent reserve margin for 2013. And what it shows in the first row is identical to what I have presented in SRS-1.

It shows that we had no units in Column B out on planned maintenance in August as scheduled. It showed in Column E, how much of our total reserves were generating capacity reserves, which is 905 megawatts, which would represent a reserve margin generator only of 3.5 percent. So instead a 14.8 percent reserve margin, we would be down a 3.5 percent reserve margin counting only generation options.

Column F shows the DSM that is available, and none of it would be needed because we would have generation available on that date. And our total reserves are over on the last column of 3,421. So what the first row basically shows is of a 14.8 reserve margin in that year our generation reserves are

3.5 percent reserve margin.

Now, the point that was made in Mr. Silva's testimony is that we are uncertain in regard to both the timing of when our loads occur, they can occur not only in August, but also in June and July. And we are also uncertain of the magnitude of our load. As I mentioned earlier, in 2005 we saw such an unexpectedly high load.

So Row 2 says what happens if that exact same load that we projected for August were to occur in June. Now, in June, as shown in Column B, we do have scheduled maintenance, so we would be taking out 799 megawatts in June, which would reduce in Column E our generation capacity reserves from the 905 minus 799 down to 106. So we would be essentially at a zero percent generation reserves on our system if that were to occur. Again, in the last three columns we still have DSM available. Slightly less in June than we do in August because of the monthly accumulation of sign-ups, but essentially the same number.

And Column 3 shows what would happen if not only the peak load occurred in June, but that the peak load was significantly higher than what was projected. And in this example we have used the percent variance that we observed over the last three years, which is almost 11 percent and have increased the load in Column D. What that would show is if you look at generation only in Column E, we would have a deficit of generation available to serve the load of 2,676 megawatts. And even if you applied all of the 2,500 megawatts in Column F of DSM, our total reserves would be a negative 176.

So, therefore, without even assuming forced outages or breakages of units, without talking about fuel supply interruptions, transmission interruptions, or providing any assistance to another utility that was experiencing a high load on that date, a 15 percent reserve margin simply does not protect FPL from variances in both the timing and the magnitude of the load forecast. So, this example is a very good one that shows that a 15 percent reserve margin is simply viewed as unsuitable for FPL's system in order to provide reliable service.

CHAIRMAN EDGAR: Commissioners? Commissioner Carter.

COMMISSIONER CARTER: Madam Chairman, I would like to make a comment. Is that okay?

CHAIRMAN EDGAR: You may.

COMMISSIONER CARTER: I went back because for awhile I thought maybe I was on another planet here.

CHAIRMAN EDGAR: I can't imagine why.

COMMISSIONER CARTER: And I went back to the beginning on this need determination at the basic positions of the parties, and I see where FPL has requested for the Glades Power Park Units 1 and 2, 1960 megawatts on this 4900-acre site in Glades County. And I see where they have taken into consideration DSM, gone with the solid fuel as opposed to natural gas. I looked at OPC's position, and they are saying that in order to determine whether or not ultra-supercritical pulverized coal plants are the most cost-effective alternative available you need to take into account the very high probability of carbon dioxide emission regulation during the lives of the plant. They also say that there is a significant probability of this occurring.

I looked at the position of the Sierra Club and others, and they are saying that while they are against any kind of coal plant whatsoever, but certainly if one is built it should be an IGCC, and said also that FPL could be expected to intensify and accelerate their efforts with DSM and would, therefore, not require additional generation.

And what I'm trying to say, Madam Chairman, and Mr. Krasowski is saying that based upon the population projections in Florida there are some questions, and those questions are until there is a clear understanding of all the energy options being achieved, that no single project of the magnitude of this should be accomplished. And I'm just kind of thinking aloud of where I am looking for the parties that made these representation to stick to the issues that they have announced here. And I think we are getting way, way beyond the position of the parties. Either they meant what they said when they applied or they did not mean that.

So just from a point of reference, Madam Chairman, that I think that it would be helpful to all of us concerned, we have given additional time, and I think that the time should be spent on the issues that were raised instead of obfuscation, walks in the park, and things of that nature. And I just wanted to raise that just as a statement. Thank you.

CHAIRMAN EDGAR: Are you saying that my questions are too far afield?

COMMISSIONER CARTER: I would never say that your questions are -- in fact, your questions actually made sense based upon the positions of the parties, Madam Chair.

CHAIRMAN EDGAR: Thank you. I hear you, Commissioner Carter.

Commissioner McMurrian, questions?

COMMISSIONER McMURRIAN: Thank you.

Actually, I, too, have looked back at the prehearing order and was looking at FPL's position with regard to Issue 1, and within that there is a statement about approximately 76 percent of the reserves in 2013 would be supplied by DSM megawatts and approximately 88 percent of the reserves in 2014 would be supplied by DSM megawatts. This means that load control would be exercised frequently.

And at the risk of asking you something that is somewhere elsewhere in the record, I wanted to get a handle on what the current situation is. So can you tell me what the percent of reserves, what percent of reserves are supplied by DSM currently, or some kind of number that gets us close to current?

THE WITNESS: Yes, Commissioner. In fact, we have another handout which walks you through that calculation, if you would care to see it.

COMMISSIONER McMURRIAN: Sure.

THE WITNESS: And while this is being handed out, let me explain that the handout is based, again, on my Exhibit SRS-1 which calculated reserve margins without FGPP; and SRS-4, which calculated them with FGPP. And I have added a couple of columns to the right-hand side of that exhibit which answers your question.

MR. ANDERSON: Madam Chairman, while things are being passed out, could we mark the first document we looked at? I think it is 187. And the one that is coming around, 188, I think.

CHAIRMAN EDGAR: These are not in previous exhibits?

MR. ANDERSON: That's correct.

CHAIRMAN EDGAR: Okay. All right. Then the document example of operations that Doctor Sim just discussed will be 187, and this document that is headed SRS-1 with additional information will be 188.

(Exhibit 187 and 188 marked for identification.)

COMMISSIONER McMURRIAN: I think Mr. Sim was going to walk us through what this shows in response to my question, which I believe I had posed originally to Mr. Brandt and they told me to save it for you.

THE WITNESS: Let me first state that Columns 1 through 9 are identical to what was in SRS-1. That is the top series of calculations. And then at the bottom of the page 1 through 9 is identical to what was presented in SRS-4.

So, to try to explain the calculation, if you look in Column 8 at the top for 2007, you see a 22.6 percent reserve margin. Now, that includes both generation as well as DSM. So what I have done, Commissioner, is I have essentially removed or zeroed out Column 5 to take away all of the DSM. And then I have recalculated what our forecast of summer reserves are without DSM. That appears in Column 10. Using that lower reserves, generation only reserves, I calculated what the new summer reserve margin is without DSM, and that is 12.8 percent.

Then, I look at the original 22.6 percent of reserves with generation and DSM, look at the 12.8 percent reserve margin without DSM, and then calculate what the complementary reserve margin is that DSM contributes, which in this case is 43 percent. So, in other words, the 12.8 percent reserve margin is 43 percent of the original 22.6.

COMMISSIONER McMURRIAN: So that means the 43.1 percent is the current percent of reserves supplied by DSM and can be compared to what, at least in the position statement, I believe it is --

THE WITNESS: Yes, we will come to the position statement momentarily.

COMMISSIONER McMURRIAN: Okay.

THE WITNESS: You had asked what it was currently and that is what we show in 2007. If you go down to 2013, the same calculation on the far right column, Number 12, shows that DSM's percentage contribution to FPL's total reserve margin is 76.1 percent, and for the next year, 2014, it would be 88.3 percent.

COMMISSIONER McMURRIAN: Okay. That's helpful. And with respect to the sentence that reads this means that load control will be exercised frequently, I guess a similar question. How frequently is load control being used today, or in 2007?

THE WITNESS: It is being used relatively infrequently, which is, I think, another advantage of the 20 percent reserve margin. Because with the 20 percent reserve margin we have a reasonable amount of generating reserves which allows us not to call on load control except under conditions in which we have an unexpected number of units out for maintenance, both planned and forced, or the load is significantly higher than what would otherwise be expected on that day.

COMMISSIONER McMURRIAN: Thank you. And I had one other question that was a follow-up to a question, I think, Ms. Brubaker was asking you. And it was within the Exhibit 155 with the yellow sheet, and I believe Ms. Brubaker was asking you about the comparison of the SO2 numbers with respect to USCPC versus the IGCC. And I think she asked about why those numbers were identical, and I believe your answer -- and I don't want to mischaracterize it, so correct me, was that the IGCC part was representative of IGCC filings with projected SO2 amounts.

THE WITNESS: That's my understanding, yes.

COMMISSIONER McMURRIAN: Okay. Could you tell me what the number would be if it was based on current IGCC projects and the SO2 numbers that they show, or is that somewhere elsewhere in the record?

THE WITNESS: Give me just a moment. I thought we had that in our answer to Interrogatory 112, but I don't seem to find that in front of me at the moment. But I'm sure we can provide that as a late-filed exhibit if after checking it's not the numbers that you're requesting.

MR. ANDERSON: We would also indicate, Commissioner, that either Mr. Jenkins or Mr. Kosky would be able to provide that information on current SO2 emissions for IGCC.

CHAIRMAN EDGAR: Ms. Brubaker.

MS. BRUBAKER: Whatever your preference, Commissioners. We could either defer the question to the appropriate witness, or if you prefer to have it as a late-filed. I don't know that I see it in the answer to 112, but then it was a very brief scan of the document.

CHAIRMAN EDGAR: Okay. Then how about we wait until the next witness, Commissioner, that you would like to pose your question to, or more than one, and if not at that point we can do a late-filed then if it is still needed.

COMMISSIONER McMURRIAN: That's perfectly fine. That was all my questions.

CHAIRMAN EDGAR: Okay. Mr. Anderson, about how much do you have on redirect?

MR. ANDERSON: Probably 20 minutes.

CHAIRMAN EDGAR: Mr. Guest.

MR. GUEST: Well, of course, that creates timing issues now because we had had fantasies yesterday about finishing today.

CHAIRMAN EDGAR: Actually, my fantasy initially was that we were going to get done with Mr. Sim yesterday.

MR. GUEST: Yes, that's true. Well, we had had a representation that we were going to have about 20 minutes of questions. It is over an hour now, and we flew Mr. Plunkett in in the wee hours of the morning, and he has to leave, of course, today. I think if we can get through him today, things are going to work out. But we really need a commitment to try to do that.

I, in response to your suggestion, had foregone a number of questions about emission controls even though that came up, and about a number of other items that also came up. But I think since there is another witness coming up on rebuttal, I'm going to heed your suggestion and narrow my questions to one person whenever possible. And would hope that we would get the same courtesy on redirect here, that if these are questions that can be asked of another witness we won't replow the same ground.

CHAIRMAN EDGAR: I will expect mutual courtesies.

MR. GUEST: Thank you.

CHAIRMAN EDGAR: Does that mean, Mr. Guest, that your reference is to take up Mr. Plunkett before Mr. Furman?

MR. GUEST: Most definitely.

CHAIRMAN EDGAR: And, Mr. Anderson, I think you indicated yesterday that you were amenable to that.

MR. ANDERSON: That's fine. Thank you.

CHAIRMAN EDGAR: Okay. Then at some point we will need to take a lunch break. We can take an abbreviated one. I'm going to look to make sure, Commissioners, that works for each of your schedules, we take an abbreviated lunch. Okay.

Mr. Anderson, I can go either way. Since you are up next, I'm going to look to you first. We can push through now or we can take a short lunch break now and come back with you.

MR. ANDERSON: If it's all right, let's just ask our witness how he's feeling. If he wants to --

CHAIRMAN EDGAR: Absolutely.

THE WITNESS: Twenty minutes, let's finish, please.

MR. ANDERSON: We will do our best together.

REDIRECT EXAMINATION

BY MR. ANDERSON:

Q Mr. Sim, you were given a document by Mr. Guest entitled Exhibit 183, future options for generation of electricity from coal?

A That's correct.

Q He asked you some questions about certain portions of that document. Are there any other portions of that document that you would like to provide information concerning?

A Yes. Having had a chance to review the document a little bit more thoroughly, I find that there are two pages upon which there is information that was not included in the question and answer session. The first of those has to do with, again, the gentleman, Mr. Black, the president of Tampa Electric, stating that barriers to IGCC units include, quoting, higher capital costs and higher operations and maintenance costs.

I note that that is certainly consistent with the document that we were discussing earlier where we were looking at the three columns of Staff's Exhibit 155 or 156, in which we had the ultra-supercritical and the IGCC side-by-side. And even after adjusting for the AFUDC being included on the capital cost side of the IGCC, my estimate is we are going to see capital costs about 40 percent higher, we are going to see operating cost numbers on that page about 40 percent higher, as well. Which, again, is consistent with Mr. Black's paper here on Page 6.

The other thing that I noted is that on Page 4, the first line of Mr. Black's document, he quotes the efficiency of Polk's IGCC unit or heat rate is approximately 9,500 Btu per kilowatt hour. And I will note that that is also consistent with the analyses numbers that FPL has been using. In fact, we have been generous to IGCC in using a heat rate of 9,400 instead of the higher 9,500. And that, again, points out the advantage of the ultra-supercritical unit with our heat rate of 8,800.

Q Very good. Mr. Guest was asking you some questions concerning comparative dollars per kW and asserting that there is about $2,600 per kW capital costs for the proposed TECO plant. Could you please take a look at this document which will be delivered to you.

MR. ANDERSON: If we could mark this, please. I think we are up to 189 now.

CHAIRMAN EDGAR: Yes.

(Exhibit 189 marked for identification.)

BY MR. ANDERSON:

Q Doctor Sim, we heard yesterday that the TECO plant is not even in a preliminary design stage, and cost estimates haven't been done, and all of that homework to figure out actual costs, but what is Document 189, and what does it show as being reported with respect to dollars per kW?

A The document is an excerpt from Tampa Electric's 2007, its most recent Ten-Year Site Plan, and it is showing Schedule 9 on which the utilities are required to report their best projections for future units. And what it shows down in Row 13, the third row there, total installed cost in-service year of $3,180 per kW with a footnote. And the footnote says that this is a preliminary cost estimate subject to change based on overnight construction cost of 1.6 billion.

The way I would interpret that is not only is this number of almost $3,200 a kW significantly higher than the number that we were discussing in my cross-examination earlier, it is probably a low number and will be revised upward as the preliminary costs are tightened up.

Q Doctor Sim, Ms. Brubaker discussed reserve margin, and we talked about the Hines 3 order. Did the Hines 3 order also address the effect of greater reliance on load control for meeting reserves?

A Yes, it did. In fact, I will read the appropriate portion. FPC has relied heavily in the past on demand-side management, DSM, to meet its reserve requirements. FPC cannot use DSM as often or with the same duration as physical generation without eventually affecting customer participation levels, as was demonstrated by FPC's customer attrition from its DSM programs in 1998 and 1999. The record indicates FPC's DSM programs are becoming less cost-effective compared to the cost of generation. For these reasons, FPC is attempting to build up its physical reserve percentage.

Q There were some questions about the FRCC reserve margins. Do you remember those?

A Yes.

Q Should FPL rely on the FRCC reserve margin?

A No, it shouldn't. The FRCC margin really has nothing directly to do with FPL's reserve margin. FPL is obligated to serves its customers reliably and, therefore, needs to develop plans and reserves to do just that. Whether the FRCC other member utilities are operating at a particular reserve margin or not, and the state and the peninsular as a whole is operating at a particular reserve margin has no direct effect upon FPL and its projected reserves.

I also note going back to the document that was put in front of me that we showed the FRCC was showing or projecting reserves of significantly higher than 20 percent. And what that would indicate to me, based on my knowledge of the contribution of the three IOUs to the Peninsular Florida, which is roughly in the 75 to 80 percent contribution level for the peninsular as a whole, is that if FPL, TECO, and Progress Energy Florida all were exactly at 20 percent, and each of the other member utilities was at 15 percent, we would see an FRCC reserve margin of 19 percent. What we are seeing on that document are reserve margins of 22 to 25 percent in many years, which indicates to me that a number of the member utilities which are required by the FRCC to operate at a 15 percent reserve margin, believe that a 15 percent reserve margin isn't sufficient for them. And, therefore, they are projecting reserve margins significantly higher than 15 percent. It would have to be so in order to get Peninsular Florida reserve margins in the 22 to 25 percent range.

Q Ms. Brubaker asked you about the capital costs associated with the FGPP. If in the future an opportunity arose where FPL was able to spread the fixed costs of FGPP over a greater number of billing determinants, what would the effect of that be on the cost-effectiveness of FGPP?

A I'm sorry, what was the end of the question, please?

Q What would the effect be on the cost-effectiveness of FGPP?

A I think I would answer in two parts. I'm not sure it would effect the cost-effectiveness of the unit one way or another in regard to any other type of technology, but it would result in a lower electric rate impact to our customers if it were spread over a greater number of units.

MR. ANDERSON: We may be done even quicker. Let me just consult with my colleague for a moment.

BY MR. ANDERSON:

Q Doctor Sim, what do you think would happen if the reserve margin were reduced to 15 percent as it relates to reliance on DSM and load control for maintaining adequate reserves?

A I think there are two things that would happen. I think, number one, if FPL were directed to go to a 15 percent reserve margin, despite our belief that that is not the adequate level of reserves for our company, and we followed through with a 15 percent reserve margin, we would have to examine the need for all resources, whether they are generation or DSM, because DSM competes with generating resources.

We would clearly be adding less resources to our system. We may well end up that the most cost-effective thing to do is to reduce the DSM that we are currently planning on implementing. We may end up with less generation than what we are currently planning, but there is no guarantee that we would stay with the same level of either generation or DSM. Something would have to give, we are not sure which. It would have to be analyzed in order to determine which would be the most cost-effective move to make in terms of reducing resources.

In regard to the existing load control programs that we have, I think it is safe to say that the frequency of usage of those programs would have to increase as the exhibit that we discussed earlier showed in regard to having enough capacity on-line in order to perform maintenance.

Q Did the Hines 3 order that you looked at a minute ago also discuss load control?

A Yes, it did. And I think I read the relevant passage. In the Commission's order they were referring to cannot use DSM. I take that to mean dispatchable DSM, which would be load control. And it stated that they cannot use DSM as often or with the same duration as physical generation.

Q Would use of a 15 percent reserve margin effect the company's reliance on DSM, and what do you think the effect would be on customer participation in DSM?

A We would certainly be relying more on the usage of load control than we do now. If the frequency of that usage got to the point where it did for Progress Energy Florida in 1998 and 1999, in which 70,000 of their residential load control participants bailed out of the program almost overnight due to an overreliance of it over a summer, we could experience similar, if not even greater, dropout rates. And that would also make it exceedingly difficult to sign up replacement or new customers if word got out that FPL was pushing the button with much greater frequency than they had before.

Q So what we are really talking about is the difference between having operating generating reserve to provide power versus the ability to basically push a button, interrupt service, have people stop using electricity, right?

A Yes. Each has its role, and I don't think anyone would operate a system in which there was a heavy reliance upon interruption of customers even though it were a voluntary sign-up for those customers, because you could quickly reach the point, as Progress Energy Florida did, where they simply begin losing those customers in large blocks.

MR. ANDERSON: That's all we have. Thank you.

CHAIRMAN EDGAR: Okay. Let's take up exhibits. We will start with Exhibits 46 through 60. Seeing no objection, 46 through 60 will be entered into the record.

(Exhibit 46 through 60 admitted into the record.)

CHAIRMAN EDGAR: Exhibit 182 was the need study and appendices. Seeing no objection, we will enter that into the record.

(Exhibit 182 admitted into the record.)

CHAIRMAN EDGAR: Which brings us to 183 and 184, which were put forth by Mr. Guest. Any objection?

MR. ANDERSON: We are fine with 183. We would ask that 184 be taken up with Mr. Jenkins before a ruling. That was the one that was the subject of extensive discussion.

CHAIRMAN EDGAR: Okay. 183 will be entered into the record and we will discuss 184 later in the proceeding.

(Exhibit 183 admitted into the record.)

CHAIRMAN EDGAR: And 185 was going to be late-filed. 186 was offered by Ms. Brubaker.

MS. BRUBAKER: Yes, and I would move both 185 and 186 into the record.

CHAIRMAN EDGAR: You have received 185?

MS. BRUBAKER: Well, you're right, no. My apologies.

CHAIRMAN EDGAR: Okay. 185 to be late-filed, and 186 to be entered into the record. And then 187 and 188 were passed out, Mr. Anderson. Any objection? And 189. Seeing no objection, 187, 188, and 189 entered into the record. The witness is excused.

Thank you, Doctor Sim.

(Exhibits 186 through 189 admitted into the record.)

CHAIRMAN EDGAR: Okay. The next four witnesses were stipulated. Let's go ahead and take up entering that testimony and exhibits into the record so that we will know where we are then, I think, for the next few steps.

Ms. Brubaker, am I correct that the next thing we need to do is enter the prefiled testimony of Witness Damon?

MS. BRUBAKER: That is correct. It would be Witnesses Damon, Sanchez, Coto, and Yupp. We could take up Mr. Damon first.

CHAIRMAN EDGAR: Any objection?

MR. GUEST: No objection.

CHAIRMAN EDGAR: Okay. Then we will enter the prefiled testimony of Witness Damon into the record.

MS. BRUBAKER: And I would notice that Mr. Damon does not have any prefiled direct exhibits.

CHAIRMAN EDGAR: With no exhibits, thank you. And Witness Sanchez. We will enter the prefiled direct testimony of Witness Sanchez into the record, and Exhibits 63 through 66. Seeing no objection, those exhibits will be entered into the record, as well.

Which brings me to Witness Coto. The prefiled testimony of Witness Coto will be entered into the record, as well as Exhibits 67 through 72.

(Exhibits 63 through 72 admitted into the record.)

MS. BRUBAKER: That is correct.

CHAIRMAN EDGAR: And Witness Yupp's prefiled testimony will be entered into the record. I see no exhibits, is that correct?

MS. BRUBAKER: That is correct.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WILLIAM H. DAMON III

DOCKET NO. 07_____-EI

JANUARY 29, 2007

I. INTRODUCTION AND CREDENTIALS

Q. Please state your name and business address.

A. My name is William H. Damon, III. My business address is Cummins & Barnard, Inc., 5405 Data Court, Ann Arbor, Michigan, 48108.

Q. By whom are you employed and what is your position?

A. I am employed by Cummins & Barnard, Inc. ("C&B") as the Chief Executive Officer (CEO).

Q. Please describe your duties and responsibilities in that position.

A. Currently as CEO, I am primarily focused on our strategic consulting and Owner Engineering business for industrial and utility clients in addition to managing the business operations of the firm. This includes leading the Owner Engineering assignments presently on two coal-fired projects: the We Energies 2 x 615 MW Elm Road Generation Project and the E ON U.S. 750 MW Trimble County Unit 2 Project.

Q. Please describe your educational background and business experience as it relates to your testimony.

A. I received a Bachelors of Science Degree in Mechanical Engineering from Michigan State University in 1975 and have taken graduate level courses in engineering and business administration from both Michigan State and the University of Michigan. I am a registered professional engineer in 6 states and am certified with the National Council of Examiners for Engineering and Surveying. Additionally, I am a member of the American Society of Mechanical Engineers as well as the National Society of Professional Engineers.

I began my career with an electric utility, Consumers Power Company in Jackson, Michigan as a mechanical engineer in the Corporate Management Development Program with a broad range of assignments in the design, construction and startup of utility power plants. This included startup and commissioning of the 500 MW oil-fired D.E. Karn Unit 4 and Lead Mechanical Engineer for the 770 MW coal-fired J.H. Campbell Unit 3 Plant from design development through commercial operation. I subsequently spent 8 years with an international consulting engineering firm, Gilbert/Commonwealth, Inc. with my primary assignment being Manager of Advanced Engineering and Mechanical Staff. I managed and was responsible for staff expertise in key power plant systems as well as cogeneration and advanced technologies including gasification and fluid bed combustion. For two years I was with an independent power producer (IPP), Alternative Energy Ventures and was actively engaged in the operations and development of cogeneration projects as well as the development and farm-out negotiations of coal seam methane property/leaseholds in Colorado. In 1990, I joined C&B as a principal and co-owner and have been significantly involved in power generation development and engineering projects on behalf of public utilities, power developers, municipalities, as well as large industrial and institutional clients since that time.

Q. Have you previously provided testimony in a public utility proceeding?

A. Yes. I submitted testimony in connection with the September 2003 Certificate of Public Convenience and Necessity application for Wisconsin Electric Power Company's filing for construction of the Elm Road Generating Station – 2 x 615 MW Supercritical coal-fired power project, Docket No. 05-CE-130. The purpose of my testimony was to discuss and present C&B's work associated with the bid evaluation and project development for the Engineer/Procure/Construct (EPC) contractor selection with commentary and opinion as to the reasonableness of the contracting approach and competitive bid/development process focused on the resulting design and target EPC price being submitted for the project.

Q. Are you sponsoring any part of the Need Study for this proceeding?

A. Yes. I co-sponsor Section III. G. of the Need Study.

II. PURPOSE

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the conclusions of our independent engineering review of the FPL contracting strategy and estimated cost for the FGPP Project and render opinion based on the results of our evaluation as to reasonableness and market competitiveness for this 2 x 980 MW ultra-supercritical pulverized coal-plant development (with Unit 1 and 2 commercial operations dates targeted for mid-2013 and 2014 respectively).

Q. What are the qualifications of Cummins & Barnard in offering Independent Engineering testimony?

A. C&B is very active in the present sub-critical (SPC) and large supercritical, pulverized coal-fired (SCPC) power project market serving as Owner's Engineer on multiple projects in various states of development, bidding and construction. Key representative and active projects include:

- We Energies Elm Road Generating Station – Two x 615 MW SCPC units presently under construction with commercial operating dates (COD) set for 2009 and 2010.
- E ON U.S. Trimble County Unit 2 – 750 MW SCPC unit presently under construction with the EPC contract finalized and issued July 2006 with a COD in 2010.

- UAMP/IPA Intermountain Power Plant Unit 3 – 900 MW SCPC project currently in the EPC bidding phase with a tentative COD of April, 2012.
- Nevada Power Ely Energy Center – 2 x 750 MW SCPC in development stage, with C&B currently working on finalizing contracting approach and design development/bid documents for 2007 submittals for equipment and EPC bidding.
- Target priced EPC contract development with design, construction and pricing monitoring through Owner's Engineer assignments on five large Air Quality Control System (AQCS) retrofit projects on existing coal-fired units.

Q. Are you presently involved in any major coal-fired generation projects and contracting strategy or cost development?

A. Yes. As previously noted, I am managing our engineering assignments for both the We Energies 2 x 615 MW Elm Road Generation Project and the E ON U.S. 750 MW Trimble County Unit 2 Project. Our scope of work for both assignments has involved project cost estimating, EPC contract development, major equipment selection, technical and commercial bid review, and related tasks. I am also familiar with and review similar cost estimation and development engineering efforts for the other active in-house coal-fired generation and AQCS retrofit projects for clients including Nevada Power, UAMP/IPA, Consumers Energy, Constellation, and FirstEnergy.

Q. What steps did you take in completing an independent engineering evaluation of the FGPP project?

A. FPL established the overall cost estimate for FGPP, as documented in the testimony provided by Mr. William Yeager. FPL provided access to major equipment bid tabulations, EPC cost estimates, transmission interconnection and integration data, and financial cash flow calculations that C&B used in our independent evaluation. Representatives of C&B including myself also completed a series of interviews with FPL and EPC contractor personnel to review the process, data and costs used to construct the FGPP estimate. Lastly, we compared the resulting FPL FGPP approach and costs to cost data and contracting options from other active coal projects to establish our independent opinion.

III. OVERALL PROJECT COST ESTIMATE AND CONTRACTING STRATEGY

Q. What constitutes the total installed cost estimate for the FGPP Project?

A. The overall installed cost for the two-unit FGPP, as located on a new site not previously developed and remote from interconnecting utilities (termed "green field"), includes several major cost components as presented in the testimony of Mr. William Yeager (Exhibit WLY-1). These major cost components include the following:

- Power Plant Costs, including major equipment (Boilers, Steam Turbine/Generators (ST/Gs) and Air Quality Control Systems (AQCS)), balance-of-plant equipment and commodities, construction; and startup/commissioning costs.
- Transmission Interconnection and Integration Costs, between the FGPP generator step-up transformers and the existing high voltage grid, as outlined and defined in Mr. Jose Coto's testimony.
- Owner's Costs, including Power Plant and Transmission line Land acquisition costs and allowance for funds used during construction (AFUDC).

Q. **On what aspects of the total FGPP cost did you focus your independent engineering efforts and why?**

A. C&B principally focused on the Power Plant Costs, including assessment of the commercial and contracting strategy that resulted in the major equipment and EPC contract pricing being submitted by FPL. Additionally, we reviewed the design basis and cost estimate for the Transmission Interconnection and Integration portion of FGPP and certain Owner's Costs (specifically the allowance for funds used during construction (AFUDC)).

The results of our independent review are contained in Sections IV (Power Plant), V (Transmission Interconnection and Integration) and VI (Owner's Costs) of this testimony.

Q. Please describe your understanding of the overall contracting approach and competitive pricing options being pursued by FPL as part of establishing the FGPP project cost.

A. FPL followed what I will term as a "hybrid EPC" contracting strategy for project development and definition of Power Plant costs. This strategy involves the direct purchase of major equipment by the Owner with the development of the EPC scope, price and terms on an open-book basis to conform a fixed price EPC contract.

Based on the efficient, power generation thermal cycle and major equipment requirements established by FPL for the Power Plant, a competitive solicitation, negotiation, and award process was conducted by FPL for the major equipment contracts (boilers, steam turbine/generators, air quality control systems). In parallel to major equipment competitive bidding, FPL undertook "open book" project definition and commercial negotiation of an engineer-procure-construct (EPC) contract with their selected contractor that was benchmarked against a recent, similarly sized, competitively bid project. The scope of this EPC contract did include design engineering for balance-of-plant equipment as well as materials procurement, construction, startup and commissioning services for the complete Power Plant inclusive of installation of major equipment noted above with commercial terms based on the competitively bid West County Energy Center EPC Agreement.

With respect to Transmission Interconnection and Integration, FPL selected a multiple supplier self perform strategy for development and cost estimation consistent with its past practice. The FPL Transmission Group completed all preliminary transmission line routing, and conceptual design, for the Transmission Facilities. This conceptual design served as the basis from which cost estimates for each portion of the Interconnection and Integration were developed. We understand that FPL will ultimately utilize a competitive bidding process for major equipment procurement from multiple sources and for specialized construction services for transmission lines consistent with past FPL practice. Section V of my testimony contains further commentary on Transmission Interconnection and Integration costs.

Q. **What is meant by the term "open book" as defined and utilized in the EPC Contract development?**

A. The term "open book" definition refers to the collaborative efforts of an owner and contractor to establish the EPC scope, price, and terms. For FGPP, engineered equipment, commodity quantities and costs, construction labor hours and rates, as well as construction indirect costs, were initially prepared by the contractor utilizing a similar project database that was subsequently used as the basis and proxy for contractor and FPL negotiations for FGPP.

Q. **Is this hybrid contracting approach used by FPL unique in the market place?**

A. No. The hybrid EPC contracting strategy implemented by FPL has many similarities to strategies being utilized by other public utilities and energy companies. The hybrid strategy is particularly appropriate and prevalent in today's very active market place, given that both EPC contractors and major equipment manufacturers are resource-constrained and selective in which projects or processes they are willing to participate in, typical of a seller's market.

Q. **Would other contracting strategies, such as a competitively-bid lump sum turnkey (LSTK) strategy, have yielded a more accurate estimate of the EPC costs for the Power Plant?**

A. No. As stated, resource constraints and current activity levels within the ranks of experienced EPC contractors and major equipment manufacturers, along with forecast uncertainties for material and labor escalation coupled with the timeline of FGPP development, would not be supportive of a competitive LSTK strategy. Even if the front end schedule supported a competitive bid process, the ability to secure an adequate number of qualified EPC contractors would be a significant challenge in today's market and we do not believe such an approach would yield a more accurate estimate of Power Plant costs. Combining the resources of FPL and an experienced EPC contractor to collaboratively establish EPC pricing on an open book basis, in parallel to confirming major equipment pricing, allowed for a comprehensive consideration of project-specific configuration issues as well as overall constructability and costs. Utilizing a detailed estimate from a similar proxy project on an open book basis to match FGPP project schedule and design requirements further reduced uncertainty for both parties (see Section IV.2 for additional testimony).

IV. POWER PLANT COSTS

Q. What constitutes the Power Plant cost?

A. The Power Plant Cost includes major equipment pricing, EPC contract pricing, and other Owner's Costs. The bulk of the Power Plant Cost (approximately 75 percent) is comprised of major equipment and EPC costs. The basis for these two cost components is reviewed in Parts IV.1 and IV.2 respectively, with comments on overall Power Plant cost included in Part IV.3 of my testimony. Owner's Costs are addressed in Part VI.

Q. What influence does the contracting strategy employed have on Power Plant cost?

A. The contracting strategy employed by an Owner directly affects the accuracy of the Power Plant component of the overall project cost estimate, of which the two largest components are major power generating equipment and balance-of-plant EPC costs. Certain strategies such as those employed on the FGPP project and further defined in this testimony reduce cost uncertainty via upfront negotiation of the pricing with reputable manufacturers and contractors.

The contracting strategies employed on recent and current-day major coal unit developments were compared and contrasted to the strategy implemented by FPL. Results of this comparison, with focus on the reasonableness of major equipment and EPC pricing received, are contained in Sections IV.1 and IV.2 respectively. Section IV.3 of this testimony provides commentary on the Power Plant cost component in total.

IV.1 MAJOR EQUIPMENT

Q. What constitutes "major equipment" and what contracting strategy was taken to define the major equipment scope of supply and pricing?

A. Major equipment for the two-unit FGPP consists of the boilers (with boiler auxiliaries including fans, economizers, air heaters, pumps, selective catalytic reduction equipment, and other equipment), steam turbine/generators (ST/G, with auxiliaries), and air quality control systems (AQCS). The AQCS scope includes a pulse jet fabric filter, induced draft fan, wet flue gas desulfurization equipment, and a wet electrostatic precipitator. The major equipment in each of the two units is separate but identical. FPL chose to bid, negotiate, and select major equipment using a competitive bid process with defined technical and commercial requirements, as a means of confirming price and delivery to reducing price uncertainty and escalation in today's active market.

All equipment was based on FPL's selection of an ultra-supercritical thermal cycle for this coal-fired power generation project. The equipment requirements were extrapolated from the ultra-supercritical design prepared by FPL and their engineering consultant, with defined performance requirements and airborne emissions limits consistent with those defined in the Site Certification (SCA) and Prevention of Significant Deterioration (PSD) permit applications submitted for the FGPP.

As was presented to us, the competitive bid process included at least three bids for each of the major equipment type (e.g., boilers) from what we would agree are recognized, qualified and experienced manufacturers. Bid tab comparison of manufacturer submittals were prepared by FPL staff, with technical and performance factors compared and evaluated to establish the lowest evaluated selection for each major equipment type.

Q. Was the selected strategy appropriate for obtaining competitive pricing for FGPP-specific major equipment in the current marketplace?

A. Yes. Given the very active market place, FPL did receive bids for each major equipment type and the competitive bidding process with defined commercial and technical requirements were compared to other strategies in use and found to be reasonable and representative of a well-managed process.

Q. What is the total price for the Unit 1 and 2 major equipment and is this considered reasonable in today's marketplace?

A. The pricing for the boilers, ST/Gs, and AQC systems for both FGPP units, as noted, was established through a competitive bid and evaluation process that was provided for our review. From this process, the capital price summation for major equipment in December, 2006 dollars was established at [redacted]. On a dollars per net kilowatt ($/kW) basis, this represents a cost of $[redacted].

My independent review of this pricing in comparison to recent 2006 procurements and pending awards on other projects found such pricing to be reasonable and representative of current market trends.

Q. What are industry trends for major equipment pricing looking forward, based on manufacturing capacity, prices for labor and materials, and other factors?

A. Current and near-term industry trends for major equipment pricing are still escalating upward from early 2006 pricing, as a result of the heavy commitment of space within major manufacturer's production schedules, combined demand for equipment for both new plants and existing plant retrofits, limited number of manufacturers, and continued escalation of key commodity materials such as high alloy steel. A contracting strategy wherein the equipment design requirements are established to match thermal cycle and emission limits, and then competitively bid, is considered to be a "least-cost" approach, particularly for projects having commercial operating dates targeted for 2013 and 2014, and as such will reduce exposure to potential price escalation and ensure that the equipment will be available in accordance with the project construction schedule.

Q. Why is the AQC system pricing within the overall major equipment budget not completely firm and lump-sum as for other equipment, and how will the actual incurred costs for such be closely controlled to reduce exposure?

A. Approximately 35 percent of the AQCS contract value was bid on a non-firm (provisional) basis. The pricing volatility in the high alloy steel marketplace is the result of a limited number of global producers of high alloy materials and demand for such material from many active projects. Our experience on recent projects involving AQCS systems has been that between 20 and 50 percent of the total AQCS price has been on a provisional basis. The approach typically used to control such provisional sums is to tie adjustments to published market indices (termed indexing) for future up-or-down true-ups. This indexing is generally based on a published control standard allowing use of a reasonable Owner's contingency to mitigate future risks of cost change for which neither owner or the manufacturer have control over. FPL's proposed use of an indexing mechanism as included in Mr. William Yeager's testimony is consistent with this approach and consistent with our market experience.

Q. What are your specific conclusions regarding the reasonableness of FGPP Major Equipment pricing received?

A. FPL utilized a competitive bidding process involving reputable equipment manufacturers. FPL conducted a detailed evaluation and is at the time of our review finalizing negotiations with the selected manufacturers for each major equipment component noted, that appears to be on the basis of lowest evaluated cost. This selection process was determined to be consistent with standard industry practices. As previously noted, the timing of major equipment procurements was viewed to be suitable to minimize the effects of market place price escalation and to support the overall project schedule (risk of delayed equipment delivery).

IV.2 ENGINEERING, PROCUREMENT, AND CONSTRUCTION (EPC)

Q. What constitutes the EPC price?

A. The EPC price includes all direct and indirect equipment, commodity and construction costs associated with the complete Power Plant, less the major equipment purchases discussed earlier. Major cost components within the EPC price include procurement of balance-of-plant materials, engineered equipment, and construction labor for EPC supplied equipment as well as major equipment erection costs.

Q. What was the contracting strategy that FPL used to select an EPC contractor and how was the method used to develop pricing for the EPC component of the Power Plant cost?

A. During the formative stages of the FGPP project, we understand that FPL contacted a select group of domestic EPC contractors to determine relative interest in project participation and to discuss potential bid and contracting strategies. These discussions confirmed that the EPC marketplace was highly subscribed and that contractors were non-supportive of competitively bidding such a large project, particularly on a lump-sum turnkey basis. Zachry Construction did indicate interest and resource availability to support FGPP through a joint venture of Black & Veatch Corporation and Zachry Construction (BVZ). This team was willing to pursue this project on a negotiated "open book" basis, utilizing a detailed estimate database from a number of similar supercritical coal projects, to develop a firm, lump sum EPC contract. We understand that BVZ was recently awarded the West County combined cycle project by FPL following a competitive bid process and have successfully executed several other EPC contracts for gas-based power projects in Florida for FPL. They also have a strong resume of coal-fired power generation projects with several recent EPC awards for domestic supercritical coal projects from competitive bidding.

The result was that FPL and BVZ agreed to develop the EPC price and contract for FGPP, using "open book" adjustment of the costs from a comparably sized project as the proxy for scope definition and pricing. The proxy project is a similarly sized Texas-based, single supercritical coal-fired unit with design and cost development data based on mid-2006 timing; we understand that BVZ was the lowest evaluated bidder for the EPC on this proxy project.

The open book adjustment process considered differences in project size (e.g., two units versus one), site development differences, scope changes (e.g., dry to wet AQCS scrubber conversion, increased common system sizes, larger cooling tower), specific major equipment suppliers and thermal cycle and fuel differences as a means of defining equipment and commodity requirements and changes to the benchmarked proxy project. Labor adjustments were also made, for differences such as craft/crew size changes for the different state and sites, but reflective of the 50-hour construction work week similar to the proxy. The adjusted EPC estimate for FGPP was then adjusted for escalation based on anticipated timing for procurements and construction activities. This FGPP estimate thus reflects the level of detail that would typically be prepared for a competitive bid, but tailored specifically for FGPP site, fuel, and technology requirements.

This open book process, as we reviewed it, provided a means for FPL to participate in project development and cost data in parallel. As was previously mentioned, the parties agreed that the commercial terms and conditions for the recently negotiated West County project would be the basis for the FGPP EPC agreement with minor adjustments. Given that the proxy project had been awarded to BVZ in a competitive bid process and that comparable commercial terms had been recently (2006) negotiated between the parties, the strategy of open book development and negotiation was viewed to be well-structured and cost-effective means of establishing the EPC scope and price for FGPP. This position is reinforced in today's active marketplace, wherein we are assisting other plant owners with the implementation of similar hybrid EPC contracting strategies to control costs and schedule and gain early commitments from key suppliers.

Q. Is the selected EPC contractor capable and qualified to execute the project?

A. The BVZ joint venture has a resume of successful EPC power generation projects throughout the United States, and is actively involved in a number of current domestic coal-based projects including OPPD's Nebraska City Unit 2 and CPS's Spruce Unit 2 projects. Additionally, BVZ has constructed multiple EPC-based projects for FPL in Florida in the last five years and as such is also very familiar with the construction labor market in Florida. In conclusion, we have found BVZ to be a very qualified EPC contractor and well-suited to execute the coal-based EPC contract for the FGPP.

Q. How was the price for balance-of-plant (BOP) engineered equipment and commodities established within the EPC cost estimate, and was the basis for such considered reasonable?

A. Using the open book approach, BVZ and FPL collectively defined BOP equipment and commodities required for the FGPP conceptual design through adjustment of a detailed take-off for the proxy supercritical power generating plant that BVZ previously competitively bid. This process accounted for project-specific differences as well as multiple units and common plant system differences. This approach produced both a detailed ledger of BOP equipment/commodities and a means and basis for defining the amount of construction labor (craft types, crew sizes, number of labor hours) and indirects required for the EPC pricing effort. The costs within the ledger were then adjusted via escalation factors to account for expected future timing for procurement and specific construction activities. This approach was considered to be appropriate and effectively managed by FPL to conform the technical BOP scope and price for the FGPP.

As the FGPP design is still conceptual at this time for many of the BOP system requirements, prices for the following BOP components were defined and negotiated on a provisional basis: combined Unit 1/2 chimney, Unit 1 and 2 surface condensers, fuel/limestone/gypsum material handling, mechanical draft cooling tower, site work, and water supply and wastewater injection wells. Review of these provisional sums determined that such were considered reasonable and representative of current market costs for the FGPP requirements, and that any future adjustments to these components to reflect final project design will have a nominal impact on the total Power Plant cost.

Q. How was the Construction Labor wage rate established within the FGPP estimate, and was such consistent with your experience?

A. Construction labor represents a significant portion of the overall EPC price, and consists of the labor wage rate multiplied by the number of hours expected to complete all tasks. The construction labor wage rate established for the West County project in mid-2006 was utilized as a starting point for wage rate calculation for the FGPP Power Plant cost. This wage rate was adjusted for current market conditions (e.g., fringe benefits component increase) and was then escalated to account for a later FGPP construction start in 2008. Due to uncertainty with respect to actual escalation that will be incurred, the general wage rate was agreed to be provisional and an index control standard was created to adjust the rates used in the EPC cost estimate for the impacts of unexpected labor availability or wage rate changes during project execution. Our experience from other projects has been that this indexing process is common in the current EPC market. FPL has proposed that the indexing mechanism included in Document WLY-2 attached to Mr. William Yeager's testimony be used.

Q. How was the overall price for Construction established within the FGPP estimate?

A. The overall Construction and Startup and Commissioning requirements for FGPP were established in a similar approach as was employed for BOP Equipment and Commodities. Use of a detailed estimate from the proxy project with adjustment to reflect the FGPP conceptual design and associated details furnished by major equipment manufacturers that provided a reasonable basis for definition of the overall labor required to construct and commission the FGPP. It is noted that the number of skilled trades hours established by BVZ to construct the FGPP are fixed and not subject to future adjustments. Direct and indirect labor man-hours for FGPP were reviewed and compared to similar statistics for multiple supercritical generating plants, and found to be reasonable for the green field site and productivity of the local construction labor market.

Q. Is the EPC Price for the FGPP consistent with those for other current major coal-fired power generating stations in the United States?

A. The overall EPC price offered for the FGPP project non-inclusive of major equipment including escalation to support 2013/2014 commercial dates was [redacted], or [redacted]/kW. Without escalation, the overnight EPC price for FGPP construction in December, 2006 was estimated to be [redacted]/kW. For reference the EPC price for the competitively bid proxy project used as the basis for the FGPP estimate was [redacted]/kW on a December, 2006 basis. Although project-specific differences can impact the correlation on a project-to-project basis, the FGPP EPC price compares favorably with others proposed or currently under construction (overnight EPC pricing has typically been in the range of $1000/kW to $1,400/kW). Given the relatively larger size of the FGPP project and green field construction, the EPC price for the project was judged to be in-line with market and a reasonable estimate of the future cost of this project.

Q. **Were commercial terms and conditions established governing the EPC portion of the FGPP, as such influence the EPC price?**

A. Yes. The base EPC commercial terms and conditions used for the FGPP consisted of those from another recently executed contract between FPL and BVZ. Review of primary "risk" terms in the draft FGPP contract found such to be reasonably consistent with those used on the West County project. The required contractor security to be provided to FPL (combination of guarantees, letters of credit, and surety bonds) was found to be lower than we have seen on other coal-fired projects, but as other security is being provided by the major equipment manufacturers, our general conclusion was that the current market and EPC price basis for FGPP is reasonable and cost-competitive.

Q. **Was the approach taken to establish commercial terms and conditions reasonable and appropriate with respect to influence on overall FGPP price and risks?**

A. Yes. As previously stated, there is reasonable alignment between the commercial terms and conditions used on FGPP and those on other projects in industry and such translated into equitable contingency within the EPC pricing offered by BVZ.

Q. What are your specific conclusions regarding the reasonableness of the commercial basis and EPC pricing established for the FGPP Project?

A. The process employed by FPL as a means of obtaining an accurate EPC price was based on working with an experienced EPC contractor on an "open book" basis to conform a recently developed, detailed EPC cost estimate from another project to the FGPP specific conceptual design. This allowed for detailed scope, current pricing, and commercial term definitions, with negotiations that resulted in an FGPP project-specific price development in a very active and challenged EPC market.

Through interviews and review of documents associated with the EPC basis for computation and assessment of the EPC scope, price and terms, our conclusion from comparison of the FGPP development to other projects is that the EPC price component of the FGPP Power Plant cost is reasonable and in-line with the current competitive market.

IV.3 POWER PLANT COST ESTIMATE – SUMMARY

Q. Please provide your conclusions regarding the reasonableness of the Power Plant Cost Estimate prepared for the FGPP and its correlation to cost at project completion.

A. As previously mentioned in this testimony, the two largest cost components under the Power Plant Cost are those for major equipment and EPC work. The contracting strategy employed by FPL in our view produced a very accurate estimate of these costs through competitive bidding and open book adjustment and negotiations of a recent detailed EPC cost basis from another project to match to the FGPP conceptual design. Early upfront definition of the plant conceptual design and thermal cycle by FPL was also crucial to this strategy. Our experience to date has indicated that there is strong correlation between a bottom-up cost estimate and actual costs. Understanding this correlation in turn allowed FPL to include what is viewed as a reasonable contingency against the Power Plant cost estimate (included in Owner's Costs). As a result, I have concluded that the Power Plant cost established and indices used to control several provisional items are reasonable and representative of current market conditions.

V. TRANSMISSION INTERCONNECTION COSTS

Q. What was the process used in developing the scope and details of the Transmission Interconnection and Integration configuration for the FGPP?

A. As illustrated in testimony provided by Mr. Coto, the FPL Power Delivery Projects and Engineering Group and Transmission Services and Planning Group were involved in the assessment of the interconnection and integration requirements for the FGPP project. We met with the FPL Power Delivery Group and received design and cost estimate data for review from which Mr. Coto's testimony was also based. The basis of the Transmission Interconnection and Integration design appeared to be very comprehensive and consistent with FPL standards regarding interconnection of the FGPP with the existing transmission grid. Issues such as overall grid stability, reliability, maintenance, minimization of electrical/system losses, post-project load flow on the grid, land and right-of-way constraints, existing grid limitations, avoidance of environmental impacts, and capital costs for new transmission facilities were stated to be factored in the selection of the most appropriate interconnection and integration plan. Cost information for the defined Transmission Interconnection and Integration (hereinafter referred to as "Interconnection") were based on conventional FPL estimating methods. A summary of these costs was included in the testimony provided by Mr. Coto.

As a result, no significant changes to the plan, as reviewed, are anticipated that would significantly alter the FPL cost estimate.

Q. How were capital costs estimated for the Electrical Interconnection, and what importance did capital costs have on route selection and configuration?

A. FPL utilized a "bottom-up" estimating process to determine project costs associated with the Transmission Interconnection between the FGPP generator step-up transformers and existing grid. This estimating process principally utilized budgetary equipment and labor quotes, as well as FPL's in-house data base of labor and material unit costs, and was based on a conceptual design of overhead 500 kV circuits and supporting structures, in accordance with the National Electric Safety Code (NESC) and other corporate and industry standards. Equipment (e.g., transformers, circuit breakers, switches, insulators) costs were stated to be established from vendor quotes and FPL's database that we understand are maintained from current and historic construction efforts. Similarly, the unit costs for 500 kV and 230 kV conductors, supporting structures, and other commodities were also obtained from budgetary vendor quotes and in-house historical data.

Capital costs were an important factor in defining the voltage class, routing requirements (e.g., circuit and structure types and land/easement needs), and interconnection to the existing grid. However, other factors including system reliability appeared to have equal or greater weighting as further addressed in Mr. Sanchez's testimony.

Q. Is the capital cost estimate for the Interconnection reasonable in the current marketplace?

A. Yes. The FPL Power Delivery Group's initial capital cost estimate was based on current industry standard practices and costs for construction metrics common in the transmission and distribution field. The capital cost estimate was then factored using historically derived escalation factors for both equipment and material based on the timing of when such materials would be purchased and labor would be expended. Given the remote FGPP site location, early installation of at least one of the 500 kV circuits from the existing grid to FGPP substation is needed to provide power to support FGPP testing prior to commercial operations.

We independently verified the costs estimated for various components of the Transmission Interconnection system (with the exception of land and right-of-way costs) using in-house methods and conceptual design basis. We found that the costs established by FPL were representative of overhead circuit installation costs. On a cost per lineal mile basis, the 500 kV circuit segments of the conceptual Interconnection design fell within our typical metrics without considering land and right-of-way costs. The costs included for intermediary substations, based on conceptual design, were also found to be reasonable.

Q. What are your specific conclusions regarding the reasonableness of FGPP Transmission Interconnection Costs?

A. Our review of the equipment and construction costs estimated for FPL's Transmission Interconnection found such to be reasonable and consistent with industry metrics in today's marketplace. FPL applied escalation factors to present-day capital cost estimates for materials and labor that are consistent with published industry rates, using anticipated material purchase dates and construction timeline per the overall project schedule, as a means of arriving at a final cost estimate for the Interconnection work. The testimony provided by Mr. Coto provides further insight on the costs associated with the Interconnection.

VI. OWNER'S COSTS

Q. What are "Owner's Costs", and how were the Owner's Costs for FGPP established?

A. Owner's Costs on a new power generation project typically include the following components: land acquisition (green field projects); project development costs (e.g., technology development, environmental permitting); utility interconnections (e.g., water, wastewater); spare parts and non-capital equipment (e.g., rail cars, plant furnishings); Owner's project management and operating staff salaries; plant startup and commissioning support (e.g., training, fuel purchase); professional services costs (e.g., legal and tax advice); Owner's overall contingency; and, financing costs (e.g., AFUDC, credit facility administration).

The Owner's Costs for the FGPP were developed and estimated by the FPL project team, based on significant experience with power generation plant development and construction in the state of Florida. Certain Owner costs, such as simple utility connections, land acquisition, and environmental permit application fees, seem to be established with reasonable certainty based on FPL current work and previous experience. Other Owner's costs, including AFUDC, spare parts, training, and staff costs, were computed based on developed project cash flows, and expected spare parts and staffing requirements specific to FGPP. The last category of Owner's Costs, including fees and costs for utility needs during construction and professional services fees we understand were estimated from similar needs on historical projects and have limited impact to the overall Owner's Cost component.

As indicated in Mr. Yeager's testimony, Owner's costs associated with Power Plant and Transmission Interconnection and Integration were included with their respective direct costs. Costs for Power Plant and Transmission line Land and AFUDC were separately listed.

Q. How was AFUDC computed on the FGPP project and, based on other similar projects, are such AFUDC cost estimates for FGPP reasonable?

A. We reviewed the computation basis for AFUDC values reported in Mr. Yeager's testimony and compared such to AFUDC calculations for other similar projects. This comparison yielded strong correlation between the accrual of AFUDC over the construction phase of a typical coal generation project. The AFUDC value for Unit 1 was significantly affected by the early upfront costs for land acquisition (green field development) and down payments to secure major equipment; the AFUDC value for Unit 2 was principally affected by the extended project schedule from joint award for major equipment with Unit 1 equipment and the EPC contractor's initial fees. My general conclusion from this review was that accurate unit-based AFUDC costs were calculated by FPL for the FGPP in accordance with the anticipated cash flows from project approval through commercial unit operations.

Q. What level of contingency is included in the FGPP cost estimate, and is such comparable to that seen on other active coal fired power generation projects?

A. The owner contingency included by FPL against the total FGPP project is on the order of 9%. While 5-7% is more typical of owner contingencies applied on other active coal-fired generation projects, based on the provisional sums being carried in the Power Plant cost and schedule uncertainties, this amount of contingency was viewed to be reasonable in the current marketplace given the complexity of this project.

Q. What are your specific conclusions regarding the reasonableness of FGPP Owner's Costs, particularly with respect to AFUDC?

A. We reviewed FPL's development of Owner's Costs for the FGPP project, as documented in specific Power Plant and Transmission Interconnection costs and in total, as furnished by FPL. We also conducted several interviews to confirm the process used in quantification of these costs. Subsequently, we compared the magnitude of these costs including contingency and AFUDC to those budgeted for several other major coal-fired generating plants. On the basis of this comparative review, I have concluded that the process used for developing Owner's Cost and their magnitude within the total FGPP project cost estimate are reasonable and comparable in industry for other complex generating station projects.

VII. CONCLUSIONS

Q. Please summarize your testimony.

A. As independent engineers, we completed a review of the estimated FGPP project costs to determine whether such costs were reasonable in magnitude, comparable to market conditions, and consistent with industry estimating practices. This review included comparison of FGPP Owner's and Power Plant Cost components to those of other active projects of similar configuration, checking FPL's Transmission Interconnection cost build-up, and assessed FPL's cash flow model used to compute AFUDC costs.

Through these reviews, a conclusion was drawn that the FGPP costs listed in Mr. William Yeager's testimony are reasonable and competitive in today's marketplace.

As pointed out in Mr. Yeager's testimony, the FGPP is a complex project and a number of external factors could produce delays to the project schedule and unit in-service dates. The FGPP project cost was established on the basis of 2013 and 2014 in-service dates.

Q. Does this conclude your direct testimony?

A. Yes.

In re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant	)))	Docket No: 070098-EI

ERRATA SHEET

DIRECT TESTIMONY OF WILLIAM H. DAMON III

PAGE #	LINE #	CORRECTION
22	**19**	**Change** $1,214 to $1,226

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER AND LIGHT COMPANY

DIRECT TESTIMONY OF HECTOR J. SANCHEZ

DOCKET NO. 07_____-EI

JANUARY 29, 2007

Q. Please state your name and business address.

A. My name is Hector J. Sanchez. My business address is Florida Power and Light Company, 4200 West Flagler Street, Miami, FL 33134.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company (FPL) as the Director of Transmission Services and Planning.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for matters relating to the provision of transmission services on the FPL system and for planning the expansion of the FPL transmission system to meet the requirements of FPL's retail customers, wholesale customers, and its transmission service obligations.

Q. Please describe your educational background and professional experience.

A. In December 1985, I received a Bachelor of Science degree in Electrical Engineering from the University of Miami. In 1990, I completed the Southeastern Electric Exchange's Course in Modern Power Systems Analysis held at Auburn University. In 1991, I received a Master of Business

Administration degree from Florida International University. Additionally, I have completed various other power system courses offered by Power Technology Incorporated, courses offered internally at FPL, and business and management courses at Columbia University.

Since joining FPL in 1985, I have held positions of increasing responsibility. My first positions at FPL were as an Applications Engineer in the Power Systems Control group and as an Engineer in the Protection and Control department. In 1989, I joined the System Operations group in the area of operations planning where I was responsible for performing technical analyses associated with short-term planning and operation of the FPL system. In 1994 I became a Transmission Business Manager where I was responsible for issues associated with the provision of transmission service. Subsequent to that assignment, in March 2000, I held the position responsible for the planning of the bulk transmission system and interconnections. In January of 2006 I became responsible for the operation and dispatch of the FPL system on a real time basis. Lastly, in March of 2006 I assumed my current position as Director of Transmission Services and Planning.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit which consists of the following documents:

Document No. HJS-1: Summary of Required Facilities and Performance for the Fuel Diversity Expansion Plan with Coal;

Document No. HJS-2: Summary of Required Facilities and Performance for the Expansion Plan without Coal;

Document No. HJS-3: Peak Load Comparison of Transmission Losses for the Fuel Diversity Expansion Plan with Coal versus the Expansion Plan without Coal; and

Document No. HJS-4: Average Load Comparison of Transmission Losses for the Fuel Diversity Expansion Plan with Coal versus the Expansion Plan without Coal.

These documents tabulate the following transmission inputs provided for the economic analysis:

- FPL System – Interconnection and Integration Facilities Requirements
- Peak and Average Losses
- Annual Loss differences between plans
- Third party transmission service requirements and costs, if any
- Southeast Florida import limits

Q. Are you sponsoring any sections in the Need Study document?

A. Yes. I am sponsoring the portions of Section III. D. addressing Transmission Facilities – Interconnection and Integration. In addition, I sponsor Appendices A and J, and co-sponsor Appendix O of the Need Study document.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe how FPL developed the most cost effective transmission plan for the interconnection and integration of FPL's

Glades Power Park (FGPP). I discuss the overall transmission evaluation process, and the attendant results of power flow studies used in determining the most cost effective manner to interconnect and integrate into the transmission system the Fuel Diversity Expansion Plan with Coal (Plan with Coal) that includes the two ultra-supercritical pulverized coal units at FGPP for the period of 2012 through 2016. I also discuss the performance of, technical aspects related to, and the evaluation of transmission related costs associated with the interconnection and integration of the Fuel Diversity Expansion Plan with Coal. Mr. Coto discusses the physical characteristics, schedule, permitting requirements and estimated costs associated with the transmission upgrades and new transmission facilities required for the Fuel Diversity Expansion Plan with Coal.

Secondly, I provide an overview of the transmission related requirements for the Expansion Plan without Coal (Plan without Coal) for the same period that was provided to me by Dr. Sim for a comparative analysis associated with this Need Filing. The Expansion Plan without Coal includes only gas-fired, combined-cycle units in the same 2012 through 2016 time frame. Transmission requirements and performance for the Expansion Plan without Coal will be presented separately. The testimony of Mr. Coto also provides an assessment of the required transmission facilities and estimated costs for the Expansion Plan without Coal.

EVALUATION PROCESS FOR DETERMINING FPL'S TRANSMISSION SYSTEM REQUIREMENTS

Q. Please describe FPL's evaluation process for new generation resources that results in determining the most cost effective transmission interconnection and integration plan.

A. The process commences with a team, including engineers from transmission and substation planning, operations, engineering, project management, permitting and siting who together use their combined knowledge and years of experience to perform the evaluation and develop the most cost effective transmission interconnection and integration plan. The evaluation process considers many factors as outlined below in order to develop a feasible cost effective transmission plan. In some instances the determination of the most cost effective transmission interconnection and integration plan is relatively straight forward; however, other times it requires an iterative assessment of the various factors and a substantial amount of time to perform studies. The resultant plan is in compliance with North American Electric Reliability Council (NERC) reliability standards and will provide firm transmission service.

Generally, the first step in the process is to evaluate the proposed generating plant site location to determine its proximity to existing transmission facilities. To the extent there are existing transmission facilities nearby, they are then assessed to determine their capabilities for reliably interconnecting and integrating the proposed new generation into the transmission system as a firm FPL generation resource. Next, other factors such as those listed below are considered as applicable:

- Amount of generation (MW) being added at the new generation site, and the dispatch profile of the new generation resource relative to FPL's other generation resources in serving FPL's load;
- Capabilities to upgrade existing facilities (e.g., can the conductor on an existing transmission line be upgraded on the existing structures or would the entire transmission line have to be rebuilt?);
- Capability of transmission lines needed, right-of-way requirements, existing right-of-way capabilities, siting of new right-of-way, permitting requirements, and expected time-frame to acquire right-of-way and necessary permits;
- Ability to transport power efficiently (e.g., would using higher voltages be more cost effective by reducing the amounts of transmission losses incurred when moving large amounts of power over long distances?);
- Existing and new substation requirements, capabilities and availability;
- Impact on existing facilities (e.g., does the proposed interconnection or integration plan result in an overload on an existing facility or does it result in a material adverse impact somewhere else on the transmission system?);

- Constructability (e.g., can the transmission facilities necessary be constructed without having to take clearances on existing operating facilities during periods that would result in an adverse reliability impact?);
- Overall compatibility with the system (e.g., do the new facilities being added require new material stocking requirements or the need for new tools to maintain?);
- Compliance with NERC and FRCC Reliability Standards;
- Operating considerations (e.g., what are the maintenance requirements of the proposed interconnection and integration facilities, and how will they impact the on-going operation of the system?);
- The timing and amount of power needed for testing of equipment such as pumps and motors;
- Expected in-service testing and commercial operations dates for new generation (e.g., which transmission facilities needed for interconnection and integration need to be in-service prior to the commercial operations in-service date for testing?);
- The need for procuring transmission service from a third party;
- Material adverse impact on third party transmission owner; and
- Costs (e.g., initial and on-going costs of facilities and operations).

The next step in the interconnection and integration evaluation process is to perform power flow studies for a proposed transmission interconnection and integration plan. These power flow studies are used to evaluate the performance of the system, and to converge on specific new system facilities and upgrades that would be needed to interconnect and integrate the new generation into the transmission system.

When the evaluation team is satisfied that they have developed the most cost effective transmission interconnection and integration plan that is in compliance with NERC and FRCC reliability standards for the new generation resources being proposed to serve FPL's load, the process is deemed complete. If this result is not achieved, the evaluation process proceeds iteratively, as needed.

Q. **Did the evaluation process discussed above result in the most cost effective interconnection and integration plan for FGPP?**

A. Yes. FPL's evaluation resulted in the interconnection and integration plan discussed later in my testimony, which I believe to be the most cost effective plan to interconnect and integrate FGPP after considering the above factors.

I would also note that this evaluation process, including the power flow studies is the same as that used in FPL's most recent Need Determination proceedings in determining the most cost effective interconnection and integration plan.

Q. Please describe how FPL evaluated the transmission related costs associated with the generation plans.

A. FPL, in its evaluation of a generation plan, considers five different categories associated with transmission that could result in costs that arise from the proposed delivery of additional power over FPL's transmission system. These categories are:

1) Transmission interconnection;
2) Transmission integration;
3) Third party transmission service costs (as applicable);
4) Transmission system losses; and
5) Impact of operating existing FPL generation units in Southeast Florida out of economic order to maintain system reliability.

FPL evaluated each of these categories. FPL's Transmission Services and Planning department evaluated the first three categories under my direction, and provided transmission loss data and Southeast Florida import capabilities for categories 4 and 5 for use as inputs in Dr. Sim's economic analyses.

Q. Please describe in more detail each of the five categories associated with transmission costs that you have identified.

A. The five categories can be summarized as follows:

Transmission interconnection requirements

Transmission interconnection requirements are generally the facilities necessary to connect the new generation to the system. These facilities typically include generator step-up transformers, connection facilities from the transformers to the switchyard and certain substation equipment at the point of interconnection. Mr. Coto discusses the physical attributes and cost estimates associated with the interconnection facilities.

Transmission integration requirements

Transmission integration requirements include system upgrades of existing transmission facilities and new transmission facilities that power flow studies have determined are necessary for the reliable operation and firm delivery of the new FPL generation resources to FPL's load. Mr. Coto discusses the physical attributes and cost estimates associated with the upgrades and new facilities required for transmission integration.

As part of this assessment, any adverse impacts that result in reliability criteria violations on third party transmission systems are identified. In such instances, FPL would check with the parties to confirm that the violation is valid and, if so, see if there is a mitigation measure already available, or jointly develop mitigation measures to address the violation.

Third party transmission service requirements and costs (as applicable)

Third party transmission service requirements and costs are considered when generation resources are connected to an external transmission provider's system(s). These requirements may include the payment of transmission wheeling charges, ancillary services, and losses. Because neither of the FPL generation plans contains generation connected to a third party transmission system, there is no need to procure transmission service for the delivery of generation connected to a third party to the FPL system. Thus, third party transmission service costs are not applicable to any of the FPL generation plans evaluated.

Transmission losses

The two FPL generation plans contain new generation resources at the same specific locations in relation to the FPL transmission system with different in-service dates, and each plan will have an impact on FPL's transmission system losses. The impact on losses is determined by a comparison of resulting losses among generation plans that serve the same load. Losses were calculated for each plan, at both the peak and the average load levels, for each year in the period 2012 through 2016. The different generation plans are evaluated with respect to losses in terms of the differences in incremental losses among generation plans. Document No. HJS-3, Peak Load Comparison of Transmission Losses for the Fuel Diversity Expansion Plan with Coal versus the Expansion Plan without Coal summarizes the differences in peak load losses and Document No. HJS-4, Average Load Comparison of Transmission Losses for the Fuel Diversity Expansion Plan with Coal versus the Expansion Plan without Coal summarizes the differences in average load losses between plans by year.

Impact of operating existing FPL generation units in Southeast Florida to maintain reliability

The Southeast Florida import limit is the amount of power that can be imported into Southeast Florida in a reliable manner under various conditions. In this context, Southeast Florida is generally defined as the portion of the FPL system located south and east of, and including FPL's Corbett Substation. During those periods when no additional power can be imported into Southeast Florida, there is a reliability need to operate more expensive generation in Southeast Florida out of economic order. Such occurrences result in increased operating costs.

Dr. Sim presents the overall economic results for the two generation expansion plans, including any increase in the production costs for each plan resulting from the Southeast Florida import limit analyses.

FPL'S EXPANSION PLANS' TRANSMISSION EVALUATION

TRANSMISSION SYSTEM REQUIREMENTS FOR FPL'S FUEL DIVERSITY EXPANSION PLAN WITH COAL

Q. Please describe FPL's Fuel Diversity Expansion Plan with Coal for the 2012 through 2016 period for which transmission requirements are being evaluated.

A. The Fuel Diversity Expansion Plan with Coal is described below:

FGPP 1 (Coal) = 980 MW net coal unit (1,050 MW gross output) with the potential at this time of being in-service as early as the second half of 2012, as discussed in Mr. Silva's testimony.

FGPP 2 (Coal) = 980 MW net coal unit (1,050 MW gross output) with the potential at this time of being in-service as early as the second half of 2013, as discussed in Mr. Silva's testimony.

South Florida CC unit = 1,219 MW net combined cycle unit (1,243 MW gross output) assumed for analysis purposes to be sited in the vicinity of the West County Energy Center with an in-service date of June, 2015.

Transmission Interconnection

Q. Please describe the transmission interconnection requirements for the new generation in the Fuel Diversity Expansion Plan with Coal.

A. The required transmission interconnection facilities for the Fuel Diversity Expansion Plan with Coal are summarized in Document No. HJS-1, Summary of Required Facilities and Performance for the Fuel Diversity Expansion Plan with Coal.

These facilities include:

For FGPP 1 and 2 (Coal):

- The connection of FGPP 1 and 2 Generator Step Up (GSU) transformers to the FGPP switchyard, and attendant bus equipment;

For South Florida CC unit:

- The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard, and the string buses from the collector yard to the South Florida 230 kV substation; and
- The circuit breaker and overhead ground wire upgrades required.

Transmission Integration

Q. Please describe the transmission integration evaluation for the new generation in the Fuel Diversity Expansion Plan with Coal.

A. The integration evaluation is comprised of power flow studies. The power flow studies are used to identify any upgrades to existing transmission facilities or new transmission facilities that may be needed to integrate the capacity additions in the Fuel Diversity Expansion Plan with Coal into the transmission system as firm FPL generation resources while meeting reliability criteria. The methodology used to perform these power flow studies is the same as that used in connection with FPL's most recent Need Determination proceedings, and is consistent with the methods used to ensure compliance with the NERC reliability standards. I reviewed and approved the results of the power flow studies, and reviewed the need for new facilities and upgrades required to integrate the capacity additions for the Fuel Diversity Expansion Plan with Coal into the transmission system as firm FPL generation resources used to serve FPL's retail customers. Mr. Coto discusses the permitting, construction and cost estimates associated with the new transmission facilities and upgrades that were identified as being necessary for the Fuel Diversity Expansion Plan with Coal.

My review determined that to reliably integrate the new generation resources in compliance with NERC reliability standards, new system facilities and upgrades are required for the Fuel Diversity Expansion Plan with Coal. Document No. HJS-1, Summary of Required Facilities and Performance for the Fuel Diversity Expansion Plan with Coal, summarizes the new system facilities and facility upgrades required.

Q. Please describe the power flow analyses performed.

A. As discussed above, the in-service dates for the generation additions included in the Fuel Diversity Expansion Plan with Coal span 2012 through 2016. As Mr. Silva states in his testimony, at this time there is the potential that FGPP 1 and FGPP 2 could be in-service as early as the second half of 2012 and 2013, respectively. Therefore, the transmission assessment performed, including the power flow analysis, to determine the transmission facilities required to interconnect and integrate these units addresses an in-service date consistent with the potential that FGPP 1 and FGPP 2 could be placed in-service as early as the second half of 2012 and 2013, respectively. First contingency, Alternating Current (AC) power flow analyses were performed for the Fuel Diversity Expansion Plan with Coal for each year to assess the need for transmission system upgrades and new facilities. All analyses were performed using the latest available 2006 FRCC power flow databank cases that were used for the re-study of the Florida Central Coordinated Study (FCCS), updated to reflect FPL's latest load and resource forecast as well as the projects that resulted from the FCCS re-study. Since the FCCS re-study only developed load flow cases through 2014, the 2015 and the 2016 cases were developed by scaling FPL's load in the 2014 case to the latest available load forecast for 2015 and 2016, incorporating FPL's most recent load and resource data and available information on third party systems.

Analyses were performed using power flow simulations to identify the facilities that may become overloaded because of the integration of the generation additions contained in the Fuel Diversity Expansion Plan with Coal, as well as the upgrades and new transmission facilities required to mitigate such overload(s). An AC solution technique was also used to assess the voltage performance of the system against reliability criteria. For all the years of the analysis, the Fuel Diversity Expansion Plan with Coal was subjected to a first contingency screening for loss of transmission elements or generators out of service, one at a time, in accordance with reliability criteria. This resulted in approximately 3,600 power flow calculations being performed for each year assessed. All of the Peninsular Florida interconnected transmission system was monitored to determine whether thermal or voltage reliability criteria violations for system elements at voltages of 69 kV and above occur as a result of the generation resource addition. Reliability violations on any FPL or other Peninsular Florida system elements directly related to the generation resource addition could indicate the potential need for transmission reinforcements.

Q. What factors associated with FGPP have a major impact on the results of the analysis?

A. The requirement to add major transmission facilities is the result of the need to deliver 1960 MW (two 980 MW units) of new generation from a new site in Glades County, an area where no major transmission infrastructure exists, to Florida's East and West coasts, in order to serve FPL's load. This results in significant transmission facilities being required. Mr. Coto addresses the physical attributes of these major transmission facilities, scheduling and permitting requirements, and attendant estimated costs to construct these facilities.

Q. Please provide a general description of the transmission upgrades and new transmission facilities required for the Fuel Diversity Expansion Plan with Coal.

A. When the first unit is placed in-service, the unit will be connected to the FGPP 500 kV switchyard located at the FGPP site in Glades County. This switchyard will be connected by two 500 kV transmission lines to the 500 kV section of the Hendry 500 kV substation in Hendry County which will be located approximately 25 miles south of the FGPP switchyard. The Orange River to Andytown 500 kV line will be looped into the Hendry substation by constructing two parallel 500 kV lines from the Hendry substation to the existing 500 kV right-of-way, approximately 24 miles to the south. This effectively creates two 500 kV lines; the Hendry to Orange River line, and the Andytown to Hendry line. Additionally, Hendry substation will also have a 230 kV section. The Hendry 500 and 230 kV sections will be connected via a 500/230 kV auto-transformer. The Alva to Corbett 230 kV line, which is in close proximity to the proposed Hendry substation, will be looped into the Hendry substation.

The FGPP 2 980 MW net output coal unit will also be connected to the FGPP 500 kV switchyard before it enters into service. In order to integrate this additional generation, a 500 kV transmission line from the Hendry substation to the Levee substation will be necessary. This new 500 kV line will be connected at Andytown to an existing Andytown to Levee 500 kV line, forming the Hendry to Levee 500 kV line.

In 2015, the South Florida CC unit is assumed to be added in the vicinity of the West County Energy Center by interconnecting it to the 230 kV section of the South Florida substation. The South Florida 500 kV and South Florida 230 kV sections will be connected via a 500/230 kV autotransformer. Additionally, the Corbett to Green 230 kV and the Corbett to Germantown 230 kV lines will be re-routed from the Corbett 230 kV substation to the South Florida 230 kV substation. The facilities discussed above are summarized as follows:

For FGPP 1 and 2 (Coal):

- The FGPP switchyard;
- Two 500 kV lines from FGPP 500 kV switchyard to Hendry 500 kV substation;
- The Hendry 500/230 kV Substation;
- The looping in of the Andytown to Orange River 500 kV and the Alva to Corbett 230 kV transmission lines into the Hendry substation; and
- The construction of a 500 kV transmission line spanning from the Hendry to Levee substations. This transmission line will be constructed between the Hendry and Andytown substations and connected to an existing Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line.

For the assumed South Florida CC unit:

- The South Florida 230 kV substation; and
- Reroute the Corbett-Green 230 kV and the Corbett-Germantown 230 kV lines into the 230 kV section of the South Florida substation.

These facilities for the Fuel Diversity Expansion Plan with Coal are also summarized in Document No. HJS-1, Summary of Required Facilities and Performance for the Fuel Diversity Expansion Plan with Coal.

Q. Will either FGPP 1 or 2 increase the size of the single largest unit in the FRCC when they enter service?

A. No. Progress Energy Florida has recently filed with the Commission to increase the size of their Crystal River 3 nuclear unit to approximately 1,080 MW gross output by the end of its planned refueling outage in 2011. FGPP 1 and 2 each have a 1,050 MW gross output rating with the first unit potentially going into service as early as the second half of 2012. The 910 MW gross output of FPL's St. Lucie nuclear units are currently the largest sized units in the FRCC.

Q. Will the size of the FGPP coal unit impact the FRCC's import capability from the Southeast Electric Reliability Council (SERC)?

A. No. FPL's assessment indicates that by 2012 the system becomes sufficiently robust to support the sudden loss of 1,050 MW gross output of either FGPP 1 or 2 without reducing the current capability to import 3,600 MW into the FRCC from the SERC.

Q. How was the assessment performed to verify this conclusion?

A. FPL's assessment was performed with the same load flow models used for the 2006 Southern/Florida long term screening evaluations, modified with the addition of the FGPP generation and corresponding transmission facilities, and using the same process that is currently followed every year to assess the import capability of the FRCC from the SERC.

Q. Do you know why the system becomes sufficiently robust in the 2012 and forward time-frame to withstand the loss of a larger size unit?

A. Based on a review of the load flow analyses performed for this Need Filing, it is apparent that FPL's addition of almost 3,600 MW in Southeast Florida (i.e., the Turkey Point 5 unit with 1,144 MW of output in 2007, and the West County 1 and 2 units, each with 1,219 MW of output in 2009 and 2010) reduces the amount of power that is transferred from the north to the south on FPL's 500 kV backbone facilities that span the entire length of the state. Locating the above generation in southeast Florida closer to the load centers has the effect of reducing the loading on the transmission system, resulting in the ability to reliably increase the size of the largest unit in the FRCC while still maintaining the 3,600 MW of import capability into the FRCC from SERC.

Q. Has this assessment, along with the FGPP interconnection and integration requirements discussed above been reviewed by the FRCC?

A. Yes. FPL's interconnection and integration plan for the FGPP and the FRCC-SERC interface capability assessments discussed above was provided to the FRCC to affirm that no reliability issues exist. The FRCC's review affirmed FPL's results associated with the transmission plan, and determined that FPL's interconnection and integration plan will be reliable, adequate and will not adversely impact the reliability of the FRCC transmission system.

Third Party Transmission Service Requirements and Costs

Q. Please describe the third party transmission service requirements and attendant costs incurred by the Fuel Diversity Expansion Plan with Coal.

A. The Fuel Diversity Expansion Plan with Coal involves new generation at the FGPP site and, for purposes of the economic analyses, at the South Florida site. These sites will be directly connected to the FPL transmission system. Therefore, the Fuel Diversity Expansion Plan with Coal does not require or incur third party transmission service costs.

Transmission Losses

Q. Please describe how the effects of transmission losses were included in the economic comparison of the two generation expansion plans and how the loss calculations were performed.

A. The transmission loss impact is a function of the location of generation resources, output capability of each of the resources and system loading conditions. The economic impact of transmission losses is determined by Dr. Sim's economic analyses of the transmission losses that I provide.

Q. Please describe the methodology applied in the determination of transmission losses.

A. The same methodology that was applied in FPL's two most recent Need Determination proceedings was used to determine losses in each year of each Plan. I will summarize that methodology.

Transmission losses are incurred by current (I) flowing through transmission elements that have resistance (R). Losses are calculated as I^2R and occur in each transmission element as the current flows from generator to load. The further the generator is from the load, the larger the value of resistance and the higher the losses. However, the current (I) and voltage (V) are inversely proportional, so as a higher voltage level is used to transport the power (assuming the same R), the same amount of power can be transported with less losses. Therefore, integrating large amounts of generation in areas remote and distant from the concentration of major load centers with major transmission facilities (500 kV) accomplishes not only the requirement of delivering such amounts of power to the various load centers, but also mitigates incurring substantial transmission losses in the process. It is important to note that there are multiple generators, transmission elements and loads distributed throughout the system, and losses will vary as a function of generator dispatch and load level.

Power flows and the losses in the transmission system will be impacted whenever a new generating resource is dispatched. Therefore, the impact on losses of a new generation resource and, more generally, a generation plan of new generation resources, will depend both on where the new generation resources are located and the characteristics of the resources. While base load resources may operate and impact transmission losses most of the time, more expensive peaking resources tend to operate, and impact losses, only at higher load levels.

The impact of losses can be evaluated by power flow calculations assuming that generation resources will be dispatched economically. This evaluation can be performed with reasonable precision for the years 2012 through 2016. However, for 2017 and beyond, increasing load will require additional generation resources, the location and composition of which are uncertain at this time. The expansion of the transmission system beyond 2017 is also uncertain. Therefore, the impact of a particular generation expansion plan on transmission losses becomes progressively more uncertain with time.

To deal with this uncertainty in a consistent fashion, it was assumed that the transmission loss impacts for the year 2017 and beyond would be identical to the transmission loss impacts calculated for the year 2016. While the accuracy of the losses applied in this analysis can only be ascertained in retrospect after the actual resource and transmission system expansions over the 40 year life of the FGPP 1 and 2 is known, I believe that the methodology developed is a reasonable one, is consistent with the methodologies applied in previous Need Determination proceedings, and produces a fair assessment associated with the impact of transmission losses.

Q. Please describe how the power flow analysis was applied to calculate losses.

A. Transmission losses were calculated for the years 2012 through 2016. Losses were calculated for summer peak load conditions and for average system load conditions. Losses calculated for summer peak load conditions were used by Dr. Sim to estimate the cost of additional capacity required each year to compensate for transmission losses.

Peak load losses for the years 2012 through 2016 were determined using the same power flow representation applied in the transmission integration studies. Also, all FPL resources, other firm resources and the new generation additions in the generation plan were assumed to be dispatched economically. The losses calculated under this methodology reflected the transmission losses only on FPL transmission facilities. Losses for average load conditions used the same system model as for peak load conditions but with resources dispatched economically to meet the lower load level.

Increased Operation of Generating Units in Southeast Florida and Associated Increased Operating Costs

Q. **What was the rationale for including the increased operating requirements arising from the uneconomic dispatch of generating units in Southeast Florida as a transmission-related cost?**

A. The Southeast Florida import limit is the amount of power that can be imported into Southeast Florida in a reliable manner under high load conditions or during planned or forced outages of generation. In this context, Southeast Florida is generally defined as the portion of the FPL system located south and east of, and including, FPL's Corbett Substation. During those periods where no additional power can be imported into Southeast Florida, there is a reliability need to operate generation in Southeast Florida out of economic order. Such occurrences result in increased operating cost. Dr. Sim's testimony presents the production cost results for the Fuel Diversity Expansion Plan with Coal.

Q. **Please describe the methodology and results obtained from the calculation of the Southeast Florida import limits.**

A. Document No. HJS-1, Summary of Required Facilities and Performance for the Fuel Diversity Expansion Plan with Coal, shows the Southeast Florida import limit for the Fuel Diversity Expansion Plan with Coal for each year of analysis. The limit is measured as the sum of the flows on the transmission lines connecting the Southeast Florida load center to the rest of the Florida system to the west and north. A power flow analysis was performed by gradually increasing the interface flows and applying a critical contingency until an acceptable solution could not be obtained. In all cases, the limiting condition was the requirement to avoid voltage collapse in Southeast Florida for the largest single contingency loss, which is a portion of the Turkey Point Unit 5 (i.e., two of the four combustion turbines and the steam unit). These import limits may be reduced as a function of planned operational outages of transmission facilities in Southeast Florida. Conforming to operating experience, this reduction in import limit may also vary with the amount of generation on planned outages and other generation maintenance outages. The table in Document No. HJS-1, Summary of Required Facilities and Performance for the Fuel Diversity Expansion Plan with Coal, shows the Southeast Florida import capability associated with the Fuel Diversity Expansion Plan with Coal for each year, 2012 through 2016.

Q. What are your conclusions based on the analyses involved in performing an economic evaluation of the transmission-related costs?

A. It is my opinion that these analyses provide reasonable estimates of the real transmission-related costs arising from a generation plan and that all such costs should be captured in performing an economic evaluation of different generation plans. These analyses and costs should be relied upon by the Commission.

TRANSMISSION SYSTEM REQUIREMENTS FOR THE EXPANSION PLAN WITHOUT COAL

Q. Please describe the Expansion Plan without Coal for the 2012 through 2016 period for which transmission requirements are being evaluated.

A. The non-coal-based generation expansion plan, the Expansion Plan without Coal, is described below:

The assumed South Florida CC unit = 1,219 MW net combined cycle unit assumed for analysis purposes to be sited in the vicinity of the West County Energy Center with an in-service date of June, 2012;

The assumed FGPP 1 (Gas) = 1,119 MW net sited at FPL's FGPP site in Glades County (the Expansion Plan without Coal) with an in-service date of June, 2014; and

The assumed FGPP 2 (Gas) = 1,119 MW net sited at FPL's FGPP site in Glades County (the Expansion Plan without Coal) with an in-service date of June, 2016.

Transmission Interconnection

Q. Please describe the transmission interconnection for the new generation additions included in the Expansion Plan without Coal.

A. The transmission interconnection facilities are summarized in Document No. HJS-2, Summary of Required Facilities and Performance for the Expansion Plan without Coal.

These facilities include:

South Florida CC unit

- The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard, and the string buses from the collector yard to the South Florida 230 kV substation;
- Circuit breaker and overhead ground wire upgrades required; and

FGPP 1 and 2 (Gas)

- The connection of FGPP 1 and FGPP 2 CC GSU transformers to the collector yard, including attendant bus equipment, the collector yard, and the string buses from the collector yard to the FGPP switchyard.

The results of the assessment are summarized in Document No. HJS-2, Summary of Required Facilities and Performance for the Expansion Plan without Coal.

Transmission Integration

Q. Please describe FPL's transmission integration assessment results for the Expansion Plan without Coal.

A. My review determined that to reliably integrate the Expansion Plan without Coal in compliance with NERC reliability standards, new system facilities and facility upgrades are required. Document No. HJS-2, Summary of Required

Facilities and Performance for the Expansion Plan without Coal summarizes the new system facilities and upgrades required.

With respect to the Expansion Plan without Coal, the overall transmission requirements are also very similar to those for the Fuel Diversity Expansion Plan with Coal, except that the timing is reversed as to when the new transmission facilities are required, based on the reversal in timing for the new generation. In other words, those facilities in the Fuel Diversity Expansion Plan with Coal that are needed in 2012 and 2013 would instead be postponed from 2012 and 2013 to 2014 and 2016 in the Expansion Plan without Coal due to new generation at the FGPP site in that later time frame.

Third Party Transmission Service Requirements and Costs

Q. Please describe the third party transmission service requirements and attendant costs incurred by the Expansion Plan without Coal.

A. The Expansion Plan without Coal only includes new generation at the FGPP and South Florida sites that will be directly connected to FPL. Therefore, the Expansion Plan without Coal does not require or incur third party transmission service costs.

Transmission Losses

Q. **Please indicate in general terms how the Expansion Plan without Coal performs in terms of transmission losses.**

A. Document No. HJS-2, Summary of Required Facilities and Performance for the Expansion Plan without Coal, lists the peak load level losses and average load level losses for the Expansion Plan without Coal for the 2012 – 2016 period. The difference in losses between the Fuel Diversity Expansion Plan with Coal and the Expansion Plan without Coal is not significant: only about one-half of one percent (0.5%) of the total transmission losses.

Document No. HJS-3, Peak Load Comparison of Transmission Losses for the Fuel Diversity Expansion Plan with Coal versus the Expansion Plan without Coal, indicates the differences in losses between plans at peak load and Document No. HJS-4, Average Load Comparison of Transmission Losses for the Fuel Diversity Expansion Plan with Coal versus the Expansion Plan without Coal, indicates the differences in losses between plans at average load, and each extrapolates them over a 40 year period. These differences were used by Dr. Sim to calculate the incremental capacity and energy costs due to the differences in losses between plans.

Increased Operation of Generating Units in Southeast Florida and Associated Increased Operating Costs

Q. **Please describe the results obtained from the calculation of the Southeast Florida import limits for the Expansion Plan without Coal.**

A. The table in Document No. HJS-2, Summary of Required Facilities and Performance for the Expansion Plan without Coal, indicates the Southeast Florida import limits associated with the Expansion Plan without Coal.

Dr. Sim used the Southeast Florida import limits calculated for the Expansion Plan without Coal in the production cost model so that the production cost projections include any incremental operating costs. Dr. Sim's testimony presents the production cost results for this generation expansion plan.

Q. **Please summarize your testimony.**

A. My testimony provides a description of the evaluation process used to develop the most cost effective plan of transmission-related requirements for FGPP, considering factors associated with planning, construction and operation of the electric system. Additionally, I discuss five aspects of transmission-related requirements that were evaluated for each of the two generation expansion plans:

- The transmission interconnection requirements;
- The new transmission facilities and upgrades of existing transmission facilities required to integrate the generation additions in each plan to the FPL system;

- Third party transmission service requirements;
- Transmission losses during peak load and average load conditions considering the transmission improvements required for the generation additions in each plan based on the attendant operating characteristics (with costs associated for these losses calculated by Dr. Sim); and
- The impact of Southeast Florida import limits (with costs associated with these import limits included in production costs calculated by Dr. Sim).

Each of these transmission-related categories were included in the economic evaluation of the two expansion plans. Their inclusion is necessary and appropriate to capture a reasonable estimate of the transmission-related requirements and attendant costs arising from a generation plan.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JOSE COTO

DOCKET NO. 07_____-EI

JANUARY 29, 2007

Q. Please state your name and business address.

A. My name is Jose Coto. My business address is Florida Power and Light Company, Power System Engineering Division, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Transmission Engineering Manager in the Transmission Group.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for the oversight of transmission engineers in the group in the performance of their duties associated with transmission system expansion projects which include:

- Support of transmission line route selection;
- Preparation of permit and license applications;
- Structure layout;
- Application of Standards;
- Preparation of Bill of Materials;

- Preparation of plans and specifications for right-of way preparation and line construction; and
- Preparation of cost estimates and project schedules.

In addition, I am also responsible for reviewing the feasibility of proposed transmission system expansion projects and associated costs of these expansions.

Q. Please describe your educational background and professional experience.

A. I obtained a Bachelor of Science Degree in Electrical Engineering from the University of Miami in December 1979. I am a registered Professional Engineer in the State of Florida and a member of the Institute of Electrical & Electronics Engineers (IEEE).

Since joining FPL in 1978, I have held various positions of increasing responsibility within Power Delivery, either in the Transmission or Substation Areas. From 1979 to 1985, I was a transmission line engineer. During this time, I engineered transmission line projects ranging in voltage from 69kV up to 500 kV. From 1985 to 1999, I held various supervisory positions in the Transmission Lines Group and the Transmission Substation Group. In 1999, I became Project Manager in the Transmission Projects Group responsible for the central area of FPL's service territory. As Project Manager, I was responsible for the oversight of both transmission and substation projects. In March of 2006, I assumed my current position of Transmission Engineering Manager.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring an exhibit consisting of 7 documents attached to my direct testimony. Those 7 documents are:

- Document No. JC-1 Cross Sectional View of 350 Feet Right-of-Way
- Document No. JC-2 Cross Sectional View of 494 Feet Right-of-Way
- Document No. JC-3 Cross Sectional View of 330 Feet Right-of-Way
- Document No. JC-4 Cross Sectional View of 660 Feet Right-of-Way
- Document No. JC-5 One Line Diagram for FGPP
- Document No. JC-6 Geographical Map Showing the Locations of FGPP and the Transmission Line Corridors Associated with the Project
- Document No. JC-7 Summary of Required Transmission Facilities, Cost and Schedule for the Fuel Diversity Expansion Plan with Coal

Q. Are you sponsoring any sections in the Need Study document?

Yes. I sponsor Section III. D. 2. Transmission Facilities – Cost, Construction and Schedule. In addition, I sponsor Appendix I and co-sponsor Appendix O of the Need Study document.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the physical characteristics of the transmission facilities required to interconnect and integrate, into the transmission system, the two coal units at FPL's Glades Power Park (FGPP) and other non-coal units contained in the 2012-2016 generation plan associated with FPL's Fuel Diversity Expansion Plan with Coal. Additionally, I discuss permitting requirements, engineering, construction, schedule and estimated costs associated with these transmission facilities.

Secondly, I will also provide an overview of the facilities required to interconnect and integrate the Expansion Plan without Coal into the transmission system.

The technical requirements of the facilities needed to interconnect and integrate the Fuel Diversity Expansion Plan with Coal and the Expansion Plan without Coal into FPL's transmission system were developed by and provided to me by Mr. Sanchez.

DESCRIPTION OF TRANSMISSION FACILITIES REQUIRED FOR THE FUEL DIVERSITY EXPANSION PLAN WITH COAL

Q. Please describe the transmission facilities required for the Fuel Diversity Expansion Plan with Coal.

A. The transmission facilities associated with the Fuel Diversity Expansion Plan with Coal are described below:

1. The connection of FGPP 1 and 2 Generator Step Up (GSU) transformers to the FGPP switchyard, and attendant bus equipment; (TF-1)
2. The FGPP switchyard; (TF-2)

3. The Hendry 500/230 kV Substation; (TF-3)
4. The two 500 kV transmission lines from the FGPP switchyard to the Hendry Substation; (TF-4)
5. The looping in of the Andytown to Orange River 500 kV and the Alva to Corbett 230 kV transmission lines into the Hendry substation; (TF-5)
6. A new 500 kV transmission circuit from the Hendry to Levee substations. This transmission line will be constructed between Hendry and Andytown substations and connected to an Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line; (TF-6)
7. The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard, and the string buses from the collector yard to the South Florida 230 kV substation; (TF-7)
8. The South Florida 230 kV substation; (TF-8)
9. The re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation; (TF-9) and
10. The circuit breaker and overhead ground wire upgrades required. (TF-10)

Q. **Please describe the physical characteristics of the facilities that connect FGPP 1 and FGPP 2 GSU transformers to the FGPP switchyard, and attendant bus equipment. (TF-1)**

A. The GSU transformers are located in close proximity to the generator. The GSU transforms the output from the generator from a lower voltage to a higher voltage so that the power can be transmitted to the load. From the high voltage side of the GSU transformers string buses will extend and connect to the FGPP switchyard.

Q. Please describe the physical characteristics of the FGPP switchyard. (TF-2)

A. The FGPP switchyard will be located at the FGPP site. It will be a fenced area approximately 600 by 800 feet that contains switches, circuit breakers, buses and other electrical equipment. The FGPP switchyard will have a total of six transmission terminals. Two of the terminals will be used to connect the GSU transformers for FGPP 1 and 2. The GSU transformers associated with FGPP 1 and 2 will be connected via string buses to the FGPP switchyard. Another two terminals will be used to connect to equipment used for the start-up power for FGPP 1 and 2 and the remaining two terminals are used for the 500 kV lines that will connect the FGPP switchyard and Hendry substation.

Q. Please describe the physical characteristics of the proposed Hendry substation. (TF-3)

A. Hendry substation will be a fenced area approximately 800 by 1,200 feet that contains switches, circuit breakers, buses, transformers and other electrical equipment. Hendry substation will have a 500 kV section (the 500 kV substation) and a 230 kV section (the 230 kV substation) connected via a 500/230 kV autotransformer. A total of five 500 kV and two 230 kV transmission lines will connect to Hendry substation. Two 500 kV lines will connect the Hendry substation to FGPP switchyard, two 500 kV lines will connect Hendry substation to Orange River and Andytown substations and a fifth 500 kV transmission line will connect Hendry substation to Levee substation. The two 230 kV lines will connect Hendry substation to Alva and Corbett substations.

Q. Please describe the physical characteristics of the two proposed transmission lines required between FGPP switchyard and Hendry substation. (TF-4)

A. Two 500 kV transmission lines will connect the FGPP switchyard and Hendry substation. The distance between FGPP switchyard and Hendry substation is estimated to be approximately 25 miles, depending on the final route of the right-of-way for these transmission lines. These transmission lines will be located within a proposed right-of-way that will be 350 feet in width. The current plan is for these transmission lines to be constructed using H-frame type steel structures. The centerline to centerline spacing of the structures will be 144 feet. Structures will typically be spaced at approximately one quarter mile intervals, but this spacing may vary depending on existing land features. The typical structure will be approximately 125 feet in height. The transmission line conductors will consist of a bundle of three aluminum conductors per phase and will have a minimum clearance to ground of 35 feet. These two lines will each have two overhead ground wires. One of these overhead ground wires on each line will contain optical fibers that will be used for line communications and line protection.

The physical characteristics of the typical structures, spacing, span length and height, conductor configuration and ground clearance described above will be used for all other 500 kV lines on this project. Document No. JC-1, Cross Sectional View of 350 Feet Right-of-Way, provides a representative illustration of the right-of-way that I describe above.

Q. **Please explain why the distance between structures may vary.**

A. The distance between structures can vary for a number of reasons. For example, variations are often necessary in order to minimize impacts to wetlands or other land features, to provide proper clearances over roads and canals or other existing obstructions, or to reduce the height of structures where shorter structures are required. If spans are consistently shorter than anticipated, it would translate to more structures per mile and could have a direct impact on the total cost of the project.

Q. **Please describe the physical characteristics of the proposed transmission lines that constitute the looping of the Orange River to Andytown 500 kV and the Alva to Corbett 230 kV transmission lines into the Hendry substation. (TF-5)**

A. Two of the 500 kV transmission lines connecting to Hendry substation will result from looping in the Andytown-Orange River 500 kV line. The distance between Hendry substation and the Andytown-Orange River 500 kV right-of-way is estimated to be approximately 24 miles, depending on the final route of the right-of-way for these transmission lines. These 500 kV transmission lines will be located within a proposed right-of-way that will be 494 feet in width spanning from Hendry Substation to the point where this new corridor intersects with the existing Andytown-Orange River transmission line right-of-way. These two 500 kV transmission lines will be constructed in the same manner with regard to structures, spacing, span length and height, conductor configuration and ground clearance as the previously described 500 kV transmission lines, except that the overhead ground wires will not contain optical fibers. Document No. JC-2, Cross Sectional View of 494 Feet Right-of-Way, provides a representative illustration of the right-of-way that I describe above.

Additionally, the Alva to Corbett 230 kV line, which is in close proximity to the proposed Hendry substation, will be looped into Hendry substation. The structures used to loop the Alva to Corbett 230 kV transmission line will be concrete poles. The typical structure will be approximately 85 to 100 feet above ground and spaced approximately 300 to 600 feet apart. The transmission line will have a single aluminum conductor per phase and will have a minimum clearance to ground of 25 feet.

Q. Please describe the physical characteristics of the proposed Hendry to Levee 500 kV transmission line segment between Hendry and Andytown 500 kV substations that will connect to the Andytown to Levee 500 kV transmission line. (TF-6)

A. From Hendry substation this transmission line will be located within the same 494 feet wide proposed right-of-way with the same spacing and configuration as the looped Andytown-Orange River line from Hendry substation to the point where this corridor intersects with the existing Andytown-Orange River right-of-way. From this point, the Hendry-Levee 500 kV line will be located within the existing Andytown-Orange River right-of-way and continue to Andytown substation. The distance between the points where the new corridor intersects the existing Andytown-Orange River 500 kV right-of-way to Andytown substation is estimated to be approximately 50 miles. There are two basic configurations of the existing Andytown-Orange River 500 kV right-of-way that this line segment will follow, a 330 feet and a 660 feet right-of-way. Document Nos. JC-3, Cross Sectional View of 330 Feet Right-of-Way, and JC-4, Cross Sectional View of 660 Feet Right-of-Way, show a representative illustration of the right-of-ways that I describe above. This 500 kV transmission line will be constructed in the same manner as the previous 500 kV transmission lines that I discussed. One of the overhead ground wires installed will contain optical fibers that will be used for line communications and line protection.

Q. Please summarize the transmission facilities required to interconnect and integrate FGPP.

A. The project will require the construction of the following:

- Two string buses between the GSU transformers and FGPP switchyard;
- One 500 kV switchyard (FGPP);
- One 500/230 kV substation (Hendry);
- Five 500 kV lines or line sections totaling 172 circuit miles in length; and

- Looping of the Alva-Corbett 230 kV line.

Document No. JC-5, One Line Diagram for FGPP, provides a one line representation of the project with the distances between FGPP and the existing FPL infrastructure.

Q. Does the location of the FGPP site in relation to existing transmission infrastructure have a bearing on the extent of 500 kV transmission line construction required on this project?

A. Yes. The location of the FGPP site does have a bearing on the extent of 500 kV transmission lines required for this project. The amount of transmission line construction required is driven by the distance between the FGPP site and existing transmission infrastructure. This is depicted in Document No. JC-6, Geographical Map Showing the Locations of FGPP and the Transmission Line Corridors Associated with the Project.

Q. Please describe the physical characteristics of the facilities that connect South Florida CC unit GSU transformers to the South Florida substation, including the GSU transformers, attendant bus equipment, the collector yard and the string buses that connect the collector yard with South Florida substation. (TF-7)

A. The GSU transformers are located in close proximity to the generators. From the high voltage side of the GSU transformers, string buses will extend and connect to the collector yard. From the collector yard, there will be string buses that will connect to the South Florida 230 kV substation.

Q. Please describe the physical characteristics of the South Florida 230 kV substation. (TF-8)

A. The South Florida 230 kV substation will be located adjacent to and connected to the South Florida 500 kV substation. It will be located within a fenced area approximately 800 by 900 feet that contains switches, circuit breakers, buses and other electrical equipment. The 500 and 230 kV substations will be connected via a 500/230 kV autotransformer. The 230 kV substation will have a total of four transmission terminals. Two of the terminals will be used to connect the string buses coming from the collector buses of South Florida CC unit. The other two terminals will be used for the 230 kV lines that will connect South Florida substation to Green and Germantown substations.

Q. Please describe the physical characteristics of the re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation. (TF-9)

A. The Corbett-Green and Corbett-Germantown 230 kV lines, which are in close proximity to South Florida substation, will be rerouted to terminate at South Florida instead of Corbett substation. The structures used to reroute these transmission lines will be concrete poles. The typical structure will be approximately 85 to 100 feet above ground and spaced approximately 300 to 600 feet apart. The transmission line conductors will consist of a single conductor per phase and will have a minimum clearance to ground of 25 feet under maximum operating conditions. The structures will have one overhead ground wire.

Q. Please describe the physical characteristics of the circuit breaker and overhead ground wire upgrades required for short circuit duty associated with the addition of South Florida CC unit. (TF-10)

A. As a result of the interconnection and integration of the South Florida CC unit into the transmission system, the fault interruption capability of several 230 kV breakers will be exceeded and will require upgrading. In addition, sections of overhead ground wire on various transmission lines will need to be upgraded because their fault current carrying capacity will also be exceeded.

DISCUSSION OF PHASES OF CONSTRUCTION SCHEDULE, COST AND PERMITS REQUIRED FOR THE PROPOSED FACILITIES

Q. Please describe the approach FPL used in preparing the construction schedule and cost estimates for the transmission facilities required to interconnect and integrate FGPP.

A. As stated in Mr. Silva's testimony, FPL plans to bring FGPP 1 and 2 into service as soon as reasonably possible. FPL believes that the earliest possible date that it can place the first FGPP unit into service is during the second half of 2012, and the second unit during the latter half of 2013. In order to ensure that these transmission facilities will be available to deliver electricity from FGPP as soon as the units are available, FPL developed a transmission facilities construction schedule sufficient to support an early in service date. However, for the purpose of the economic analysis performed in support of this filing, FPL used the in-service dates of June 2013 for FGPP 1 and June 2014 for FGPP 2. The cost estimates for the transmission facilities are also based on these in-service dates.

Q. Please describe the phases of construction for the facilities that connect FGPP 1 and FGPP 2 GSU transformers to the FGPP switchyard, and attendant bus equipment. (TF-1)

A. The site will be prepared by clearing and removing any undesirable material from the site. Fill material will then be hauled in, placed and compacted to the required elevation. The next step will be to install the foundations required to set the equipment. After the foundations have been installed, the structural and electrical equipment portion of the project begins. This will include the installation of the GSU transformers and attendant buses. This will be followed by the installation of the protective relay equipment and commissioning activities associated with placing equipment in-service.

Q. What is the schedule for the construction of this portion of the project?

A. Construction of this portion of the project is expected to begin once the Site Certification Order is issued, the land rights have been secured, post-certification reviews have been completed and all required federal permits have been obtained. At this time, FPL anticipates that construction will begin on or about September 2009 and be completed by November 2010. This portion of the project is important since it will be required to provide power to the plant during testing prior to commercial operation.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The connection of FGPP 1 and 2 Generator Step Up ("GSU") transformers to the FGPP switchyard, and attendant bus equipment; (TF-1)		
String buses	$	2,295,000
Total	$	2,295,000

Q. Please describe the phases of construction for the FGPP switchyard. (TF-2)

A. The site will be prepared by clearing and removing any undesirable material from the site. Fill material will then be hauled in, placed and compacted to the required elevation. This area will have a perimeter fence installed and the relay vault will be constructed. The next step will be to install the foundations required to set the equipment. After the foundations have been installed, the structural and electrical equipment portion of the project begins. This will include the installation of structures, switches, circuit breakers, buses and other electrical equipment. This will be followed by the installation of the protective relay equipment and commissioning activities associated with placing equipment in-service.

Q. What is the schedule for the construction of this portion of the project?

A. Construction of the FGPP switchyard is expected to begin once the Site Certification Order is issued, the land rights have been secured, post-certification reviews have been completed and all required federal permits have been obtained. At this time, FPL anticipates that construction will begin on or about September 2009 and be completed by November 2010. This portion of the project is important since it will also be required to provide power to the plant during testing prior to commercial operation.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The FGPP switchyard; (TF-2)	
Switchyard Construction	$ 19,090,000
Total	$ 19,090,000

Q. Please describe the phases of construction for the Hendry substation. (TF-3)

A. The phases of construction for the Hendry Substation will be accomplished in the same manner as the FGPP switchyard.

Q. What is the schedule for the construction of this portion of the project?

A. Construction of the Hendry Substation is expected to begin once the Site Certification Order is issued, the land rights have been secured and all required permits have been obtained. FPL anticipates that construction will begin on or about January 2009 and be completed by November 2010. This portion of the project will be required to provide power to the plant during testing prior to commercial operation.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The Hendry 500/230 kV Substation; (TF-3)		
Site Acquisition	$	1,560,000
Substation Construction	$	54,475,000
Total	$	56,035,000

Q. Please describe the phases of construction for the two 500 kV transmission lines from FGPP switchyard to Hendry substation. (TF-4)

A. The first step will be to clear the right-of-way of vegetation that might interfere with the safe and reliable operation of the transmission lines. Then, where roads are not available for access, new roads will need to be constructed. Roads will be constructed from fill material and will not be paved. Roads will provide a suitable driving surface that will be used for access during construction, future patrol and maintenance of the transmission lines. At structure locations, a structure pad will be constructed using the same process as the access roads. After the roads and pads have been built, foundations will be constructed at each structure location. Once foundations are completed, tubular steel structures will be hauled to the site, assembled, framed and erected on the foundations. Once the structures have been erected, the conductors and overhead ground wires will be installed.

Q. Where roads are constructed how will existing water flow be maintained?

A. Water flow will be maintained by avoiding road construction in wetlands areas wherever practicable. In addition, culverts or other drainage structures will be installed under the road as required to maintain flow.

Q. How will the location and size of culverts in the access roads ultimately be determined?

A. Engineering calculations will be performed to determine flow patterns, drainage areas and ultimately the size and location of culverts using field survey data, U.S. Geodetic surveys, aerial photographs and any other available data.

Q. What techniques will be used in order to minimize the potential for erosion of roads in areas adjacent to wetlands during construction?

A. Filtration devices such as fabric fences or straw bales will be used as required in order to minimize the potential for soil erosion from roads in areas adjacent to wetlands.

Q. Where there is an existing road, how will access to the structures be provided?

A. The existing road will be upgraded as required to provide a suitable driving surface. Then a finger road extending from the existing road to the structure pad will be constructed.

Q. What is the schedule for the construction of this portion of the project?

A. Construction of the FGPP to Hendry 500 kV lines is expected to begin once the Site Certification Order is issued, the land rights have been secured, post certification reviews have been completed, and all required federal permits have been obtained. FPL anticipates that construction will begin on or about March 2009 and be completed by November 2010 for one of the 500 kV transmission lines. This portion of the project will also be required to provide power to the plant during testing prior to commercial operation. The second line is expected to be completed by November 2011, prior to commercial operation of FGPP 1.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The two 500 kV transmission lines from the FGPP switchyard to the Hendry Substation; (TF-4)		
Right of Way Acquisition	$	27,950,000
Transmission Line Construction	$	95,511,000
Total	$	123,461,000

Q. Please describe the phases of construction for the 500 kV transmission lines from Hendry Substation that connect to Orange River, Andytown and Levee substations and the looping of the Alva-Corbett 230 kV line. (TF-5) and (TF-6)

A. The phases of construction for the 500 kV transmission lines from Hendry Substation that connect to Orange River, Andytown and Levee substations will be accomplished in the same manner as the lines between FGPP switchyard and Hendry substation. The phases of construction for the Alva to Corbett 230 kV loop into the Hendry substation will be similar to the methods previously described; the main difference is that the 230 kV loop will be constructed using concrete poles rather than steel poles with foundations.

Q. What is the schedule for the construction of this portion of the project?

A. Construction of the loop of the existing Alva-Corbett 230 kV transmission line into the Hendry substation is expected to begin once the Site Certification Order is issued, the land rights have been secured, and all required local, state and federal permits for the substation and loop have been obtained. FPL anticipates that construction for these lines will begin on or about May 2010 and be completed by November 2010. This portion of the project will be required to provide power to the plant during testing prior to commercial operation.

Construction of the lines from Hendry substation to the existing Andytown-Orange River right-of-way is expected to begin once the Site Certification Order is issued, the land rights have been secured, post certification reviews have been completed, and all required federal permits have been obtained. FPL anticipates that construction for these lines will begin on or about March 2009 and be completed by November 2011. This portion of the project will be required prior to FGPP 1 entering commercial operation. The construction of the Hendry to Levee 500 kV from Hendry to the intersection of the Andytown to Orange River right-of-way will follow the same schedule as the other two lines. However, from the intersection of the Andytown-Orange River right-of-way to Andytown substation, construction will continue and will be completed by November 2012. This portion of the project will be required prior to FGPP 2 entering commercial operation.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The looping in of the Alva to Corbett 230 kV and the Andytown to Orange River 500 kV transmission lines into the Hendry substation; (TF-5)		
Right of Way Acquisition	$	43,686,000
Transmission Line Construction	$	128,149,000
Remote Station Construction	$	731,000
Total	$	172,566,000

A new 500 kV transmission circuit from the Hendry to Levee substations. This transmission line will be constructed between Hendry and Andytown substations and connected to an existing Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line; (TF-6)		
Transmission Line Construction	$	96,020,000
Total	$	96,020,000

Q. Please describe the costs associated with the facilities that connect South Florida CC unit GSU transformer to the South Florida substation, including GSU transformers, collector yard, attendant bus equipment and the string buses that connect the collector yard with South Florida substation. (TF-7).

A. The costs associated with this portion would be as follows:

The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard and the string buses from the collector yard to the South Florida 230 kV substation; (TF-7)		
Collector yard and string buses	$	6,900,000
Total	$	6,900,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about August 2013 and be completed by July 2014.

Q. Please describe the costs associated with construction for the South Florida 230 kV substation. (TF-8)

A. The costs associated with this portion would be as follows:

The South Florida 230 kV substation; (TF-8)		
Substation Construction	$	43,700,000
Total	$	43,700,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about May 2013 and be completed by July 2014.

Q. Please describe the costs associated with the re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation. (TF-9)

A. The costs associated with this portion would be as follows:

The re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation; (TF-9)		
Transmission Line Construction	$	4,000,000
Total	$	4,000,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about August 2013 and be completed by July 2014.

Q. Please describe the costs associated with the circuit breaker and overhead ground wire upgrades required. (TF-10)

A. The costs associated with this portion would be as follows:

The circuit breaker and overhead ground wire upgrades required; (TF-10)	
Substation Construction	$ 2,700,000
Transmission Line Construction	$ 1,100,000
Total	$ 3,800,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about January 2014 and be completed by April 2014.

Q. Please summarize the cost and schedule for the required transmission facilities for the Fuel Diversity Expansion Plan with Coal?

A. The total cost and schedule for the required transmission facilities for the Fuel Diversity Expansion Plan with Coal are shown on Document No. JC-7, Summary of Required Transmission Facilities for the Fuel Diversity Expansion Plan with Coal.

Q. Do you believe that the estimated total cost associated with the transmission facilities required for the interconnection and integration of FGPP are reasonable?

A. Yes. I believe that the estimated total cost of the transmission facilities are representative of what would be expected to interconnect and integrate the FGPP plant due to its remote location relative to FPL's existing transmission infrastructure.

In addition, to ensure the reasonableness of these estimated costs, FPL also hired the services of a consultant, Cummins & Barnard, who performed an independent detailed review of the installed cost estimate for interconnection and integration of FGPP. In his testimony, Mr. William Damon of Cummins & Barnard affirms that the estimates were found to be reasonable.

PERMIT REQUIREMENTS

Q. What permits will be required for the transmission facilities associated with this project and how long will it take to obtain these permits?

A. All State of Florida, local government and state agency permits for transmission lines associated with FGPP in new right-of-way, will be secured through the FGPP Site Certification approval process under the Florida Electrical Power Plant Siting Act (PPSA). However, if wetlands are impacted as a result of the construction of the structure pads and access roads, FPL will have to file for dredge and fill permits with the U.S. Army Corps of Engineers. Any applicable federal, State of Florida, local government and state agency permits and approvals required for the Hendry substation and Alva-Corbett 230 kV loop into that substation will also be secured through the appropriate governing agency. These non-PPSA permits may take up to 12 to 18 months to obtain.

FPL must also go through a formal consultation with the U.S. Fish and Wildlife service and obtain a Biological Opinion to determine if primary/secondary impacts to endangered species (e.g., Florida Panther) will occur during or after construction. The U.S. Army Corps will not issue the wetland dredge or fill permit without a Biological Opinion report from the U.S. Fish and Wildlife Service. The Biological Opinion report from the U.S. Fish and Wildlife Service may take from to 3-12 months to obtain.

Q. **What are the consequences of a delay in obtaining approval from the U.S. Army Corps of Engineers for the dredge and fill permits associated with the construction of pads and access roads?**

A. Any delay in issuing these permits will have a direct impact on the start of construction. The installation of the structure pads and access roads is one of the first activities to be completed. A delay of 30 days or less, should not have a serious impact on the project, however a longer delay could impact the completion date of the transmission line. If the construction of pads and roads are not permitted, construction access would have to be provided via temporary pads and access roads or by changing construction techniques or a combination of the two. Typically, temporary access is provided through the installation of matting or board roads which must be removed after construction. Generally speaking, in addition to the cost of temporary access, FPL can also expect to pay a premium for construction labor in this circumstance. These costs would be somewhat mitigated by the savings of not building the permanent structure pads and roads but depending on final right-of-way alignment, FPL may experience an increase in the overall project cost. In addition, any future benefit associated with operation and maintenance activities of the transmission line would be lost if permanent structure pads and roads are not constructed.

An alternative to permanent access would be constructing the line using "road-less" construction techniques which would include using specialized equipment and helicopters. Similar to temporary access, the increased cost of using "road-less" construction techniques does not offset the savings of not building permanent access in most situations. Therefore, construction costs could increase without any corresponding future benefit.

Q. What are the consequences of a delay in obtaining approval from U.S. Army Corps of Engineers for the dredge and fill permits associated with the construction of Hendry substation?

A. If permits are required and they cannot be obtained within the allotted timeframe, FPL would not be able to start construction of the substation as scheduled. This could have an impact on the schedule to provide start up power for FGPP.

Q. What codes, standards, and industry guidelines will be used for the design and construction of the transmission facilities?

A. FPL's transmission facilities are designed to comply with all applicable codes, guidelines and standards. The primary code used in the design of the transmission line is the National Electrical Safety Code (NESC). The NESC is an American National Standard Institute (ANSI) standard that covers electrical clearances, loading and strength requirements including extreme wind. There are other agencies and standard organizations that provide rules, guidelines and conditions for particulars not specified by the NESC, such as:

- Occupational Safety & Health Administration Rules (OSHA), provides requirements for safe minimum approach distances;
- American Society of Civil Engineers (ASCE) Manual 74, "Guidelines for Electrical Transmission Line Structural Loading" and Standard 48-05, "Design of Steel Transmission Pole Structures";
- Federal Aviation Administration (FAA) Guidelines, covers requirements in the vicinity of airports; and
- FPL Standards and Transmission Engineering Manual Documents.

These codes, guidelines and standards, discussed above, provide design parameters and guidelines with the primary goal of protecting public safety.

DISCUSSION OF DEVELOPMENT OF COST ESTIMATES AND THE UNCERTAINTY ASSOCIATED WITH THESE ESTIMATES.

Q. **How were the estimates for the transmission facilities related to the substation portion of the project developed?**

A. The estimates were developed using FPL's estimating processes, using current quotes received for similar transformers and other electrical equipment, and projected labor rates for 2007. These estimates were then escalated to the year that the expense would be incurred.

Q. What are the uncertainties associated with the estimates for the transmission facilities related to the substation portion of the project?

A. A major driver for the uncertainties associated with substation estimates is associated with the costs for transformers and other major electrical equipment. Although our current estimates are based on the most current quotes for the type of transformer required, due to the limited number of suppliers and high global demand for this type of equipment, pricing can not be guaranteed until orders are actually placed. From 2005 to 2006, FPL experienced increases in some cases as high as 28 percent. Future increases of this magnitude would have a direct impact on total project costs.

Q. How were the estimates for the transmission facilities related to the transmission line portion of the project developed?

A. For the 500 kV lines, a preliminary design was developed for the typical tangent H-frame structure. Using the preliminary design weight of this structure, FPL estimated the design weight of the other structures by comparing to previous designs. A similar process was used to develop the preliminary foundation designs. FPL then obtained non-binding quotes for the major material components, such as fabricated steel, foundations (including concrete and steel) and the conductor. For the remainder of the materials, FPL used current pricing. FPL next obtained non-binding preliminary quotes for the labor to construct the access roads and transmission line. All of these cost components were assembled to develop the per mile cost that was used in the estimates previously provided. All costs were estimated in 2007 dollars and then escalated to year that the expense would be incurred.

With regard to the estimates associated with the construction of the 230 kV line and upgrades, these estimates were developed using FPL's estimating processes, including projected labor rates for 2007. These costs were then escalated to the year that the expense would be incurred.

Q. What are the uncertainties associated with the transmission facilities related to the transmission line portion of the project?

A. The major drivers for the uncertainties associated with the transmission line estimates are associated with the cost of steel and zinc that is required for foundations, structures and hardware, the aluminum for the conductors and the concrete for the foundations. Although FPL's current estimate is based on current but non-binding quotes from vendors, the high global demand for these commodities can cause large price fluctuations. Pricing cannot be guaranteed until orders are placed. Although there are some indications that prices may have leveled off, if FPL experiences the spikes that were seen in 2004 and 2005, further increases would have a direct impact on total project cost.

The other large driver is the cost of labor associated with transmission line construction. Transmission line construction is done by a limited number of highly specialized workers and equipment. It is not uncommon for these workers to travel from job to job in a region and sometimes nationwide. The risk of price increases associated with transmission line construction labor will be directly related to the regional or national demand for transmission line construction services at the time the project is ready to be constructed. If there is a high level of transmission line construction in the U.S. at the time the project is scheduled, the labor costs would increase. Additionally, if a natural disaster similar to the ones that occurred in 2004 and 2005 re-occur during the construction time frames for this project, significant increases in labor costs are possible because of the high demand for services during those times. As an example, during the aftermath of Hurricane Wilma, FPL experienced labor costs increases of approximately 40%. Such an increase would have a direct impact on total project costs.

Q. How were the estimates for the real estate portion of the project developed?

A. The estimates for the real estate component of the project address all real estate acquisition costs for the project, including the estimated value of property interests to be acquired and associated title, survey, appraisal, and project management/administration expenses. These combined costs were used to calculate an estimated cost per acre for the project. A review of local market sales provided a range of land values dependent upon size, use and location of the property. The estimated costs of title, survey, appraisal, management/administration fees are based on experience in recent acquisition projects.

Q. What are the uncertainties associated with the estimates for the real estate portion of the project?

A. Real estate values are affected by numerous market influences which are not always predictable. Uncertainty as to the willingness of property owners to convey necessary property interests also contributes uncertainty as to total acquisition costs. The current land uses in Glades and Hendry County are dominated by agriculture. These uses involve citrus, sugar cane, ornamental plant nurseries, and row crops, each being affected by various economic influences.

DESCRIPTION OF TRANSMISSION FACILITIES REQUIRED FOR THE EXPANSION PLAN WITHOUT COAL

Q. Please describe the transmission facilities required for the Expansion Plan without Coal.

A. The only difference between the facilities required for the Expansion Plan without Coal as compared to the Fuel Diversity Expansion Plan with Coal is that in the Expansion Plan without Coal, FGPP would be combined cycle gas fired units instead of coal units. The combined cycle units would require additional GSU transformers and a collector yard that would then connect to

FGPP switchyard via two string buses. This arrangement would be similar to the way South Florida CC unit is connected to the transmission system as previously discussed.

These facilities include:

1. The connection of FGPP 1 and FGPP 2 CC GSU transformers to the collector yard, including attendant bus equipment, the collector yard, and the string buses from the collector yard to the FGPP switchyard, and attendant bus equipment; (TFND-1)
2. The FGPP switchyard; (TFND-2)
3. The Hendry 500/230 kV Substation; (TFND-3)
4. The two 500 kV transmission lines from the FGPP switchyard to the Hendry Substation; (TFND-4)
5. The looping in of the Andytown to Orange River 500 kV and the Alva to Corbett 230 kV transmission lines into the Hendry substation; (TFND-5)
6. The creation of a new 500 kV transmission circuit spanning from the Hendry to Levee substations. This transmission line will be constructed between Hendry and Andytown substations and connected to an existing Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line; (TFND-6)
7. The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard, and

the string buses from the collector yard to the South Florida 230 kV substation; (TFND-7)

8. The South Florida 230 kV substation; (TFND-8)
9. The re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation; (TFND-9) and
10. The circuit breaker and overhead ground wire upgrades required. (TFND-10)

Q. What is the schedule for the construction of the facilities associated with TFND-1?

A. At this time, FPL anticipates that construction of this portion of the project would begin on or about May 2012 and be completed by July 2013.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The connection of FGPP 1 and 2 CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard and the string buses from the collector yard to the FGPP switchyard, and attendant bus equipment; (TFND-1)	
Substation Construction	$ 20,100,000
Total	$ 20,100,000

Q. What is the schedule for the construction of the facilities associated with TFND-2?

A. At this time, FPL anticipates that construction of this portion of the project would begin on or about May 2012 and be completed by July 2013.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The FGPP switchyard; (TFND-2)		
Switchyard Construction	$	24,000,000
Total	$	24,000,000

Q. What is the schedule for the construction of the facilities associated with TFND-3?

A. At this time, FPL anticipates that construction of this portion of the project would begin on or about September 2011 and be completed by July 2013.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The Hendry 500/230 kV Substation; (TFND-3)		
Site Acquisition	$	1,600,000
Substation Construction	$	60,000,000
Total	$	61,600,000

Q. What is the schedule for the construction of the facilities associated with TFND-4?

A. Construction of the FGPP to Hendry 500 kV lines is expected to begin on or about August 2011 and be completed by July 2013 for one of the 500 kV transmission lines. The second line is expected to be completed by May 2014, in time for the commercial operation of FGPP 1.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The two 500 kV transmission lines from the FGPP switchyard to the Hendry Substation; (TFND-4)		
Right of Way Acquisition	$	29,000,000
Transmission Line Construction	$	101,700,000
Total	$	130,700,000

Q. What is the schedule for the construction of the facilities associated with TFND-5?

A. Construction of the loop of the existing Alva-Corbett 230 kV transmission line is expected to begin on or about January 2013 and be completed by July 2013. Construction of the lines from Hendry substation to the existing Andytown-Orange River right-of-way is expected to begin on or about August 2011 and be completed by May 2014.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

The looping in of the Alva to Corbett 230 kV and the Andytown to Orange River 500 kV transmission lines into the Hendry substation; (TFND-5)		
Right of Way Acquisition	$	45,400,000
Transmission Line Construction	$	137,400,000
Remote Station Construction	$	800,000
Total	$	183,600,000

Q. What is the schedule for the construction of the facilities associated with TFND-6?

A. Construction of the line from Hendry substation to the existing Andytown-Orange River right-of-way is expected to begin on or about August 2011 and be completed by May 2014. The construction of the Hendry to Levee 500 kV from Hendry to the intersection of the Andytown to Orange River right-of-way will follow the same schedule as the other two lines. However, from the intersection of the Andytown-Orange River right-of-way to Andytown substation, construction will be completed by November 2015.

Q. Please describe the costs associated with this portion of the project.

A. The costs associated with this portion are as follows:

A new 500 kV transmission circuit from the Hendry to Levee substations. This transmission line will be constructed between Hendry and Andytown substations and connected to an existing Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line; (TFND-6)	
Transmission Line Construction	$ 100,100,000
Total	$ 100,100,000

Q. Please describe the costs of the facilities associated with the connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard and the string buses from the collector yard to the South Florida 230 kV substation (TFND-7).

A. The costs associated with this portion are as follows:

The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard and the string buses from the collector yard to the South Florida 230 kV substation; (TFND-7)	
Substation Construction	$ 6,100,000
Total	$ 6,100,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about August 2010 and be completed by July 2011.

Q. Please describe the costs associated with the South Florida 230 kV substation (TFND-8).

A. The costs associated with this portion are as follows:

The South Florida 230 kV substation; (TFND-8)		
Substation Construction	$	39,000,000
Total	$	39,000,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about May 2010 and be completed by July 2011.

Q. Please describe the costs associated with the re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation (TFND-9).

A. The costs associated with this portion are as follows:

The re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation; (TFND-9)		
Transmission Line Construction	$	3,600,000
Total	$	3,600,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about August 2010 and be completed by July 2011.

Q. Please describe the costs associated with the circuit breaker and overhead ground wire upgrades required (TFND-10).

A. The costs associated with this portion are as follows:

The circuit breaker and overhead ground wire upgrades required; (TFND-10)	
Substation Construction	$ 2,400,000
Transmission Line Construction	$ 1,000,000
Total	$ 3,400,000

Q. What would be the schedule for the construction of this portion of the project?

A. Construction for this portion of the project would begin on or about January 2011 and be completed by April 2012.

Q. Please summarize your testimony.

A. My testimony provides a description of the physical characteristics, schedule and cost of the transmission facilities required to interconnect and integrate the Fuel Diversity Expansion Plan with Coal and the Expansion Plan without Coal into FPL's transmission system. Specifically, I discussed the transmission facilities required for FGPP, including:

- A 500 kV switchyard at FGPP
- A 500/230 kV substation at Hendry
- 172 circuit miles of 500 kV transmission lines including the looping of the Andytown-Orange River 500 kV line into Hendry substation
- The looping of the Alva-Corbett 230 kV line into Hendry substation

I discuss the phases of construction of each of the required portions of the proposed facilities and the associated permits required.

The estimated total cost of the transmission facilities associated with FGPP is $469 million. This cost is representative of the remote location of FGPP relative to the existing FPL transmission infrastructure that can support the amount of generation at FGPP.

I discuss various uncertainties present at this time associated with the transmission facilities. First, there is the potential for the inability to acquire permits in a timely manner: for example, the U.S. Army Corps of Engineers dredge and fill permits that are required for the construction of the roads, pads and the Hendry substation. Secondly, the uncertainty associated with the cost of materials such as steel, zinc and aluminum which are needed for the construction of the required transmission facilities in significant quantities, which commodities can vary according to world markets, and labor which also can acutely increase under certain instances such as following hurricanes. Finally, I discuss how real estate values are affected by numerous market influences which are not always predictable and the uncertainty as to the willingness of property owners to convey necessary property interests also contributes uncertainty as to total acquisition costs.

Q. Does this conclude your testimony?

A. Yes.

In re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant	)))	Docket No: 070098-EI

ERRATA SHEET

DIRECT TESTIMONY OF JOSE COTO

PAGE #	LINE #	CORRECTION
3	11-12	Delete: Document No. JC-6 Geographical Map Showing the Locations of FGPP and the Transmission Line Corridors Associated with the Project.
11	12-14	Delete: This is depicted in Document No. JC-6, Geographical Map Showing the Locations of FGPP and the Transmission Line Corridors Associated with the Project.
NA	NA	Remove: Document No. JC-6, Page 1 of 1, in the exhibit section.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF GERARD YUPP

DOCKET NO. 07____ EI

JANUARY 29, 2007

Q. Please state your name and business address.

A. My name is Gerard J Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for managing the daily activities of the Wholesale Operations Group. Daily activities include natural gas and fuel oil procurement and fuel management among plants for FPL's oil and/or natural gas burning plants, coordination of plant outages with wholesale power needs, real-time power trading, short-term power trading, transmission procurement and scheduling. Longer-term initiatives include fuel planning and evaluating opportunities within the wholesale power markets based on forward market conditions, FPL's outage schedule, fuel prices and transmission availability.

Q. Please describe your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer and worked in the area of relay engineering. While employed by FPL, I earned a Master of Business Administration degree from Florida Atlantic University in 1994. In May of 1995, I joined Cytec Industries as a plant electrical engineer where I worked until October of 1996. At that time, I rejoined FPL as a real-time power trader in the Energy Marketing and Trading Division. Since rejoining FPL in 1996, I have moved from real-time trading to short-term power trading, power trading manager and assumed my current position in December, 2004.

Q. Are you sponsoring any sections of the Need Study document?

A. Yes. I am sponsoring Sections V.A.2.a., V.A.2.b. , V.A.2.c. (Parts i, ii, v and vi) and V.A.4.a.ii and I co-sponsor Appendix E of the Need Study.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain: (1) the benefits of fuel diversity in FPL's system resulting from the addition of two 980 MW solid fuel units, including the benefits of on-site fuel inventory; (2) the inherent uncertainty in oil and natural gas price forecasts which necessitates the use of scenario analysis in the long-term economic evaluation of FPL Glades Power Park (FGPP); (3) the methodology for the multiple oil and natural gas price forecasts used by Dr. Sim in FPL's economic evaluation of FGPP; (4) the projected price differential between the delivered price of natural gas to the FPL system and the delivered price of solid fuel (coal and petroleum coke) to FGPP; and (5) the estimated costs of building and operating fuel inventory capability for a 1,960 MW gas fired generating plant that would be equivalent to the 60-day inventory capability of FGPP.

Q. What are the benefits of maintaining fuel diversity in FPL's system?

A. The primary benefits of maintaining fuel diversity are greater system reliability and reduced fuel price volatility. An electric system that relies on a single fuel to generate all the electricity needed to meet its customers' demand, all else being equal, is less reliable than a system that uses a more balanced, fuel-diverse generation portfolio. In addition, greater fuel diversity mitigates the impact of sudden swings in the price of any one fuel, a phenomenon that has characterized the oil and natural gas market over the last several years.

Q. Please explain how fuel diversity enhances system reliability.

A. An electric system that relies exclusively on one fuel is more susceptible to events that cause delays or interruptions in the production and delivery of that fuel. For example, in 2005 a significant number of natural gas production facilities in the Gulf of Mexico were shutdown as a result of hurricanes. FPL was forced to manage its system fuel requirements with much lower than normal natural gas volumes. Although these supply disruptions presented many challenges to FPL in the area of fuel management, FPL continued to produce sufficient energy to meet its customers' demand for electricity. In part, this was attributable to FPL's fuel-diverse system (in 2005: 42% natural gas, 17% fuel oil, 19% nuclear, 18% coal, and 4% from other sources). Because FPL's system offers a significant amount of flexibility through its diverse fuel mix and storage capability, FPL was able to continue to meet its customers' demand for electricity with alternate fuel sources until natural gas production was restored. Had FPL's system relied to a substantially greater extent on natural gas to produce electricity, there would have been a greater risk of failing to meet customers' requirements.

Q. **Does FPL believe that future additions of natural gas-fired generation will require changes to the current natural gas infrastructure serving Florida?**

A. Yes. The existing natural gas pipeline infrastructure into peninsular Florida is comprised of two pipelines from the Gulf Coast region. While this infrastructure has provided a high level of reliability over the years, the demands on both pipelines have continued to grow. In fact, by mid-2009, these pipelines will be fully subscribed. Therefore, the addition of incremental natural gas-fired generation will require an expansion of one or both pipelines into Florida. Even with expansion of the existing pipelines to meet additional demand, the need to consider alternatives that will help promote the diversity of natural gas supply will become imperative. As described above, natural gas production curtailments as a result of 2005 hurricanes, limited the amount of natural gas available to Florida for a period of time. Simply expanding the existing infrastructure will not help reduce this vulnerability. Therefore, as more natural gas-fueled generation increases demand, the need to consider alternatives to maintain reliability will also become imperative. These alternatives could include the addition of a new interstate pipeline, additional underground natural gas storage, on-site Liquefied Natural Gas (LNG) storage facilities, and identifying alternate supply sources, including access to new producing regions as well as the addition of LNG supply. LNG imports are projected to increase to meet U.S. natural gas demand growth from approximately 1.6 BCF per day in 2006 to approximately 14.3 BCF per day by 2020. By 2020, LNG supply is projected to account for approximately 20% of total U.S. natural gas supply. Although LNG supply is projected to play an essential role in helping meet U.S. natural gas demand growth, it is important to note that as LNG's percentage of total U.S. natural gas supply increases, the risks associated with foreign supply fuel sources will become more prevalent in the overall U.S. natural gas picture. FPL has recognized the need to implement alternative strategies even in today's environment. In an effort to create supply diversity and help strengthen reliability, FPL recently contracted for additional natural gas storage and firm transportation on a new pipeline that will bring on-shore natural gas supply from East Texas into the Mobile Bay area in the Gulf of Mexico. While both projects will help strengthen reliability by helping mitigate FPL's exposure to supply disruptions, the new pipeline will also provide long-term supply diversity. The cost of implementing these strategies will vary depending on the type of alternative being considered. However, it is important to recognize that this investment will have to be made in order to maintain today's level of natural gas reliability in the future as demand for natural gas grows.

Q. Please explain how fuel diversity reduces price volatility.

A. Fuel diversity helps to mitigate the impact of price increases in one or two fuels on the total system cost of fuel. Natural gas and oil have experienced extreme price increases over the past several years. As indicated in Mr. Seth Schwartz's testimony, oil and natural gas prices are historically much more volatile than coal prices. The increase in natural gas prices since 1992 has been three times the increase in coal prices over the same period (and up to nine times the increase at the peak of natural gas prices in 2005). To the extent that multiple fuels are used to produce electricity, the impact of price increases in any one fuel is lessened when that particular fuel does not make up a significant percentage of the total fuel mix. Stated another way, a more balanced fuel portfolio will result in less volatile total fuel costs. Although it is impossible to predict future fuel prices with certainty, based on current fuel price forecasts, the exclusive addition of natural gas-fueled generation in the future would likely result in more volatile and higher fuel costs over time.

Q. Does the addition of FGPP with on-site fuel inventory enhance the reliability of the FPL system compared with a natural gas-fired plant?

A. Yes. FGPP will be able to store up to 60 days of solid fuel (coal and petroleum coke) at the plant site. This equates to approximately 1,000,000 tons or 24,640,000 MMBtu of coal and petroleum coke available for consumption regardless if FPL were to experience a curtailment in the solid fuel supply chain for example, as a result of rail transportation disruption, labor disputes or hurricanes. The capital cost and corresponding operation and maintenance expenses, and working capital for this coal and petroleum coke storage infrastructure is included in the economic evaluation of FGPP. In comparison, a natural gas-fired plant will generally have three days of back-up fuel oil storage on-site. Therefore, a natural gas-fired plant is more susceptible to interruptions from fuel supply problems such as supply or pipeline curtailments.

Q. Please identify the key factors that contribute to uncertainty in forecasting the price of oil and natural gas.

A. Projections for future prices of oil and natural gas are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil and natural gas. These drivers include: (1) current and projected worldwide demand for crude oil and petroleum products; (2) current and projected worldwide refinery capacity/production; (3) expected worldwide economic growth; (4) non-OPEC production and expected growth in non-OPEC production; (5) OPEC production and the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity; (6) the geopolitics of the Middle East, West Africa, the Former Soviet Union, Venezuela, etc., as well as, the uncertainty and impact upon worldwide energy consumption related to U. S. and worldwide environmental legislation, politics, etc.; (7) current and projected North American natural gas demand; (8) current and projected U. S., Canadian and Mexican natural gas production; and (9) the worldwide supply and demand for LNG.

Q. Why has FPL developed multiple oil and natural gas price forecasts to support the economic evaluation of FGPP and the Plan without Coal?

A. In the economic evaluation for FGPP, a solid fuel burning plant, the Plan without Coal was based on units which burned natural gas. In this economic evaluation, variations in natural gas price forecasts would impact the differential between natural gas and solid fuel prices and therefore impact the potential fuel savings from FGPP compared with the Plan without Coal. The inherent uncertainty and unpredictability in the factors that affect natural gas prices today, tomorrow, and in the future life of FGPP, clearly underscores the need to develop a set of plausible oil and natural gas price scenarios that will bound the reasonable set of long-term price outcomes for economic evaluation purposes.

Accordingly, to support the economic valuation of FGPP and the Plan without Coal, FPL developed several fuel price forecasts. These forecasts are referred to as: the Medium, Low, High and Shocked Medium price forecasts, all of which are described in detail below.

Q. Did FPL develop several oil and natural gas price forecasts to support the economic evaluation in FPL's most recent Need Determination for the West County Energy Center (WCEC)?

A. No. In FPL's most recent Need Determination filing for WCEC, the primary fuel for all of the alternate projects evaluated, as well as for FPL's self-build project (WCEC), was natural gas. Accordingly, the economic evaluation of all projects assumed the same natural gas price forecast using the same forecast methodology in the Medium price forecast which is described in detail below. Variations in natural gas price forecasts would therefore impact each alternative and FPL's self-build project equally.

Q. What is the methodology for the development of FPL's Medium price forecast for oil and natural gas?

A. FPL's Medium price forecast methodology, used in FPL's economic evaluation of FGPP and alternative expansion plan, is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology: (1) for 2006 through 2008, the methodology used the October 3, 2006 forward curve for New York Harbor one % sulfur heavy oil, U. S. Gulf Coast one % sulfur heavy oil and Henry Hub natural gas commodity prices; (2) for the next two years (2009 and 2010), FPL used a 50/50 blend of the October 3, 2006 forward curve and monthly projections from The PIRA Energy; (3) for the 2011 through 2020 period, FPL used the annual projections from the PIRA Energy Group; and (4) for the period beyond 2020, recognizing that prices cannot increase indefinitely and that significantly high prices have created, and will continue to create, technological and economic opportunities for commodity substitution in the energy markets, FPL applied the annual rate of increase in the delivered price of solid fuel to the commodity cost of oil and natural gas. In addition to the development of commodity prices, price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation projections resulted in delivered price forecasts. These delivered price forecasts were used in the economic evaluation of FGPP and the Plan without Coal.

Q. What is the methodology for the development of the alternative oil and natural gas price forecasts used in the economic evaluation of FGPP and the Plan without Coal?

A. The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based upon the historical relationship of prices realized by FPL's customers when compared to the average for the same 2000 through 2005 timeframe. For example, the 2000 through 2005 average natural gas price delivered to FPL's system was $6.45/MMBtu. The high price range was $9.34/MMBtu or 145% of the average and the low price range was $4.20/MMBtu or 65% of the average. These factors were multiplied by the monthly Medium price forecast to determine the Low and High price for each commodity for the duration of the forecast period. This same process was applied to oil, coal and petroleum coke consistently. FPL developed these forecasts to account for the uncertainty that exists within each commodity as well as across commodities. These forecasts align with FPL's actual price variability realized during the 2000 to 2005 period, thus ensuring that the analyses of the two resource plans will reflect a range of reasonable forecast outcomes.

The development of the Shocked Medium (Shocked) price forecast for oil and natural gas was based on the same methodology as described above however;

the increase was applied to only the oil and natural gas prices and is consistently applied through 2016. In 2017, FPL averaged the Medium price forecast with the Shocked price forecast. From 2018 forward, oil and natural gas prices are the same as prices in the Medium price forecast. FPL developed the Shocked price forecast as a sensitivity to show the impact of what a significant price increase in oil and natural gas will have on the value of adding FGPP to FPL's portfolio of assets.

Q. **Are FPL's Medium, Low, High, and Shocked price forecasts for oil and natural gas prices reasonable and necessary for the economic evaluation of FGPP and the Plan without Coal?**

A. Yes. FPL's long-term oil and natural gas price forecasts are reasonable and necessary for the economic evaluation of FGPP and the Plan without Coal. FPL's fuel price forecasts identify a reasonable set of forecast outcomes based on an actual historical range of prices realized by FPL's customers during the 2000 through 2005 period, a period of time that experienced high variability among commodity prices, unprecedented price volatility on a domestic and worldwide basis, and a period of low and high price differentials between commodities.

Q. **Have you provided FPL's forecasts for the price of oil and natural gas?**

A. Yes. FPL's forecasts for the price of oil and natural gas are provided in Appendix E of the Need Study document.

Q. What is the projected price differential between the delivered price of natural gas to the FPL system and the delivered price of solid fuel to FGPP?

A. The projected price differential between the delivered price of natural gas to the FPL system and the delivered price of solid fuel to FGPP is a major driver in the economic evaluation of FGPP and the Plan without Coal. The four delivered price forecasts for natural gas to the FPL system, as shown in Appendix E of the Need Study document less the corresponding forecasts for the delivered price of solid fuel to FGPP, as discussed in Mr. Schwartz's testimony, result in four projected price differential forecasts between natural gas and solid fuel. These price differential forecasts are shown in Appendix E of the Need Study document. The economic evaluation of FGPP and the Plan without Coal provides a range of potential cost outcomes given the potential price differential scenarios. Although periods of lower natural gas prices will reduce the fuel cost benefits to FPL's customers specifically from the addition of FGPP, periods of lower gas prices will at the same time benefit FPL's customers due to the significant level of natural gas generation in the FPL system.

Q. Will future environmental regulations be a key determinant of the price differential between natural gas and solid fuel?

A. Yes. Future environmental regulations will be a key determinant of the price differential between natural gas and solid fuel. As varying degrees of environmental regulations impact the demand for natural gas and solid fuel, the price differential between the fuels will be impacted. While it is difficult to quantify how environmental regulations will impact this price differential, as there are many variables to consider, certain intuitive assumptions can be made to help better define the trend of this differential under varying degrees of environmental regulation. In particular, if future environmental regulations were to impose high compliance costs on solid fuel generating plants as opposed to natural gas-fueled plants, the demand for natural gas would most likely increase as natural gas-fueled generation would become preferable from an economic standpoint. Conversely, in this scenario, the demand for solid fuel would likely decrease. In general, an increase in demand for natural gas and decrease in demand for solid fuel should result in a widening of the price differential between natural gas and solid fuel. Therefore, although possible, we would not expect to see a narrowing of the price differential between natural gas and solid fuel as environmental compliance costs on solid fuel generation increase.

Q. **Has FPL estimated the cost of building and operating fuel inventory capability for a 1,960 MW gas-fired generating plant that would be equivalent to the 60-day inventory capability of FGPP?**

A. Yes. FPL estimated the cost of providing equivalent fuel inventory capability using LNG and light fuel oil. FPL did not consider on-site natural gas storage mainly due to the lack of economically viable geological formations to develop natural gas storage in Florida. The only way to replicate this type of reliability for natural gas would be to build a comparable on-site LNG storage facility which would include liquefaction, storage and regasification. The Cumulative Present Value of Revenue Requirements (CPVRR) to build, operate and maintain this type of comparable LNG storage facility, including working capital, would be approximately \$1.42 billion. Another on-site storage alternative is to build, operate and maintain light oil storage and gain air permitting approval from the Department of Energy (DOE) to burn light oil beyond 500 hours per year. The CPVRR to build, operate and maintain this light oil infrastructure, including working capital, would be approximately \$0.41 billion for a 3.7 million barrel tank farm, which would consist of 8-500,000 barrel tanks. Furthermore, assuming inventory turnover once per year with an additional light oil cost of approximately \$6.00 per MMBtu higher than that of natural gas, the total CPVRR for comparable light oil storage would be \$1.50 billion compared to a Plan without Coal.

Q. Will FGPP reduce FPL's reliance on natural gas and fuel oil for electric generation?

A. Yes. FGPP will greatly reduce FPL's reliance on natural gas and fuel oil compared to the Plan without Coal. The operation of FGPP will displace approximately 100 BCF of natural gas consumption per year. Stated another way, during its first 20 years of operation, FGPP will displace and prevent the need for the consumption of as much natural gas as FPL's system consumed in the six year period from 2001 through 2006.

Q. Please summarize your testimony.

A. Maintaining fuel diversity in FPL's generation portfolio will enhance reliability and reduce fuel price volatility. First, a fuel-diverse system is more reliable than one that is dependent on a single fuel source. As described in this testimony, a system that maintains a balanced fuel portfolio is able to withstand delays or interruptions in the delivery of any one particular fuel, as evidenced by FPL's ability to withstand severe natural gas production curtailments during the 2005 hurricane season. Furthermore, FPL will be able to store up to 60 days of solid fuel at the plant site, an option that a traditional analysis of a natural gas-fired plant does not include. Second, a fuel-diverse system will help reduce fuel price volatility as the susceptibility to severe price swings in any one fuel type is mitigated in a more balanced fuel portfolio.

FPL developed multiple oil and natural gas price forecasts to address the variability among fuels over time in the economic evaluation of FGPP because projections for future prices of oil and natural gas are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short and long-term price of oil and natural gas. FPL's multiple oil and natural gas price scenarios define a reasonable set of long-term price outcomes for economic evaluation purposes.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN EDGAR: Okay. It is approximately 1:00 o'clock. We will come back -- I hate to have short lunches because there's so little opportunities for everybody, but 30 minutes? Do you want to do 30 minutes to keep things moving?

Mr. Guest, it is your witness.

MR. GUEST: I think our next witness is going to be Richard Furman. I think we are going to have to just let Mr. Plunkett go back home for a second time here, unless we can -- I know you can't control that. We have had, as I said earlier, we had representation we were going to have about 20 minutes of cross from the staff. We had a relatively short cross as you saw, that would have landed us around 11:00 o'clock, which would have been enough time to do the cross-examination of Mr. Plunkett. I don't see a reasonable possibility of them getting done, and so I think it might be --

CHAIRMAN EDGAR: Hang on. Excuse me just a moment.

Ms. Brubaker, does the staff, excuse me, have questions for Witness Plunkett?

MS. BRUBAKER: In the interest of moving time along, we are happy to waive any questions for Mr. Plunkett.

CHAIRMAN EDGAR: Mr. Anderson.

MR. ANDERSON: We have a short cross-exam.

CHAIRMAN EDGAR: Mr. Beck.

MR. BECK: (Indicating no.)

CHAIRMAN EDGAR: Mr. Krasowski.

MR. KRASOWSKI: Yes, I have quite a few questions for Mr. Plunkett. A lot of my evidence is based on some of his comments, the whole DSM issue.

CHAIRMAN EDGAR: I understand. This is what I would suggest that we do. Commissioners, can you do about 30 minutes? Let's take 30 minutes for a very fast lunch. We don't want anybody passing out this afternoon from low blood sugar, and we will come back at about 1:35 by the clock on the wall, and I will try to keep to that myself.

And before we all step out in different directions, we're going to break now, but let's gather for just a few minutes and talk schedules. And so we are on lunch break.

(Transcript continues in sequence with Volume 10.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 27th day of April, 2007.

Jane Faurot

JANE FAUROT, RPR
Official FPSC Hearings Reporter
FPSC Division of Commission Clerk
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