BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI

In the Matter of:

PETITION TO DETERMINE NEED FOR TURKEY POINT NUCLEAR UNITS 6 AND 7 ELECTRICAL POWER PLANT, BY FLORIDA POWER & LIGHT COMPANY.

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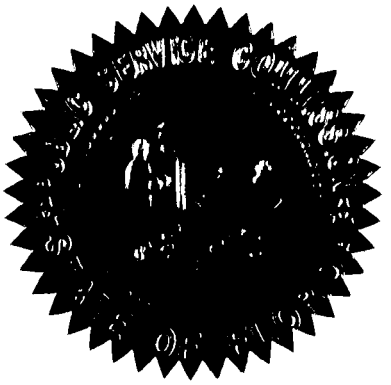

VOLUME 8

Pages 965 through 1078

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN MATTHEW M. CARTER, II COMMISSIONER LISA POLAK EDGAR COMMISSIONER KATRINA J. McMURRIAN COMMISSIONER NANCY ARGENZIANO COMMISSIONER NATHAN A. SKOP
DATE:	Friday, February 1, 2008
TIME:	Commenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

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P R O C E E D I N G S

CHAIRMAN CARTER: Okay. We are back on the record.

The last time we left we had Mr. Sim on cross, and I think staff was in the process of getting ready to ask some questions. If that serves my memory correctly. Is that right?

Staff, you're recognized.

MS. KLANCKE: Thank you, Chairman.

DR. STEVEN R. SIM

continues his testimony under oath from Volume 7:

CONTINUED CROSS EXAMINATION

BY MS. KLANCKE:

Q Doctor Sim, let me refresh your memory about where we left off. I was going to ask you a few questions about your late-filed exhibits to your deposition testimony, Exhibits 1, 2, and 3. Okay?

A Okay.

Q With regard to Late-filed Exhibit 1 to your deposition testimony, this exhibit compares the break-even cost values for the year 2060 versus the break-even cost values --

CHAIRMAN CARTER: Excuse me. Let's make sure that we are all on the same page.

Commissioners, that's found in -- let's thumb through here -- Staff's Composite Exhibit Number 14, and that's --

MS. KLANCKE: Bates stamped Number 550.

CHAIRMAN CARTER: Okay. You may proceed.

BY MS. KLANCKE:

Q With regard to this exhibit, it reflects a comparison between the break-even cost values for the year 2060 versus the break-even cost values for the year 2050, is that correct?

A That's correct.

Q What effect would the 2007 ICF projection that we discussed this morning have on the analysis contained in this exhibit illustrated in the break-even capital costs for the year 2050?

A Since an analysis was not done with the ICF numbers that were just released, I can just answer in the direction the numbers would go. The break-even costs for both the 2060 break-even point and for the 2050 break-even point would all go up, so the break-even costs would all be higher.

Q You were also asked to file a similar late-filed exhibit to your deposition testimony, which is Bates stamped 551, that illustrates the break-even capital costs for the year 2040, isn't that correct?

A Yes.

Q And could you describe the general trend that theoretically would similarly apply with regard to the effect of a 2007 ICF report on this late-filed exhibit?

A My answer would be the same as for the 2060 and 2050 exhibit. In other words, the higher CO2 costs would result in higher break-even costs for nuclear.

Q So, is it still correct, therefore, with regard to both of these exhibits, in light of the 2007 ICF study figures, that the results of your analysis would reflect the break-even cost values would be -- eight of nine of which would be higher than or within the cost estimate range -- let me rephrase. I'm getting a little convoluted.

With regard to the impacts of the 2007 ICF study on your two late-filed exhibits, would they have any impact on the conclusions that you came to in the notes portion of these two exhibits? And I'll describe further. It states in the notes portion of Late-filed Exhibit 1 that, quote, the break-even costs in the left-hand matrix show the break-even costs are higher than or within the current cost estimate for nuclear in nine of the nine scenarios. Is that still the same?

A For the 2060 break-even, that's correct.

Q And with regard to the 2050, it shows that the break-even cost estimates are higher than or within the current cost estimates for nuclear in eight of the nine scenarios. Would that still be the same?

A Yes.

Q Similarly, with regard to Late-filed Exhibit Number 2, it also reflects that the break-even costs for the year 2040 analysis are higher than or within the current cost estimate for nuclear in eight of the nine scenarios and lower than the range in one scenario. Is that still the case with

regard to any impact that may be incurred by the 2007 ICF study?

A I think the only thing we can safely conclude at this point would be that the results that we have using the Appendix F CO2 numbers are that for either 2040 or 2050, our break-even costs are higher than or within eight of the nine scenarios. If we were to apply higher CO2 costs, it would get no worse than that. It might turn out that we would move from eight of nine to nine of nine, but I can't tell at this point. But it would certainly move it in the direction, again, of nuclear's break-even costs going higher than what are currently shown here.

Q I would like to turn your attention now to Exhibit SRS-3 of your prefiled testimony. Could you please turn to that page for me?

A Yes.

MS. KLANCKE: Commissioners, this is Exhibit 78. It has been identified as Exhibit 78.

BY MS. KLANCKE:

Q Does this exhibit show that even with the addition of Turkey Point 6 & 7, that FPL would still have a reliability need for additional capacity in the years 2018 and 2020 to meet its 20 percent reserve margin?

A The answer would be yes, if as assumed in this table we were not adding any capacity after our West County Units

1 and 20 that come in in 2009 and 2010.

Q So to clarify, even if FPL chose the 1,500-megawatt design, your testimony is that FPL would still require additional capacity in the years 2018 and 2020 in order to meet its 20 percent reserve margin, is that correct?

A No, I don't believe so. Except in the one instance in this exhibit in which we were to assume that no capacity would be added within the -- from 2011 through 2020. I think the point I would like to make with this exhibit is we have assumed in 2018 and 2020, Commissioners, that we are adding the two nuclear units, one in 2018 and one in 2020, and it shows that we have a capacity need by 2020 of 3,956 megawatts. So, let me round that off to 4,000 megawatts.

What it says in the time period between 2011 and 2020, there is a capacity need even after the nuclear units have been assumed to be added that will need to be filled and could be filled by a variety of resource options, DSM, renewables, other fossil fuel units, et cetera.

Q Now, could you please turn to Exhibit SRS-4, the next exhibit in your prefiled testimony.

A Yes.

Q This exhibit shows FPL's expansion plans with and without the nuclear units, is that correct?

A It shows a trio of expansion plans that were assumed for the purpose of these analyses.

Q And these plans are identical up through the year 2018 in that each plan contemplates the addition of approximately 4,400 megawatts of new gas-fired combined cycle generators before the nuclear units come on-line, is that correct?

A Yes, with one slight correction, they are identical through the year 2017 up until 2018. At 2018, the plans diverge.

Q Now, if this Commission were to grant the need for Turkey Point 6 & 7, and then something in the future were to happen, such as a drastic change in the load growth or reduction of FPL's reserve margin criterion, would the most likely result be the removal of some of these gas plants from FPL's generation plans?

A Yes. The more immediate effect of any change such as that would be that the capacity need and, therefore, the capacity options that FPL would select to meet that need in the years prior to 2018 would change. And, again, let me stress that FPL has not committed at this point to build the gas-fired units that are shown in this exhibit. We have merely selected those as reasonable and representative capacity options for purposes of analysis, and we sought to keep them identical for all three plans so we would not bias the analysis of nuclear versus combined cycle versus IGCC from 2018 forward.

Q You stated this morning in your testimony that the

prime driver of savings associated with these units is fuel cost, is that correct?

A Yes.

Q I would like to turn your attention now to your Exhibit SRS-9, identified as Exhibit 84 of your prefiled testimony. Would you agree that there are long lead projections associated with your analysis, as is reflected in SRS-9?

A I'm sorry, could you clarify long lead projections of.

Q By that I mean that it is a long-term analysis, by those -- those long lead projections include a long-term analysis?

A The analysis shown on this exhibit does run a number of years from 2009 through 2021, yes.

Q Does the long lead time associated with your payback analysis reflected in this document, indicate that the current ratepayers will be paying for benefits received by future ratepayers?

A Can you repeat the question, please.

Q Does the long lead time analysis that's undertaken with regard to -- as illustrated in SRS-9, reflect a general trend that the current ratepayers will be paying for benefits that will be received by future ratepayers?

A I will agree in part. But using myself as an

example, if a need determination for the nuclear units is approved in this proceeding, I would be paying for the early capital costs of nuclear units, but I certainly hope I would be, as you call, a future ratepayer by 2021. I hope I'm still around by then.

Q Of course, I'm sure we all do. Subject to check, what is the annual level of increased rates that will have to be paid for by the current ratepayers in each of the scenarios reflected in SRS-9?

A SRS-9 only presents one scenario, so I'm afraid I will have to ask for a clarification on the question, please.

Q I will just move on. Not to belabor the point, I will just move on.

Have you developed any rate mitigation plans to lessen the impact of potential increased costs in the earlier plant operation years?

A In the early years of the nuclear plant operation?

Q Yes.

A I would have to say no, because as shown in this example, once we get to 2021, which would be the first full year in which both new nuclear units would be operating, we would be seeing a savings on our customers' bill due to the massive savings in fuel and the concurrent savings in environmental costs. So customers would be saving as early as 2021, and this savings would continue for all years thereafter

and be increasing all years thereafter.

Q I just have a few more questions for you. I would like to turn your attention back briefly to Exhibit SDS-7 of Witness Scroggs' testimony?

A Okay.

Q I would like for you to elucidate the origins of these capital costs used in SDS-7. In particular, are the capital costs used in SDS-7 based on generic screening cost estimates, engineering cost estimates, or site-specific bids from vendors?

A Which costs are you referring to on this page, please, the left or the right?

Q The one on the left, 3108?

A All right. And could you repeat your question as to what the options were you were providing me, please.

Q Certainly. Are the capital costs associated with the 3108 figure represented on the left-hand side of SDS based on generic screening cost estimates, engineering cost estimates, or site-specific bids from vendors?

A I'm not sure any of those categories would accurately capture how I would describe these costs. I would describe them as a range of costs that we are seeing after discussions with potential vendors and manufacturers of new nuclear units, what we think it would cost.

Q With regard to this range of costs that is depicted

in this exhibit, what would you attribute the margin of error to be with regard to this range?

A I could not answer that. I think among our witnesses, Witness Scroggs would have been the appropriate witness for that. I will point out that that range is a fairly large one, and would, I think, cover a lot of territory here in regard to costs.

Q When will the Commission know the exact capital costs associated with Turkey Point 6 & 7?

A I think in each annual review that FPL would bring forward before the Commission those numbers would be refined until the point where we got to a specific technology selection at which point the cost numbers would be nailed down with much greater precision than they are now.

Q You mentioned the technology selection. What is the first year when cumulative present value fuel savings would exceed the cumulative present value of revenue requirements for the Westinghouse unit?

A I would have to say that we cannot answer that question with any sort of precision at this point because we don't know what the Westinghouse technology cost will be. That will be one of the items that FPL seeks to determine in our discussions with the different vendors. So we would need to know what the actual Westinghouse costs would be in order to perform that calculation.

Q And that is the same with the GE unit, is that correct?

A That's correct.

MS. KLANCKE: Commissioners, I have no further questions for this witness, but Ms. Brubaker does.

CHAIRMAN CARTER: Ms. Brubaker, you're recognized.

MS. BRUBAKER: Thank you. And just for clarity --

CHAIRMAN CARTER: Ms.

MS. BRUBAKER: Still single.

CHAIRMAN CARTER: I finally got it right today, Ms. Brubaker.

CROSS EXAMINATION

BY MS. BRUBAKER:

Q Good afternoon, Doctor Sim. Just a few questions. You spoke just a few minutes ago about the large range of cost that has been discussed in this proceeding, correct?

A Yes. We were speaking about the nuclear capital costs, the nonbinding estimate range we have.

Q And that has largely to do, would you agree, with the fact that there has not been a final selection of the unit to be involved between the two main competing vendors?

A I would say that would certainly be a large contributor to that, yes.

Q Your analyses are -- basically in terms of using the unit capacity, your analyses used the Westinghouse unit, is

that correct?

A Yes, 1100 megawatts.

Q Are you confident that your analyses can accommodate both unit designs depending on what the final selection is? In other words, do you believe that this large range of costs that are used can comfortably accommodate either the GE or the Westinghouse unit?

A I believe so. If I can expand on that a little bit.

Q Please.

A We use no capital costs in our analysis and worked backwards, so to speak, in order to come up with the break-even cost. We did use two costs or two cost and performance numbers that we think correspond equally well to both Westinghouse and GE. That would be a heat rate and a fixed O&M cost, and we think the numbers that were selected are reasonable for both of those two technologies.

Likewise, we used a transmission cost not only for the nuclear units, but also for the comparable capacity of IGCC and combined cycle of $500 million. All of this, our analysis was based on the 1,100-megawatt unit. If we were to ultimately select the 1,500-megawatt unit, what would happen is assuming that our heat rate and our fixed O&M cost numbers are still accurate for the larger sized unit, we feel like we have adequately captured that in the analysis.

The fuel savings and the environmental compliance

costs savings would go up commensurate with the increased size of the unit. The one item that would be subject to change in theory would be the transmission costs. We would be running into, I think, two aspects of transmission costs increase. One would be the sheer size of the total capacity. Instead of 2,200 megawatts, there would be 3,000 megawatts added to the system, and we think that that would be, I guess, comparable across all three resource plans. Whether we move from 2,200 to 3,000 of nuclear, 2,200 to 3,000 of combined cycle, or IGCC, there are going to be certain system integration costs that will have to be captured regardless of the technology.

Now, nuclear does have one aspect that differentiates it in regard to transmission from combined cycle and IGCC, and that is the largest unit on our system component of transmission costs, if the loss of that unit requires us to keep a certain amount of spending reserve, et cetera, that is not specifically captured in our cost calculations if we were to move to that number. However, in looking at the break-even costs and looking at how we did the break-even analysis, I would say we are reasonably well covered there.

My rationale for that is our calculations said that a one dollar per kW increase in the cost of the unit equates to roughly a $2 million CPVRR number. Let's say that our $500 million transmission cost would be increased by another 500 million due to this aspect of the largest generating unit.

That would equate to about a $250 a kW value added onto our break-even costs. The majority of our break-even costs would still be higher than the current capital cost range. And, in fact, even if it were to go to a billion dollars higher transmission cost, which I think is highly unlikely, we would see $500 per kW of break-even costs being added on. And I think we would move from our current situation of perhaps eight scenarios of break-even costs above the current nuclear capital cost range and one within, so an eight and one, to we would move within, I think, seven, one, and one.

So, it would be a relatively minor change even if we were to assume a billion dollars more of transmission cost for nuclear compared to combined cycle and IGCC, which I think is highly unlikely. I think any increase for the higher nuclear, the larger nuclear-sized unit would be less than that. A long-winded answer to yes, is the short answer to your question.

Q Well, you discussed a little bit about the difference between the cost in the scenarios and also the break-even cost. And would you agree that the difference in those amounts indicate a high probability that there will be savings?

A From everything we have seen in our analysis so far, yes. I would say regardless of the technology that we are choosing between, we would anticipate at this point that there would be significant savings. And, again, going back to the

comment I made earlier of a billion dollars a year in fuel savings starting in 2021, that's for an 1,100-megawatt unit. If we were to go from 2,200 megawatts to 3,000, that is roughly a 50 percent increase. I would expect to see fuel savings go up 50 percent off of one billion, so it would be significant.

Q You used the term reasonably well covered in terms of the costs and the estimates in this proceeding, especially when compared to the break-even analysis. Would you agree that this provides a buffer or a cushion to allow FPL to adjust to changes in costs associated with the plant?

A I don't understand the meaning to adjust.

Q In other words, let's say that FPL experiences increases in construction costs. Given the cost projections, you believe that there is still room to adjust for those costs and yet still come under the break-even analysis, correct?

A In all likelihood, yes. I would expect that if there were increases in capital costs to a nuclear unit, we would also see some increase in capital cost to the competing units of combined cycle and IGCC. And I believe that is -- or it is items like that which is why FPL has advanced the approach where we will be coming back before this Commission on an annual basis with updated costs, more recent assumptions, a greater refinement of the nuclear unit costs, et cetera, just to provide that sort of refinement to the analysis as we go forward.

Q And you also discussed some transmission cost aspects if FPL were to go with the 1,500-megawatt units. Is it also your opinion that any increases in transmission costs due to going with those units is still going to be covered within the existing cost projection range?

A From what we know now, that would be my guess, yes.

Q You also mentioned coming back to the Commission during the nuclear cost-recovery process. Would you agree it is important to continue reviewing cost effectiveness in that proceeding for the plant?

A I'm sorry, I'm having trouble associating the cost-recovery portion of your question with the term cost-effectiveness. Can you clarify?

Q In other words, in the cost-recovery process items are reviewed for prudence, correct?

A Yes.

Q Would it not be reasonable to expect that items are also reviewed on an ongoing basis just to make sure that the plant is still cost-effective?

A Yes, I would.

Q Okay.

A Thank you.

Q Certainly. Would part of the cost-recovery process, in your mind, also include additional or updated break-even analyses?

A I would have to think yes, although I have not been involved in discussions as to exactly what we would be providing and when, but I have been told that we will be performing these similar analyses on a going-forward basis at least on an annual basis.

MS. BRUBAKER: Thank you, Doctor Sim. I have no more questions.

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Chairman Carter.

Good afternoon, Doctor Sim.

THE WITNESS: Good afternoon, sir.

COMMISSIONER SKOP: Just one quick question referring back to, I believe, SRS-7.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: And this matrix is similar to the one that was performed in the Glades need determination, is that correct, in terms of showing, you know, the various scenarios that are applicable to this need determination?

THE WITNESS: Yes. The format of the presentation is very similar. However, as I believe has been mentioned before, both are fuel cost forecasts, and our environmental cost forecast differ from what was in Glades. Those have been updated.

COMMISSIONER SKOP: And, again, I was just more looking at the matrix concept. But based upon the data, the

best available data that we have today as reflected in these matrices, it seems that in every scenario the addition of nuclear, the proposed nuclear units would benefit your customers, as well as being cost-effective to them, is that correct?

THE WITNESS: Yes, sir, it would. However, let me make sure that while this table may not be clear, let me try to clarify it. The analyses that were done whose results are shown on this page assume zero capital cost for nuclear, so we would have anticipated before we even started the analysis that this page would have shown the plan with nuclear present value revenue requirements calculation would have been lower than those with either gas or IGCC. It's the magnitude of the difference here that leads to our break-even costs on the next slide.

COMMISSIONER SKOP: And thank you for that. Again, I think what I'm trying to ascertain, which is, I think, readily apparent from looking at the matrix is that in all possible scenarios based upon the best available data that we have today, that there is a substantial benefit for the addition of the nuclear units based on this matrix.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Thank you very kindly.

Commissioners, any other questions?

Mr. Anderson, I believe you are on for redirect.

MR. ANDERSON: FPL has no redirect for this witness.

CHAIRMAN CARTER: Excellent. Excellent.

Mr. Anderson, you are on for the exhibits.

MR. ANDERSON: May we please offer into evidence Exhibits 76 through 86, I believe. Let me just double-check that.

CHAIRMAN CARTER: Okay.

MR. ANDERSON: That may be the wrong note. It is 76 to 86.

CHAIRMAN CARTER: 76 through 86. Any objections? With no objection, show it done.

(Exhibits 76 through 86 admitted into the record.)

CHAIRMAN CARTER: Staff, you are recognized for exhibits.

MS. FLEMING: I believe all of the staff's exhibits have already been moved in. There aren't any additional.

CHAIRMAN CARTER: I know that we had moved in 14, but I didn't know if had moved in 15 or not. Have we done that?

MS. FLEMING: Yes, we have, Chairman.

CHAIRMAN CARTER: I didn't check it off. All right, then. Let's do this, staff.

Okay. Commissioner Argenziano, our legal staff needs a moment to get together, and we are going to allow them to chat. I know they need to talk to our Public Counsel. And

Mr. Beck is going a great job. He's here by himself right now, but I know that they need to get with him, so we are going to give them a moment. Ten minutes.

COMMISSIONER ARGENZIANO: Okay. Thank you, Mr. Chairman.

CHAIRMAN CARTER: Thank you. We are on recess for ten minutes.

(Recess.)

CHAIRMAN CARTER: Okay. We are back on the record. We are a couple of lawyers short, but we will go on nevertheless.

Staff, you are recognized.

MS. FLEMING: Thank you, Chairman. It is my understanding that all parties can stipulate to Witness Ousdahl. And I have checked with all the Commissioners, and I think it is appropriate to state that I believe none of the Commissioners have questions for Witness Ousdahl; and if that is the case, I believe that we could stipulate Witness Ousdahl, move her testimony into the record at the appropriate time, and I believe she could be excused. Is that correct?

CHAIRMAN CARTER: Okay. Commissioner Argenziano, were you able to hear that?

COMMISSIONER ARGENZIANO: Yes, Mr. Chair. I have no problem with that at all.

CHAIRMAN CARTER: Okay.

Mr. Butler, or is it Mr. Anderson? Mr. Anderson, you are recognized.

MR. ANDERSON: Thank you, Chairman Carter. FPL moves into the record the Prefiled Direct Testimony of Kim Ousdahl consisting of eight prefiled pages of questions and answers. We ask this be reflected in the record as though read.

CHAIRMAN CARTER: The prefiled testimony of Witness Ousdahl is entered into the record as though read.

MR. ANDERSON: She has no exhibits.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF KIM OUSDAHL

DOCKET NO. 07____-EI

OCTOBER 16, 2007

Q. Please state your name and business address.

A. My name is Kim Ousdahl. 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 or the Company) as Controller.

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

A. I am responsible for financial accounting and internal reporting for FPL, including property accounting and management of the regulatory accounting function. In this role I have responsibility for managing the accounting and financial and regulatory reporting of the nuclear capital project costs.

Q. Please describe your educational background and professional experience.

A. I graduated from Kansas State University in 1979 with a Bachelor of Science Degree in Business Administration, majoring in Accounting. That same year, I was employed by Houston Lighting & Power Company in Houston, Texas. During my tenure there, I held various accounting and regulatory management

positions. Most recently, prior to joining FPL in June 2004, I was the Vice President and Controller of Reliant Energy.

I am a certified public accountant (CPA) licensed in the State of Texas and a member of the American Institute of CPAs, the Texas Society of CPAs and the Florida Institute of CPAs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain how FPL will comply with Florida Administrative Code Rule 25-6.0423, Nuclear Power Plant Cost Recovery (the Rule) during the time prior to Turkey Point Nuclear Units 6 and 7 (Turkey Point 6 & 7) being sited, through the construction period until the plant goes into service. I will also address the time frame for filing the Nuclear Filing Requirements (NFRs) which will be used to facilitate implementation of the Rule.

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

A. I am co-sponsoring Appendix H of the Need Study along with FPL witnesses Scroggs and Sim.

Q. Please describe the purpose of the Rule and the development of the NFRs implementing the rule.

A. On March 20, 2007, in Order No. PSC-07-0240-FOF-EI, this Commission adopted the Rule to implement Section 366.93, Florida Statutes (the Statute), which was enacted by the Florida Legislature in 2006. The stated purpose of the Statute is to promote utility investment in nuclear power plants, and it

directed the Commission to establish alternative cost recovery mechanisms for costs incurred to build nuclear power plants. The Rule implements such a mechanism. It allows FPL to recover prudently incurred costs in the siting, design, licensing and construction phases of nuclear power plants after an annual prudence review. The Rule also provides definitions to be used to segregate costs into various cost categories, and defines the cost recovery mechanism for each category of costs.

Section 5(c) and Section 8 of the Rule outline the annual filing requirements necessary to obtain a determination of prudence. FPL is working with Commission Staff, the Office of Public Counsel, Progress Energy Florida and others to develop a comprehensive set of NFRs, which will provide an overview of a nuclear plant project and a roadmap to the detailed project costs. The parties are currently working together toward consensus on the specific format of the schedules. Once finalized, the NFRs will form a framework for the Commission to review the costs projected to be incurred and the actual costs incurred during each year for the nuclear power plants being constructed in Florida. The Rule then provides for the annual recovery of these costs through the Capacity Cost Recovery Clause (CCRC).

Q. Briefly describe the various cost categories which are defined in the Rule.

A. Section 2 of the Rule identifies and defines three categories of costs: Site Selection Costs; Pre-Construction Costs; and Construction Costs. The Rule provides the following definitions:

'Site Selection Costs' are costs that are expended prior to the selection of a site. A site will be deemed to be selected upon the filing of a petition for a determination of need for a nuclear power plant pursuant to Section 403.519, Florida Statutes.

'Pre-Construction Costs' are costs that are expended after a site has been selected in preparation for the construction of a nuclear power plant, incurred up to and including the date the utility completes the site clearing work.

'Construction Costs' are costs that are expended to construct the nuclear power plant including, but not limited to, the cost of constructing nuclear power plant buildings and all associated permanent structures, equipment and systems.

Q. What are the major costs incurred in each category?

A. Site Selection Costs will include the cost incurred in the development of the detailed site alternative analysis, review of technology options, preparation and filing of the zoning applications, and environmental impact studies performed during this time frame.

Pre-Construction Costs will consist primarily of costs incurred in development of the license application, detailed engineering, design, long-lead procurement, permitting, clearing and temporary construction facilities costs.

Construction Costs include project management, payroll, training, as well as the costs for constructing nuclear power plant buildings and all associated permanent structures, equipment and systems.

All of these costs will ultimately be recorded in account 107, Construction Work in Progress and will be transferred to account 101, Plant in Service, net of the amounts recovered under the Rule, when the plants go into service.

Q. What cost recovery treatment will be applicable for long-lead procurement items?

A. FPL believes that payments made for long-lead procurement items during the preconstruction phase are properly categorized as preconstruction costs. Therefore, consistent with Section 5 of the Rule these costs will be recovered over a one-year period through the CCRC along with the related carrying costs, if applicable.

Q. Is FPL requesting Commission assurance in connection with the determination of need that the costs of long-lead procurement items are properly categorized as Pre-Construction Costs pursuant to Section 5 of the Rule?

A. Yes. As FPL witness Scroggs indicates, the Company will incur these costs to facilitate the earliest practical deployment schedule. The Company requests that the Commission acknowledge specifically in its need determination order that long-lead procurement costs will be categorized as pre-construction costs

and to the extent prudently incurred, will be afforded recovery as such through the CCRC.

Q. What will be the timing of FPL's initial filing of the NFRs?

A. Assuming this Commission grants an affirmative determination of need for Turkey Point 6 & 7 by the first quarter of 2008, FPL will make an initial filing in May 2008 of projected and prior Pre-Construction Costs and Site Selection Costs. These Pre-Construction Costs, if approved by the Commission, will be included for recovery through the CCRC.

Q. Will the May 2008 filing include a request for recovery of Site Selection Costs?

A. FPL has not yet determined how it will propose that its Site Selection costs be recovered, but will do so by filing a petition pursuant to Section 4 of the Rule. To the extent FPL proposes to recover such costs through the CCRC, the Company would submit NFRs supporting the costs along with the petition.

Q. How would the Commission's Rule for recovery of Pre-Construction Costs and Carrying Costs on the Construction Cost Balance prior to the in-service date of the new unit be applied in practice?

A. Appendix H to FPL's Need Study provides a quantitative example of how capital costs for a new nuclear unit would be recovered. Because FPL does not have a definitive capital cost for a new nuclear unit as discussed in FPL witness Scroggs' testimony, this example uses a $1/kw nuclear capital cost.

The projected and actual Site Selection and Pre-Construction Costs for 2007 through 2009 of $31 thousand, including estimated carrying costs of $2

thousand, would be included in the May 2008 filing. After approval of these costs by the Commission, the amounts would be included in setting the CCRC for 2009. This would take place in the November 2008 clause proceedings. The amounts collected during 2009 through the CCRC would be trued up including any applicable carrying charges and would then be collected or refunded in future periods through the CCRC.

As shown on Appendix H, the estimated Carrying Costs on the Construction Cost Balance during the construction period 2012 through 2018 of $563 thousand for Turkey Point 6 and $358 thousand for Turkey Point 7 during the construction period 2013 through 2020 would be treated in a similar manner: projected in May, approved in the fall, included in November clause proceedings and collected in the subsequent year through the CCRC. All amounts would be subject to true up with any difference, including applicable carrying charges, collected or refunded in future periods through the CCRC.

When the plants are placed in service in 2018 and 2020, only actual construction costs would be reflected in rate base, as all Site Selection Costs, Pre-Construction Costs and Carrying Costs on the Construction Cost Balance during the construction period will have been fully recovered. This assumes the CCRC fully recovers all other prudent costs and that the fixed AFUDC rate allowed to be recovered during construction as prescribed by the rule,

does not fall below the Company's otherwise authorized AFUDC rate, such that the full carrying costs are not recovered during the construction period.

Q. Does this conclude your testimony?

A. Yes.

MR. ANDERSON: The other housekeeping matter is we would like to at this time offer into the record the need study for electrical power.

CHAIRMAN CARTER: Whoa. Back up. Hang on a second.

MR. ANDERSON: Yes, sir.

CHAIRMAN CARTER: Whoa Kemosabe. Let's do this. Now we need to move into the record her testimony. We just entered it into the record as though read. Since there is no objection to it, it has been stipulated, so it is now officially part of the record.

Now, let's move. We have got Witness Ousdahl. Okay. Got it. All right. Now, Mr. Anderson, sir, you are recognized.

MR. ANDERSON: Thank you. Pardon me for rushing ahead like that.

CHAIRMAN CARTER: No problem. I'm here to help.

MR. ANDERSON: Thank you very much. We have the need study for electrical power and the Appendices A through K, which has been remarked as Exhibit 96.

CHAIRMAN CARTER: Exhibit 96.

MR. ANDERSON: We would offer that into the record at this time, also.

CHAIRMAN CARTER: Okay. See, I knew that we hadn't entered that in yet, Exhibit 96. And show it done without -- because there was no objection. If fact, we all asked for it,

did we not? All the parties. So show that done without objection. That would be -- Commissioners, Exhibit Number 96 is now entered in. It is the need study. The FPL Need Study is entered in without objection. Show that done.

(Exhibit 96 marked for identification and admitted into the record.)

CHAIRMAN CARTER: Mr. Anderson, you're recognized, sir.

MR. ANDERSON: Thank you. That is the end of my work before you, and I will turn this over to my colleague.

CHAIRMAN CARTER: Mr. Butler, you're recognized.

MR. BUTLER: Thank you. I would call our last witness, Mr. Reed, to the stand. And I don't believe that Mr. Reed has be sworn previously.

CHAIRMAN CARTER: Mr. Reed has not been sworn.

(Witness sworn.)

CHAIRMAN CARTER: Mr. Butler.

MR. BUTLER: Thank you.

JOHN J. REED

was called as a witness on behalf of Florida Power and Light Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BUTLER:

Q Could you please state your name and business address for the record.

A My name is John J. Reed. My business address is 293 Boston Post Road, Marlborough, Massachusetts.

Q Thank you. And by whom are you employed and in what capacity?

A I am the Chairman and Chief Executive Officer of Concentric Energy Advisors and CE Capital Advisors.

Q Have you prepared and caused to be filed 47 pages of Prefiled Direct Testimony in this proceeding on October 16, 2007?

A Yes, I have.

Q Do you have any corrections or additions to your testimony?

A No, I do not.

Q Do you adopt this as your prefiled direct testimony in this proceeding?

A Yes, I do.

MR. BUTLER: Chairman Carter, I would ask that Mr. Reed's prefiled direct testimony be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony will be accepted into the record as though read.

MR. BUTLER: Thank you.

BY MR. BUTLER:

Q Mr. Reed, do you have attached to your testimony exhibits designated RS-1, 2, 3, and 4? I'm sorry, that

wouldn't work right. JJR-1, 2, 3, and 4.

A Yes, thank you, I do.

MR. BUTLER: And, Mr. Chairman, I would note that these have been previously identified as Exhibits 87, 88, 89, and 90.

CHAIRMAN CARTER: Thank you, sir. For the record.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JOHN J. REED

DOCKET NO. 07_____-EI

OCTOBER 16, 2007

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John J. Reed. My business address is 293 Boston Post Road West, Marlborough, Massachusetts 01752.

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

A. I am the Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. (CEA).

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

A. CEA is an economic advisory and management consulting firm, headquartered in Marlborough, Massachusetts, which provides economic and financial services relating to energy industry transactions, energy market analysis, litigation, and regulatory support.

Q. Please describe your educational background and professional experience.

A. I have more than 30 years of experience in the energy industry, having served as an executive in energy consulting firms, including the position of Co-Chief

Executive Officer of the largest publicly-traded management consulting firm in the U.S. and as Chief Economist for the largest gas utility in the U.S. I have provided expert testimony on a wide variety of economic and financial issues related to the energy and utility industry on numerous occasions before administrative agencies, utility commissions, courts, arbitration panels, and elected bodies across North America.

Q. Have you previously provided expert testimony?

A. Yes. I have been accepted as an expert in dozens of jurisdictions in the United States and Canada.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits JJR-1 through JJR-4, which are attached to my direct testimony.

Exhibit JJR- 1	Curriculum Vitae
Exhibit JJR- 2	Testimony of John J. Reed 1997 – 2007
Exhibit JJR- 3	CO_2 Reductions by Technology Type
Exhibit JJR- 4	2007 U.S. Electricity by Technology Sector vs. 2030 US Electricity by Technology Sector Including Advanced Technologies

Q. What is the purpose of your testimony?

A. My testimony explains why FPL's proposal to pursue the development of new nuclear generation is appropriate given the significant uncertainty that currently exists regarding future environmental policies, renewable resource development potential, fossil fuel prices, and the ultimate cost of long lead time baseload generating technologies such as new nuclear facilities and integrated gasification combined cycle (IGCC) facilities. In addition, my

testimony addresses the regulatory policies and processes that are needed to maintain a balanced and flexible "regulatory compact" between Florida Power & Light Company (FPL) and the Florida Public Service Commission (the Commission), which will simultaneously serve to establish a new nuclear plant as a baseload option for FPL and protect FPL's customers from being limited to potentially uneconomic generating resource commitments.

II. SUMMARY AND CONCLUSIONS

Q. Please briefly review your conclusions regarding the current environmental and regulatory policy issues that FPL is facing.

A. While the precise timing and details remain uncertain, it is reasonably anticipated by most industry observers and others that there will be some form of greenhouse gas (GHG) regulation. Whether it be federal, regional or state regulation, it is anticipated that such regulation will include potential requirements for significant GHG reductions in the not too distant future, and certainly within FPL's current resource planning horizon. Florida itself appears to be moving toward requiring material reductions in GHG emissions. Indeed, those that have been proposed by Governor Crist are as ambitious as any in North America. In addition, a penetration level of renewable generation technologies that is several times higher than current levels is being discussed in Florida. These emerging and, to a certain extent, competing objectives are made more challenging by the fact that Florida's

electric demand growth is among the highest in the nation, and Florida's indigenous resources which can be used for renewable generation (e.g., hydro, wind, wood, geothermal) are not abundant and/or economic.

As a consequence of its limited indigenous resource base, its rapid demand growth and its focus on environmental stewardship, Florida's electric generation mix has become increasingly reliant on natural gas as a generation fuel. If the state's next two decades were to mirror the past two decades, Florida's generation mix would become unacceptably dominated by gas-fired generation, and the state would be highly susceptible to gas price spikes and acutely vulnerable to gas supply disruptions. Furthermore, the state would fall short of achieving any meaningful reductions in GHG levels and achieving renewables targets.

Q. What are your conclusions about the other sources of uncertainty and change that FPL must consider?

A. On top of the policy challenges, FPL faces an energy market in which fossil fuel prices have risen dramatically and natural gas and fuel oil price volatility has increased significantly, and in which the costs, not related to performance of alternative baseload generating technologies (e.g., new nuclear), are uncertain and evolving. The surge in political and regulatory support for renewable generating technologies has somewhat accelerated the development pace for these alternatives, and new technologies, such as ocean current/wave/thermal projects, are beginning to be developed. However, it is

becoming increasingly clear that it would require a quantum jump in the performance and/or a quantum reduction in the cost of these alternatives before renewables can be expected to provide any more than single-digit percentage contributions to the nation's (or Florida's) generating resource mix. Furthermore, most renewable resource options are unable to meet baseload generating needs, but are better positioned as intermediate and peaking resources that enable a utility to replace its gas- and oil-fired generation. Even with a heavier emphasis on the development of renewable resources in Florida, the realities of: 1) land use economics, 2) a relatively low level of renewable resource availability, and 3) the incompatibility of renewables that involve combustion or incineration with GHG reduction targets, make it very unlikely that the state can count on renewables to meet the bulk of its incremental power supply needs or to be the principal means of providing significant reductions in GHG levels over the next ten to twenty years.

Q. If supply-side resources face so many challenges, is there a better alternative in vigorously pursuing demand side management and demand reduction (DSM) programs?

A. These programs should be vigorously pursued, and FPL is recognized throughout the electric utility community as being one of the most aggressive and successful utilities in the nation in achieving cost-effective DSM programs. However, there is no likelihood that even the successful utilization of all of the available cost-effective DSM programs can do anything more

than slow the demand growth that the system is facing, and thus will not eliminate the need for new non-GHG-emitting baseload resources in order to both meet demand and mitigate GHG emissions.

Q. What are the consequences of these circumstances and challenges for FPL?

A. Quite simply, in an era of increasing uncertainty, FPL is appropriately focusing on creating and preserving a high level of resource optionality for its system. Given FPL's current fuel mix, the addition of non-fossil fuel, non-GHG-emitting sources for generation is necessary to maintain system reliability, increase fuel diversity and allow progress toward meaningful GHG reductions. This is especially important for long lead time generating resources such as new nuclear, which, if not purposefully pursued and preserved, will be unavailable when a final commitment needs to be made to new supply-side and demand-side solutions.

Q. How does the option of a new nuclear plant fit into these competing objectives?

A. The addition of new nuclear resources would be a major step toward the decarbonization of FPL's resource mix and achieving any GHG reduction targets. It is extremely unlikely that FPL can achieve any meaningful reduction in GHG emissions, let alone reach aggressive targets that may be instituted, without significantly expanding its nuclear power resources. Although the ultimate cost of these resources can only be estimated at this time and the deployment timeline is long, it is clear that if FPL does not

commit to at least enabling this alternative now, new nuclear resources will not be available within the next decade or more. The global competition for the raw materials and professional services needed to construct new nuclear facilities will place continued pressure on securing these resources.

It is also clear that the approval FPL is seeking in this proceeding will not foreclose any options for cost-effective renewable resources or DSM programs that can be developed over the intervening years. Renewable resources and DSM programs, even if successful beyond anything seen in recent trends, may allow FPL to avoid a heavier dependence on fossil fuels, but should not be falsely viewed as direct competitors or alternatives to a new nuclear facility, which is the best option FPL currently has for a non-GHG-emitting baseload resource addition. The projected resource needs of FPL's service area are large enough to accommodate all of the renewable resources that are likely to be available plus the proposed new nuclear facilities.

Q. What regulatory policy initiatives have you concluded are necessary for FPL to create an option for new nuclear resources?

A. Even with all of the federal support that has been developed to encourage nuclear power's renaissance in the United States, it is unreasonable to expect any regulated utility to pursue this option under the regulatory regime that existed twenty years ago when the last group of nuclear plants became operational. The nuclear prudence cases of that era, which consumed years of hearing time and cost utility investors more than $18 billion, left a lasting

impression on all who participated in that set of processes. Commitments that had been made with the expectation of reducing customer's bills ended up becoming "bet the company" gambles that left no post-Three Mile Island (TMI) nuclear project unscathed. This time around, the stakes are equally high and the lessons from the 1980s have not faded to the point that proponents of new nuclear units will be willing to enter into a highly asymmetric risk-reward regulatory paradigm with billions of dollars at risk.

I fully endorse FPL's proposed approach to creating an option for a new nuclear resource. This approach substitutes an open, options-based, collaborative and comprehensive resource planning process for the all-or-nothing "used and useful" regulatory paradigm that prevailed in the 1980s. Under this process, optionality can be maximized, new developments can be reflected in the resource plan, and the complex tradeoffs that are likely to arise can be fully evaluated and resolved. As a result, FPL's customers will not be asked to face the economic, environmental and energy reliability consequences of a resource plan that is constrained by inaction to ever greater dependence on fossil fuels and their energy delivery infrastructure.

FPL's proposed annual review process, consistent with the Commission's Nuclear Power Plant Cost Recovery Rule, Section 25-6.0423, F.A.C. permits rational and economically efficient decision-making and aligns customer and investor interests far better than the regulatory process of the 1980s did. But

this framework will require continued active and responsive regulatory support for the successful deployment of new nuclear generation in Florida. In exchange for a high level of assurance of recovery of prudently incurred costs, customers will benefit from a process that provides assurance that uneconomic projects will not be pursued.

III. AVAILABLE RESOURCES IN TODAY'S HIGHLY UNCERTAIN MARKET

Q. Please explain the more recent sources of uncertainty and complexity in the resource planning process.

A. Over the last few years we have seen a significant increase in concerns about energy security, GHG emissions, and energy price volatility, leading in various jurisdictions to policy shifts in favor of renewable energy, new nuclear facilities and advanced clean coal facilities as potential solutions or, at least mitigating measures, for one or more of these concerns.

In Florida, Governor Crist has called for the establishment of GHG reduction targets that would be as aggressive as any in North America:

By 2017:	Reduce GHG emissions to 2000 levels
By 2025:	Reduce GHG emissions to 1990 levels
By 2050:	Reduce GHG emissions by 80% of 1990 levels

The Governor has also requested that the Commission initiate a rulemaking to consider requiring that utilities produce at least 20% of their electricity from renewable sources, with a strong focus on solar and wind energy.

FPL faces significant challenges harmonizing these two important policy objectives under consideration in Florida, *i.e.*, aggressive standards for GHG reductions and renewable energy content, while continuing to provide adequate, reliable, and reasonably priced electric service to one of the fastest growing areas in the country.

Q. Are there uncertainties associated with choosing a new nuclear plant as a generating resource?

A. Yes, there are. Foremost among these are the cost and the timeline for deployment of this option. What is virtually certain, however, is that new nuclear plants will require several years for planning, permitting and construction, and that there is no conceivable "cookie cutter" or "shortcut" approach to getting one built and operational. Successful implementation will require almost a tripling of the development term associated with more conventional gas-fired combined-cycle option. Mr. Scroggs addresses these uncertainties in his testimony.

Q. Are there similar uncertainties for other non-GHG-emitting resources?

A. Yes. For example, it is often suggested that there could be substantial improvements in the cost, performance, and reliability of renewable energy alternatives in response to greater demand. As discussed later in this

testimony, for example, many people have predicted that the cost per square meter of solar photovoltaic panels will decrease significantly as production of these units' scales up to meet increased demand. Others predict that new renewable generating technologies, such as ocean current/wave/thermal resources, will be commercialized and provide a clean, affordable means of producing electricity. The future cost and performance parameters of these alternatives are inherently uncertain, which adds to the challenges facing electric resource planners. And, of course, cost is not the only potential factor that could limit penetration of these resources. Property rights and permitting issues, among others, will also affect the deployment of such resources, in terms of both number of installations and location.

Q. You stated earlier that your review of FPL's resource plan indicated that it is highly unlikely that FPL could even come close to achieving any meaningful reduction in GHG emissions without additional nuclear resources. What review have you performed and what is the basis for your conclusions?

A. I have reviewed the testimony in this application, FPL's most recent CO_2 projections, FPL's most recent 10-year Site Plan and several studies of renewable resource potential. The analysis presented by FPL witness Kosky in Exhibit KFK-4 and FPL witness Sim in Exhibit SRS-10 indicates that under a non-nuclear generation approach to resource planning, CO_2 emissions from FPL's own generation resources are expected to increase 63% by 2021 as compared to the 2005 levels, or a 3.3% compound annual growth rate over

this period. However, if Governor Crist's CO_2 reduction targets become law in Florida, FPL will be required to achieve a 42% reduction from the non-nuclear generation approach levels to achieve the proposed 2017 CO_2 target. In addition, in order to achieve the 2025 target proposed in Executive Order 07-127, FPL would be required to achieve a 67% reduction from the projected non-nuclear approach levels. These are enormous reductions for any utility, and are even more challenging for a utility that has already achieved a successful track record of pursuing DSM programs and deploying new high-efficiency, low emitting gas-fired combined-cycle units. Such targeted reductions could not be achieved solely through reliance on cleaner technologies for new generation, because these CO_2 reduction targets would be far greater than FPL's projected growth in energy requirements. Achieving these goals would require a "decarbonization" of FPL's existing resource mix. This would be facilitated by substituting new low-carbon resources for expiring high-carbon purchased power contracts and by reducing the capacity factors for FPL's existing oil-fired resources. Again, assuming the 2025 target for CO_2 reductions is adopted in Florida, based on current projections, *all* new generation added by FPL after 2017 would have to be non-GHG-emitting resources. Quite simply, there is no plausible scenario in which such CO_2 targets could be achieved in a cost-effective manner without new nuclear resources.

Q. How can the Commission be certain that FPL's proposal for two new nuclear units at the Turkey Point site is the most cost-effective solution for simultaneously achieving targeted GHG reductions and meeting FPL customers' energy requirements?

A. Until the cost estimates for FPL's two proposed nuclear units have been further developed, it is not possible to reach a definitive answer to this question. But absolute certainty, if such a concept ever exists, is not required today. Rather, based on all the information available today, it is important to take the steps and make the expenditures necessary to retain the option of new nuclear capacity coming on line in 2018. Even as FPL moves forward with this process, the question will need to be posed again and addressed in each annual resource review to determine if the answer remains the same. This is precisely the process contemplated by the Commission's Nuclear Cost Recovery Rule and FPL's proposal in this proceeding.

The ultimate answer will hinge on balancing at least two key economic considerations: 1) the cost of alternate means of meeting the projected electric demand; and 2) the cost and significant uncertainties of alternate means of meeting any GHG reduction targets.

While it is premature to quantify a potential cost "premium" for the nuclear option as a means of meeting electric demand, if there is such a premium, it is beginning to be possible to quantify the avoidable costs for alternate GHG

reduction strategies. For example, current estimates for the costs of carbon capture and sequestration (CCS) in an IGCC unit are approximately $30 to $40/ton of CO_2, excluding any cost premium for the IGCC unit itself. The costs for high levels of CCS in an ultra super critical pulverized coal (USCPC) unit are estimated to be $30 to $50/ton of CO_2, and for a natural gas-fired combined cycle (NGCC) plant the costs are estimated to be $50 to $86/ton of CO_2. When these estimated CCS costs are applied to the CO_2 emission levels for each technology, we can derive a "justifiable cost premium" for any non-GHG emitting resource as compared to these alternatives. That comparison is presented in Table 1 below:

Table 1: Avoidable CCS Costs and Justifiable Power Cost

Technology	CCS $/ Ton CO_2[1]	Ton CO_2/MWh	Justifiable Power Premium for Non-CO_2 Technologies ($/Mwh)
USCPC	$30 - $50	0.9105[2]	$27.32 - $45.53
IGCC	$30 - $40	0.9665[3]	$29.00 - $38.66
NGCC	$50 - $86	0.3750[4]	$18.75 - $32.25

Of course, these figures assume that the only means of achieving CCS is to do so at that particular type of plant. If public policy permits GHG reduction targets to be met through national or international mitigation strategies, then the justifiable cost premium for non-CO_2 emitting technologies could be less.

[1] Based on a compendium of sources, including Standard & Poors, Black and Veatch and the Intergovernmental Panel on Climate Change. (2006$)

[2] Clean Coal Technology Selection Study, Black and Veatch, January 2007, at 5-10.

[3] Id.

[4] West County Energy Center.

Q. What role have you assumed for new renewable energy resources in FPL's portfolio?

A. I have assumed that FPL pursues all of the cost-effective renewable resources that are available to it. Moreover, even if the "cost-effectiveness" constraint is relaxed, the renewable resource potential in Florida is still not sufficient to defer the need for new generating resources even by one to two years. As shown in Exhibit SRS-3 from the testimony of FPL Witness Sim, there is still a need for 3,956 MW of generating resources assuming Turkey Point 6 & 7 come online in 2018 and 2020, respectively. Therefore, there would exist the opportunity for renewable energy resources to meet almost 4,000 MW of need prior to 2018, which is four times the capacity potential from renewable technologies that has been projected for the entire state.[5]

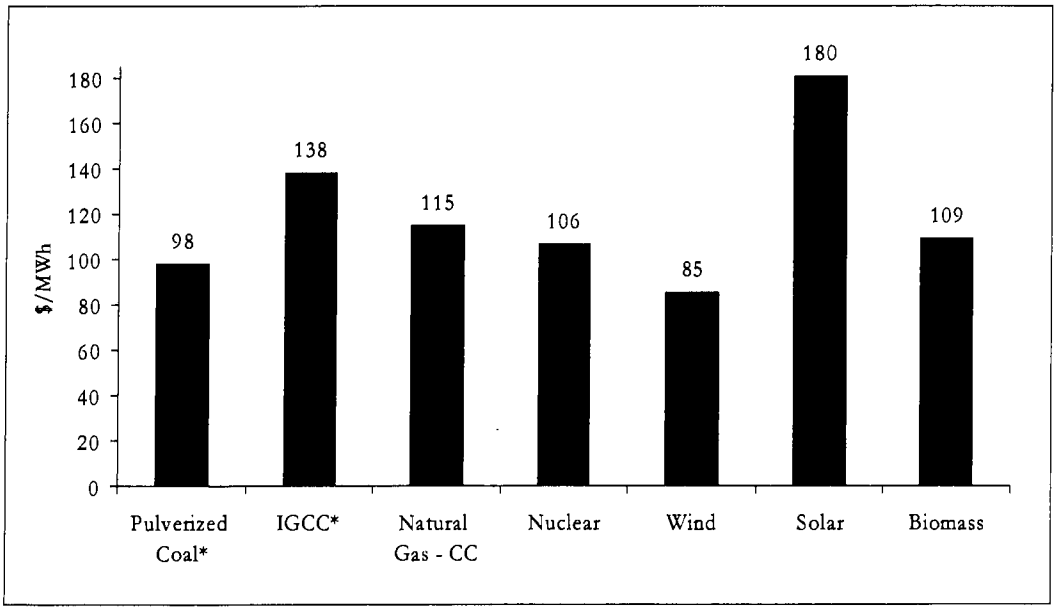
Let me begin by pointing out some of the realities of renewable resource development in broader terms. Renewable power generation resources have received broad public support for almost two decades. All of the development to date has led to non-hydroelectric renewable resources contributing about 2.3% of annual energy production for the United States. The Energy Information Administration (EIA) projects that with a continued policy push and technological advancement, non-hydro renewables could account for 3.6% of electric production by 2030.[6]

[5] The renewable resource potential in Florida is discussed in the Direct Testimony of FPL Witness McBee in this proceeding.

[6] EIA, Annual Energy Outlook 2007, February 2007, p. 86.

Standard & Poor's recently performed an analysis of power generation technologies that could be employed to help mitigate GHGs on a national level. As shown in Chart 1 below, the life cycle costs of certain renewables, like wind and biomass, are somewhat comparable to fossil and nuclear capital costs. Other renewables, like solar, have much higher life cycle costs than fossil and nuclear. The Standard & Poor's analysis, supplemented by FPL-specific information, produces the following estimates of life-cycle costs based on an assumed cost for CCS of only $10/ton.

Chart 1: Life Cycle Power Costs with CCS (2012$)[7]



Other studies by the EIA,[8] General Electric[9] and the engineering firm of Burns & McDonnell[10] confirm these relative rankings, and also note that solar-

[7] Standard & Poor's, "Which Power Generating Technologies Will Take the Lead In Response to Carbon Controls?", May 11, 2007, p. 5. This analysis assumes the maximum achievable capacity factors for each technology. *Pulverized coal and IGCC data from the Clean Coal Technology Selection Study, Black and Veatch, January 2007.

[8] EIA, Assumptions to the Annual Energy Outlook 2007, February 2007, p. 77.

photovoltaic and fuel cells have current costs that extend far beyond the range shown in the chart above.

Q. Are the costs in Florida for these various renewable alternatives likely to be similar?

A. No, in general, I would expect them to be higher. The unit power costs shown in Chart 1, which reflect national averages, are the quotient of total costs divided by the total output. Florida specific data indicate that installed costs for renewables are generally higher, and output is lower, leading to state-specific costs that range from slightly higher than national averages (biomass), to far higher than national averages (wind).

The higher installed costs for Florida renewable resources reflect higher land costs, higher labor costs, and in some cases, more expensive technology (e.g., the use of off-shore wind vs. on-shore wind). The lower output levels reflect Florida's relatively poor wind and solar resources, leading to lower capacity factors for these technologies. The combination of, for example, a 25% cost premium and a 35% lower level of output yields a total cost that is almost twice the "average" level.

Q. What is your understanding of the future renewable generating resource potential in Florida?

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[9] Abate, Victor, "Unlocking America's Energy Resources: Next Generation", Written Testimony before the House Subcommittee on Energy and Air Quality, May 18, 2006.

[10] Burns & McDonnell, "Analysis of Baseload Generation Alternatives: Big Stone Unit II", September, 2005.

A. It has been estimated that the total incremental capacity potential from renewable technologies (without regard to economics) could be as much as 1,000 MW for the entire state of Florida. This estimate is consistent with the Commission's and the Florida DEP's assessment of renewable resources from January 2003.[11] These estimates are presented and discussed in the Direct Testimony of FPL Witness McBee in this proceeding.

The renewable resource potential for each state in the continental United States has also been analyzed by the Union of Concerned Scientists (UCS). The UCS ranks Florida's renewable resource potential (as a percent of state electric consumption) as 46th out of the 48 states.[12] Notably this evaluation was performed without regard to cost-effectiveness.[13] Almost three-quarters of Florida's potential is in the solar-photovoltaic category, which is by far the most expensive option studied. This ranking reflects the scarcity of commercially-viable renewable resources in the state.

Q. The Governor's recently announced targets for renewable resources stress the importance of wind and solar power as non-GHG-emitting resources in terms of CO_2 reductions. You have already discussed the relatively high cost of solar applications, but is there potential for wind resources in Florida?

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[11] Florida Public Service Commission and the Florida Department of Environmental Protection, "An Assessment of Renewable Electric Generating Technologies for Florida", January 2003, p. 2.

[12] Union of Concerned Scientists, "Plugging In Renewable Energy: Grading the States", May 2003, p. 39.

[13] The UCS study does not consider different electric consumption levels or patterns across the U.S., and is measured based on total energy consumption.

A. There is some potential, but it is quite modest. Florida is one of only three states in the United States where virtually the entire state is ranked as being in Wind Power Class 1, which equates to essentially zero wind resources.[14] Florida's only measurable wind resources are offshore, which make development of these resources far more expensive than onshore.

Offshore wind resources also raise significant issues regarding siting, permitting, and cost-effectiveness as recently experienced by projects in the U.S. Northeast.[15] It should also be noted that Florida's offshore wind resources are modest enough to require the utilization of at least 8,000 turbines that if strung together would line the entire coast of the state to produce the same amount of electric energy (not capacity) that could be produced by FPL's proposed new nuclear facilities at Turkey Point.

Q. Are there other renewable resource technologies in Florida with potentially fewer hurdles to overcome in terms of siting and land use issues as compared to wind resources?

A. Yes, but only on a small scale. A recent study examined the land use characteristics for the biomass, wind, and solar facilities that would produce the same annual energy output as one 1,000 MW nuclear facility. Table 2, below shows the results of this analysis:

[14] National Renewable Energy Laboratory, "Classes of Wind Power Density".

[15] Suffolk Life, "LIPA Likely to Abandon Wind Park Project", August 29, 2007.

Table 2: Land Use Requirements by Technology[16]

Technology	Land (acres)	Relationship to Nuclear
1,000 MW Nuclear	100	N.A.
Biomass Equivalent (30% combustion efficiency, cultivated land)	617,500	6,175 times
Solar Equivalent*	37,050	370 times
Wind Equivalent	190,190	1,902 times

* Excludes storage area requirements

Q. Your discussion of renewable energy alternatives has not mentioned the potential from ocean energy projects. Are these projects viable for commercial application as baseload generating resources within the 10-year development period for a new nuclear facility?

A. No. Ocean energy projects come in many forms, such as ocean current turbines, tidal power projects, wave energy conversion systems and hybrid offshore wind/water projects. Since these projects are in the development phase, most proponents of these systems are focusing on 2020 and beyond before utility-scale commercial applications are considered possible. While the potential for these technologies is substantial (in terms of the raw energy contained in the water resources), there are numerous engineering, environmental, and legal challenges that need to be overcome before even

[16] Jesse H. Ausubel, "Renewable and Nuclear Heresies", March 10, 2005, at pp. 4-5.

proof of concept projects, pilot projects, and demonstration projects can be achieved.

FPL has received one ocean current project proposal in its most recent Renewables RFP, which offers to produce energy only, not capacity, but would help to further the development of this technology. This project, which is planned to be 100 MW and on-line by 2011 is currently under review by FPL.

Ocean energy projects are good examples of moderate- to high-potential, long-term alternatives for baseload generation that we should all hope to see reach commercially viable status. However, they also exemplify the kind of quantum leap in technology, performance and cost reduction that will be required in order for a renewable energy technology to make a major contribution to the nation's electric energy mix.

Q. **After considering all of the existing and potential contributions from renewable resources, what conclusion have you reached regarding the impact of renewables on FPL's request in this proceeding for a need determination for two new nuclear facilities at the Turkey Point site?**

A. I have concluded that FPL's need will not be eliminated even if renewable resources achieve a level of development that is far greater than expected. As discussed earlier, currently deployed renewable technologies, such as waste-to-energy, biomass, landfill gas and hydro, appear to have only about 1,000

MW of total development potential in Florida, even if this development is not constrained by economics. This is the equivalent of less than one year of growth in Florida's electric requirements (even if all renewables were treated as capacity resources). Achieving any level of significant contribution from wind resources is highly unlikely given Florida's lack of viable wind resources. Solar thermal, solar photovoltaic and ocean energy projects would all require quantum leaps to achieve a significant, cost-effective level of penetration in the Florida market. While we can be hopeful that these breakthroughs may occur, prudent resource planning would not rely on these events in order to meet projected demand.

In addition, from a policy perspective, I do not believe that it is appropriate to consider renewables development as competing against new nuclear resources for inclusion in FPL's resource mix. While the best information currently available is that FPL can easily absorb all of the renewable resources that are likely to be available to it, the question that should be asked is: if renewables far exceed this development estimate, what changes should be made in the resource plan? I would not want to essentially squander the good fortune of highly successful renewable resource development by sacrificing the only conventional generation alternative that is essentially a non-GHG-emitting resource. This renewables "bonus," if realized, could be much more effectively used to back down FPL's purchases from coal-fired resources, or to back down generation at existing fossil-fuel fired units in order to reduce

FPL's reliance on the more price-volatile and supply-constrained fossil fuels, and for FPL to have a better chance of achieving any GHG reduction targets. Relying on better-than-expected results in one potentially environmentally-beneficial sector as a basis for giving up another environmentally-beneficial resource would be both short-sighted and self-defeating.

Q. Can the combination of more robust DSM programs and more robust renewables development eliminate the need for FPL's proposed new nuclear resources?

A. No. This is even more unlikely if we are to consider the "need" for a resource to be based on both the ability to serve new load and the ability to reduce GHG emissions. To meet the magnitude of GHG reductions that have been proposed for Florida will require a continued strong DSM plan, robust renewables development, significant new nuclear resources, successful strategies for carbon sequestration, and more.

The Electric Power Research Institute (EPRI) has just published a Discussion Paper entitled "The Power to Reduce CO_2 Emissions: The Full Portfolio," which examines the nation's ability to reduce CO_2 emissions from the power sector to 1990 levels by 2030. Exhibits JJR-3 and JJR-4 present two important charts taken from the Discussion Paper.

As shown on Exhibit JJR-3, in order to be able to return to 1990 levels for CO_2 emissions from the power sector, on a national level, all of the following achievements will be needed over the next 23 years:

- Using energy efficiency measures to slow load growth from 1.5%/year to 1.1%/year
- Tripling the growth in renewable generation
- Dramatically increasing nuclear generation levels by building more than 50 new nuclear plants
- Doubling the rate of efficiency improvement in clean coal technologies and retrofitting these technologies into about one-half of the existing coal-fired fleet
- Achieving wide-spread deployment of CCS at coal plants after 2020
- Achieving major breakthroughs in Plug-In Hybrid Electric Vehicles (PHEVs), which can be utilized as resources on an "intelligent grid" and reaching a 30% market share for these vehicles by 2030, and
- Successfully increasing the role of distributed energy resources (including distributed solar) from less than 0.1% of baseload requirements to at least 5% of baseload requirements.

Candidly, achieving any one of these objectives would be a challenge. But achieving the GHG target studied (reducing CO_2 emissions from the power sector to 1990 levels by 2030) requires that *every single one* of these strategies be fully successful.

This challenge is even more daunting for Florida, which is currently experiencing annual load growth that is far in excess of the national average, is considering more ambitious GHG reduction targets than those modeled by EPRI, and which, at present, has more limited commercially available renewable resources than almost any other state in the country.

Q. Given the magnitude of the GHG reduction challenge, what are the implications for FPL's resource plan and its request for a need determination in this case?

A. To meet aggressive GHG reduction targets, whether state or national-imposed, it is clear that even with two new nuclear units at Turkey Point, FPL and the entire state of Florida will need to undergo a dramatic transformation of the electric production and electric consumption sectors over the next 20 years.

The key to doing this while discharging the traditional utility mandates of satisfying demand and achieving the lowest reasonable cost for customers will be to maximize the number of options in the resource planning portfolio, and to be responsive to market developments as they occur over the development term for new resources. Of these, today nuclear generation appears to be the best choice; this technology appears to be essential to meeting incremental demand and at the same time meeting any GHG reduction targets. While conditions can, and will, change over the next 10 years, the costs for new nuclear units should improve relative to competing technologies as more of these units are deployed and become operational. But the framework

contemplated by the Commission's Nuclear Cost Recovery Rule and FPL's proposal in this proceeding fully allows for such changing conditions to be considered and evaluated throughout the process relative to the development of Turkey Point 6 & 7.

The most important conclusion for the Commission is that entering into the transformational process that must occur in Florida's electric sector over the next 20 years without having new nuclear units as a viable option in the resource portfolio would confine FPL and the state to an energy future that is risky, potentially costly, and unresponsive to the likely environmental policies.

IV. REGULATORY COMPACT NEEDED TO SUCCESSFULLY ESTABLISH THE NUCLEAR DEPLOYMENT OPTION

Q. Does FPL's proposal to construct Turkey Point 6 & 7 require any regulatory policy initiative from the Commission?

A. Yes. This case is a ground-breaking proceeding. While a number of new nuclear plant proposals have been announced[17] and two have filed their federal applications at the NRC,[18] this is one of the first state-level filings for

[17] Nuclear Regulatory Commission, "New Reactor Licensing Applications (Site and Technology Selected)", August 14, 2007. Plans have been announced for at least 17 new nuclear power facilities.

[18] Constellation filed its combined license application (COLA) in July 2007 for Calvert Cliffs Unit 3.

a new nuclear facility in the nation in over 25 years. Given the billions of dollars of investment in nuclear plants that was disallowed by state regulators in the 1980s, the actions of this Commission with regard to cost recovery mechanisms and assurances for prudently incurred costs will be keenly watched by *all* industry participants and investors, not just the Florida stakeholders.

Q. What messages or assurances do you believe the industry will be seeking from the Commission?

A. Quite simply, a recognition that the State of Florida intends to avoid the prior regulatory and economic debacle that marked deployment of the nation's current nuclear fleet, as well as affirmation that the Commission and the State stand behind FPL's efforts to establish this option for its customers. Specifically, there will be a focus on the regulatory compact between FPL and the Commission and whether the Company, and its investors, can be assured that FPL will receive a return of and on its prudently incurred costs without the use of new standards of review or hindsight that was sometimes applied during the last round of nuclear construction.

Q. Are you familiar with Section 25-6.0423 of the Florida Administrative Code, the Florida Public Service Commission's (PSC) Nuclear Power Plant Cost Recovery Rule?

A. Yes.

Q. Does that rule sufficiently address the regulatory paradigm shift required to enable new nuclear plants?

A. The Nuclear Power Plant Cost Recovery rule, and the enabling legislation (section 366.93, Florida Statutes), strongly suggest that the Florida Legislature and the Florida PSC wish to provide a framework within which the Commission has the opportunity to address and avoid many flawed aspects of other states' past regulatory processes. That being said, given the magnitude of the pending investment and past experience with the regulatory climate and rules changing as rate increases for cost recovery were sought, it will be incumbent upon this Commission to continue its willingness to embrace these initiatives on an ongoing basis as this process unfolds. This requires that the Commission stand behind the Company's decisions that were prudent, based on the best information available at the time the decision was made, and resist any temptation to engage in hindsight. While this is true for all regulatory processes, it is even more important given the size and duration of a commitment to a new nuclear unit.

Q. Would you briefly summarize the regulatory processes that were applied to, and the financial consequences of, the nuclear development era that occurred in the US in the 1970s and '80s?

A. In short, the events at TMI in 1979 led to significant changes, delays, and additional costs for nuclear plants still under construction. As the costs for these plants soared beyond expectations, social and political pressure mounted against the rate increases that were required to recover the full investment utilities had made. In response to these pressures, some regulatory commissions disallowed cost recovery using newly created variations on the

prudence and "used and useful" standards. Several state regulatory processes did not effectively or fairly deal with the realities of the safety-mandated changes and costs associated with building that generation of nuclear plants.

Q. Was any one party responsible for the cost overruns and financial losses associated with the post-TMI nuclear units?

A. No. Responsibility for those costs exceeding expectations was widespread and cut across all segments of the industry. The following is a summary of the challenges and shortcomings, by industry segment, that were encountered in the post-TMI nuclear development era:

- Design/Build - Ongoing changes to design contributed to expanded regulatory review and resulted in delays and cost overruns, some stemming from a desire to continually improve design and pursue cost-effectiveness, some a direct response to NRC-mandated changes.
- National Regulatory - Elongated review processes, sometimes stemming from design changes, resulted in an NRC review process that frequently added years to the development process.
- State Regulatory - Changing policies on cost recovery, the use of hindsight to disallow cost recovery, and the highly aggressive use of prudence proceedings to respond to political pressures regarding rate shock, were the leading cause of billions of dollars in disallowances.
- Utility Sponsors - Many imprudence disallowances were really political judgments on the viability of the rate increases required if plant costs were fully recovered under traditional ratemaking.

Overall, utility behavior did not warrant the extreme regulatory results that many had imposed on them.

Q. How did these issues manifest themselves in economic terms?

A. The financial effect of the cost overruns and subsequent disallowances were felt in many ways. For example:

- Over $18 billion in nuclear construction costs were disallowed;
- Several utilities were forced into bankruptcy;
- Numerous utilities suffered large decreases in stock value; and
- Decades of litigation led to more than $100 million and untold man-hours being spent litigating these disputes.

The economic consequences of a utility's decision to develop a nuclear power plant turned out to be a "bet the company" decision which many utilities made and lost. These projects led to long and contentious regulatory proceedings, often resulting in multi-year delays before costs were put into rates. Many utilities spent tens of millions of dollars each pursuing rate recovery and defending themselves in prudence proceedings. Without interim rate relief for the utilities, these delays further exacerbated the economic impact as allowance for funds used during construction (AFUDC) continued to accumulate on the construction work in progress (CWIP) balances.

Q. What was the regulatory basis for the series of prudence disallowances?

A. The lack of a clear basis for prudence determinations was part of the problem. The regulators looked at everything from truly "dishonest, or obviously wasteful or imprudent actions"[19] to results-oriented hindsight reviews which determined whether plants turned out to be economic a decade or more after construction was begun.

Q. Would you describe in greater detail the state level regulatory policies that contributed to these disallowances?

A. Certainly. While there was an array of contributing factors, the key problems stemmed from state regulatory processes that abandoned traditional standards of prudence *after* billions had been spent.

In addition, some of the rate-making principles, such as the used and useful standard, whereby a utility had to get a plant into service in order for it to be included in rate base, understandably led to some irrational choices on the part of utilities. The economic incentives were not aligned between the utility and its customers. While some choices regarding plant construction were understandable and rational from a utility management perspective, they were neither rational nor wise from a customer perspective.

Across the industry both the prudence review process and the economic alignment between the parties need to be corrected for the next generation of

[19] This was the U.S. Supreme Court standard in effect at the time. *Missouri ex. rel. Southwestern Bell Tel. Co. v. Public Service Commission*, 262 U.S. 276 (1923), separate concurring opinion of Justice Brandeis.

nuclear plants to be successfully pursued and result in a cost-effective and environmentally- acceptable resource.

Q. Were any specific prudence standards applied?

A. Yes; however, the standards used by regulators evolved from traditional prudence reviews to include also an "economically used and useful" standard which, based on hindsight determined what portion of a plant's prudently incurred cost was "economically" useful in providing service to customers. The recovery of prudently-incurred costs was further narrowed by the adoption of more onerous standards such as an "economic benefits test" and eventually simple "risk sharing," whereby costs were simply declared unrecoverable on the basis that the total cost was too large for customers alone to bear the burden.

Q. In what ways were these various prudence tests problematic?

A. Generally, the concern with application of these various standards was that they were developed and applied *after* the plant was committed to and largely built. In addition, these various tests were used to incrementally diminish the amount of investment that utilities could include in rate base. For example, in the Wolf Creek case before the Kansas Corporation Commission (KCC), the KCC ultimately approved the following set of disallowances as shown in Table 3, below:

Table 3: KCC Treatment of Wolf Creek Costs

	($ Million)
Total Plant Cost	$2,904.0
Imprudence Disallowance	$256.1
Excess Capacity Disallowance	$1,524.1
Economic Value Disallowance	$411.2
Total Disallowance	$2,192.3
Fully Recoverable Costs	$711.7

The KCC did eventually allow for partial, delayed recovery of the excess capacity and economic value disallowances through depreciation expense over the life of the plant.[20]

Q. What was the magnitude of the nuclear disallowances imposed on utilities?

A. Table 4 below summarizes some of the largest disallowances by plant and illustrates the magnitude of the issue faced by the utility sector.[21] While the total disallowance from these 26 plants is a staggering $18 billion (in mid-1980s dollars), the fact that six units had an aggregate disallowance of $10 billion highlights the underpinnings of the current market-perceived risk as new nuclear generation is pursued.

[20] R.J. Rudden Associates, Inc., "Nuclear Prudence Reviews: Retrospective and Commentary", April 1987, p. IV-5.

[21] Thomas P. Lyon and John W. Mayo, "Regulatory Opportunism and Investment Behavior: Evidence From the US Electric Utility Industry", June 2000, p. 46.

Table 4: Cost Disallowance by Plant ($Million)[21]

Unit	Utility	Disallowed
Nine Mile Point 2	Multiple	$ 2,141
Diablo Canyon 1&2	Pacific Gas & Electric Co.	$ 2,000
Wolf Creek 1	Multiple	$ 1,618
Shoreham 1	Long Island Lighting	$ 1,395
Comanche Peak 1&2	Texas Utilities	$ 1,381
Fermi 2	Detroit Edison Co.	$ 1,310
River Bend 1	Gulf States Utilities Co.	$ 1,297
Susquehanna 1&2	Pennsylvania Power & Light	$ 847
Clinton 1	Illinois Power Co.	$ 665
Perry 1	Multiple	$ 665
Seabrook 1	Multiple	$ 646
Vogtle 1&2	Georgia Power co.	$ 541
Hope Creek 1	Multiple	$ 512
Callaway 1	Union Electric Co.	$ 414
South Texas 1&2	Houston Lighting & Power	$ 376
Limerick 1	Philadelphia Electric Co.	$ 369
Millstone 3	Multiple	$ 353
Waterford 3	Louisiana Power & Light	$ 284
Braidwood 1	Commonwealth Edison Co.	$ 278
San Onofre 2&3	Multiple	$ 252
Grand Gulf 1	Multiple	$ 246
Palo Verde 1-3	Multiple	$ 188
Byron 2	Commonwealth Edison	$ 181
Beaver Valley 2	Multiple	$ 125
Summer 1	South Carolina Electric & Gas	$ 123
Byron 1	Commonwealth Edison	$ 102
TOTAL		**$ 18,308**

Q. Can you quantify the economic loss associated with the application of various prudence and economic benefits tests as applied to the last generation of nuclear plants?

A. The total economic loss is enormous but virtually impossible to quantify. It would include the investments that were disallowed, the impact on stock prices of the utilities, the cost of the various litigious proceedings in which

investment decisions were arbitrated, and the increased capital costs for utilities and their customers which were felt for years following these losses.

Q. How is it that the economic consequences were felt by customers when the various state commissions explicitly excluded costs from rate base?

A. While state commissions excluded those specific dollars from being collected, the overall effect of that loss was reflected in capital markets, and the resulting higher costs were incurred by utilities and ultimately included in the costs passed through to customers. In some cases, nuclear prudence disallowances led to the bankruptcy of the sponsoring utility. These regulatory actions put significant upward pressure on the cost of capital for virtually all utilities as the potential risk of a disallowance was considered by the market. As a September 1, 1988 article in Public Utilities Fortnightly pointed out, the early cancellations of nuclear plants (up until 1983) led to only modest stock price movements as compared to the Standard & Poors Utilities average, but those effects became much more adverse as the changing regulatory climate was observed and concerns spread about disallowances.[22]

Q. How did Florida's regulatory process, with respect to the last generation of nuclear plants, compare to the rest of the country?

A. My understanding is that three of FPL's four nuclear units went into rates without any disallowances or lengthy prudence process. St. Lucie 2, the last nuclear plant that FPL placed into service, was subjected to a detailed cost review, but the process did not result in a major cost disallowance. The fact

[22] Public Utilities Fortnightly, "Regulatory Issues in Nuclear Power Plant Cancellations", September 1, 1988.

that the Commission has not used onerous prudence reviews for FPL's past nuclear units is helpful, but the financial community remains wary of future proceedings based on the national experience with the last wave of new nuclear units.

Q. Have the flaws in the prior processes been recognized and addressed?

A. Yes, for the most part. The flaws in the processes were widely recognized and much was subsequently written about the possible ways of correcting these problems going forward. However, they have not been formally "addressed" insofar as no new nuclear plants have been proposed which would afford regulators an opportunity to rectify the approach and regulatory compact. One group that offered a comprehensive review of the past practices and made specific suggestions for the next generation was the National Regulatory Research Institute (NRRI). In its 1985 report, The Prudent Investment Test in the 1980's, NRRI recommended four guidelines for successful use of the prudent investment test. In summary those guidelines were:

i. Utilities should be afforded the presumption of prudence,

ii. Regulators should be prohibited from use of hindsight; the application of the prudence standard should be based on whether a decision was reasonable at the time it was made,

iii. Regulators should be prohibited from supplementing the reasonableness standard with other standards that look at the outcome of a decision, and

iv. Regulatory inquires should be factual inquiries and testimony should be based on facts, not opinion.

In addition to the NRRI report, there were many other contemporaneous acknowledgements of the flawed and frustrating prudence review process. The manner in which prudence cases were handled was recognized as likely to have an impact on future investors, as noted in a brief filed by Kansas Gas & Electric in the Wolf Creek case:

> ... there will come a time when Kansas Gas and Electric or some other Kansas company must build another power plant in order to assure an adequate and reliable supply of electric energy in Kansas. When that time comes, investors will have to decide if and at what price they are willing to invest in the Kansas electric energy infrastructure. One important factor in their decision making will no doubt be their memory of how the Wolf Creek rate cases were handled.[23]

Q. What actions if any, have been taken to correct those problems?

A. Virtually all nuclear industry segments are approaching this potential new generation of nuclear power plants with an eye toward correcting the flaws of the past.

[23] R.J. Rudden Associates, Inc., "Nuclear Prudence Reviews: Retrospective and Commentary", April 1987, p. V-11.

- Design/Build – Engineering and construction firms and equipment manufacturers are standardizing designs and, in some cases, initiating the NRC approvals to establish certified designs which can become the basis for subsequent Construction and Operating License (COL) Applications, thus facilitating the potential pace of the licensing process.
- National Regulatory – Federal efforts to alleviate delay and the cost of delay have been embraced both legislatively through incentives in the Energy Policy Act (EPACT) of 2005 and at the NRC with its COL process, described by other FPL witnesses.
- Industry Consortiums – Utility sponsors and technology vendors have formed industry consortiums, such as NuStart Energy, to collectively take the early steps in identifying how the deployment of new nuclear generation will be executed. These reviews have been conducted proactively and with the full cooperation of the NRC to work out many of the practical detailed issues related to meeting the requirements of 10 CFR Part 52. The consortiums are responsible for the development of two reference COLAs that are scheduled to be submitted in 2007.
- Utility Sponsors - Utilities have been working with all stakeholders to assess the opportunity for new nuclear facilities to meet the needs of their customers cost-effectively and in compliance with emerging environmental standards. In addition, these utility sponsors are beginning to make their filings at the federal level, and now with this

application at the state level to ensure that plans can go forward within a stable and predictable long-term regulatory framework.

Each of these groups is working toward offering a viable solution to the growing and competing needs nationwide for increased baseload electric generation, along with decreased GHG emissions and vulnerability to fossil fuel prices.

Q. Is the financial community prepared to support utilities embarking on construction programs for a new fleet of baseload nuclear generation?

A. Yes. The financial community recognizes that significant capital projects will be required to meet the growing national demand and will stand behind utilities engaged in developing these projects, so long as the risks are managed and prudent cost recovery is assured.

Specifically with regard to nuclear, the market in general, and rating agencies in particular, recognize the importance of environmental issues as well as traditional utility obligations in the coming decades and note the economic advantage that nuclear power can have in a carbon-constrained world.

> Climate change appears set to emerge as an overarching policy consideration that will affect how utilities procure resources, although issues of cost, system reliability, fuel diversity, and other factors can be at odds with carbon controls.[24]

[24] Standard & Poor's, Ratings Direct, "Which Power Generation Technologies Will take the Lead in Response to Carbon Controls?", May 11, 2007, p. 3.

These parties stand ready to support the commencement of a new nuclear development program with the appropriate regulatory and political assurances of cost recovery.

Q. Do you have reason to believe that rating agencies are concerned about regulatory support for cost recovery of large baseload units such as Turkey Point 6 & 7?

A. Yes. Rating agencies are concerned that the level of infrastructure investment needed to meet growing demand in an environmentally acceptable manner will create the same "perfect storm" of economic and political pressures that preceded the prudence disallowances and hindsight reviews of the past.

Moody's has noted:

> Conceivably, the combination of rising costs, higher infrastructure investment needs and larger or more frequent requests for rate relief could create pressure for future incremental rate relief from state regulators, or at a minimum, raise the uncertainty level associated with expected recoveries—thereby directly affecting one of our primary rating drivers. This potential for increased regulatory uncertainty and pressure for rate relief might peak several years from now, at precisely the time when many companies are completing their base-load generation construction projects or other non-discretionary infrastructure investment projects and

> the potential for rate shock to consumers would be highest. ...However, none of the issues currently facing the industry are new. In fact, the utility sector has faced an environment with eerily similar uncertainties in the past. The risk, in our opinion, is whether or not the experiences of the past will be repeated in the future. The most significant risk might be future disallowances of investments that were made with an understanding that those investments were prudent and necessary at the time they were made.[25]

Similarly Standard & Poors is very focused on the regulatory message:

> Standard & Poor's expects that the credit implications of building new nuclear plants will center on timely and on-budget construction and the ability to quickly recover capital costs with a reasonable rate of return. ...Until the plant goes into service, recovery of all or a majority of financing costs in rates, such as construction work in progress (CWIP) would not only demonstrate regulatory support and a willingness to provide ongoing support in the future, but also ensure that a utility's cash generation does not suffer. Just as important, such a provision would demonstrate clearly that regulators:

[25] Moody's Investors Service, Global Credit Research, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector", August 2007, pp. 1, 15.

- Share the utility's vision of building a new nuclear plant,
- View the construction of the plant as effectively addressing a utility's increasing demand, and are willing to provide the necessary political and financial support.[26]

Q. Does this support indicate that the Commission needs to essentially *pre-approve all* costs associated with the Turkey Point 6&7 project?

A. No. Both the Company and the financial market participants will look for the Commission to reasonably and appropriately apply the Nuclear Cost Recovery Rule and appropriate prudence standards, including those standards set forth in sections 403.519(4)(e) and 366.93, Florida Statutes. Standard & Poor's notes that it looks:

> .... for a regulatory framework that provides for a fair opportunity to recover prudently incurred costs, even through changing regulatory commissions. Without such a framework, a utility's financial condition may rapidly deteriorate.[27]

[26] Standard & Poor's Ratings Direct, "Why U.S. Utilities Are Seeing Nuclear Power In A New Light", January 9, 2007, pp. 9-10.

[27] Standard & Poor's, Rating Direct, "Which Power Generation Technologies Will take the Lead in Response to Carbon Controls?", May 11, 2007, p. 7.

However, all industry segments want to be assured that the standards will be not be revisited as the project progresses, thereby jeopardizing recovery of and return on investments that were deemed prudent by the Commission at the time they were made.

Q. What are some of the key elements of Florida's regulatory policy that will need to be embodied in Commission actions and orders to enable a cost-effective nuclear resource for FPL's customers?

A. FPL will need to be able to demonstrate throughout the development process that it has the support and backing of the state in general and the Commission in particular, and that such support will manifest itself in recovery of and on its prudently incurred costs in developing this non-GHG-emitting baseload resource. While the new nuclear cost recovery rule and approval of this request by FPL will be viewed as positive, past experience combined with the size of the financial commitment will continue to engender concern and skepticism from some financial market participants, as noted in the following statement:

> Investors are open and interested but still need to be convinced. The financial community has long memories. They lost tens of billions of dollars during the 1980s and 1990s when utilities built the current reactors.[28]

[28] Nuclear News, "High Cost Seen as Roadblock to New Nuclear Plants", March 28, 2007.

The Florida Commission and all other stakeholders need to be aware of the ongoing need to support the project and ensure a viable cost recovery mechanism for prudently incurred costs.

Q. Do you have particular recommendations regarding regulatory policy?

A. Only very generally at this time. First, the Commission should stand ready to re-affirm its policy initiatives that are codified in the Nuclear Power Plant Cost Recovery Rule, Section 25-6.0423, F.A.C. I note, however, that the market will be watchful and react with great swiftness and severe financial consequences if the Commission's administration of that rule is not consistent with market expectations.

Additionally, the following actions by the Commission would be supportive of this effort by FPL:

1. Having the Commission enunciate its policies regarding the application of prudence standards, so all parties know the rules as they embark on this process.
2. Implementing rules which would continue to allow pre in-service cost recovery so as to avoid the problems of hindsight reviews and to avoid the impact of spiraling AFUDC experienced in the past.
3. Acknowledging the likely rate impact of building the next generation of clean baseload technology; recognizing that the

higher cost associated with new nuclear baseload generation will not be used as a measure of imprudence for FPL and that it is understood that GHG reduction and energy security/diversity benefits will carry a cost premium.

4. Communicating to FPL and the financial community that the *quid pro quo* for the cost recovery assurances is that customers will have the right to expect that the nuclear development alternative will be deferred, modified or cancelled if market conditions, costs, alternatives or policies change so as to make the nuclear development option uneconomical or otherwise unattractive.

5. Embracing greater regulatory certainty to ensure that the utility will not be laden with a perverse incentive, seen in the past among other utilities, to press forward with completion of a plant simply to meet the used and useful standard, regardless of the results of updated demand, cost and technological data.

Q. You have noted that FPL is one of the first in the nation to have filed for state regulatory approval of a nuclear plant, and yet it is not first in terms of projected on-line date or in the queue at the NRC. How would you characterize FPL's approach to the approval process?

A. While I think either sequence (NRC first or State PSC first) is acceptable, FPL's approach is consistent with Florida's recent mandates in the resource planning process. The recent focus on GHG reduction and renewables

development will add a significant complexity to FPL's already significant task of resource planning for 20 years or more. In addition, as discussed above, the Company believes, and I share its belief, that no new nuclear baseload plant will be built in the next decade without some form of customer support, in the form of a reasonable assurance of recovery of prudently incurred costs. FPL is mindful of the financial market's need to see on-going state-level regulatory support for this type of project. Given this business context and the relative speed of the Commission's need determination process, it is reasonable to seek this approval in order to determine the financial viability for a decision to proceed.

Q. How do you expect the annual review process will affect the development of Turkey Point 6&7?

A. The Nuclear Power Plant Cost Recovery Rule, and the protections it appears to afford project sponsors, such as annual Commission reviews and approvals, timely cost recovery, and a commitment that costs once approved and determined to be prudent "will not be subject to disallowance or further prudence review," offers the necessary regulatory certainty to become a national example of an effective and equitable regulatory construct for enabling development of capital-intensive, environmentally-acceptable baseload resources. I would caution however that the rule is only as good as its application. Many of the failed regulatory processes of the past were the result of changing regulatory policies after the fact. Informed participants and observers are aware that the actions of one commission cannot bind future

commissions, and this knowledge and the vivid memories of the enormous disallowances of the past will require repeated reaffirmation of the Commission's cost recovery framework.

The Commission has promulgated the rules necessary to enable FPL to pursue this vital and valuable resource for its customers, and for all of the state's residents that benefit from reduced GHG emissions. The review process allows all parties to continuously re-evaluate and assess the "going forward" benefits. This reassessment will be viewed as a rational and constructive element in the regulatory process as long as FPL is at the same time assured of recovery of the prudently-incurred costs of preserving this option for customers.

Q. Does this conclude your direct testimony?

A. Yes.

BY MR. BUTLER:

Q Would you please summarize your direct testimony for the Commission, Mr. Reed?

A Certainly. As I have said, I am the Chairman and Chief Executive Officer of Concentric Energy Advisors and CE Capital. My background includes providing expert testimony on economic and financial issues related to the energy industry on more that than 100 occasions over the past 30 years.

The purpose of my testimony here is to provide my analysis of the appropriateness of FPL's proposal to pursue the development of new nuclear generation from both a resource planning and a public policy perspective. My conclusions are as follows: First, while the precise timing and details remain uncertain, we should expect that there will soon be some form of greenhouse gas regulation. Whether it is federal, regional, or state regulation, this regulation is likely to include requirements for significant GHG reductions within FPL's current resource planning horizon.

Florida's electric demand growth is among the highest in the nation, and Florida's indigenous resources which can be used for renewable generation, for example, hydro, wind, wood, solar, and geothermal, are not abundant and are economically disadvantaged by higher than average costs and lower than average capacity factors.

At the same time, fossil fuel prices have risen

dramatically, and natural gas and fuel oil price volatility has increased significantly. The cost of alternative baseload generating technologies, likes new nuclear and IGCC, are still evolving in this time frame.

The renewable resources that are available to FPL are largely unable to meet baseload generating needs. But, more importantly, renewable resource projects should not be viewed as a competitive alternative or threat to the development of new nuclear resources. Florida needs to maximize the economic development of both resource types.

In this environment of heightened uncertainty, the addition of new nuclear resources could be a major step towards the decarbonization of FPL's resource mix and achieving any GHG reductions targets, as well as providing needed baseload generating capacity, greater reliability, and a more robust fuel mix. It is clear that if FPL does not commit to at least enabling this alternative now, new nuclear resources will not be available to FPL and its customers within the next 15 years or more. Preserving this option has significant value in and of itself and deserves your approval.

Even with all of the federal support that has been developed to encourage nuclear power's renaissance in the United States, it is unreasonable to expect any regulated utility to pursue this option under the regulatory regime that existed 20 years ago when the last group of nuclear power

plants became operational. The nuclear prudence cases of that era, which consumed years of hearing time and cost utility investors more than $18 billion in disallowances, left a lasting impression on all who participated in those processes.

As one of those participants, I fully endorse FPL's proposed approach to creating an option for new nuclear resources. This approach substitutes an open options-based collaborative and comprehensive resource planning process instead the all or nothing used and useful regulatory paradigm that existed in the 1980s.

This new regulatory paradigm asks the Commission to engage in active and near realtime reviews of FPL's decisions beginning with this case. The proposed process permits rational and economically efficient decision-making and aligns customer and investor interests far better than the regulatory processes of the 1980s did. In exchange for a high level of assurance of recovery of prudently incurred costs, FPL's customers will benefit from a process that provides assurance that uneconomic projects will not be pursued, and that allows FPL to continue to secure capital on reasonable terms.

The utility industry, the nuclear power community, and the financial community are all closely watching this proceeding and have high hopes for the successful implementation of this framework. Approval of this need petition is an appropriate and important first step in

achieving that success. Thank you.

MR. BUTLER: Thank you, Mr. Reed.

I tender the witness for cross-examination.

CHAIRMAN CARTER: Thank you. Mr. Krasowski.

MR. KRASOWSKI: Thank you, Mr. Chairman.

CHAIRMAN CARTER: You're recognized.

CROSS EXAMINATION

BY MR. KRASOWSKI:

Q Hello, Mr. Reed.

A Hello.

Q My name is Bob Krasowski, and I am here with my wife, Jan, and we are ratepayers and customers of FPL, and we have an interest in energy policy, and have taken the opportunity to participate in this hearing in order to have the opportunity to ask questions of people who have submitted pre-testimony. So we look forward to the opportunity of talking to you today.

A I look forward to it, as well.

Q Thank you, sir.

If we could go to your prefiled testimony, Page 4, Lines 1 through 3.

A I have that.

Q You refer to Florida's indigenous resources, and I have two questions, but let me ask you about one.

What do you mean by geothermal?

A Geothermal is the ability to tap into the heat energy

in the earth's crust.

Q How would you classify the type of geothermal that allows for heating and cooling by the use of the earth's temperature to mitigate the need to heat or cool from the existing temperature outside?

A Well, I think we may be talking about different things. Geothermal here to me is essentially tapping hot water and steam sources underneath the earth's crust. I think you may be talking about what are generally referred to as ground source heat pumps, or end use technologies. Not generation technologies, but end use technologies that provide a basis for reducing energy consumption. Those are different things. This refers to renewable generating technologies for electric generation.

Q Yes, you're correct in your understanding of my understanding of the question I'm asking you.

So what is your assessment of the availability of the heat pump geothermal type that I'm asking about to customers in Florida to mitigate the need for electricity?

A I think that technology is emerging. Again, it's not a generation technology, it is really more of a DSM or conservation measure, an energy efficiency measure. But it is a technology that is still developing.

Q I notice you comment on solar energy in your testimony. But, once again, on Page 4, Lines 1 through 3, you

don't list solar as a resource, an indigenous resource in Florida. Could you speak to that?

A Yes. The potential for grid connected solar generation in Florida is actually quite limited. There are a lot of programs, as you know, for rooftop solar for end use applications, but not for grid connected generation. So, as a vehicle for, again, providing the need we are addressing in this case, baseload generation on a large scale, right now solar technology does not provide that opportunity within Florida.

Q Thank you. Are you familiar with the Ausra Company?

A In general terms. I am familiar with the joint venture that they have with FPL in very general terms.

Q What opportunities now and in the future might they present for mitigating the need for peak load and then also contributing to baseload generation?

A I think Witness McBee probably would have been the best witness to speak to that. I would say, again, that is still in the development stage and not on the large scale format. But, again, the point I would make is that the resource plan for FPL certainly has the ability to accept all of the contribution that those types of programs can make to the generation mix without doing anything to reduce, or obviate, or eliminate the need for new baseload generating resources like the Turkey Point plants.

Q Thank you.

Are you familiar with the RIM standards test that is used to determine which DSM programs to pursue in Florida?

A In general terms.

Q Thank you. Are you familiar with the amount of participants -- let me rephrase this.

MR. KRASOWSKI: Mr. Chair, I have a document here that has been submitted already that identifies the percentage rate of participants.

CHAIRMAN CARTER: Hang on a second. Let's see what document you are talking about there. Is it an exhibit that has been introduced already?

MR. KRASOWSKI: Yes, sir. It is Interrogatory Number 76.

CHAIRMAN CARTER: One second.

MR. KRASOWSKI: Sure.

CHAIRMAN CARTER: Okay. That would be on Staff's Exhibit Number 14, and that is Interrogatory Number 4, which covers Number 75 through 79.

MR. KRASOWSKI: Okay. Well, this is Number 76, Page 1 of 1, and it is the chart that Mr. Brandt and I discussed in terms of percentages. And what I would like to do --

CHAIRMAN CARTER: Hang on a second. Staff, do you have a copy of this document that Mr. Krasowski is referencing? Just hang on. We may have a copy, Mr. Krasowski. Give one to

the witness. Okay. That's fine.

Commissioners, it's in our documents already.

Okay, Mr. Krasowski, you made proceed.

BY MR. KRASOWSKI:

Q Are you familiar with this document, Mr. Reed?

A No, I have never seen it before.

Q Are you familiar with the content of the document?

MR. BUTLER: Mr. Chairman, I'm going to object to the questions as irrelevant to Mr. Reed's testimony. He just testified he hasn't seen the document before. Mr. Krasowski addressed it with our Witness Brandt yesterday, who is very familiar with it. I don't see what this is adding.

CHAIRMAN CARTER: I'm going to have to sustain the objection. You won't you able to use this witness for this. He said he is not familiar with it, so you won't be able to ask him any questions pertaining to it.

MR. KRASOWSKI: Okay. I was going to try to pursue the content of the document, but as you are directing, I will move on.

CHAIRMAN CARTER: No problem.

MR. KRASOWSKI: So we can just forget that for now.

BY MR. KRASOWSKI:

Q Are you familiar with Florida's DSM programs?

A With FPL's programs?

Q Yes. Well, actually, they are true to all

investor-owned utilities in Florida. The PSC sets the demand-side management programs from my understanding, but let's stay specific to FPL.

A Again, in general terms I'm familiar with their programs.

Q Okay. Are you familiar with what percentage of people participate in those programs?

MR. BUTLER: Same objection as before. This is way beyond the scope of Mr. Reed's testimony and is a subject that could be and actually was pursued with the witness who is more appropriate for it.

MR. KRASOWSKI: Mr. Chair --

CHAIRMAN CARTER: Hang on a second, because I remember this line of questioning yesterday, and let me look at my notes, because I remember -- Mr. Butler, which witness was that?

MR. BUTLER: That would have been Mr. Brandt.

CHAIRMAN CARTER: Mr. Brandt. Yes, we went through that with Mr. Brandt, so I'm going to have to sustain the objection.

MR. KRASOWSKI: Mr. Chair, in his testimony he speaks of the DSM programs in Florida and relates a lot of his assumptions based on what he knows about it.

MR. BUTLER: Would you refer us to the page and line reference and perhaps that will clarify it for me. Perhaps I

won't have the objection, but I need to have it grounded in Mr. Reed's testimony.

MR. KRASOWSKI: It's on Page 5 and 6.

CHAIRMAN CARTER: Hang on a second. Don't ask any questions here, just hold up. Hold up. Page 5 and 6.

Mr. Butler, I'm going to look to you to see if this purports to --

MR. BUTLER: I will withdraw my objection for the moment and see if these questions are legitimately related to Mr. Reed's brief discussion of DSM.

CHAIRMAN CARTER: Okay. Mr. Krasowski, you're recognized, sir.

MR. KRASOWSKI: Thank you, sir.

BY MR. KRASOWSKI:

Q Mr. Reed, in your testimony you refer to the DSM programs FPL has, and I was curious to know if -- let me rephrase. Okay. We will pass on this, I'm sorry. We have already asked what we were going to ask, so let's forget it.

CHAIRMAN CARTER: That's okay. I know you had a great discussion with Mr. Brandt yesterday. Very informative, by the way.

MR. KRASOWSKI: A very positive exchange.

BY MR. KRASOWSKI:

Q Mr. Reed, do you include nuclear power in your non-greenhouse gas emitting category? And let me direct you to

Page 6, Line 1 through 3.

A Yes, I do include nuclear power in the category of new non-GHG emitting baseload resources.

Q Could you qualify that statement as far as nuclear power being non-greenhouse gas emitting?

A I'm not sure what you mean by qualify it.

Q Well, if I can explain. What we're looking for is could you speak to the issue of full understanding of the nuclear fuel cycle as it relates to greenhouse gas emissions?

A I think I can -- I understand your question now. I think I explain that. My answer here is limited to the production of electricity from the plant. It's not by what one would call a fuel cycle or a life-cycle analysis. As we have said and as other witnesses have said, all human activity produces greenhouse gases. Respiration, people breathing produces greenhouse gases. But when we are comparing them to the magnitude of what is produced in a coal plant or even a gas plant, those are truly de minimis. So my statement here is based upon the production of electricity at the plant, not on the fuel cycle or a life-cycle analysis.

Q Thank you. Thank you, Mr. Reed.

You identify the fact that there is a target in Florida to reduce greenhouse gas levels to 2000 levels by 2017. This is Page 9, Line 20.

A Yes.

Q Since these power plants aren't projected to come on line until 2018, how do you suggest that will be accomplished?

A Well, of course, what you have reviewed there are the standards established or proposed by Governor Crist for 2017, 2025, and 2050. These plants are not going to help, on their own, to get to the 2017 target, but they will be very important to continue to meet that target past 2017 and have any chance of getting towards the 2025 or 2050 targets.

Q Okay, thank you, sir. Page 10, Line 1 through 3. Are you aware that what is now identified as renewable resource power generation in Florida is primarily waste-to-energy facilities?

A Yes, that is the largest component of the total.

Q Are you familiar with the greenhouse gas and other emissions from waste-to-energy facilities?

A In general terms, yes.

Q Do you agree that waste-to-energy facilities represent renewable resources?

A They are renewable in terms of their fuel source, both biomass plants as well as MSW plants. Some states consider MSW to be renewables, others do not. I think all states consider biomass plants to be renewable.

Q On Page 10, as well, Lines 12 to 15. I would like to ask you, Mr. Reed, are you familiar with Doctor Diaz's testimony of yesterday?

A Yes.

Q In your testimony, you say on Line 15 that there is no cookie cutter or shortcut approach to getting a nuclear facility built and operational. But yesterday Doctor Diaz mentioned that the standardization of design is important. Could you speak to that?

A Yes, it certainly is important.

My point here was that even once you get beyond the reference case at the NRC for any plant design, or get any design certified you still have a lot of site-specific issues and you still have obviously issues related to need and environmental impacts that are very local or regional. The process is going to take a substantial amount of time, even if you move forward with an approved design.

Q Okay, thank you. On Page 11, Lines 3 through 10. I would just like to ask you, are you familiar with Florida's distributed energy efforts?

A Again, I'm generally familiar with FPL's distributed energy efforts.

Q Are you familiar with the Florida Solar Energy Center?

A I have seen reference to it, yes.

Q Are you familiar with their renewable energy research?

A In general terms.

Q Thank you. On Page 13, 5 through 14. Okay. I'll pass on that. I think you have said what -- made your position known.

Page 21, Lines 4 through 8. Could you specify what project, ocean current project you are referring to in this paragraph?

A It is the one that Ms. McBee referred to with the university co-sponsoring it.

Q Do you know of any utilities that are working on research in the same -- along the same lines as tapping ocean currents for power?

A No, not yet. The other research that is going on, which is primarily in the Pacific Northwest, is researched being conducted by vendors and by universities. I'm not aware of any other utility that has gone as far as FPL has on this item.

Q Are you familiar with the matrix that was developed to compare nuclear to other available technologies for the generation of the power need we see?

MR. BUTLER: What matrix are you referring to, Mr. Krasowski?

MR. KRASOWSKI: The one that compares -- I'll withdraw that question. It's not in his testimony. Sorry.

Thank you very much, Mr. Reed. We appreciate your comments. Those are all the questions we have for now.

THE WITNESS: Thank you, Mr. Krasowski.

CHAIRMAN CARTER: Thank you. Commissioners, obviously I will come back to you after staff, but at this point in time are there -- after staff? Okay.

Staff, you're recognized.

MS. FLEMING: We don't have any questions for this witness. Thank you.

COMMISSIONER SKOP: That was quick.

CHAIRMAN CARTER: Commissioner Skop, you're recognized.

COMMISSIONER SKOP: Good afternoon, Mr. Reed. How are you?

THE WITNESS: Good afternoon, Commissioner Skop.

COMMISSIONER SKOP: Just one quick thing. Not to belabor the point, but, again, if I could draw you to Page 21 of your testimony, prefiled testimony. And, again, I believe that you mentioned you are familiar with Ms. McBee's comprehensive testimony.

THE WITNESS: That's correct.

COMMISSIONER SKOP: When you speak to the wind potential in Florida, you mentioned there is some potential, but it is quite modest. And also you relate the state is ranked as wind power class one, which equates to essentially zero winds resources. And then you speak that the only measurable wind resources are offshore. Again, I don't want to

get in a big debate, but I was trying to print something to suggest that perhaps that is not consistent with Ms. McBee's testimony to the extent that I think that she spoke to different wind studies and some coastal wind resource capability.

And would you admit that -- I don't want to put words in your mouth, but would you suggest that there may be other studies that would support that Florida does have a marginal wind resource along the coastal areas?

THE WITNESS: Yes, I would describe it as marginal on the coastal areas. I can accept that.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Thank you. Any other Commissioners?

Mr. Butler, we need to -- do you want to redirect?

MR. BUTLER: No, no redirect. I was just going to move the exhibits.

CHAIRMAN CARTER: I was reading your expression. That would be --

MR. BUTLER: We move Exhibits 87, 88, 89, and 90 into the record.

CHAIRMAN CARTER: Any objections? No objections, show it done.

(Exhibits 87 through 90 admitted into the record.)

CHAIRMAN CARTER: Commissioners, I think that as we

get prepared to -- I really look forward to getting the other information that we had in the late-filed exhibits and get those and incorporate it within the confines of our docket here, and let staff have an opportunity to go through it and review it and make their recommendations. And we can individually make our own.

But I do look forward to an opportunity for us to go forward in this bold new frontier in Florida. Because, in my opinion, the bottom line is we have got to keep the lights on. You know, we have got to keep the lights on. And we have got some good information; there is still more information to be gathered. And I really look forward to reading staff's recommendation. I really look forward to reading the additional late-filed exhibits that we have admitted today.

I want to thank -- first of all, Commissioners, with your indulgence I want to thank all of the parties that participated. FPL, the Office of Public Counsel, the Krasowskis, Jan and her driver, Bob. Thank you for your participation. To the witnesses, to our staff, the finest staff in the country, for your deliberation and your dedication to duties.

Before we have our final recommendation from staff about briefing and scheduling and all like that, I did want to take a moment to make some comments and then have an opportunity for our Commissioners to have some comments.

So, with that, Commissioner Edgar, you're recognized.

COMMISSIONER EDGAR: Thank you, Commissioner Carter, Mr. Chairman.

I have, if I may, one question and then a brief comment. And my question would be when we were -- gosh, it seems like weeks ago, so I don't remember if it was yesterday or the day before, but at one of the days earlier in this proceeding, we had some discussion, and I think we had asked staff to work with the parties with the possibility of maybe some different language coming forward for consideration on Issue 9. And I'm just wondering if that is something that would come forward, if, indeed, there is that possibility at the agenda conference, or come forward with briefs, or if it is the sort of thing that staff will continue to work on, and just wondering where we are kind of in that direction.

CHAIRMAN CARTER: Okay. Excellent question. I'm sorry, I overlooked that, Commissioner. Thank you for bringing it to my attention.

Staff? Mr. Cooke.

MR. COOKE: Commissioners, we have had discussions, but we haven't got any proposed changes to present. We believe the issue should go forward as it is at this point. We will continue to have discussions with the parties to the point of seeing if there can be a stipulation at some point, but right now it is the way it is.

COMMISSIONER EDGAR: Can I ask a follow-up question, Mr. Chairman?

CHAIRMAN CARTER: You're recognized.

COMMISSIONER EDGAR: Realizing that when we gather together the next time to talk about this issue, that will be a post-hearing, closed, no participation from the parties. If discussions go on between staff and the parties on this point, and any other, would that then be included as maybe discussion in the staff recommendation? Or I'm just wondering procedurally if, indeed, there is some other language that the parties are interested in us reviewing, how that would come before us?

CHAIRMAN CARTER: Mr. Cooke, before you respond, what I would think, Commissioner, is that, first of all, as staff continues their discussion, we certainly want to make sure that the Office of Public Counsel is part of this discussion and this dialogue. And I think that when that is the case, then with that participation, both from the Office of Public Counsel, then whatever recommendation is brought to us is something that -- you know, we won't have to go through that litany, did you talk to the Public Counsel, what did the Public Counsel -- we won't have to do that. So whatever recommendation we have will be fully, you know, disclosed among all the parties.

COMMISSIONER EDGAR: Absolutely. And when I said

staff discussion with the parties, that meant all the parties, which certainly included OPC.

CHAIRMAN CARTER: And I cut you off, but I was going to let Mr. Cooke respond, and then Commissioner Skop would like to respond -- speak on this issue, too. But I did want you to finish your question before I cut Mr. Cooke off.

COMMISSIONER EDGAR: Thank you.

And the point I was trying to get clarification of just in my own mind, maybe inartfully, is, Mr. Cooke, you have told us that discussions may still go on between staff and all the parties. And, again, I'm just wondering how, if indeed, how the product of those discussions would come to us for potential consideration.

MR. COOKE: Thank you, Commissioner.

The normal process would be likely to be in the form of a proposed stipulation among the parties that we likely would present at the final decision-making agenda for approval or not by the Commission. That's the normal course of what we would be talking about at this stage.

And there has been discussion with OPC, and we need to involve other parties, as well, to the extent they are willing to participate, and see if the parties can reach a stipulation. And in that case if there is one reached then we would bring that to the Commission.

COMMISSIONER EDGAR: Thank you.

And just to close out my thought on that. We did have some discussion, we had a number of questions, I know there was a desire from all of the parties to try to help us clarify the answer to some of those questions, and so I'm very pleased to know that staff will continue to work on that. And I look forward to seeing any product, if, indeed, one may be arrived at. And that's my only question. Is it time for comment, or should I yield?

CHAIRMAN CARTER: We will come back for your comments. Yield for a question, because in this area -- I think Commissioner Skop had a question or comment on this particular area.

COMMISSIONER SKOP: Thank you, Chairman Carter, I appreciate it.

I just wanted to ask FPL -- because, again, it's my understanding as represented by our General Counsel that the parties have been maybe engaging in some discussions. And, again, I think where we left it yesterday was that certainly we wanted to find some compromise language or something that our colleagues could all be comfortable with. And I just wanted to -- because, again, I don't have the opportunity of picking up the phone and calling you guys, I have to do it here.

CHAIRMAN CARTER: That could be a problem.

COMMISSIONER SKOP: Yeah, that could be a problem, that's why I don't go there.

But, essentially, I just wanted to ask publicly whether, you know, as the issue was framed, it essentially spoke to making a payment directly to the forgery and is that something that is still a possibility under the existing language or is it something that -- I mean, can you just give me a status of kind of where you guys are at.

MR. LITCHFIELD: Commissioner Skop, this is Wade Litchfield for Florida Power and Light. That is a fair question.

And I think as among Office of Public Counsel and staff, we are comfortable -- and Florida Power and Light, we are comfortable with the wording of the issue remaining as it stands, provided that there is at least an implicit notion within the construct of that issue that the payments, in fact, could be made to a vendor who would be then be remitting the payment to Japan Steel Works itself. So whether the payment is direct or indirect, we would hope that for purposes of disposing of this issue that it would be treated equivalently.

COMMISSIONER SKOP: Thank you.

And, again, I do think that, again, it is predicated by a need determination and not predisposed to one way another or on that. But I do think that if it is predicated by affirmative determination of need, it is a very important issue, I think, for this Commission to address should we come to some consensus language to the extent that it does show a

commitment to having a stable regulatory environment for nuclear construction in Florida.

So, thank you.

CHAIRMAN CARTER: Thank you, Commissioner.

Now we are in our comments phase.

MR. BUTLER: Before we get to that, a very minor housekeeping matter. Could Mr. Reed be excused?

CHAIRMAN CARTER: Sorry, Mr. Reed.

MR. BUTLER: Thank you very much.

CHAIRMAN CARTER: We took in his exhibits?

MR. BUTLER: We took in the exhibits, I just didn't ask for him to be excused and we just skipped over that.

CHAIRMAN CARTER: You may be excused, Mr. Reed. Sorry about that.

We are now in the phase of Commissioner comments, and then at the end, after we finish our comments, then I will come back to staff for the briefing schedule and all.

Commissioner Edgar, you are recognized.

MR. KRASOWSKI: Mr. Chairman, if I may. Bob Krasowski, intervenor, with Jan here. We would just like to understand that we are the only party that has identified a no response to Number 9, and have presented an explanation of our position, so I am just curious to know if we will be included in the future discussions.

CHAIRMAN CARTER: Absolutely.

MR. KRASOWSKI: Okay, thanks. We hadn't heard our name mentioned, and in that frenzy of --

CHAIRMAN CARTER: Commissioner Edgar said all the parties. I don't know if you got that. She said all the parties.

MR. KRASOWSKI: Sorry. I might have missed that.

CHAIRMAN CARTER: That's okay. That's all right. It's a beautiful and lyrically sounding name, Krasowski. You know, I know you like hearing it, but --

MR. KRASOWSKI: Thank you, Mr. Matthew Carter.

CHAIRMAN CARTER: It rolls off your tongue, doesn't it?

MR. KRASOWSKI: It's wonderful. I see how you got to where you are.

CHAIRMAN CARTER: You will be involved in all portions of the proceedings.

MR. KRASOWSKI: Thank you. Thank you very much.

CHAIRMAN CARTER: Commissioner Edgar, you are recognized.

COMMISSIONER EDGAR: Thank you. And to follow up from that, what I wanted to begin by saying is just as you did, but to repeat, I want to say thank you to all the parties. I have said it many, many, many times. Our processes and our decisions are best when we have full and diverse participation, and hearings are certainly more beneficial to me when we have

intervening parties who help us flesh out the record and flesh out the issues, and that includes OPC and Mr. and Mrs. Krasowski. And, of course, in other proceedings when we have multiple parties participating, I think that is a very, very good thing and very, very helpful. So, thank you to all the parties.

MR. KRASOWSKI: Thank you. We agree with you 100 percent that the more the better. Thank you.

COMMISSIONER EDGAR: And as to a little more of the larger issue at hand, as has been stated, this the first proceeding that this Commission has under a new statute, and we are learning as we go. I think it is incredibly interesting, fascinating, and I am very, very proud, personally, to be a part of how Florida moves forward on our energy policy. And I think that this proceeding is a very important part of that, and I would just come back to when I am doing my consideration over the next few weeks, and the briefs, and the next stages of the process on this, I'm going to focus back to the statutory criteria in Issues 1 through 8, what does this project do as proposed for reliability, for fuel diversity, for baseload generating capacity, for adequate electricity at a reasonable cost. And I think that that is probably where we all are trying to go and to accomplish. So, again, thank you. Thank you for everyone's patience, and thank you for not rolling into Monday. And it has been good day.

CHAIRMAN CARTER: Thank you, Commissioner.

Commissioner McMurrian.

COMMISSIONER McMURRAN: Thank you, Chairman. I don't have very lengthy comments. I will just thank everyone for providing the information that helped clarify the issues before us, and we look forward to the next part of the process, which is reviewing all the information that you have helped put into the record and moving forward to the decision. And thank you particularly to our staff, who have worked a lot of long hours to get us where we are today. Anyway, I appreciate it, and thank you all.

Thank you, Chairman.

CHAIRMAN CARTER: Thank you, Commissioner.

Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Can you hear me?

CHAIRMAN CARTER: We can now.

COMMISSIONER ARGENZIANO: Well, first of all, let me say hopefully some day -- I really hope to see you all soon, and I really appreciate the accommodation. Because not only do I look kind of weird, having an allergic reaction to the drug they gave me to make me feel better, but I probably would have been very disruptive in the hearing room, and very loud. So I appreciate the accommodation.

I also want to thank everybody for participating and staff for doing an excellent job, and really am looking forward

to gathering more information, and more input is always better, and moving this along to where we need to be.

CHAIRMAN CARTER: Thank you, Commissioner.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Chairman Carter.

And, again, I just want to echo the views of my colleagues. Again, I would like to thank all the parties. The Krasowskis, you guys did an admiral job for not being practitioners in representing your intervention interests and the parties. Staff, legal staff, a tremendous job. We had quite a lot of things going on getting up to the prehearing and the intervention order, so I would like to recognize all my legal staff, and technical staff, and our General Counsel for all their assistance in getting us through this process.

And, again, I don't want to be predisposed to our decision, because it will reflect the staff recommendation whatever that may be. But I look forward to ultimately bringing this forward, back to decision, and see where we go from there. So, thank everyone again.

CHAIRMAN CARTER: Excellent, excellent. And there is a group of people who are not here with us now, but I do on behalf of my colleagues, and I from the depths of my heart I sincerely appreciate the amount of public participation that we had both down in Miami and here in Tallahassee. The process works better when the people are involved.

And I think that when people feel like they have got a fair shake in the decision, you know, then they feel like it may be more palatable. It may not be approved, but at least they feel like they got a fair shake. I am just pleased about our process on how we allow the public to participate. And they are not here now, but they were here for the public testimony portion both in Miami and here in Tallahassee, and I just want to thank them for their support, because when the public is involved then government is better run.

With that, staff, recommendations and close out for our housekeeping matters on briefings and, et cetera, et cetera, et cetera.

MS. FLEMING: Thank you, Chairman.

The briefs are due February 15th, which is two weeks from today. The staff recommendation is scheduled to be filed March 6th, and this will be heard, the posthearing recommendation will be addressed at the posthearing agenda on March 18th.

CHAIRMAN CARTER: Mr. Krasowski, did you get those dates? Were you able to get those?

MR. KRASOWSKI: Yes, we did.

CHAIRMAN CARTER: Excellent. It has been a great day, guys and dolls. It is a wonderful day, and we are here on the forefront of a bold and courageous new frontier. I look forward to reading your report. I look forward to making a

decision. And, again, Commissioners, thank you for your participation. We are adjourned.

(The hearing concluded at 2:35 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

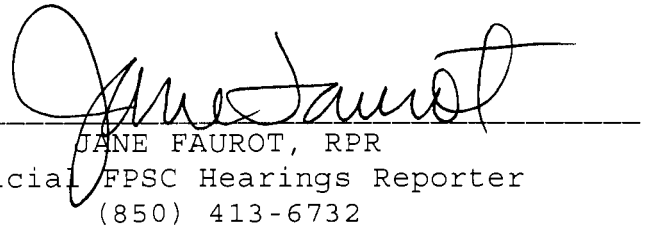
COUNTY OF LEON)

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 4th day of February, 2008.



JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
Service Hearing Exhibits				
1	Jon Burgess	Service Hearing Exhibit #1	Resolution No. 2007-12-153 of the City Council (Homestead) signed December 17, 2007	
2	Nancy Lee	Service Hearing Exhibit #2	Map (Turkey Point – Miami)	
3	Mary Olson	Service Hearing Exhibit #3	Comments & Supporting Documents (Nuclear Information & Resource Service)	
4	Mark Oncavage	Service Hearing Exhibit #4	Comments & Supporting Documents (memos from Meetings & Public Hearings)	
5	Deb Arnason	Service Hearing Exhibit #5	Comments & Supporting Documents (Newspaper & Magazine articles, Electric Ratepayers Resolution)	
6	George Cavros	Service Hearing Exhibit #6	Comments & Supporting Documents (Articles, Workshop, & Report)	
7	Jen Rock	Service Hearing Exhibit #7	Poster	
8	Steve McGonigle	Service Hearing Exhibit #8	Comments & Supporting Documents (Nuclear Regulatory Commission)	
9	Sharon Griemsman	Service Hearing Exhibit #9	United Way of Miami-Dade Statement	
10	Laura Sue Wilansky	Service Hearing Exhibit #10	Comments & Supporting Documents (The Silver Nightingale)	
11	Cathy Gilbert	Service Hearing Exhibit #11	Comments & Supporting Documents (Green Party)	
12	Suzette Rice	Service Hearing Exhibit #12	Comments & Supporting Documents (The Tehran Times Daily Newspaper)	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 14
COMPANY FL PSC Staff Exhibit List
WITNESS Comprehensive Exhibit List
DATE 01/30/08

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
13	Steven Showen	Service Hearing Exhibit #13	Comments & Supporting Documents (Green Party)	
Staff				
14		Exhibit List	Comprehensive Exhibit List	
15		Staff's Composite Exhibits - stipulated	**Interrogatories** 1. FPL's Response to Staff's First Set of Interrogatories (Nos. 1-5, 8-23, including supplemental response to No. 3) *[Bates Stamp Nos. 000001 – 000074]* 2. FPL's Response to Staff's Third Set of Interrogatories (Nos. 28-30, 32-34, 36-41, 43-52, 54-60) *[Bates Stamp Nos. 000075 – 000129]* 3. FPL's Response to Staff's Fourth Set of Interrogatories (Nos. 63-72) *[Bates Stamp Nos. 000130 – 000154]* 4. FPL's Response to Staff's Fifth Set of Interrogatories (Nos. 75-79, 81-84) *[Bates Stamp Nos. 000155 – 000171]*	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			5. FPL's Response to Staff's Sixth Set of Interrogatories (Nos. 85, 87-97) *[Bates Stamp Nos. 000172 – 000228]* 6. FPL's Response to Staff's Eighth Set of Interrogatories (Nos. 107-112, 114) *[Bates Stamp Nos. 000229 – 000242]* 7. FPL's Response to OPC's First Set of Interrogatories (No. 1) *[Bates Stamp Nos. 000243 – 000250]* **Production of Documents** 8. FPL's Response to Staff's Fourth Request for Production of Documents (No. 18, including supplemental response) *[Bates Stamp Nos. 000251 – 000357]* 9. FPL's Response to Staff's Fifth Request for Production of Documents (No. 24, 26) *[Bates Stamp Nos. 000358 – 000370]*	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			Deposition Transcripts 10. Deposition Transcript of Leonardo E. Green including Deposition Exhibit No. 1 (including errata sheet) *[Bates Stamp Nos. 000371 – 000400]* 11. Deposition Transcript of Claude A. Villard *[Bates Stamp Nos. 000401 – 000429]* 12. Deposition Transcript of Gerard J. Yupp *[Bates Stamp Nos. 000430 – 000494]* 13. Deposition Transcript of Kennard F. Kosky (including errata sheet) *[Bates Stamp Nos. 000495 – 000523]* 14. Deposition Transcript of Steven R. Sim including Late-Filed Deposition Exhibit Nos. 1-3 (including Errata sheet) *[Bates Stamp Nos. 000524 – 000559]*	

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			15. Deposition Transcript of Steven D. Scroggs including Late-Filed Deposition Exhibit Nos. 1-3 and Deposition Exhibit No. 4 (including errata sheet) *[Bates Stamp Nos. 000560 – 000722]* 16. Deposition Transcript of C. Dennis Brandt including Late-Filed Deposition Exhibit Nos. 1-3 (including errata sheet) *[Bates Stamp Nos. 000723 – 000768]*	

Testimony Exhibit List

FLORIDA POWER & LIGHT (Direct)				
16	Armando J. Olivera	AJO-1	Biographical Information	
17	Rene Silva	RS-1	Actual Energy Mix 2006	
18	Rene Silva	RS-2	Projected Energy Mix 2021	
19	Rene Silva	RS-3	Resource Need	
20	Rene Silva	RS-4	Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs	
21	J.A. Stall	JAS-1	WANO Indices	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
22	J.A. Stall	JAS-2	NRC Performance Indicators	
23	Steven D. Scroggs	SDS-1	Development Process Timeline	
24	Steven D. Scroggs	SDS-2	Site Selection Study Report	
25	Steven D. Scroggs	SDS-3	FPL Technology Review	
26	Steven D. Scroggs	SDS-4	COL Application Content	
27	Steven D. Scroggs	SDS-5	Estimated Project Milestones	
28	Steven D. Scroggs	SDS-6	Overnight Cost Estimate Range (2007$)	
29	Steven D. Scroggs	SDS-7	Comparison to Economically viable Range (2007$)	
30	Steven D. Scroggs	SDS-8	Total Project Cost Estimate Range (Year Spent $)	
31	Steven D. Scroggs	SDS-9	Project Cost Expenditure by NPPCRR Category	
32	Dr. Nils J. Diaz	NJD-1	Summary Resume of Dr. Nils J. Diaz, PhD.	
33	Dr. Nils J. Diaz	NJD-2	Collective Radiation Exposure of Nuclear Power Plant Personnel	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
34	Dr. Nils J. Diaz	NJD-3	10 Years of NRC's Safety Indicators	
35	Dr. Nils J. Diaz	NJD-4	WANO Indicators & Weighting Factors	
36	Dr. Nils J. Diaz	NJD-5	U.S. Nuclear Industry Capacity Factors	
37	Dr. Nils J. Diaz	NJD-6	License Renewal Impact on Nuclear Power	
38	Dr. Nils J. Diaz	NJD-7	Expected Power Plant Applications	
39	Dr. Nils J. Diaz	NJD-8	Design Centered Review Approach	
40	Dr. Leonardo E. Green	LEG-1	Total Average Customers	
41	Dr. Leonardo E. Green	LEG-2	Summer Peak Load Per Customer	
42	Dr. Leonardo E. Green	LEG-3	Summer Peak Load	
43	Dr. Leonardo E. Green	LEG-4	Winter Peak Load Per Customer	
44	Dr. Leonardo E. Green	LEG-5	Winter Peak Load	
45	Dr. Leonardo E. Green	LEG-6	Summer Peak Weather	
46	Dr. Leonardo E. Green	LEG-7	Florida Real Personal Income	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
47	Dr. Leonardo E. Green	LEG-8	Net Energy for Load Use Per Customer	
48	Dr. Leonardo E. Green	LEG-9	Net Energy for Load	
49	Dr. Leonardo E. Green	LEG-10	Non-Agricultural Employment	
50	Dr. Leonardo E. Green	LEG-11	Real Price of Electricity	
51	Dr. Leonardo E. Green	LEG-12	Impact of the 2005 Energy Policy Act Adjustment	
52	C. Dennis Brandt	DB-1	FPL Current FPSC DSM Goals	
53	C. Dennis Brandt	DB-2	FPL DSM Programs & Measures	
54	Henrietta G. McBee	HGM-1	Renewables by State	
55	Henrietta G. McBee	HGM-2	Renewables by State Excluding Hydro and Geothermal	
56	Henrietta G. McBee	HGM-3	NREL United States Classes of Wind Power Density Map	
57	Henrietta G. McBee	HGM-4	NREL United States Solar Energy Potential Map	
58	Gerard J. Yupp	GJY-1	Historical Fuel Prices	
59	Gerard J. Yupp	GJY-2	Nuclear Fuel Savings	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
60	Claude A. Villard	CAV-1	Description of Nuclear Fuel	
61	Claude A. Villard	CAV-2	Uranium Projected Prices	
62	Claude A. Villard	CAV-3	Conversion Services Projected Prices, Dollars per kgU as UF6	
63	Claude A. Villard	CAV-4	Enrichment Services Projected Prices	
64	Claude A. Villard	CAV-5	Fabrication Services Projected Prices	
65	Claude A. Villard	CAV-6	Annual Nuclear Fuel Expense Projection	
66	Kennard F. Kosky	KFK-1	KFK Curriculum Vitae	
67	Kennard F. Kosky	KFK-2	Graphical Representation of Turkey Point Site	
68	Kennard F. Kosky	KFK-3	Fossil Fuel and Air Emissions Displaced by FPL's Nuclear Units Since Initial Operation as of 2006	
69	Kennard F. Kosky	KFK-4	Florida CO_2 Emissions Avoided by FPL Nuclear Units	
70	Kennard F. Kosky	KFK-5	Avoided Air Emissions from FPL's Nuclear Generation in 2006	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
71	Kennard F. Kosky	KFK-6	Environmental Benefits of Nuclear Generation	
72	Kennard F. Kosky	KFK-7	Future Annual CO_2 Emissions Avoided by FPL New Nuclear Generation	
73	Kennard F. Kosky	KFK-8	Reduction in Annual CO_2 Emissions Achieved by Adding 1,000 MW of Non-Emitting CO_2 Generation Alternatives in Florida	
74	Kennard F. Kosky	KFK-9	Choosing Nuclear Helps Reduce CO_2 Emissions in the Year 2021 by 76% Toward the Year 2000 Level of 62.6 Million Tons	
75	Hector J. Sanchez	HJS-1	Summary of Required Facilities for Turkey Point 6 & 7	
76	Dr. Steven R. Sim	SRS-1	Projection of FPL's 2007 - 2020 Capacity Needs	
77	Dr. Steven R. Sim	SRS-2	Projected Incremental FPL DSM: 2006 – 2020	
78	Dr. Steven R. Sim	SRS-3	Projection of FPL's 2007 – 2020 Capacity Needs: with Turkey Point 6 & 7	
79	Dr. Steven R. Sim	SRS-4	The Three Resource Plans Utilized in the Analyses	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
80	Dr. Steven R. Sim	SRS-5	Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario	
81	Dr. Steven R. Sim	SRS-6	Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios	
82	Dr. Steven R. Sim	SRS-7	Economic Analysis Results: Matrix of Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios	
83	Dr. Steven R. Sim	SRS-8	Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios	
84	Dr. Steven R. Sim	SRS-9	Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7: 2009 – 2021	
85	Dr. Steven R. Sim	SRS-10	Non-Economic Analysis Results: System Fuel Mix Projections by Plan	
86	Dr. Steven R. Sim	SRS-11	Non-Economic Analysis Results: FPL System CO_2 Emissions	
87	John J. Reed	JJR-1	Curriculum Vitae of John J. Reed	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
88	John J. Reed	JJR-2	Expert Testimony of John J. Reed	
89	John J. Reed	JJR-3	CO_2 Reductions by Technology Type	
90	John J. Reed	JJR-4	2007 U.S. Electricity by Technology Sector vs. 2030 US Electricity by Technology Sector Including Advanced Technologies	

HEARING EXHIBITS				
Exhibit #	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**
91				
92				
93				
94				
95				
96				

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 15
COMPANY FL PSC Staff
WITNESS Staff's Composite Exhibits - Stipulated
DATE 01/30/

EXHIBIT NO. _____

DOCKET NO: 070650-EI

WITNESS: VARIOUS

PARTY: FLORIDA POWER & LIGHT COMPANY

DESCRIPTION: STAFF'S STIPULATED COMPOSITE EXHIBITS – 15

DOCUMENTS:

Interrogatories - Docket No. 070650-EI

1. FPL's Response to Staff's First Set of Interrogatories (Nos. 1-5, 8-23, including supplemental response to No. 3) *[Bates Stamp Nos. 000001 – 000074]*

2. FPL's Response to Staff's Third Set of Interrogatories (Nos. 28-30, 32-34, 36-41, 43-52, 54-60) *[Bates Stamp Nos. 000075 – 000129]*

3. FPL's Response to Staff's Fourth Set of Interrogatories (Nos. 63-72) *[Bates Stamp Nos. 000130 – 000154]*

4. FPL's Response to Staff's Fifth Set of Interrogatories (Nos. 75-79, 81-84) *[Bates Stamp Nos. 000155 – 000171]*

5. FPL's Response to Staff's Sixth Set of Interrogatories (Nos. 85, 87-97) *[Bates Stamp Nos. 000172 – 000228]*

6. FPL's Response to Staff's Eighth Set of Interrogatories (Nos. 107-112, 114) *[Bates Stamp Nos. 000229 – 000242]*

7. FPL's Response to OPC's First Set of Interrogatories (No. 1) *[Bates Stamp Nos. 000243 – 000250]*

Production of Documents - Docket No. 070650-EI

8. FPL's Response to Staff's Fourth Request for Production of Documents (No. 18, including supplemental response) *[Bates Stamp Nos. 000251 – 000357]*

9. FPL's Response to Staff's Fifth Request for Production of Documents (No. 24, 26) *[Bates Stamp Nos. 000358 – 000370]*

Deposition Transcripts - Docket No. 070650-EI

10. Deposition Transcript of Leonardo E. Green including Deposition Exhibit No. 1 (including errata sheet) *[Bates Stamp Nos. 000371 – 000400]*

11. Deposition Transcript of Claude A. Villard *[Bates Stamp Nos. 000401 – 000429]*

12. Deposition Transcript of Gerard J. Yupp *[Bates Stamp Nos. 000430 – 000494]*

13. Deposition Transcript of Kennard F. Kosky (including errata sheet) *[Bates Stamp Nos. 000495 – 000523]*

14. Deposition Transcript of Steven R. Sim including Late-Filed Deposition Exhibit Nos. 1-3 (including Errata sheet) *[Bates Stamp Nos. 000524 – 000559]*

15. Deposition Transcript of Steven D. Scroggs including Late-Filed Deposition Exhibit Nos. 1-3 and Deposition Exhibit No. 4 (including errata sheet) *[Bates Stamp Nos. 000560 – 000722]*

16. Deposition Transcript of C. Dennis Brandt including Late-Filed Deposition Exhibit Nos. 1-3 (including errata sheet) *[Bates Stamp Nos. 000723 – 000768]*

PROFFERED BY: STAFF

1

FPL's Response to Staff's First Set of Interrogatories (Nos. 1-5, 8-23 – including supplemental response to No. 3)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's	)	Docket No. 070650-EI
Petition to Determine Need for	)	
Turkey Point Nuclear Units 6 and 7	)	
Electrical Power Plant	)	Filed: November 14, 2007

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIRST SET OF INTERROGATORIES (NOS. 1-23)

Florida Power & Light Company gives notice of service of its Responses to the Staff of the Florida Public Service Commission's First Set of Interrogatories (Nos. 1-23), to Katherine E. Fleming.

Respectfully submitted this 14th day of November, 2007.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
700 Universe Boulevard
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P. O. Box 551
Tallahassee, FL 32302-0551

Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

RECEIVED
NOV 16 2007
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: November 14, 2007

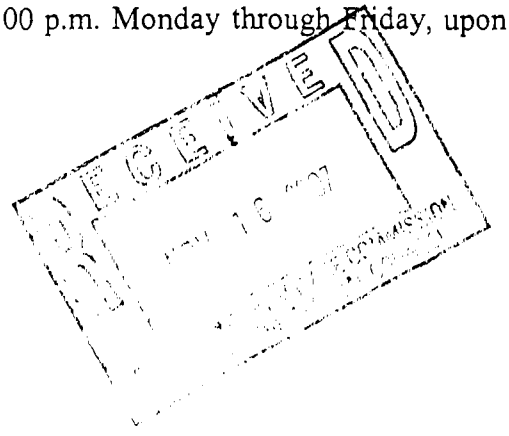
FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIRST SET OF INTERROGATORIES (NOS. 1-23)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following responses to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories (Nos. 1-23).

FPL adopts and incorporates by reference, as though fully restated herein, all General and Specific Objections listed in Florida Power & Light Company's Objections to Staff's First Set of Interrogatories (Nos. 1-23), dated November 8, 2007.

Staff's First Set of Interrogatories (Nos. 1-23)

Attached hereto are FPL's answers to Staff's First Set of Interrogatories Nos. 1-23, consistent with its prior objections, together with the affidavits of the persons providing said answers. The confidential responses to interrogatories Nos. 2 and 6 will be made available by FPL for inspection and review by Staff at FPL's offices at 215 South Monroe Street, Tallahassee Florida, during regular business hours of 8:00 a.m. to 5:00 p.m. Monday through Friday, upon reasonable notice to FPL's counsel.



Respectfully submitted this 14th day of November, 2007.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
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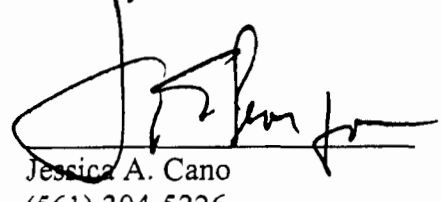
Attorneys for Florida Power & Light Company

By: 

Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000004

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Responses to Staff's First Set of Interrogatories (Nos. 1-23) has been furnished electronically and by United States Mail this 14th day of November, 2007, to the following:

Katherine E. Fleming
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

By: _____
Jessica A. Cano
Florida Bar No. 0037372

Hearing Exhibit 000005

Q.
What is the total site capability for the Turkey Point site? How much land will Turkey Point 6 and 7 occupy?

A.
The total site capability (megawatt capacity) for the Turkey Point site is undetermined. The total capacity that can be hosted on the site will be a function of the technologies selected over time through the integrated resource planning process, as each technology has its own unique requirements with respect to the land acreage needed to support it. The integrated resource planning process is further influenced by a host of issues, including: fuel supply, transmission interconnection and integration and cooling water availability.

The Turkey Point site is comprised of approximately 11,000 acres in southwest Miami-Dade County. Turkey Point 6 and 7 is proposed to be built within the boundaries of the Industrial Waste Water Facility (Cooling Canal System) on 296 acres of land that will support the generation units and auxiliary buildings. There are also planned improvements to areas surrounding the Turkey Point 6 and 7 plant site. Approximately 900 acres have been identified for potential lake excavations, as "associated facilities." The excavated material would provide fill for the plant site, while the lakes would create opportunities for coastal wetlands rehydration, as a form of environmental mitigation.

Q.
Has FPL done an assessment of what additional renewable generation is physically available? If so, what were the results?

A.
Yes. FPL has performed assessments of what additional waste to energy, landfill gas, biomass, wind, solar, and ocean current renewable generation is physically available.

During 2006, FPL performed an assessment of the amount of waste to energy, landfill gas and biomass renewable generation that is physically available in the State of Florida. This information was previously presented at a Commission workshop on January 19, 2007. The results for the entire State are summarized below:

Technology	Total Potential (MW)	Existing Capacity (MW)	Incremental Capacity (MW)
Waste to Energy	868	476	392
Landfill Gas	86.8	20.4	66.4
Biomass	492	202	270

The analysis also included wind, solar, closed loop biomass, and ocean energy resources, without estimating potential production in the State.

During 2005 and 2006, FPL retained an expert consultant to perform assessments of the wind resources that are physically available. The first wind resource assessment was completed during March 2005 and covered the entire State of Florida. During March and June, 2006, two additional wind resource assessments were performed, focusing on coastal regions within FPL's service territory. The wind resource studies, constituting proprietary and confidential business information, contain the results of the studies, and are being made available in response to this interrogatory.

During 2007, FPL retained an expert consultant to perform an assessment of the solar resource that is physically available. The report focuses on three geographical areas of interest for possible development of a utility-scale solar energy facility. The solar resource study, constituting proprietary and confidential business information, contains the results of the study, and is being made available in response to this interrogatory.

During 2007, FPL conducted a renewable energy Request for Proposals (2007 Renewable RFP). While conducted in order to identify new renewable resources for serving its customers, the amount and types of additional renewable generation bid in response to the 2007 Renewable RFP are an additional useful input in assessing additional renewable generation that may be physically available. The 2007 Renewable RFP sought proposals for new renewable energy with expected in-service dates prior to June 2015. The 2007 Renewable RFP also sought information regarding

new renewable firm capacity and/or energy sources with expected in-service dates beyond 2015. The 2007 Renewable RFP contained no restriction on price and provided maximum flexibility for potential suppliers of renewable energy in order to encourage as much participation as possible. The 2007 Renewable RFP was available to potential bidders in Florida, across the country and beyond, for their consideration and response. As a result of the 2007 Renewable RFP, FPL received proposals from five bidders totaling 144 MW of new firm renewable generation capacity. FPL also received a proposal for the supply of 100 MW of non-firm capacity and energy from technology under development based on harnessing ocean current energy.

The confidential documents provided in response to this interrogatory will be made available by FPL for inspection and review at FPL's offices at 215 South Monroe Street, Suite 810, Tallahassee, Florida during regular business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Q.
Please provide any information on FPL's current and planned solar projects, including the project description, MW size, kwh output, installation dates and square footage required for each project. Also, please provide the costs (capital, operating and maintenance of such projects).

A.
FPL is investigating development and construction of solar photovoltaic and solar thermal capacity that FPL would own and operate. FPL is also promoting its Sunshine Energy® Program, which permits FPL's customers to more directly and immediately support renewable solar photovoltaic development in Florida.

With respect to FPL's investigation of developing and constructing solar photovoltaic capacity, FPL is working on a possible large photovoltaic installation (up to 2 MW) that would be installed on about 20 acres of property within FPL's service territory, for which siting rights and approvals are in process as of the date of this response. FPL has issued a request for information in order to identify potentially qualified suppliers that could provide photovoltaic panels and installation, and at the time of this response is completing meetings with potential suppliers in connection with the bidder qualification process.

With respect to FPL's investigation of developing and constructing solar thermal capacity, FPL is working on a utility-scale demonstration of a project that in its first stage would have a net capacity of up to 10 MW. Discussions are preliminary, but FPL anticipates proposing up to 300 MW of solar thermal capacity if the 10 MW project is successful, subject to technical due diligence, commercial negotiations and regulatory approvals.

With respect to currently deployed solar energy projects, FPL's current Sunshine Energy® Program was launched as a pilot in January 2004 and made permanent in January 2007. In 2005, FPL was a recipient of the DOE's Green Power Leadership Award for the Sunshine Energy® Program. FPL's residential and business customers are provided a voluntary opportunity to contribute money to a fund that capitalizes solar energy projects in Florida which provides customers the opportunity to purchase a portion of their monthly energy supply from a renewable energy resource. In 2006, Sunshine Energy® Program was 3rd in the U.S. for renewable sales. As of April 2007, there were 30,000 participants. For every 10,000 participants, there will be 150 kW of new solar resources built in Florida. Sunshine Energy Solar sites under development or completed include the following:

- 250 kW facility located at Rothenbach Park in Sarasota tied to Sunshine Energy® Program;
- 2 kW solar array installed at the Miami Science Museum;
- SunSmart Schools such as 2 kW at Palm City Elementary, 2 kW at MAST Academy, 2 kW at South Miami Senior High School, and 2 kW at Edgewood School; and
- 40 kW of rooftop solar being installed on over 40 homes at "The Quarry" subdivision by Centex located in Naples, Florida.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Filed: January 23, 2008

NOTICE OF SERVICE
OF FLORIDA POWER & LIGHT COMPANY'S
SUPPLEMENTAL AND CORRECTED RESPONSES

Florida Power & Light Company gives notice of service of its supplemental response to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories No. 3 and corrected responses to Staff's Third Set of Interrogatories No. 32 and Sixth Set of Interrogatories No. 85, to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 23rd day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
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John T. Butler
Bryan S. Anderson
Antonio Fernandez
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By: *s/ Jessica A. Cano*
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically and by United States mail this 23rd day of January, 2008, to the following:

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James A. Dickenson
P.G. Para
JEA
21 West Church Street
Jacksonville, FL 32202

By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

Hearing Exhibit 000011

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: January 23, 2008

FLORIDA POWER & LIGHT COMPANY'S
SUPPLEMENTAL AND CORRECTED RESPONSES TO THE
STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S INTERROGATORIES

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following supplemental response to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories No. 3 and corrected responses to Staff's Third Set of Interrogatories No. 32 and Sixth Set of Interrogatories No. 85.

FPL adopts and incorporates by reference, as though fully restated herein, all objections previously provided in response to the interrogatories. Attached hereto are FPL's supplemental and corrected answers, consistent with its prior objections.

Respectfully submitted this 23rd day of January, 2008.

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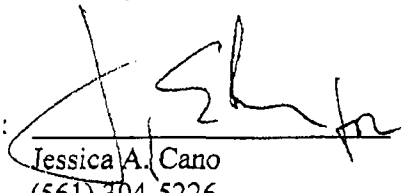
By: 

Jessica A. Cano
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Hearing Exhibit 000013

CERTIFICATE OF SERVICE

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By: _____
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Hearing Exhibit 000014

Q.

Please provide any information on FPL's current and planned solar projects, including the project description, MW size, kwh output, installation dates and square footage required for each project. Also, please provide the costs (capital, operating and maintenance of such projects).

A.

FPL is investigating development and construction of solar photovoltaic and solar thermal capacity that FPL would own and operate. FPL is also promoting its Sunshine Energy® Program, which permits FPL's customers to more directly and immediately support renewable solar photovoltaic development in Florida.

With respect to FPL's investigation of developing and constructing solar photovoltaic capacity, FPL is working on a possible large photovoltaic installation (up to 10 MW) with NASA that would be installed on about 50 acres of property at NASA's Kennedy Space Center. The siting rights and approvals with NASA are in process as of the date of this response. The first 2 MW of the PV facility is targeted to be installed by the end of 2008, which remains subject to technical due diligence and successful negotiations with NASA, among other matters. The remainder of the facility would be completed in 2009. FPL issued a request for information in order to identify potentially qualified suppliers that could provide photovoltaic panels and installation, and at the time of this response has completed meetings with potential suppliers in connection with the bidder qualification process. FPL is currently preparing to issue a Request for Proposal to a list of suppliers for a turnkey project engineering, procurement and construction contract. FPL is also in the preliminary stage of locating a site for a second large photovoltaic installation (up to 20 MW) to be located within our service territory. As part of the development process, FPL is continuing to evaluate technology choices and analyze offerings from PV suppliers and integrators.

With respect to FPL's investigation of developing and constructing solar thermal capacity, FPL is working on a utility-scale demonstration of a project that in its first stage would have a net capacity of up to 50 MW. Discussions are preliminary, but FPL anticipates proposing up to 300 MW of solar thermal capacity if the 50 MW project is successful, subject to technical due diligence, commercial negotiations and regulatory approvals.

With respect to currently deployed solar energy projects, FPL's current Sunshine Energy® Program was launched as a pilot in January 2004 and made permanent in January 2007. In 2005, FPL was a recipient of the DOE's Green Power Leadership Award for the Sunshine Energy® Program. FPL's residential and business customers are provided a voluntary opportunity to contribute money to a fund that capitalizes solar energy projects in

Florida which provides customers the opportunity to purchase a portion of their monthly energy supply from a renewable energy resource. In 2006, Sunshine Energy® Program was 3rd in the U.S. for renewable sales. As of April 2007, there were 30,000 participants. For every 10,000 participants, there will be 150 kW of new solar resources built in Florida. Sunshine Energy Solar sites under development or completed include the following:

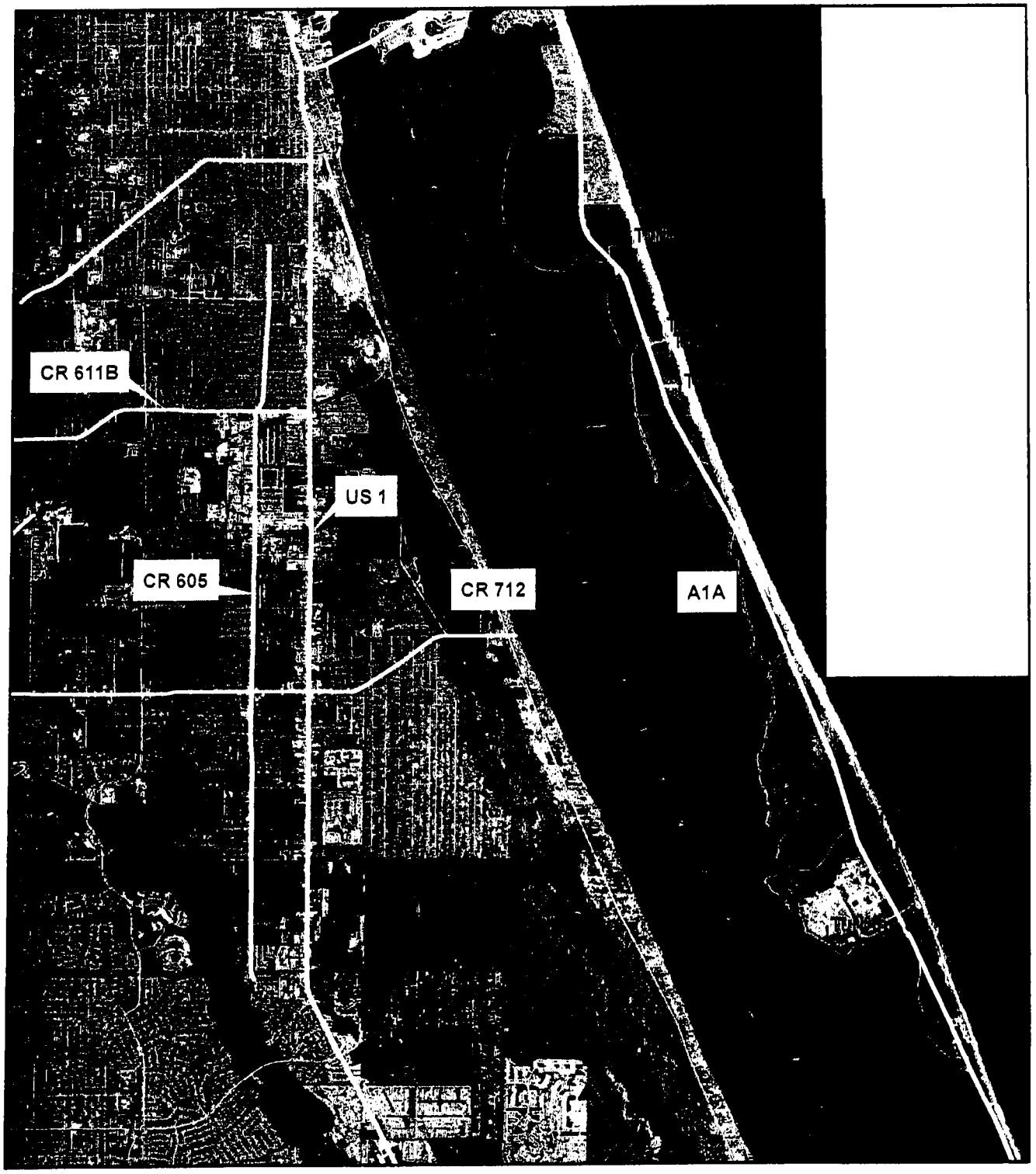
- 250 kW facility located at Rothenbach Park in Sarasota tied to Sunshine Energy® Program;
- 2 kW solar array installed at the Miami Science Museum;
- SunSmart Schools such as 2 kW at Palm City Elementary, 2 kW at MAST Academy, 2 kW at South Miami Senior High School, and 2 kW at Edgewood School; and
- 40 kW of rooftop solar being installed on over 40 homes at "The Quarry" subdivision by Centex located in Naples, Florida.

Q.
Please provide any information on FPL's current and planned wind projects, including the project description, MW size, kwh output, installation dates and square footage required for each project. Also, please provide the costs (capital, operating and maintenance of such projects).

A.
Florida's wind resource is limited to coastal areas, the wind resource declines significantly inland, and the wind resource is better in the winter season (October through March). Taking these factors into account, FPL has made several attempts to develop wind generation to serve its customers. Development efforts at four sites could not move forward due to matters including avian, land, aviation, and electronic signal interference considerations. These development efforts were directed at sites in New Smyrna Beach, at the Cape Canaveral Air Force Base, at NASA facilities, and in Sarasota County.

FPL is presently seeking to site up to nine (9) wind turbine generators ("WTGs") with a target of 9.2 MW to 20.7 MW on Hutchinson Island in St. Lucie County. Attached is an aerial photograph showing the possible sites for the WTGs. Several of the proposed WTG locations are on FPL's St. Lucie facility property with the remaining proposed sites located on St. Lucie County and TIFF (Board of Trustees of the Internal Improvement Trust Fund) - DEP property. Currently FPL is performing an in-depth WTG supplier evaluation and is striving for an overall target for an engineering, procurement and construction contract award in 2008. FPL has applied to St. Lucie County for construction permits and is hopeful of receiving approval by the middle of March 2008. Along with the construction permits submitted to the county, FPL is working with various environmental organizations and is expecting to receive environmental permits/approvals during early Summer 2008. Assuming that all construction and environmental permits are obtained and that WTGs are available, FPL plans to begin construction by Summer 2008 with the overall schedule achieving commercial operation by 4th quarter 2008. A key area of project uncertainty is whether it will be possible to site WTGs on public lands. While FPL would pay compensation for the right to use the lands, the question remains whether public land usage for WTGs will be approved. Regarding square footage, a typical wind turbine generator site requires about a 42' x 42' gravel area, the boundaries of which can be farmed and grazed up to. The estimated project costs remain in development and will depend largely upon site acquisition costs as well as WTG commercial negotiations, which processes have not been concluded. In addition to the St. Lucie County wind project, due diligence on additional Florida sites is currently in progress.

St. Lucie Wind Project



- Turbine 1
- Turbine 2
- Turbine 3
- Turbine 4
- Turbine 5
- Turbine 6
- Turbine 7
- Turbine 8
- Turbine 9

TETRA TECH EC INC
759 South Federal Hwy., Suite 100
Stuart, Florida 34994-2936

08-14-07

Q.

Please list all purchase power contracts that will expire before the installation date of Turkey Point 6 and 7. Please list whom the contract is with, expiration date of the contract, amount of capacity lost, and whether FPL has considered renewing the contract.

A.

FPL's Need Study document presents a listing of all of FPL's purchase power contracts from 2007 through 2020 in Table II.B.2.1 on page 15 of the Need Study document. Please refer to this table that provides the name of the supplier, the annual amounts of capacity, and the term dates for the power purchase.

In this table, the following information should be noted:

- Three line items in the "I. Purchases from QF's" section at the top of the table are shaded: Broward South at 50.6 MW, Broward North at 45 MW, and Palm Beach SWA at 47.5 MW. These three contracts, respectively, are currently scheduled to end on 8/1/2009, 12/31/2010, 3/31/2010. FPL intends to pursue the extension of these contracts and for purposes of the analyses conducted for this filing (and for the Nuclear Uprates filing) has assumed the extension of these contracts past 2020.
- One line item in the "III. Other Purchases" section near the bottom of the table shows a fourth shaded row titled "Other Renewables". The values presented in this row represent all of the firm capacity proposals received on July 2, 2007 in response to FPL's Renewable RFP. FPL is currently evaluating these proposals. For purposes of the analyses conducted for this filing (and for the Nuclear Uprates filing), FPL has assumed that all this capacity is under contract for the duration of the proposed terms of service.
- In the "II. Purchases from Utilities" section, it should be noted that FPL has already renewed the 931 MW UPS purchase from Southern Company that expires in 2010. This renewal is through 2015, the maximum amount of time that Southern would agree to contract for.
- Also in this section is the end of a 381 MW purchase from SJRPP. As explained in FPL's filing, the projected loss of this capacity is based on Internal Revenue Service regulations and is not the result of an expiring contract. Consequently, this is a purchase that is not subject to a potential renewal during this time period.
- Finally, there are several contracts shown in the near term in the "Other Purchases" section including Indian River, Oleander, Williams, and Progress Energy Ventures that were entered into in early 2006 to meet projected short-term capacity needs after FPL experienced a higher-than-expected Summer peak load in 2005. These purchases were entered into to meet short-term capacity needs that could not be met by FPL self-build options or longer term contracts that could be identified through the capacity RFP process.

In summary, FPL's analysis has already accounted for a significant amount of capacity purchases, including the assumption that existing renewable energy-based contracts would be extended and the new renewable energy-based proposals would be signed. FPL believes there is not a significant amount of additional capacity purchases that are available and that additional capacity purchases are certainly not sufficient to meet FPL's projected capacity needs through 2020.

Q.
Has FPL assessed the availability of purchases from coal or nuclear base-load capacity from other utilities outside of Florida?

A.
Yes. FPL has had discussions regarding potential coal purchases from several non-Florida entities including Southern and LS Power. To date these discussions have not resulted in a promising opportunity for FPL and its customers. The issue of new purchases of coal-based capacity is complicated by the current unsettled status in Florida regarding the permitting and other regulatory aspects of new coal capacity and the corresponding CO2 emissions that would result from this capacity.

FPL is not aware of the availability of any nuclear generation for purchase in the Southeastern U.S.

Q.
How many FPL customers are participating in each DSM program that is offered?

A.
FPL has a very robust offering of DSM programs which has been revised and expanded over time as described in the testimony of FPL witness Brandt. Below is a listing of the current programs with the cumulative participation number for each of the programs.

Residential Programs	Participation (through YE 2006)
Residential Building Envelope	732,591
Duct System Testing & Repair	404,859
Residential Air Conditioning	1,093,990
Residential Load Management (On Call)	742,395
BuildSmart	14,487
Residential Low Income Weatherization	476
Residential Conservation Service	2,254,528

Business Programs	Participation (through YE 2006)
Business Air Conditioning	14,178
Business Efficient Lighting	18,540
Business Building Envelope	6,011
Business Custom Incentive	22
Business On Call	19,206
Commercial Demand Reduction/ Commercial Load Control	606
Business Energy Evaluation	105,805

Q.
Please provide the number of DSM audits performed in 2006. What percentage of eligible customers have utilized FPL's DSM audits over the past five years.

A.
In 2006, there were a total of 167,538 DSM audits performed. Of these, 155,398 were for the Residential Conservation Services Program, and 12,140 were for the Business Energy Evaluation Program. Over the past five years, approximately 15% of residential customers have participated in the Residential Conservation Services Program, and approximately 9% of business customers have participated in the Business Energy Evaluation Program.

Q.
Please describe any DSM programs offered by FPL that specifically provide consumer education.

A.
The following DSM programs provide consumer education:

Residential Conservation Service (RCS): Free energy surveys (audits) available to all FPL residential customers. The survey includes information to educate customers on energy saving practices, including no-cost or low-cost options. It also determines customers' eligibility for FPL's incentive programs, providing a customized report with energy savings information and recommendations. It is available as a walk-through energy audit, by phone, or online.

Business Energy Evaluation (BEE): An energy audit program which offers businesses free energy evaluations on-site and on-line. Customers are provided a comprehensive report with recommendations that explain what can be done, based on their facilities and their operations, to save energy. The BEE also identifies what FPL incentive programs they qualify for and encourages customer participation in FPL's other business DSM programs.

Green Power Program (marketed as the Sunshine Energy ® program): A voluntary program providing interested residential and business customers with the opportunity to support renewable energy development via construction of new renewable facilities and a way for them to offset their carbon footprint via renewable energy credits. The program helps customers understand the renewable energy market, the various types of renewables, and how the use of renewable energy credits helps the development and construction of new renewable facilities.

Compact Fluorescent Lighting (CFL) Promotion: Recently, FPL started this promotion which gives a free CFL to customers who participate in our surveys. This exposes our customers to a new technology which shows them how to save.

All of FPL's other DSM programs, for example, the incentive programs, also educate customers by providing information either on a specific energy saving technology or by explaining the benefits of installing energy efficient equipment. For example, the Residential Air Conditioning program educates customers, not only on high efficiency air conditioners, but also on duct sealing and the correct sizing of this equipment. In a similar manner, the Business Lighting program educates retail customers that energy efficiency lighting cannot only reduce their energy bill but can also enhance the display of their products.

Q.
Does FPL have any plans to expand the consumer education efforts of its DSM plan?

A.
By way of background, through the Residential Conservation Service and Business Energy Evaluation programs, FPL has continuously expanded its DSM outreach efforts to customers - providing information, through a multitude of communication channels: TV, radio ads, print media, bill inserts and the internet. FPL employees are also key ambassadors of consumer education, not only while performing audits but also when hosting workshops, delivering presentations to organizations, participating in home shows, and assisting at conventions attended by FPL customers.

FPL has also expanded consumer education through recent efforts targeting the low-income market. As part of this initiative, multiple approaches are being used and expanded to educate and assist the low-income consumer in better managing energy consumption. FPL works with low-income organizations to conduct educational workshops in targeted neighborhoods; sponsors energy efficiency booths at community fairs; and is customizing energy survey for low-income customers with a focus on no-cost and low-cost energy savings tips.

FPL intends to continue its commitment to educating its customers, via DSM programs, on the benefits of energy conservation, including its positive environmental impacts. FPL conducts research on an ongoing basis to keep abreast of new technologies and provide information to its customers. This is done through programs such as the Conservation Research and Development Program (CRD), as well as other sources. This provides key inputs in the development of additional DSM offerings and allows FPL to educate its customers on the latest information and technology regarding energy savings opportunities.

FPL is also investigating other methods to educate our customers about our programs and ways they can save energy. FPL recently piloted several webinars for customers in specific business segments on energy efficiency. For example, a webinar for private schools was recently held that discussed how schools use energy, the applicable FPL DSM programs and low-cost tips they can implement. FPL is also looking at using email campaigns to educate and sign up customers for our programs.

Q.
Please complete the following table to reflect FPL's DSM savings:

Year	Projected Summer (MW)	Projected Winter (MW)	Projected Annual GWH
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			

A.
Table TP 6&7 Staff 13 provides the requested information.

Q.

Please complete the following table to show an estimated impact on FPL's Summer Reserve Margin with and without the proposed nuclear units:

Estimated Impact on FPL's Summer Reserve Margin
YearReserve Margin w/o nuclearReserve Margin with nuclear
2015
2016
2017
2018
2019
2020
2021
2022

A.

Table TP 6&7 Staff 14 presents the requested information that is consistent with the reserve margin projections through the year 2017 previously provided by FPL witness Sim's testimony in Exhibit SRS-4 and with the resource additions assumed in FPL's analyses conducted for this filing.

FPL witness Silva's testimony discusses what FPL's reserve margins and capacity needs would be starting in 2018 if instead of adding a 2x1 G CC unit (approx. 812 MW) in 2017, the capacity need in 2017 of 517 MW were met instead with a capacity addition of exactly that size. In that case, the reserve margin values in the table for the Reserve Margin without Turkey Point 6&7 for the years 2018 – 2022 would become: 2018 = 17.5 %, 2019 = 15.1%, 2020 = 12.6%, 2021 = 10.0%, and for 2022 = 7.2%. The corresponding values in the table for the Reserve Margin with Turkey Point 6&7 for the years 2018 – 2022 would become: 2018 = 21.8%, 2019 = 19.3%, 2020 = 20.8%, 2021 = 18.1%, and for 2022 = 15.1%.

Q.

Please refer to Exhibit SRS-6, attached to the direct testimony of Steven R. Sim. Please provide annual and cumulative present value revenue requirements for all scenarios shown on Exhibit SRS-6.

A.

Table TP 6&7 Staff 15 provides the requested information for each of the three resource plans included in FPL's analyses and for each of the 9 scenarios analyzed. Pages 1 of 9 through 3 of 9 provide the requested data for the Turkey Point 6&7 nuclear units. Pages 4 of 9 through 6 of 9 provide the requested data for CC units. Pages 7 of 9 through 9 of 9 provide the requested data for IGCC units.

Table TP 6&7 Staff 15: Turkey Point 6&7

Fuel Cost Forecast	High Gas Cost											
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV		
Year	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	6,785	6,785	6,785	6,777	6,777	6,777	6,775	6,775	6,775	6,775	6,775	6,775
2008	8,056	7,438	14,223	8,046	7,429	14,206	8,044	7,427	14,202	8,044	7,427	14,202
2009	8,326	7,098	21,322	8,324	7,097	21,303	8,322	7,095	21,297	8,322	7,095	21,297
2010	8,680	6,833	28,155	8,293	6,528	27,831	8,948	7,044	28,341	9,145	7,199	28,496
2011	8,507	6,184	34,338	8,243	5,992	33,823	8,842	6,427	34,768	9,057	6,583	35,079
2012	8,396	5,633	39,972	8,259	5,541	39,364	8,808	5,910	40,678	9,052	6,074	41,153
2013	8,784	5,442	45,414	8,739	5,414	44,778	9,143	5,664	46,343	9,393	5,820	46,973
2014	9,506	5,439	50,853	9,528	5,450	50,228	9,961	5,698	52,041	10,249	5,863	52,836
2015	10,559	5,577	56,429	10,633	5,615	55,844	11,032	5,827	57,867	11,356	5,997	58,833
2016	11,892	5,799	62,228	12,071	5,886	61,730	12,454	6,073	63,940	12,806	6,244	65,077
2017	12,476	5,616	67,844	12,815	5,769	67,499	13,140	5,915	69,855	13,529	6,091	71,168
2018	12,906	5,364	73,208	13,320	5,537	73,035	13,580	5,645	75,500	13,998	5,819	76,987
2019	13,666	5,245	78,453	14,216	5,456	78,491	14,445	5,544	81,044	14,904	5,720	82,707
2020	13,967	4,949	83,403	14,723	5,217	83,709	14,924	5,289	86,332	15,435	5,470	88,177
2021	14,744	4,824	88,227	15,655	5,122	88,831	15,828	5,179	91,511	16,375	5,358	93,535
2022	15,849	4,788	93,014	16,899	5,105	93,936	17,083	5,161	96,672	17,722	5,354	98,889
2023	16,911	4,716	97,730	18,132	5,057	98,993	18,298	5,103	101,775	18,991	5,297	104,186
2024	18,283	4,707	102,438	19,757	5,087	104,081	19,984	5,141	106,916	20,765	5,347	109,533
2025	19,846	4,670	107,108	21,264	5,060	109,140	21,484	5,107	112,023	22,338	5,311	114,843
2026	21,159	4,643	111,751	22,960	5,043	114,184	23,292	5,112	117,136	24,233	5,319	120,162
2027	22,927	4,645	116,396	24,960	5,062	119,245	25,446	5,158	122,292	26,514	5,373	125,535
2029	26,012	4,492	125,468	28,376	4,998	124,243	27,497	5,144	127,436	28,724	5,374	130,909
2030	27,810	4,434	129,902	30,290	4,930	129,144	29,440	5,085	132,521	30,802	5,321	136,230
2031	29,733	4,377	134,279	32,361	4,764	133,974	31,714	5,058	137,578	33,234	5,300	141,530
2032	32,279	4,387	138,665	35,104	4,771	138,739	33,905	4,992	142,570	35,524	5,231	146,761
2033	35,876	4,501	143,167	39,005	4,896	143,510	36,807	5,003	147,574	38,580	5,242	152,003
2034	38,437	4,452	147,619	41,768	4,839	148,405	40,926	5,136	152,710	42,880	5,382	157,384
2035	40,833	4,367	151,986	44,373	4,747	153,244	43,859	5,082	157,792	45,952	5,325	162,709
2036	44,697	4,414	156,400	48,567	4,797	157,991	46,840	4,990	162,781	48,875	5,229	167,939
2037	47,688	4,348	160,748	51,808	4,724	162,787	51,088	5,046	167,828	53,546	5,290	173,228
2038	50,063	4,214	164,963	54,406	4,581	167,512	54,537	4,974	172,801	57,157	5,213	178,441
2039	52,892	4,111	169,074	57,489	4,469	172,093	57,351	4,829	177,631	60,129	5,064	183,505
2040	56,135	4,029	173,103	61,025	4,381	176,562	60,856	4,716	182,347	63,610	4,946	188,452
2041	57,765	3,828	176,931	62,828	4,164	180,943	64,445	4,627	186,974	67,588	4,853	193,304
2042	59,317	3,630	180,561	64,558	3,951	185,107	66,419	4,403	191,377	69,676	4,619	197,924
2043	61,970	3,502	184,063	67,493	3,815	189,059	68,333	4,183	195,560	71,718	4,391	202,314
2044	64,235	3,352	187,415	69,994	3,653	192,873	71,529	4,044	199,603	75,113	4,246	206,561
2045	65,478	3,158	190,571	71,429	3,443	196,527	74,263	3,877	203,480	78,017	4,073	210,634
2046	66,744	2,970	193,541	72,892	3,244	199,970	75,889	3,658	207,138	79,780	3,846	214,480
2047	68,041	2,796	196,337	74,393	3,058	203,214	77,553	3,452	210,590	81,585	3,632	218,112
2048	69,363	2,632	198,969	75,927	2,882	206,272	79,262	3,268	213,848	83,441	3,430	221,542
2049	70,737	2,479	201,448	77,519	2,717	209,153	81,013	3,075	216,923	85,344	3,240	224,781
2050	72,150	2,335	203,783	79,157	2,562	211,870	82,832	2,903	219,826	87,320	3,061	227,842
2051	73,598	2,199	205,983	80,838	2,416	214,432	84,707	2,742	222,568	89,359	2,892	230,735
2052	75,096	2,072	208,055	82,577	2,279	216,848	86,635	2,589	225,158	91,455	2,734	233,468
2053	76,647	1,953	210,008	84,377	2,150	219,127	88,630	2,446	227,604	93,626	2,584	236,053
2054	78,274	1,842	211,850	86,261	2,030	221,278	90,698	2,312	229,916	95,876	2,444	238,498
2055	79,946	1,737	213,587	88,198	1,917	223,308	92,880	2,186	232,101	98,226	2,312	240,808
2056	81,658	1,639	215,226	90,184	1,810	225,225	95,088	2,067	234,168	100,649	2,188	242,996
2057	83,406	1,546	216,771	92,216	1,709	227,034	97,378	1,954	236,122	103,141	2,070	245,066
2058	85,199	1,458	218,229	94,302	1,614	228,743	99,725	1,848	237,970	105,697	1,959	247,025
2059	87,076	1,376	219,605	96,483	1,525	230,357	102,141	1,748	239,718	108,330	1,854	248,879
2060	89,058	1,299	220,904	98,776	1,441	231,882	104,664	1,654	241,372	111,079	1,755	250,634
						233,322	107,314	1,566	242,937	113,962	1,663	252,296

Fuel Cost Forecast	Medium Gas Cost											
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV		
Year	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	5,037	5,037	5,037	5,027	5,027	5,027	5,025	5,025	5,025	5,025	5,025	5,025
2008	5,857	5,500	10,537	5,946	5,490	10,517	5,944	5,488	10,513	5,944	5,488	10,513
2009	6,158	5,250	15,787	6,180	5,251	15,769	6,159	5,251	15,764	6,159	5,251	15,764
2010	6,572	5,174	20,960	6,184	4,868	20,637	6,840	5,384	21,148	7,036	5,539	21,303
2011	6,517	4,737	25,697	6,253	4,545	25,181	6,847	4,977	26,125	7,059	5,131	26,434
2012	6,514	4,371	30,068	6,378	4,279	29,460	6,923	4,645	30,770	7,162	4,805	31,239
2013	6,810	4,219	34,286	6,763	4,190	33,650	7,162	4,437	35,207	7,410	4,591	35,830
2014	7,334	4,195	38,481	7,352	4,205	37,856	7,777	4,449	39,655	8,062	4,611	40,441
2015	8,198	4,329	42,810	8,270	4,367	42,223	8,685	4,576	44,231	8,984	4,744	45,186
2016	9,103	4,438	47,248	9,281	4,525	46,747	9,660	4,709	48,941	10,008	4,880	50,066
2017	9,588	4,316	51,564	9,824	4,467	51,214	10,247	4,613	53,553	10,634	4,787	54,852
2018	9,965	4,141	55,705	10,374	4,311	55,526	10,832	4,418	57,972	11,045	4,590	59,443
2019	10,517	4,035	59,740	11,061	4,244	59,770	11,288	4,332	62,303	11,743	4,506	63,949
2020	10,768	3,822	63,562	11,532	4,086	63,856	11,732	4,157	66,460	12,239	4,337	68,285
2021	11,397	3,728	67,291	12,292	4,021	67,877	12,465	4,078	70,538	13,013	4,257	72,543
2022	12,282	3,712	71,003	13,334	4,027	71,905	13,516	4,082	74,621	14,148	4,273	76,815
2023	13,160	3,669	74,672	14,384	4,011	75,915	14,543	4,056	78,676	15,230	4,247	81,062
2024	14,244	3,866	78,538	15,708	4,044	79,959	15,915	4,097	82,773	16,703	4,300	85,363
2025	15,313	3,639	81,977	16,937	4,025	83,984	17,133	4,072	86,845	17,975	4,272	89,635
2026	16,511	3,622	85,599	18,318	4,019	88,003	18,631	4,088	90,933	19,557	4,291	93,926
2027	17,930	3,631	89,230	19,960	4,043	92,046	20,428	4,138	95,071	21,475	4,350	98,277
2028	19,193	3,588	92,819	21,403	4,002	96,048	22,180	4,148	99,219	23,379	4,373	102,649
2029	20,390	3,520	96,338	22,729	3,924	99,972	23,787	4,107	103,326	25,118	4,337	106,987
2030	21,803	3,475	99,813	24,257	3,887	103,839	25,671	4,092	107,418	27,150	4,329	111,315
2031	23,355	3,436	103,249	25,953	3,819	107,658	27,487	4,046	111,464	29,063	4,278	115,593
2032	25,377	3,447	106,696	28,175	3,828	111,486	29,856	4,057	115,521	31,583	4,289	119,883
2033	28,164	3,532	110,228	31,258	3,921	115,407	33,161	4,160	119,681	35,065	4,399	124,282
2034	30,189	3,495	113,723	33,488	3,878	119,285	35,557	4,118	123,799	37,594	4,355	128,636
2035	32,031	3,424	117,147	35,542	3,800	123,085	37,780	4,040	127,839	39,964	4,274	132,911
2036	35,010	3,455	120,602	38,846	3,835	126,920	41,337	4,081	131,920	43,737	4,319	137,229
2037	37,384	3,406	124,008	41,465	3,779	130,699	44,155	4,025	135,945	46,713	4,259	141,488
2038	39,201	3,298	127,306	43,519	3,662	134,361	46,409	3,906	139,851	49,123	4,135	145,623
2039	41,367	3,213	130,519	45,935	3,569	137,930	49,041	3,811	143,662	51,928	4,036	149,659
2040	43,873	3,147	133,666	48,735	3,496	141,427	52,082	3,737	147,400	55,154	3,958	153,618
2041	45,094	2,986	136,652	50,126	3,321	144,747	53,638	3,554	150,954	56,817	3,765	157,383
2042	46,184	2,825	139,476	51,393	3,144	147,891	55,084	3,370	154,324	58,390	3,573	160,956
2043	48,057	2,714	142,191	53,547	3,025	150,917	57,499	3,249	157,573	61,008	3,448	164,404
2044	49,671	2,591	144,782	55,393	2,890	153,807	59,576	3,109	160,682	63,260	3,301	167,705
2045	50,550	2,435	147,216	56,461	2,720	156,527	60,835	2,931	163,613	64,684	3,116	170,821
2046	51,442	2,288	149,504	57,550	2,560	159,087	62,121	2,764	166,377	66,102	2,942	173,763
2047	52,356	2,150	151,655	58,687	2,410	161,497	63,444	2,607	168,984	67,582	2,777	176,540
2048	53,286	2,021	153,676	59,807	2,269	163,766	64,798	2,459	171,443	68,900	2,622	179,162
2049	54,256	1,901	155,577	60,995	2,137	165,903	66,210	2,320	173,763	70,683	2,477	181,638
2050	55,259	1,788	157,364	62,220	2,013	167,917	67,669	2,190	175,952	72,318	2,340	183,980
2051	56,284	1,681	159,045	63,477	1,897	169,813	69,169	2,067	178,019	74,002	2,211	186,191
2052	57,349	1,582	160,628	64,781	1,787	171,601	70,726	1,952	179,971	75,750	2,090	188,282
2053	58,457	1,489	162,117	66,136	1,685	173,288	72,346	1,844	181,814	77,568	1,977	190,258
2054	59,629	1,403	163,520	67,562	1,590	174,875	74,048	1,742	183,557	79,476	1,870	192,129
2055	60,834	1,322	164,841	69,031	1,500	176,375	75,804	1,647	185,204	81,447	1,770	193,898
2056	62,068	1,245	166,086	70,537	1,415	177,790	77,610	1,557	186,761	83,475	1,675	195,574
2057	63,327	1,173	167,260	72,077	1,335	179,126	79,461	1,472	188,234	85,556	1,585	197,159
2058	64,618	1,108	168,365	73,659	1,260	180,386	81,369	1,392	189,626	87,706	1,501	198,660
2059	65,982	1,042	169,408	75,323	1,190	181,576	83,372	1,317	190,943	89,959	1,421	200,081
2060	67,435	984	170,391	77,086	1,125	182,700	85,487	1,247	192,190	92,334	1,347	201,428

Table TP 6&7 Staff 15: Turkey Point 6&7

Fuel Cost Forecast	*Low Gas Cost*		
Environmental Compliance Cost Forecast	*Env I*		
Year	*Total Annual Costs (Millions)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	3,718	3,718	3,718
2008	4,394	4,058	7,775
2009	4,518	3,852	11,627
2010	4,869	3,833	15,460
2011	4,837	3,516	18,976
2012	4,945	3,318	22,294
2013	5,172	3,204	25,497
2014	5,556	3,178	28,675
2015	6,238	3,294	31,969
2016	6,938	3,382	35,351
2017	7,323	3,296	38,646
2018	7,877	3,189	41,838
2019	8,103	3,109	44,944
2020	8,307	2,942	47,886
2021	8,791	2,875	50,761
2022	9,511	2,872	53,633
2023	10,197	2,842	56,475
2024	11,037	2,840	59,315
2025	11,850	2,815	62,130
2026	12,779	2,802	64,932
2027	13,894	2,812	67,744
2028	14,903	2,785	70,529
2029	15,834	2,731	73,260
2030	16,919	2,695	75,955
2031	18,161	2,670	78,625
2032	19,751	2,681	81,306
2033	21,876	2,741	84,047
2034	23,458	2,713	86,760
2035	24,851	2,654	89,415
2036	27,100	2,672	92,087
2037	28,861	2,636	94,723
2038	30,328	2,549	97,273
2039	31,946	2,479	99,752
2040	33,849	2,426	102,177
2041	34,735	2,298	104,476
2042	35,444	2,166	106,641
2043	36,689	2,070	108,712
2044	37,768	1,968	110,680
2045	38,349	1,846	112,526
2046	38,936	1,731	114,257
2047	39,537	1,623	115,879
2048	40,147	1,522	117,401
2049	40,790	1,428	118,829
2050	41,454	1,340	120,169
2051	42,135	1,258	121,427
2052	42,845	1,181	122,608
2053	43,591	1,110	123,719
2054	44,390	1,044	124,763
2055	45,215	982	125,745
2056	46,058	924	126,668
2057	46,918	869	127,537
2058	47,797	818	128,355
2059	48,741	770	129,125
2060	49,782	726	129,850

Hearing Exhibit 000030

Table TP 6&7 Staff 15: CC

Fuel Cost Forecast	High Gas Cost											
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV		
Year	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	6,785	6,785	6,785	6,777	6,777	6,777	6,775	6,775	6,775	6,775	6,775	6,775
2008	8,056	7,438	14,223	8,046	7,429	14,206	8,044	7,427	14,202	8,044	7,427	14,202
2009	8,326	7,098	21,322	8,324	7,097	21,303	8,322	7,095	21,297	8,322	7,095	21,297
2010	8,680	6,833	28,155	8,293	6,528	27,831	8,948	7,044	28,341	9,145	7,199	28,496
2011	8,507	6,184	34,338	8,243	5,992	33,823	8,842	6,427	34,768	9,057	6,583	35,079
2012	8,396	5,633	39,972	8,259	5,541	39,364	8,808	5,910	40,678	9,052	6,074	41,153
2013	8,784	5,442	45,414	8,739	5,414	44,778	9,143	5,664	46,343	9,393	5,820	46,973
2014	9,508	5,439	50,853	9,528	5,450	50,228	9,961	5,698	52,041	10,249	5,863	52,836
2015	10,559	5,577	56,429	10,633	5,615	55,844	11,032	5,827	57,867	11,358	5,997	58,833
2016	11,892	5,799	62,228	12,071	5,886	61,730	12,454	6,073	63,940	12,806	6,244	65,077
2017	12,476	5,616	67,844	12,815	5,769	67,499	13,140	5,915	69,855	13,529	6,091	71,168
2018	13,499	5,610	73,455	13,927	5,788	73,287	14,196	5,900	75,756	14,628	6,080	77,248
2019	14,665	5,628	79,082	15,246	5,851	79,138	15,487	5,943	81,699	15,970	6,129	83,377
2020	15,617	5,533	84,615	16,444	5,826	84,964	16,664	5,904	87,604	17,224	6,103	89,480
2021	16,761	5,483	90,098	17,775	5,815	90,779	17,967	5,878	93,481	18,584	6,080	95,559
2022	17,887	5,402	95,501	19,061	5,757	96,536	19,268	5,819	99,301	19,980	6,035	101,595
2023	19,058	5,314	100,815	20,417	5,694	102,230	20,605	5,746	105,047	21,381	5,963	107,557
2024	20,359	5,241	106,056	21,990	5,682	107,891	22,221	5,721	110,768	23,104	5,949	113,506
2025	21,907	5,207	111,263	23,724	5,639	113,531	23,944	5,692	116,459	24,889	5,916	119,422
2026	23,485	5,149	116,412	25,479	5,591	119,122	25,826	5,668	122,127	26,867	5,896	125,318
2027	25,225	5,110	121,522	27,482	5,568	124,690	27,991	5,671	127,798	29,166	5,910	131,228
2028	26,879	5,028	126,550	29,342	5,489	130,179	30,199	5,649	133,448	31,557	5,904	137,132
2029	28,428	4,909	131,459	31,024	5,358	135,537	32,189	5,560	139,007	33,689	5,819	142,951
2030	30,298	4,830	136,289	33,002	5,262	140,799	34,553	5,510	144,517	36,215	5,775	148,726
2031	32,279	4,752	141,041	35,155	5,176	145,975	36,839	5,424	149,942	38,616	5,686	154,412
2032	34,798	4,729	145,770	37,886	5,150	151,125	39,731	5,401	155,343	41,651	5,663	160,075
2033	38,375	4,815	150,586	41,767	5,242	156,367	43,834	5,502	160,844	45,954	5,768	165,843
2034	41,089	4,760	155,346	44,703	5,180	161,546	46,944	5,440	166,284	49,214	5,703	171,546
2035	43,672	4,671	160,017	47,500	5,082	166,628	49,925	5,341	171,625	52,343	5,601	177,147
2036	47,516	4,692	164,709	51,686	5,105	171,733	54,374	5,371	176,997	57,020	5,633	182,780
2037	50,588	4,611	169,320	55,000	5,016	176,749	57,905	5,281	182,278	60,725	5,539	188,319
2038	53,156	4,475	173,795	57,830	4,869	181,618	60,951	5,133	187,411	63,934	5,385	193,704
2039	56,099	4,361	178,156	61,034	4,745	186,363	64,392	5,007	192,418	67,550	5,253	198,957
2040	59,547	4,274	182,429	64,796	4,651	191,015	68,424	4,912	197,330	71,792	5,155	204,111
2041	61,288	4,060	186,490	66,706	4,422	195,436	70,513	4,674	202,004	74,001	4,906	209,017
2042	62,808	3,844	190,333	68,430	4,189	199,625	72,425	4,434	206,438	76,043	4,655	213,673
2043	65,646	3,710	194,043	71,576	4,046	203,671	75,848	4,288	210,726	79,685	4,505	218,178
2044	68,017	3,550	197,593	74,197	3,873	207,544	78,715	4,109	214,836	82,732	4,319	222,497
2045	69,305	3,340	200,933	75,690	3,648	211,192	80,410	3,876	218,711	84,571	4,077	226,575
2046	70,648	3,144	204,078	77,243	3,438	214,630	82,174	3,658	222,369	86,485	3,850	230,425
2047	72,021	2,960	207,037	78,833	3,240	217,871	83,984	3,452	225,822	88,450	3,636	234,061
2048	73,434	2,787	209,824	80,471	3,054	220,925	85,851	3,259	229,081	90,477	3,435	237,496
2049	74,887	2,624	212,449	82,156	2,880	223,805	87,775	3,077	232,157	92,568	3,245	240,741
2050	76,377	2,472	214,921	83,886	2,715	226,520	89,753	2,905	235,062	94,719	3,066	243,807
2051	77,918	2,329	217,249	85,674	2,561	229,080	91,801	2,744	237,806	96,945	2,898	246,705
2052	79,510	2,194	219,443	87,522	2,416	231,496	93,918	2,592	240,399	99,248	2,740	249,444
2053	81,178	2,069	221,512	89,454	2,280	233,778	96,132	2,450	242,849	101,653	2,591	252,035
2054	82,894	1,951	223,463	91,443	2,152	235,928	98,414	2,316	245,165	104,134	2,451	254,488
2055	84,652	1,840	225,302	93,483	2,032	237,959	100,759	2,190	247,355	106,685	2,319	256,805
2056	86,490	1,736	227,038	95,612	1,919	239,878	103,206	2,071	249,426	109,346	2,195	258,999
2057	88,358	1,637	228,675	97,780	1,812	241,690	105,708	1,959	251,385	112,067	2,077	261,076
2058	90,235	1,544	230,219	99,967	1,711	243,401	108,238	1,852	253,238	114,828	1,965	263,041
2059	92,225	1,457	231,677	102,278	1,616	245,017	110,909	1,753	254,990	117,736	1,861	264,902
2060	94,298	1,376	233,052	104,680	1,527	246,544	113,686	1,659	256,648	120,758	1,762	266,663

Table TP 6&7 Staff 15: CC

Fuel Cost Forecast	*Medium Gas Cost*											
Environmental Compliance Cost Forecast	*Env I*			*Env II*			*Env III*			*Env IV*		
Year	*Total Annual Costs (Millions)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Millions)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Millions)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Millions)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	5,037	5,037	5,037	5,027	5,027	5,027	5,025	5,025	5,025	5,025	5,025	5,025
2008	5,957	5,500	10,537	5,948	5,490	10,517	5,944	5,488	10,513	5,944	5,488	10,513
2009	6,158	5,250	15,787	6,160	5,251	15,769	6,159	5,251	15,764	6,159	5,251	15,764
2010	6,572	5,174	20,960	6,184	4,868	20,637	6,840	5,384	21,148	7,036	5,539	21,303
2011	6,517	4,737	25,697	6,253	4,545	25,181	6,847	4,977	26,125	7,059	5,131	26,434
2012	6,514	4,371	30,068	6,378	4,279	29,460	6,923	4,645	30,770	7,162	4,805	31,239
2013	6,810	4,219	34,286	6,763	4,190	33,650	7,162	4,437	35,207	7,410	4,591	35,830
2014	7,334	4,195	38,481	7,352	4,205	37,856	7,777	4,449	39,655	8,062	4,611	40,441
2015	8,198	4,329	42,810	8,270	4,367	42,223	8,665	4,576	44,231	8,984	4,744	45,186
2016	9,103	4,438	47,248	9,281	4,525	46,747	9,660	4,709	48,941	10,009	4,880	50,066
2017	9,588	4,316	51,564	9,924	4,467	51,214	10,247	4,613	53,553	10,634	4,787	54,852
2018	10,447	4,341	55,905	10,870	4,517	55,731	11,136	4,628	58,181	11,565	4,806	59,658
2019	11,324	4,345	60,249	11,696	4,565	60,296	12,137	4,657	62,838	12,618	4,841	64,499
2020	12,092	4,283	64,532	12,907	4,572	64,868	13,125	4,649	67,487	13,680	4,846	69,345
2021	12,926	4,227	68,760	13,931	4,556	69,425	14,120	4,618	72,105	14,733	4,819	74,164
2022	13,658	4,184	72,944	15,022	4,536	73,961	15,223	4,597	76,702	15,927	4,810	78,974
2023	14,777	4,119	77,063	16,139	4,499	78,461	16,316	4,548	81,251	17,064	4,763	83,737
2024	15,820	4,071	81,135	17,438	4,489	82,949	17,869	4,548	85,799	18,539	4,772	88,509
2025	17,045	4,050	85,184	18,845	4,478	87,427	19,062	4,530	90,329	19,994	4,751	93,261
2026	18,272	4,008	89,192	20,267	4,446	91,873	20,613	4,522	94,851	21,639	4,748	98,008
2027	19,674	3,984	93,176	21,903	4,436	96,309	22,415	4,540	99,391	23,571	4,774	102,783
2028	20,950	3,917	97,093	23,389	4,374	100,683	24,242	4,533	103,925	25,573	4,783	107,566
2029	22,175	3,828	100,920	24,744	4,272	104,955	25,902	4,472	108,397	27,374	4,727	112,292
2030	23,659	3,770	104,690	26,338	4,198	109,153	27,875	4,444	112,840	29,501	4,703	116,996
2031	25,201	3,708	108,398	28,044	4,127	113,280	29,717	4,374	117,214	31,455	4,630	121,628
2032	27,166	3,690	112,088	30,217	4,106	117,388	32,051	4,355	121,570	33,929	4,611	126,237
2033	29,932	3,754	115,842	33,280	4,175	121,560	35,337	4,433	126,003	37,413	4,694	130,931
2034	32,061	3,712	119,554	35,629	4,126	125,686	37,851	4,385	130,388	40,085	4,645	135,575
2035	34,082	3,643	123,197	37,884	4,049	129,735	40,275	4,307	134,695	42,647	4,561	140,136
2036	37,021	3,654	126,851	41,139	4,061	133,797	43,810	4,326	139,021	46,403	4,582	144,718
2037	39,396	3,590	130,441	43,772	3,890	137,786	46,657	4,253	143,274	49,419	4,506	149,224
2038	41,416	3,484	133,925	46,033	3,874	141,660	49,125	4,135	147,409	52,051	4,382	153,606
2039	43,689	3,394	137,319	48,568	3,774	145,434	51,883	4,032	151,442	54,978	4,273	157,879
2040	46,339	3,324	140,643	51,532	3,697	149,131	55,104	3,954	155,396	58,401	4,191	162,070
2041	47,818	3,154	143,796	52,992	3,511	152,642	56,742	3,760	159,155	60,152	3,986	166,057
2042	48,690	2,978	146,774	54,247	3,319	155,961	58,181	3,560	162,715	61,721	3,777	169,834
2043	50,682	2,863	149,637	56,344	3,195	159,155	60,759	3,433	166,149	64,522	3,646	173,480
2044	52,359	2,731	152,368	58,467	3,051	162,206	62,928	3,284	169,432	66,880	3,490	176,971
2045	53,256	2,565	154,933	59,566	2,870	165,076	64,227	3,095	172,527	68,339	3,294	180,264
2046	54,198	2,411	157,344	60,716	2,701	167,777	65,586	2,918	175,446	69,865	3,109	183,373
2047	55,159	2,266	159,610	61,892	2,543	170,320	66,980	2,752	178,198	71,433	2,936	186,309
2048	56,150	2,130	161,740	63,105	2,394	172,714	68,421	2,598	180,795	73,055	2,772	189,081
2049	57,172	2,003	163,742	64,356	2,255	174,969	69,908	2,450	183,244	74,730	2,619	191,700
2050	58,219	1,883	165,626	65,640	2,124	177,093	71,439	2,312	185,556	76,457	2,474	194,175
2051	59,305	1,772	167,397	66,971	2,001	179,094	73,028	2,182	187,738	78,250	2,339	196,513
2052	60,432	1,667	169,065	68,350	1,886	180,980	74,675	2,061	189,799	80,109	2,211	198,724
2053	61,623	1,570	170,635	69,802	1,779	182,758	76,406	1,947	191,746	82,062	2,091	200,815
2054	62,850	1,479	172,113	71,299	1,678	184,436	78,194	1,840	193,586	84,060	1,979	202,794
2055	64,107	1,393	173,506	72,834	1,583	186,019	80,032	1,739	195,325	86,159	1,872	204,666
2056	65,432	1,313	174,819	74,446	1,494	187,513	81,980	1,645	196,970	88,338	1,773	206,439
2057	66,773	1,237	176,056	76,084	1,410	188,922	83,928	1,555	198,525	90,566	1,678	208,117
2058	68,109	1,165	177,221	77,728	1,330	190,252	85,914	1,470	199,996	92,825	1,588	209,706
2059	69,547	1,099	178,320	79,482	1,256	191,508	88,025	1,391	201,386	95,220	1,505	211,210
2060	71,051	1,037	179,356	81,313	1,186	192,694	90,229	1,316	202,702	97,720	1,426	212,635

Hearing Exhibit 000032

Table TP 6&7 Staff 15: CC

Fuel Cost Forecast	*Low Gas Cost*		
Environmental Compliance Cost Forecast	*Env 1*		
Year	*Total Annual Costs (Millions)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	3,718	3,718	3,718
2008	4,384	4,058	7,775
2009	4,515	3,852	11,627
2010	4,869	3,833	15,460
2011	4,837	3,516	18,976
2012	4,945	3,318	22,294
2013	5,172	3,204	25,497
2014	5,556	3,178	28,675
2015	6,238	3,294	31,969
2016	6,938	3,382	35,351
2017	7,323	3,296	38,646
2018	8,057	3,347	41,993
2019	8,733	3,349	45,343
2020	9,304	3,295	48,637
2021	9,939	3,250	51,887
2022	10,672	3,221	55,108
2023	11,387	3,173	58,281
2024	12,190	3,136	61,417
2025	13,134	3,119	64,536
2026	14,074	3,085	67,621
2027	15,171	3,070	70,692
2028	16,147	3,017	73,709
2029	17,095	2,949	76,658
2030	18,254	2,907	79,564
2031	19,438	2,858	82,422
2032	20,945	2,843	85,266
2033	23,050	2,888	88,154
2034	24,693	2,857	91,011
2035	26,251	2,804	93,815
2036	28,453	2,806	96,620
2037	30,269	2,756	99,376
2038	31,819	2,675	102,051
2039	33,544	2,603	104,654
2040	35,538	2,548	107,200
2041	36,454	2,412	109,613
2042	37,143	2,270	111,882
2043	38,448	2,170	114,052
2044	39,558	2,062	116,114
2045	40,134	1,932	118,045
2046	40,748	1,811	119,857
2047	41,373	1,698	121,555
2048	42,019	1,593	123,148
2045	42,687	1,494	124,642
2050	43,371	1,402	126,044
2051	44,087	1,316	127,361
2052	44,833	1,236	128,597
2053	45,633	1,162	129,759
2054	46,480	1,093	130,852
2055	47,308	1,027	131,879
2056	48,212	967	132,846
2057	49,122	910	133,756
2058	50,018	856	134,611
2059	51,002	806	135,417
2060	52,043	759	136,175

Hearing Exhibit 000033

Table TP 6&7 Staff 15: IGCC

Fuel Cost Forecast	High Gas Cost											
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV		
Year	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	6,785	6,785	6,785	6,777	6,777	6,777	6,775	6,775	6,775	6,775	6,775	6,775
2008	8,056	7,438	14,223	8,046	7,429	14,206	8,044	7,427	14,202	8,044	7,427	14,202
2009	8,326	7,098	21,322	8,324	7,097	21,303	8,322	7,095	21,297	8,322	7,095	21,297
2010	8,680	6,833	28,155	8,293	6,528	27,831	8,948	7,044	28,341	9,145	7,199	28,496
2011	8,507	6,184	34,338	8,243	5,992	33,823	8,842	6,427	34,768	9,057	6,583	35,079
2012	8,396	5,633	39,972	8,259	5,541	39,364	8,808	6,910	40,678	9,062	6,074	41,153
2013	8,784	5,442	45,414	8,739	5,414	44,778	9,143	6,664	46,343	9,393	6,820	48,973
2014	9,508	5,439	50,853	9,528	5,450	50,228	9,861	5,698	52,041	10,249	5,863	52,836
2015	10,559	5,577	56,429	10,633	5,615	55,844	11,032	6,827	57,867	11,356	6,997	58,833
2016	11,892	5,799	62,228	12,071	5,886	61,730	12,454	6,073	63,940	12,806	6,244	65,077
2017	12,476	5,616	67,844	12,815	5,769	67,499	13,140	6,916	69,855	13,529	8,091	71,168
2018	14,012	5,821	73,665	14,462	6,008	73,507	14,742	6,125	75,980	16,196	6,313	77,482
2019	15,448	5,924	79,589	16,078	6,166	79,672	16,337	6,266	82,245	16,860	6,466	83,948
2020	16,854	5,964	86,553	17,778	6,292	85,964	18,024	6,379	88,624	18,660	6,605	90,552
2021	18,209	5,948	91,501	19,374	6,330	92,294	19,598	6,403	95,027	20,312	6,636	97,189
2022	19,212	5,794	97,296	20,547	6,198	98,492	20,786	6,270	101,297	21,607	6,518	103,707
2023	20,251	5,639	102,935	21,793	6,070	104,561	22,009	6,130	107,427	22,901	6,379	110,086
2024	21,475	5,521	108,456	23,331	6,000	110,561	23,696	6,068	113,495	24,614	6,330	116,417
2025	22,931	5,443	113,899	24,990	5,933	116,494	25,247	5,994	119,489	26,334	6,253	122,670
2026	24,343	5,335	119,234	26,627	5,837	122,331	27,010	5,921	125,410	28,205	6,184	128,853
2027	25,953	5,252	124,486	28,502	5,769	128,100	29,066	5,883	131,293	30,410	6,156	135,009
2028	27,472	5,133	129,619	30,254	5,654	133,754	31,210	5,833	137,126	32,768	6,123	141,132
2029	28,869	4,980	134,599	31,794	5,486	139,240	33,093	5,711	142,837	34,797	6,005	147,138
2030	30,574	4,870	139,468	33,613	5,355	144,595	35,344	5,632	148,469	37,226	5,932	153,070
2031	32,434	4,770	144,238	35,650	5,244	149,839	37,528	5,521	153,990	39,534	5,817	158,887
2032	34,793	4,725	148,963	38,233	5,193	155,032	40,286	5,473	159,463	42,442	5,766	164,653
2033	38,311	4,803	153,766	42,083	5,275	160,307	44,347	5,562	165,025	46,708	5,859	170,512
2034	40,871	4,731	158,497	44,867	5,195	165,502	47,348	5,483	170,507	49,872	5,776	176,288
2035	43,189	4,617	163,114	47,413	5,069	170,571	50,091	5,356	175,864	52,774	5,844	181,932
2036	46,895	4,628	167,742	51,470	5,081	175,652	54,426	6,374	181,238	57,347	6,663	187,595
2037	49,783	4,537	172,279	54,633	4,980	180,632	57,825	5,272	186,509	60,931	5,556	193,151
2038	52,194	4,392	176,671	57,293	4,822	185,455	60,720	5,111	191,621	63,998	5,388	198,538
2039	54,983	4,272	180,943	60,355	4,690	190,145	64,027	4,977	196,597	67,491	6,246	203,785
2040	58,269	4,180	185,123	63,974	4,591	194,736	67,933	4,876	201,473	71,817	5,141	208,925
2041	59,839	3,964	189,087	65,743	4,356	199,092	69,904	4,633	206,105	73,722	4,886	213,812
2042	61,233	3,746	192,833	67,334	4,120	203,212	71,704	4,388	210,493	75,683	4,631	218,443
2043	63,805	3,605	196,438	70,235	3,969	207,181	74,900	4,233	214,727	79,090	4,471	222,913
2044	65,929	3,440	199,878	72,630	3,791	210,972	77,560	4,048	218,775	81,947	4,278	227,191
2045	66,977	3,228	203,106	73,898	3,562	214,533	79,047	3,810	222,585	83,590	4,030	231,221
2046	68,146	3,033	206,138	75,294	3,351	217,886	80,672	3,591	226,177	85,376	3,801	235,021
2047	69,462	2,855	208,993	76,843	3,158	221,043	82,459	3,390	229,566	87,331	3,590	238,612
2048	70,816	2,687	211,680	78,439	2,977	224,020	84,302	3,200	232,768	89,348	3,392	242,003
2049	72,209	2,530	214,211	80,081	2,807	226,827	86,203	3,022	235,788	91,428	3,205	246,208
2050	73,637	2,383	216,594	81,767	2,646	229,474	88,158	2,854	238,641	93,569	3,029	248,237
2051	75,114	2,245	218,838	83,510	2,496	231,969	90,181	2,696	241,337	95,785	2,863	251,100
2052	76,641	2,115	220,953	85,311	2,355	234,324	92,275	2,547	243,884	98,078	2,707	253,807
2053	78,242	1,994	222,947	87,197	2,222	236,546	94,464	2,408	246,291	100,473	2,561	256,368
2054	79,880	1,880	224,827	89,138	2,098	238,644	96,722	2,276	248,568	102,945	2,423	258,791
2055	81,579	1,773	226,600	91,128	1,980	240,624	99,042	2,153	250,720	105,487	2,293	261,084
2056	83,345	1,672	228,272	93,206	1,870	242,495	101,464	2,036	252,756	108,138	2,170	263,254
2057	85,138	1,578	229,850	95,322	1,766	244,261	103,937	1,926	254,683	110,849	2,054	265,309
2058	86,916	1,487	231,337	97,433	1,667	245,929	106,421	1,821	256,504	113,579	1,944	267,252
2059	88,639	1,404	232,741	99,699	1,575	247,504	109,075	1,724	258,227	116,487	1,841	269,093
2060	90,848	1,326	234,173	102,062	1,489	249,099	111,842	1,832	259,958	119,518	1,744	270,843

Note: For all cases, NPV Cumulative Total Costs Value in year 2060 includes a Coal Inventory Working Capital Carrying Costs of $106.738 millions in NPV $2007.

Table TP 6&7 Staff 15: IGCC

Fuel Cost Forecast	Medium Gas Cost											
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV		
Year	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Millions)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	5,037	5,037	5,037	5,027	5,027	5,027	5,025	5,025	5,025	5,025	5,025	5,025
2008	5,957	5,500	10,537	5,946	5,490	10,517	5,944	5,488	10,513	5,944	5,488	10,513
2009	6,158	5,250	15,787	6,160	5,251	15,769	6,159	5,251	15,764	6,159	5,251	15,764
2010	6,572	5,174	20,960	6,184	4,868	20,637	6,840	5,384	21,148	7,036	5,539	21,303
2011	6,517	4,737	25,697	6,253	4,545	25,181	6,847	4,977	26,125	7,059	5,131	26,434
2012	6,514	4,371	30,068	6,378	4,279	29,460	6,923	4,645	30,770	7,182	4,805	31,238
2013	6,810	4,219	34,286	6,763	4,190	33,650	7,182	4,437	35,207	7,410	4,591	35,830
2014	7,334	4,195	38,481	7,352	4,205	37,856	7,777	4,449	39,655	8,052	4,611	40,441
2015	8,198	4,329	42,810	8,270	4,367	42,223	8,665	4,576	44,231	8,884	4,744	45,186
2016	9,103	4,438	47,248	9,281	4,525	46,747	9,660	4,709	48,941	10,009	4,880	50,066
2017	9,568	4,316	51,564	9,824	4,467	51,214	10,247	4,613	53,558	10,634	4,787	54,852
2018	11,018	4,578	56,139	11,460	4,760	55,974	11,740	4,876	58,429	12,190	5,083	59,916
2019	12,232	4,689	60,828	12,854	4,928	60,902	13,113	5,027	63,458	13,631	5,226	65,142
2020	13,510	4,779	65,607	14,431	5,105	66,007	14,677	5,193	68,649	15,309	5,415	70,558
2021	14,652	4,784	70,390	15,810	5,163	71,170	16,028	5,234	73,883	16,741	5,467	76,024
2022	15,473	4,664	75,054	16,801	5,065	76,235	17,037	5,137	79,019	17,848	5,382	81,406
2023	16,277	4,530	79,584	17,828	4,962	81,197	18,033	5,020	84,039	18,919	5,267	86,673
2024	17,250	4,432	84,018	19,097	4,908	86,105	19,362	4,977	89,016	20,386	5,236	91,909
2025	18,390	4,362	88,379	20,440	4,850	90,956	20,693	4,911	93,927	21,767	5,168	97,075
2026	19,492	4,289	92,648	21,764	4,768	95,724	22,149	4,853	98,780	23,332	5,113	102,188
2027	20,788	4,200	96,847	23,302	4,714	100,438	23,809	4,829	103,608	25,196	5,098	107,286
2028	21,936	4,096	100,943	24,695	4,613	105,051	25,648	4,791	108,399	27,175	5,077	112,363
2029	23,035	3,971	104,914	25,934	4,473	109,523	27,226	4,696	113,095	28,909	4,987	117,350
2030	24,385	3,881	108,795	27,398	4,362	113,886	29,117	4,637	117,732	30,971	4,933	122,283
2031	25,818	3,794	112,590	29,009	4,265	118,151	30,875	4,540	122,273	32,851	4,831	127,115
2032	27,853	3,752	116,342	31,057	4,217	122,368	33,105	4,495	126,767	35,230	4,784	131,899
2033	30,407	3,809	120,151	34,125	4,277	126,645	36,396	4,562	131,330	38,721	4,855	136,753
2034	32,361	3,747	123,898	36,352	4,207	130,852	38,816	4,493	135,822	41,302	4,781	141,536
2035	34,173	3,650	127,548	38,362	4,099	134,951	41,020	4,384	140,206	43,683	4,667	146,202
2036	36,996	3,649	131,197	41,534	4,098	139,048	44,485	4,388	144,594	47,344	4,673	150,875
2037	39,236	3,573	134,770	44,046	4,013	143,061	47,207	4,301	148,896	50,266	4,581	155,456
2038	41,113	3,457	138,227	46,182	3,885	146,946	49,560	4,170	153,065	52,787	4,442	159,898
2039	43,258	3,358	141,585	48,602	3,775	150,720	52,219	4,057	157,122	55,630	4,322	164,220
2040	45,778	3,282	144,867	51,454	3,690	154,410	55,348	3,970	161,092	58,977	4,231	168,451
2041	48,839	3,107	147,974	52,810	3,497	157,907	56,898	3,769	164,861	60,654	4,018	172,469
2042	47,896	2,928	150,902	53,088	3,300	161,208	58,257	3,563	168,424	62,153	3,802	176,272
2043	49,643	2,803	153,705	56,039	3,165	164,373	60,625	3,425	171,849	64,755	3,659	179,931
2044	51,111	2,865	156,570	57,773	3,014	167,387	62,625	3,267	175,116	66,956	3,494	183,424
2045	51,789	2,494	158,864	58,668	2,826	170,213	63,737	3,071	178,187	68,231	3,288	186,713
2046	52,578	2,339	161,203	59,683	2,655	172,868	64,976	2,891	181,079	69,641	3,099	189,812
2047	53,534	2,198	163,401	60,641	2,500	175,368	66,399	2,727	183,806	71,211	2,927	192,738
2048	54,458	2,066	165,466	62,036	2,354	177,722	67,807	2,573	186,379	72,833	2,764	195,502
2049	55,443	1,942	167,408	63,287	2,217	179,939	69,293	2,428	188,807	74,510	2,611	198,114
2050	56,452	1,826	169,235	64,532	2,088	182,026	70,823	2,292	191,099	76,237	2,467	200,581
2051	57,439	1,716	170,952	65,843	1,967	183,994	72,410	2,164	193,263	78,030	2,332	202,913
2052	58,585	1,618	172,568	67,202	1,854	185,848	74,057	2,044	195,308	79,889	2,205	205,118
2053	59,735	1,522	174,090	68,633	1,749	187,597	75,787	1,931	197,238	81,841	2,086	207,203
2054	60,821	1,433	175,523	70,110	1,650	189,248	77,575	1,825	199,063	83,858	1,973	209,177
2055	62,135	1,350	176,873	71,623	1,556	190,803	79,414	1,726	200,789	85,935	1,867	211,044
2056	63,415	1,272	178,146	73,213	1,469	192,272	81,342	1,632	202,421	88,109	1,766	212,812
2057	64,710	1,199	179,344	74,828	1,386	193,658	83,309	1,544	203,965	90,333	1,674	214,486
2058	65,977	1,129	180,473	76,426	1,308	194,966	85,273	1,459	205,424	92,563	1,584	216,070
2059	67,376	1,064	181,538	78,166	1,235	196,201	87,305	1,381	206,805	94,960	1,501	217,571
2060	68,848	1,004	182,648	79,989	1,167	197,474	89,616	1,308	208,218	97,486	1,422	219,099

Note: For all cases, NPV Cumulative Total Costs Value in year 2060 includes a Coal Inventory Working Capital Carrying Costs of $106.738 millions in NPV $2007.

Hearing Exhibit 000035

Fuel Cost Forecast	Low Gas Cost		
Environmental Compliance Cost Forecast	Env 1		
Year	*Total Annual Costs (billions)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	3,718	3,718	3,718
2008	4,394	4,058	7,775
2009	4,518	3,852	11,627
2010	4,869	3,833	15,460
2011	4,837	3,516	18,976
2012	4,845	3,318	22,294
2013	5,172	3,204	25,497
2014	5,556	3,178	28,675
2015	6,238	3,294	31,969
2016	6,808	3,382	35,351
2017	7,323	3,296	38,646
2018	8,881	3,604	42,250
2019	9,755	3,737	45,987
2020	10,933	3,865	49,852
2021	11,942	3,896	53,749
2022	12,580	3,788	57,538
2023	13,197	3,670	61,208
2024	13,940	3,579	64,787
2025	14,808	3,510	68,297
2026	15,642	3,423	71,720
2027	16,633	3,361	75,081
2028	17,518	3,268	78,348
2029	18,355	3,161	81,510
2030	19,405	3,086	84,596
2031	20,499	3,010	87,606
2032	21,895	2,968	90,574
2033	24,019	3,006	93,581
2034	25,532	2,951	96,531
2035	26,871	2,867	99,399
2036	28,975	2,855	102,253
2037	30,882	2,791	105,045
2038	32,117	2,698	107,742
2039	33,735	2,618	110,359
2040	35,629	2,562	112,919
2041	36,454	2,411	115,331
2042	37,055	2,253	117,584
2043	36,137	2,151	119,735
2044	38,067	2,036	121,771
2045	39,444	1,898	123,669
2046	39,925	1,775	125,444
2047	40,534	1,664	127,107
2048	41,164	1,560	128,668
2049	41,816	1,464	130,132
2050	42,484	1,373	131,505
2051	43,182	1,289	132,794
2052	43,910	1,211	134,005
2053	44,663	1,138	135,143
2054	46,602	1,070	136,213
2055	48,330	1,006	137,219
2056	47,219	947	138,166
2057	48,105	891	139,057
2058	48,957	837	139,895
2059	49,930	788	140,683
2060	50,986	743	141,533

Note: For all cases, NPV Cumulative Total Costs Value in year 2060 includes a Coal Inventory Working Capital Carrying Costs of $106.738 millions in NPV $2007.

Q.

Please provide a levelized cost (in $/kwh) for various capacity factors comparing Turkey Point 6 and 7, a natural gas combined cycle unit, an IGCC unit, a single wind unit, and a roof top PV unit. Please show levelized capital costs and O&M/Fuel costs separately. Also, please provide the raw data and a chart depicting this information.

A.

FPL interprets the question to request a screening curve type of analysis for the five technologies mentioned and is providing the requested information based on such an analysis. However, FPL does not make its resource decisions based on screening curve analyses because screening curve analyses provide an incomplete analysis of resource options. For example, a screening curve does not take into account the differences in system fuel impacts or the differences in future capacity deferral impacts between two resource options. In addition, a screening curve analysis approach does not recognize the system advantages of firm capacity resources such as nuclear, CC, and IGCC capacity additions when compared to options such as wind and PV in Florida that may not provide firm capacity at a utility's peak hours. Due to the intermittent nature of the energy sources for wind and PV generation options, and due to the early winter morning and late summer afternoon peak electrical load hours in Florida, these specific renewable options may serve as non-firm or energy only resource options.

Consequently, FPL believes that the results of the screening curve analysis presented below are not appropriate for selecting among these technology alternatives.

Table TP 6&7 Staff 16 presents the levelized total costs in $/MWh, the levelized capital costs, the levelized fixed O&M costs, and the levelized variable costs (fuel, emissions and VO&M) for various capacity factors for these technologies on pages 1 through 4 of 8. The maximum capacity factor values used for each technology are representative of the highest expected capacity factor for each technology operating in Florida. Pages 5 through 7 of 8 present the data assumptions used in developing these levelized costs.

Figure TP 6&7 Staff 16, page 8 of 8, presents the total levelized costs in graphic format.

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page 1 of 8

Levelized Total Cost $/MWh

Capacity factor %	**Turkey Point 6 and 7**	**CC**	**IGCC**	**Wind**	**PV**
0	-	-	-	-	-
5	1,878	420	1,879	1,443	3,658
10	945	263	983	721	1,829
15	634	211	684	481	1,219
20	478	184	535	361	915
25	385	169	445	289	732
30	323	158	385	--	--
35	278	151	343	--	--
40	245	145	311	--	--
45	219	141	286	--	--
50	198	137	266	--	--
55	181	134	250	--	--
60	167	132	236	--	--
65	155	130	225	--	--
70	145	128	215	--	--
75	136	127	206	--	--
80	128	125	199	--	--
85	122	124	--	--	--
90	115	123	--	--	--
95	110	122	--	--	--
100	--	--	--	--	--

Levelized Capital Cost $/MWh

Capacity factor	**Turkey Point 6 and 7**	**CC**	**IGCC**	**Wind**	**PV**
0	-	-	-	-	-
5	1,443	263	1,688	1,302	3,605
10	721	132	844	651	1,802
15	481	88	563	434	1,202
20	361	66	422	325	901
25	289	53	338	260	721
30	240	44	281	--	--
35	206	38	241	--	--
40	180	33	211	--	--
45	160	29	188	--	--
50	144	26	169	--	--
55	131	24	153	--	--
60	120	22	141	--	--
65	111	20	130	--	--
70	103	19	121	--	--
75	96	18	113	--	--
80	90	16	105	--	--
85	85	15	--	--	--
90	80	15	--	--	--
95	76	14	--	--	--
100	--	--	--	--	--

TP 6 and 7 - Staff 16
page 3 of 8

Levelized Fixed O&M and Gas Transportation Costs $/MWh

Capacity factor	**Turkey Point 6 and 7**	**CC**	**IGCC**	**Wind**	**PV**
0	-	-	-	-	-
5	423	51	104	141	53
10	212	26	52	70	27
15	141	17	35	47	18
20	106	13	26	35	13
25	85	10	21	28	11
30	71	9	17	--	--
35	60	7	15	--	--
40	53	6	13	--	--
45	47	6	12	--	--
50	42	5	10	--	--
55	38	5	9	--	--
60	35	4	9	--	--
65	33	4	8	--	--
70	30	4	7	--	--
75	28	3	7	--	--
80	26	3	7	--	--
85	25	3	--	--	--
90	24	3	--	--	--
95	22	3	--	--	--
100	21	--	--	--	--

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Fuel Emission and VOM Costs $/MWh

Capacity factor	Turkey Point 6 and 7	CC	IGCC	Wind	PV
0	-	-	-	-	-
5	12	106	87	-	(0)
10	12	106	87	-	(0)
15	12	106	87	-	(0)
20	12	106	87	-	(0)
25	12	106	87	-	(0)
30	12	106	87	--	--
35	12	106	87	--	--
40	12	106	87	--	--
45	12	106	87	--	--
50	12	106	87	--	--
55	12	106	87	--	--
60	12	106	87	--	--
65	12	106	87	--	--
70	12	106	87	--	--
75	12	106	87	--	--
80	12	106	87	--	--
85	12	106	--	--	--
90	12	106	--	--	--
95	12	106	--	--	--
100	--	--	--	--	--

Unit Operating and Cost Data

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
	Avg TP 6 and 7	CC	IGCC	Wind	Photovoltaic
Operating and Cost Data					
Technology	Nuclear	3x1 G	IGCC	Wind	PV
Gas MMBTU/day	0	200	0	0	0
Gas Transportation Cost $/MMBTU	0.00	1.55	0	0	0
Base Operation (MW) annual average rating	1,100	1,267	638	100	100
Base Op 'Heat Rate, 75 deg. F (BTU/KWH)	10,400	6,582	9,250	--	--
Capital Cost $/kw (overnight)	4,718	798	4,639	4,624	11,809
Fixed O&M ($/KW-yr) see note	110.0	5.2	20.8	49.9	18.9
Capital Replace ($/kW-Yr)	30.0	12.8	16.2	0.00	0.00
VOM ($/MWh)	0.00	0.80	0.00	0.00	0.00
Nox emission rate (lb/mmbtu)	0.000	0.010	0.015	0.000	0.000
SO2 emission rate (lb/mmbtu)	0.000	0.006	0.023	0.000	0.000
CO2 emission rate (lb/mmbtu)	0.000	119.000	213.000	0.000	0.000
Hg emission rate (lb/ trillion btu)	0.000	0.000	0.500	0.000	0.000
Financial Data					
Discount rate	0.0840				
I/S Year of Units for comparison	2018				
Costs provided in year	2018				

Note:

Photovoltaic costs are are based on centralized PV installations

Fuel prices $/MMBTU nominal

	Nuclear	3x1 G	IGCC	Wind	PV
	1	2	3	4	5
2007	0.000	7.503	3.696	0.000	0.000
2008	0.000	8.898	3.176	0.000	0.000
2009	0.000	9.167	3.019	0.000	0.000
2010	0.000	8.366	3.061	0.000	0.000
2011	0.000	7.945	3.109	0.000	0.000
2012	0.000	7.320	3.150	0.000	0.000
2013	0.000	7.562	2.976	0.000	0.000
2014	0.000	7.911	3.014	0.000	0.000
2015	0.000	8.367	3.058	0.000	0.000
2016	0.000	8.617	3.111	0.000	0.000
2017	0.000	8.870	3.165	0.000	0.000
2018	0.872	9.125	3.222	0.000	0.000
2019	0.867	9.595	3.281	0.000	0.000
2020	0.914	10.070	3.344	0.000	0.000
2021	0.954	10.436	3.401	0.000	0.000
2022	0.996	10.814	3.462	0.000	0.000
2023	1.012	11.207	3.523	0.000	0.000
2024	1.022	11.614	3.590	0.000	0.000
2025	1.007	12.036	3.670	0.000	0.000
2026	1.032	12.473	3.738	0.000	0.000
2027	1.058	12.927	3.809	0.000	0.000
2028	1.085	13.397	3.882	0.000	0.000
2029	1.112	13.884	3.958	0.000	0.000
2030	1.140	14.389	4.034	0.000	0.000
2031	1.168	14.913	4.110	0.000	0.000
2032	1.197	15.456	4.188	0.000	0.000
2033	1.227	16.019	4.266	0.000	0.000
2034	1.258	16.603	4.344	0.000	0.000
2035	1.289	17.207	4.425	0.000	0.000
2036	1.322	17.835	4.509	0.000	0.000
2037	1.355	18.485	4.594	0.000	0.000
2038	1.388	19.159	4.681	0.000	0.000
2039	1.423	19.857	4.771	0.000	0.000
2040	1.459	20.582	4.861	0.000	0.000
2041	1.495	21.333	4.954	0.000	0.000
2042	1.533	22.111	5.049	0.000	0.000
2043	1.571	22.918	5.145	0.000	0.000
2044	1.610	23.755	5.243	0.000	0.000
2045	1.650	24.622	5.344	0.000	0.000
2046	1.692	25.521	5.447	0.000	0.000
2047	1.734	26.454	5.551	0.000	0.000
2048	1.777	27.420	5.658	0.000	0.000
2049	1.822	28.422	5.767	0.000	0.000
2050	1.867	29.460	5.878	0.000	0.000
2051	1.914	30.537	5.992	0.000	0.000
2052	1.962	31.653	6.107	0.000	0.000
2053	2.011	32.810	6.226	0.000	0.000
2054	2.061	34.010	6.347	0.000	0.000
2055	2.113	35.253	6.470	0.000	0.000
2056	2.166	36.542	6.596	0.000	0.000
2057	2.220	37.879	6.725	0.000	0.000

Emission prices nominal

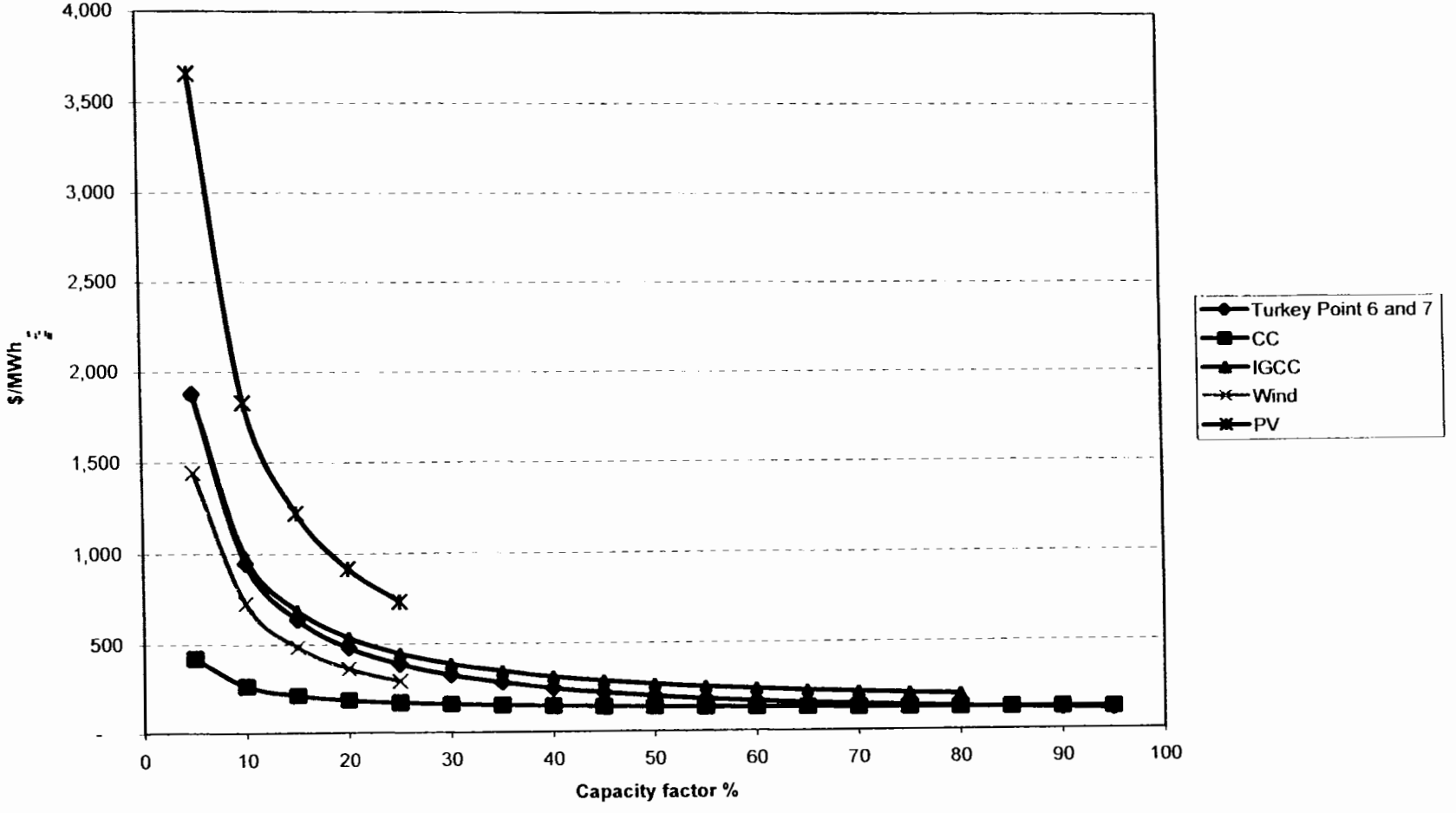
Source: Environmental Compliance Cost Forcast ENV III

Year	Nox Emission Cost in $ per ton	SO2 Emission Cost in $ per ton	CO2 Emission Cost in $ per ton	Hg Emission Cost in $ per pound
2007	0	867	0.0	-
2008	0	950	0.0	-
2009	1,633	1,040	0.0	-
2010	1,786	1,138	11.3	29,832
2011	1,955	1,247	12.8	29,533
2012	2,142	1,366	14.3	29,237
2013	2,347	1,496	14.6	28,943
2014	2,571	1,639	16.2	30,134
2015	2,815	1,793	17.9	32,994
2016	3,082	1,964	19.7	36,127
2017	3,374	2,149	21.5	39,540
2018	3,693	2,353	23.4	43,276
2019	4,041	2,576	25.4	47,366
2020	4,423	2,818	29.0	51,840
2021	3,590	3,088	31.2	56,782
2022	2,912	3,383	35.0	62,195
2023	2,363	3,704	37.4	68,123
2024	1,918	4,057	41.6	74,617
2025	1,557	4,444	44.2	81,746
2026	0	4,419	48.7	89,520
2027	0	4,395	53.4	98,052
2028	0	4,369	60.0	107,398
2029	0	4,345	65.1	117,636
2030	0	4,320	70.4	128,847
2031	0	4,489	73.4	133,893
2032	0	4,665	76.4	139,137
2033	0	4,847	79.5	144,586
2034	0	5,037	82.7	150,248
2035	0	5,234	86.0	156,132
2036	0	5,439	89.4	162,246
2037	0	5,652	93.0	168,600
2038	0	5,874	96.7	175,203
2039	0	6,104	100.5	182,064
2040	0	6,343	104.4	189,194
2041	0	6,591	108.5	196,603
2042	0	6,849	112.7	204,302
2043	0	7,118	117.1	212,303
2044	0	7,396	121.5	220,617
2045	0	7,686	126.2	229,257
2046	0	7,987	131.0	238,235
2047	0	8,300	136.0	247,565
2048	0	8,625	141.1	257,260
2049	0	8,963	146.4	267,335
2050	0	9,314	151.9	277,804
2051	0	9,678	157.6	288,684
2052	0	10,057	163.4	299,989
2053	0	10,451	169.5	311,737
2054	0	10,860	175.7	323,945
2055	0	11,286	182.2	336,632
2056	0	11,728	189.0	349,815
2057	0	12,187	196.0	363,514

Hearing Exhibit 000045

Levelized total costs - various generation technologies
Costs levelized to 2018

TP 6 and 7 Staff 16 Chart
Page 8 of 8



Q.

Please complete the following chart to show FPL's actual total retail rate, base rate percentage, fuel cost percentage, and generation by gas percentage:

Comparison of FPL's Retail Rate to % Generation by Gas
19982000200220042006
Total Retail Rate c/kwh
Base Rate %
Fuel Costs %
Generation by Gas %

A.

Comparison of FPL's Retail Rate to % Generation by Gas					
	1998	2000	2002	2004	2006
Total Retail Rate ¢/kWh [1]	7.16	6.89	7.36	8.42	11.22
Base Rate % [2]	59.4%	55.6%	49.3%	42.2%	31.2%
Fuel Costs % [2]	26.5%	30.7%	36.5%	44.4%	54.9%
Generation by Gas %	24.2%	24.6%	32.7%	37.0%	49.4%

Notes:

[1] As reported in FERC Form 1 - Sales of Electricity by Rate Schedule, page 304.1, Average Retail Revenue per kWh. Includes Applicable Taxes.

[2] Other components of the Total Bill, not included in the Base Rate % and Fuel Costs % are the following: Energy Conservation Cost Recovery, Storm Restoration Surcharge, Capacity Cost Recovery Clause, Environmental Cost Recovery Clause, Rate Refund, Gross Receipts Taxes and Franchise Fees.

Q.
Please complete the following table comparing FPL's proposed nuclear and other generation alternatives:

Comparison of FPL's Solid Fuel Generation Alternatives			
Turkey Point Unit 6	Turkey Point Unit 7	IGCC	Gas CC
Size(MW)			
Costs			
Installed costs (2018/2020$ million)			
Capital $/kW			
Fixed O&M ($/kw-yr)			
Variable O&M ($/mwh)			
Heat Rate (BTU/kWh)			
Eq. Avail. %			
Water Usage(gal/day)			
Emission Rates			
NOx (lb/Mbtu)			
SO2 (lb/Mbtu)			
CO2 (lb/Mbtu)			
Mercury (lb/Mbtu)			

A.
Table TP 6&7 Staff 18 presents the requested information. Appendix I of the Need Study document in FPL's filing also presents much of the requested information for the CC and IGCC options.

Table TP 6&7 Staff 18

Comparison of FPL's Generation Alternatives						
	Turkey Point Unit 6	Turkey Point Unit 6	Turkey Point Unit 7	Turkey Point Unit 7	IGCC	Gas CC
Size(MW, summer)	1100	1100	1100	1100	600	1219
Nuclear Cost Case	Case B *	Case C*	Case B*	Case C*	--	--
Installed costs (2018/2020$ million)	7,249	10,654	4,833	7,102	3,527	1,110
Capital $/kW	6,590	9,685	4,394	6,457	5,879	910
Fixed O&M ($/kw-yr)	120.0	120.0	120.0	120.0	27.3	5.2
Variable O&M ($/mwh)	0	0	0	0	4.7	0.8
Heat Rate (BTU/kWh)	10,400	10,400	10,400	10,400	9,250	6,582
Eq. Avail. %	92	92	92	92	80	97
Water Usage (Million gal/day)	43	43	43	43	7.5	7
Emission Rates						
NO_x (lb/Mbtu)	-	-	-	-	0.015	0.01
SO_2 (lb/Mbtu)	-	-	-	-	0.023	0.006
CO_2 (lb/Mbtu)	-	-	-	-	213	119
Mercury (lb/Mbtu)	-	-	-	-	0.5	0

Notes:

- The nuclear units will require approximately 43 milllion gallons per day per unit. These estimates are based on similar nuclear unit cooling configurations and water requirements studies and on a water source requiring limited treatment and allowing for efficient water quality management plan. Lower quality resources, such as saltwater, may require a different water quality management approach, increasing required amounts.
- A 3x1 G combined cycle unit requires and average of approximately 7 million gallons per day based on 50% surface water and 50% Floridan water with the cooling tower operating at 6 cycles of concentration. This water usage may vary depending on the quality of the water available at a given site.
- The IGCC (600MW) without capture requires an average of about 7.5 million gallons per day. This is based on inputs from an EPRI study based on a Texas site using well water at 4 cycles of concentration. This water usage may vary depending on the quality of the water available at a given site.

* The Nuclear Cost Case refers to the information provided in Appendix J of FPL's Need Study document. Case B is the lowest of the three cost cases presented and Case C is the highest of the three cost cases presented in Appendix J.

Q.

Please provide a chart of the Residential Rate Impact of Turkey Point 6 and 7 in $/1000 KWH from 2013 through 2035.

A. Please provide the same information if a gas combined cycle unit was added in lieu of Turkey Point 6 and 7.
B. Please provide the same information if an IGCC unit was added in lieu of Turkey Point 6 and 7.

A.

The requested information comparing Turkey Point 6&7 versus CC capacity is presented in Table TP 6&7 Staff 19, page 1 of 2. The data provided for the years 2013 through 2021 was previously presented in Exhibit SRS-9 of FPL Witness Sim's testimony.

The requested information comparing Turkey Point 6&7 versus IGCC capacity is presented in Table TP 6&7 Staff 19, page 2 of 2.

Table TP 6&7 Staff 19

Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7 vs CC: 2013 - 2035

Scenario: Mid Gas Cost Env II

	(1)	(2)	(3) = (1)-(2)	(4)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000)	(6) = ((5)x1,000) / 100
Year	Plan with Nuclear Annual Total Revenue Requirements ($millions, Nominal $)	Plan without Nuclear - CC Annual Total Revenue Requirements ($millions, Nominal $)	Differential in Annual Total Revenue Requirements ($millions, Nominal $)	Projected Total Sales After DSM (GWh at the meter)	Differential in System Average Electric Rates (cents/kwh)	Differential in Customer Bill of 1,000 kwh ($)
2013	6,943	6,784	159	131,170	$0.12	$1.21
2014	7,646	7,352	294	134,617	$0.22	$2.18
2015	8,733	8,270	463	138,217	$0.33	$3.35
2016	9,944	9,281	663	142,209	$0.47	$4.66
2017	10,768	9,924	843	145,542	$0.58	$5.80
2018	11,611	10,870	742	149,218	$0.50	$4.97
2019	12,489	11,898	591	152,896	$0.39	$3.86
2020	13,077	12,907	170	157,170	$0.11	$1.08
2021	13,872	13,931	-59	161,572	-$0.04	-$0.36
2022	14,852	15,022	-170	161,573	-$0.11	-$1.05
2023	15,843	16,139	-295	161,574	-$0.18	-$1.83
2024	17,111	17,438	-327	161,575	-$0.20	-$2.02
2025	18,287	18,845	-559	161,576	-$0.35	-$3.46
2026	19,613	20,267	-654	161,577	-$0.40	-$4.05
2027	21,204	21,903	-700	161,578	-$0.43	-$4.33
2028	22,594	23,389	-796	161,579	-$0.49	-$4.92
2029	23,867	24,744	-877	161,580	-$0.54	-$5.43
2030	25,343	26,338	-995	161,581	-$0.62	-$6.16
2031	26,986	28,044	-1,059	161,582	-$0.66	-$6.55
2032	29,155	30,217	-1,063	161,583	-$0.66	-$6.58
2033	32,189	33,280	-1,091	161,584	-$0.68	-$6.75
2034	34,380	35,629	-1,248	161,585	-$0.77	-$7.73
2035	36,401	37,864	-1,463	161,586	-$0.91	-$9.06

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.
(3) For purposes of this analysis, a cost $3800/kW (2007$) is assumed for both nuclear units.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: December 21, 2007

NOTICE OF SERVICE
OF FLORIDA POWER & LIGHT COMPANY'S SUPPLEMENTAL RESPONSE
TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S
FIRST SET OF INTERROGATORIES NO. 19

Florida Power & Light Company gives notice of service of its supplemental response to the Staff of the Florida Public Service Commission's First Set of Interrogatories No. 19 to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 21st day of December, 2007.

R. Wade Litchfield, Vice President &
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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

DOCUMENT NUMBER-DATE
12424 DEC 21 07
FPSC-COMMISSION CLERK
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 21st day of December, 2007, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
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Florida Municipal Electric Association**
P.O. Box 10114
Tallahassee, FL 32302-2114

By: *s/Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000051

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: December 21, 2007

FLORIDA POWER & LIGHT COMPANY'S SUPPLEMENTAL RESPONSE TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIRST SET OF INTERROGATORIES NO. 19

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following supplemental response to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories No. 19.

FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in Florida Power & Light Company's Objections to Staff's First Set of Interrogatories (Nos. 1-23), dated November 8, 2007.

FPL's supplemental response to Staff's First Set of Interrogatories No. 19 is without waiver of its general and specific objections. Attached hereto is FPL's supplemental answer to Staff's First Set of Interrogatories No. 19, consistent with its prior objections, together with the affidavit of the person providing said supplemental answer.

Respectfully submitted this 21st day of December, 2007.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
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Attorneys for Florida Power & Light Company

By: _____

Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000053

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 21st day of December, 2007, to the following:

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Florida Public Service Commission
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On Behalf of Jan M. Krasowski and Bob Krasowski**

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Attorney for Seminole Electric Cooperative, Inc.**

Barry Moline
Florida Municipal Electric Association**
P.O. Box 10114
Tallahassee, FL 32302-2114

By: _____
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000054

Q.

Please provide a chart of the Residential Rate Impact of Turkey Point 6 and 7 in $/1000 KWH from 2013 through 2035.

A. Please provide the same information if a gas combined cycle unit was added in lieu of Turkey Point 6 and 7.
B. Please provide the same information if an IGCC unit was added in lieu of Turkey Point 6 and 7.

A.

See corrected Attachment 1.

Table TP 6&7 Staff 19

Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7 vs CC: 2013 - 2035

Scenario: Mid Gas Cost Env II

Year	(1) Plan with Nuclear Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan without Nuclear - CC Annual Total Revenue Requirements ($millions, Nominal $)	(3) = (1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000) Differential in System Average Electric Rates (cents/kwh)	(6) = ((5)x1,000) / 100 Differential in Customer Bill of 1,000 kwh ($)
2013	6,943	6,784	159	131,170	$0.12	$1.21
2014	7,646	7,352	294	134,617	$0.22	$2.18
2015	8,733	8,270	463	138,217	$0.33	$3.35
2016	9,944	9,281	663	142,209	$0.47	$4.66
2017	10,768	9,924	843	145,542	$0.58	$5.80
2018	11,611	10,870	742	149,218	$0.50	$4.97
2019	12,489	11,898	591	152,896	$0.39	$3.86
2020	13,077	12,907	170	157,170	$0.11	$1.08
2021	13,872	13,931	-59	161,572	-$0.04	-$0.36
2022	14,852	15,022	-170	165,401	-$0.10	-$1.03
2023	15,843	16,139	-295	169,316	-$0.17	-$1.74
2024	17,111	17,438	-327	173,787	-$0.19	-$1.88
2025	18,287	18,845	-559	177,509	-$0.31	-$3.15
2026	19,613	20,267	-654	181,535	-$0.36	-$3.60
2027	21,204	21,903	-700	185,625	-$0.38	-$3.77
2028	22,594	23,389	-796	190,262	-$0.42	-$4.18
2029	23,867	24,744	-877	194,094	-$0.45	-$4.52
2030	25,343	26,338	-995	198,332	-$0.50	-$5.02
2031	26,986	28,044	-1,059	202,605	-$0.52	-$5.23
2032	29,155	30,217	-1,063	207,421	-$0.51	-$5.12
2033	32,189	33,280	-1,091	211,440	-$0.52	-$5.16
2034	34,380	35,629	-1,248	215,873	-$0.58	-$5.78
2035	36,401	37,864	-1,463	220,635	-$0.66	-$6.63

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.
(3) For purposes of this analysis, a cost $3800/kW (2007$) is assumed for both nuclear units.

Table TP 6&7 Staff 19

Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7 *vs* IGCC : 2013 - 2035

Scenario: Mid Gas Cost Env II

Year	(1) Plan with Nuclear Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan without Nuclear - IGCC Annual Total Revenue Requirements ($millions, Nominal $)	(3) = (1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000) Differential in System Average Electric Rates (cents/kwh)	(6) = ((5)x1,000) / 100 Differential in Customer Bill of 1,000 kwh ($)
2013	6,943	6,763	179	131,170	$0.14	$1.37
2014	7,646	7,352	294	134,617	$0.22	$2.18
2015	8,733	8,270	463	138,217	$0.33	$3.35
2016	9,944	9,281	663	142,209	$0.47	$4.66
2017	10,768	9,924	843	145,542	$0.58	$5.80
2018	11,611	11,460	151	149,218	$0.10	$1.01
2019	12,489	12,854	-366	152,896	-$0.24	-$2.39
2020	13,077	14,431	-1,354	157,170	-$0.86	-$8.61
2021	13,872	15,810	-1,938	161,572	-$1.20	-$11.99
2022	14,852	16,801	-1,949	165,401	-$1.18	-$11.78
2023	15,843	17,826	-1,983	169,316	-$1.17	-$11.71
2024	17,111	19,097	-1,986	173,787	-$1.14	-$11.43
2025	18,287	20,440	-2,153	177,509	-$1.21	-$12.13
2026	19,613	21,764	-2,152	181,535	-$1.19	-$11.85
2027	21,204	23,302	-2,098	185,625	-$1.13	-$11.30
2028	22,594	24,696	-2,102	190,262	-$1.11	-$11.05
2029	23,867	25,934	-2,068	194,094	-$1.07	-$10.65
2030	25,343	27,398	-2,055	198,332	-$1.04	-$10.36
2031	26,986	29,009	-2,024	202,605	-$1.00	-$9.99
2032	29,155	31,067	-1,913	207,421	-$0.92	-$9.22
2033	32,189	34,125	-1,936	211,440	-$0.92	-$9.16
2034	34,380	36,352	-1,972	215,873	-$0.91	-$9.13
2035	36,401	38,362	-1,961	220,635	-$0.89	-$8.89

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.
(3) For purposes of this analysis, a cost $3800/kW (2007$) is assumed for both nuclear units.
(4) For purposes of the analysis no costs were assumed for carbon capture and sequestration.

AFFIDAVIT

Sponsor:

Severino H. Lopez

State of Florida)

County of MIAMI-DADE)

I hereby certify that on this 21ST day of DECEMBER, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Severino H. Lopez**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the Supplemental answer(s) to Interrogatory No(s). 19 of Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21ST day of DECEMBER, 2007.

Notary Public
State of Florida, at Large

My Commission Expires:

JOAQUIN E. LEON
MY COMMISSION # DD 490951
EXPIRES: November 20, 2009
Bonded Thru Notary Public Underwriters

Q.
Please provide the path schedule/timeline for permitting and construction of Turkey Point 6 and 7.

A.

Project Year	Estimated Project Milestones
2008	Site Selection complete, COLA Preparation begins, Detailed Engineering begins Optional: Long Lead Procurement (Ultra-Heavy Forgings: Pressure Vessels, Steam Generator Vessels)
2009	COLA filed at NRC, SCA filed at FDEP, Application Review begins, Detailed Engineering Optional: Long Lead Procurement (Forgings, Training Simulator)
2010	Detailed Engineering and COLA review continues, SCA Hearing Optional: Site clearing and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)
2011	COLA review complete, Detailed Engineering continues Optional: Site Preparation and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)
2012	ASLB convenes license hearing, Detailed Engineering continues, Non-nuclear Construction commences Optional: Site Preparation completes
2013	Safety Related (NRC jurisdictional) Construction commences, foundation for Unit 1 constructed
2014	Reactor Pressure Vessel and major components for Unit 1 delivered and set
2015	Unit 1 system construction, foundation for Unit 2 constructed
2016	Reactor Pressure Vessel and major components for Unit 2 delivered and set
2017	Unit 1 Substantial Completion and ITAAC Hearing
2018	Unit 1 Fuel Load, testing and commercial operation.
2019	Unit 2 Substantial Completion and ITAAC Hearing
2020	Unit 2 Fuel Load, testing and commercial operation.

Note: Optional items needed to support earliest practical deployment schedule

Note: FPL currently estimates that the Site Certification will be obtained in the 2010 project year and that the COL will be obtained in 2012. FPL estimates that: the ITAAC Review of Unit 1 will be completed in 2017, commercial operation of Unit 1 will commence in 2018, the ITAAC Review of Unit 2 will be completed in 2019, and commercial operation of Unit 2 will commence in 2020.

Q.

Please provide FPL's fuel mix projection for the periods 2016-2022 with and without Turkey Point 6 and 7.

A.

Table TP 6&7 Staff 21 presents the projected FPL fuel mix values for 2016 – 2022 for each of the three resource plans utilized in FPL's analyses for this filing: the Plan with Nuclear, the Plan without Nuclear – CC, and the Plan without Nuclear – IGCC. The values presented in Table TP 6&7 Staff 21 for the years 2018 – 2021 were previously presented in Exhibit SRS-10 of FPL witness Sim's testimony.

Hearing Exhibit 000061

Table TP 6&7 Staff 21

Scenario: High Gas Cost Env III

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2016	7.5%	71.6%	2.4%	18.2%	0.3%	7.5%	71.6%	2.4%	18.2%	0.3%	7.5%	71.6%	2.4%	18.2%	0.3%
2017	7.5%	72.4%	1.8%	18.0%	0.3%	7.5%	72.4%	1.8%	18.0%	0.3%	7.5%	72.4%	1.8%	18.0%	0.3%
2018	7.3%	69.6%	2.0%	20.8%	0.3%	7.3%	73.3%	1.8%	17.3%	0.3%	10.6%	69.7%	2.2%	17.3%	0.2%
2019	7.1%	67.6%	2.6%	22.3%	0.4%	7.1%	73.4%	2.4%	16.9%	0.2%	12.7%	67.4%	2.8%	16.9%	0.2%
2020	7.0%	65.2%	1.9%	25.7%	0.2%	7.0%	74.5%	1.5%	16.7%	0.3%	15.4%	65.4%	2.2%	16.7%	0.3%
2021	6.6%	64.7%	1.9%	26.5%	0.3%	6.6%	74.9%	2.1%	16.1%	0.3%	17.2%	63.6%	2.9%	16.1%	0.2%
2022	6.6%	65.2%	1.9%	26.1%	0.2%	6.6%	75.9%	1.5%	15.7%	0.3%	16.9%	65.0%	2.2%	15.7%	0.2%

Q.

Please provide a typical load duration curve for the FPL system for both winter and summer day for the years 2006 and 2018.

A.

Figure TP 6&7 Staff 22 provides the requested information. Pages 1 of 4 and 2 of 4 provide graphic representations of the summer peak day for 2006 and the winter peak day for 2006, respectively. Pages 3 of 4 and 4 of 4 provide graphic representations of the projected summer peak day for 2018 and the projected winter peak day for 2018. Each graph provides the hourly peak loads for the 24 hours of the system peak day.

Figure TP 6&7 Staff 22 Page 1 of 4

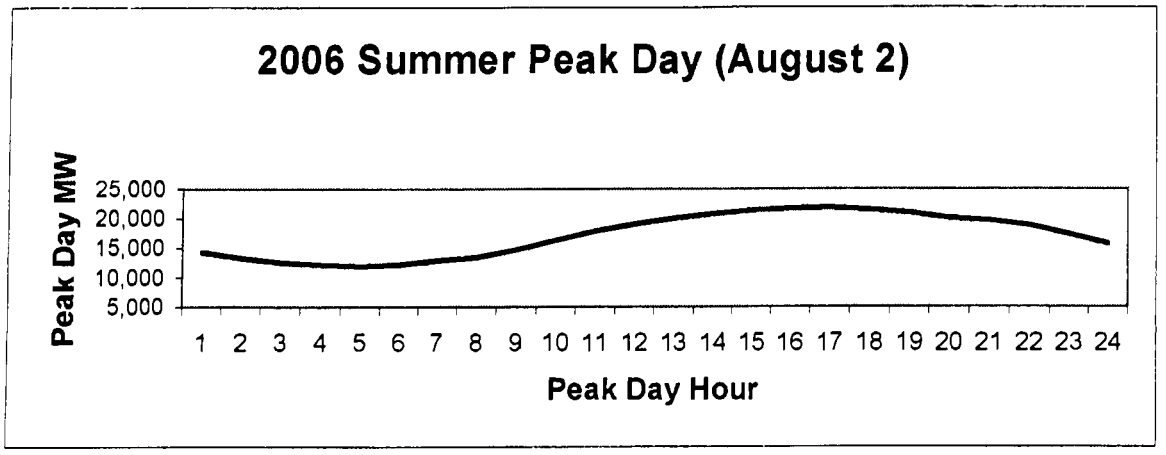


Figure TP 6&7 Staff 22 Page 2 of 4

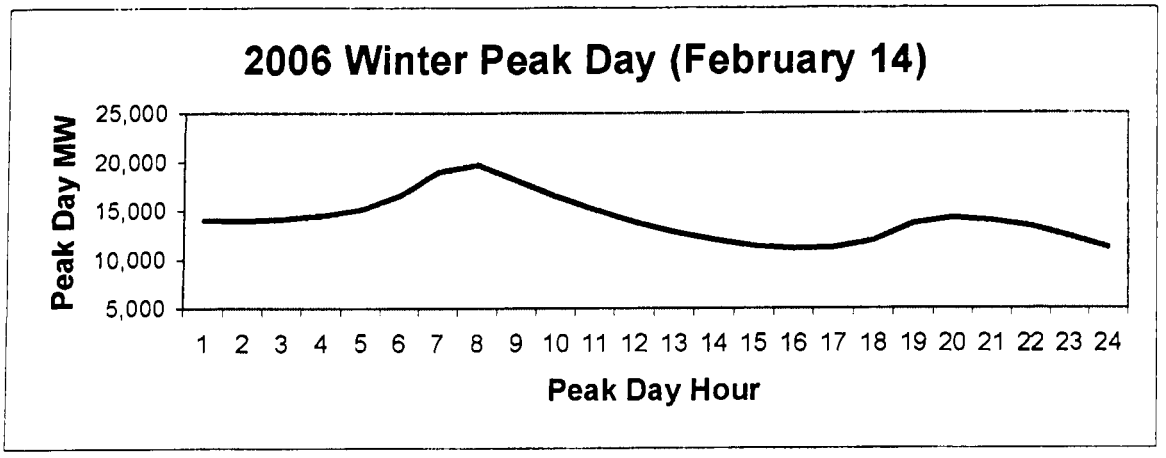


Figure TP 6&7 Staff 22 Page 3 of 4

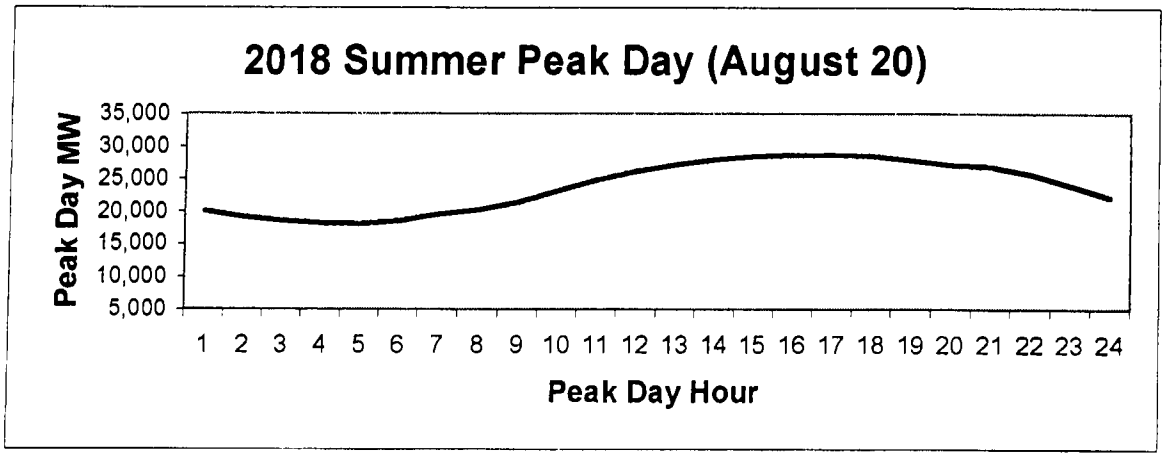
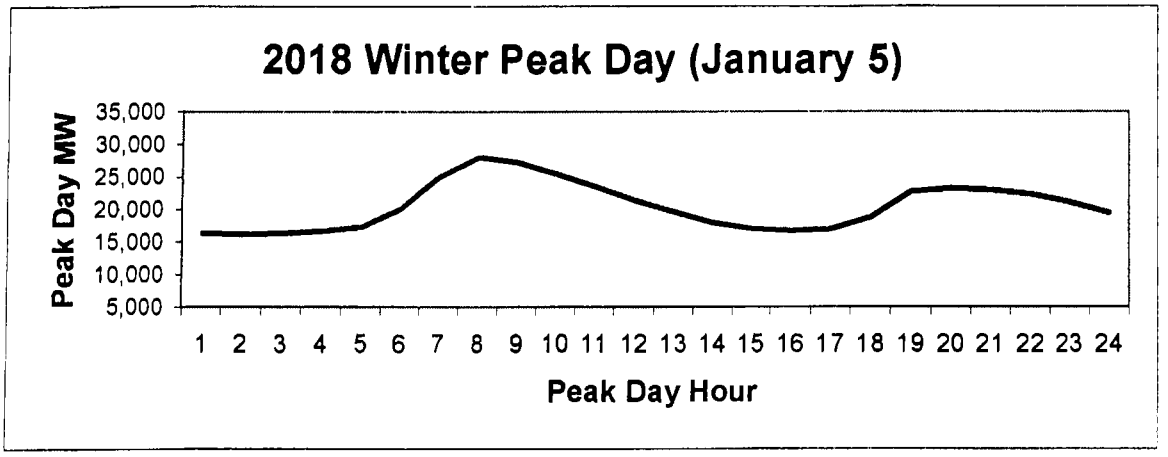


Figure TP 6&7 Staff 22 Page 4 of 4



Q.

Please complete the following table for each unit that FPL will have on its system in the year 2016. Also, please identify each unit by typical duty cycle in megawatts.

Duty Cycle	Unit Names	Capacity (MW)
Peaking		
Intermediate		
Base		

A.

The requested information is presented in Table TP 6&7 Staff 23. For purposes of responding to this interrogatory, FPL has used the following definitions of types of capacity: combustion turbines, gas turbines, and diesel generators as Peaking Capacity, oil- and gas-fired steam units as Intermediate Capacity, and combined cycle, coal, and nuclear units as Baseload Capacity. The information included in this table also includes the additional capacity from the proposed capacity uprates to FPL's four existing nuclear units. The three combined cycle additions shown in the table for the years 2011, 2015, and 2016 are units that were assumed for analysis purposes in all three resource plans evaluated for this filing.

Table TP 6 & 7 Staff 23

FPL - Owned Units in Service through 2016

Plant Name	Unit No.	Summer MW
Peaking Capacity •		
Fort Myers	3A & B	326
Fort Myers	1-12	648
Lauderdale	1-12	420
Lauderdale	13-24	420
Port Everglades	1-12	420
Turkey Point	1-5	12
Sub-Total MW:		**2,246**
Intermediate Capacity *		
Cape Canaveral	1	398
Cape Canaveral	2	398
Cutler	5	68
Cutler	6	126
Manatee	1	825
Manatee	2	825
Martin	1	838
Martin	2	831
Port Everglades	1	219
Port Everglades	2	219
Port Everglades	3	393
Port Everglades	4	395
Putnam	1	249
Putnam	2	249
Riviera	3	276
Riviera	4	281
Sanford	3	138
Turkey Point	1	398
Turkey Point	2	396
Sub-Total MW:		**7,522**
Baseload Capacity *		
Fort Myers	2	1,441
Lauderdale	4	428
Lauderdale	5	428
Manatee	3	1,125
Martin	3	471
Martin	4	461
Martin	8	1,115
Sanford	4	966
Sanford	5	962
Scherer	4	648
SJRPP	1	127
SJRPP	2	127
St. Lucie	1	777
St. Lucie	2	777
Turkey Point	3	693
Turkey Point	4	693
Turkey Point	5	1,144
West County	1	1,219
West County	2	1,219
3x1 CC - 2011 **		1,219
3x1 CC - 2015 **		1,219
3x1 CC - 2016 **		1,219
Nuclear Uprates (3 units)		310
Nuclear Uprates (1 unit)		104
Sub-Total MW:		**18,891**
Total MW:		**28,659**

• For purposes of responding to this interrogatory, FPL has defined Peak Capacity to include combustion turbines, gas turbines, and diesel generators. Intermediate Capacity as oil-and gas-fired steam units; and Baseload Capacity as combined cycle, coal and nuclear units.

** These 2011, 2015 and 2016 combined cycle units have been assumed to be added for analytical purposes in all three resources plans used in the filing.

AFFIDAVIT

Sponsor:

(Steven D. Scroggs)

State of Florida)

County of Palm Beach)

I hereby certify that on this 9th day of November, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven D. Scroggs**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 1 and 20 from **Staff's First** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of NOVEMBER, 2007.

Notary Public
State of Florida, at Large

JOAQUIN E. LEON
MY COMMISSION # DD 490951
EXPIRES: November 20, 2009
Bonded Thru Notary Public Underwriters

My Commission Expires:

AFFIDAVIT

Sponsor:

(H.M. Gurri McBee)

State of Florida)

County of Palm Beach)

I hereby certify that on this 9th day of Nov., 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **H.M. Gurri. McBee**, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 2, 3, and 4 from ***Staff's First*** *Set of Interrogatories to Florida Power & Light Company in Docket* No. 070650-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of November, 2007.

CHERYL CASH
MY COMMISSION # DD658991
EXPIRES: April 04, 2011
Fl. Notary Discount Assoc. Co.
1-800-3-NOTARY

Notary Public
State of Florida, at Large

My Commission Expires:

4/4/2011

AFFIDAVIT

Sponsor:

Steven R. Sim

State of Florida)

County of Miami-Dade)

I hereby certify that on this 9th day of November, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven R. Sim**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No(s). **5-8, 13-16, 18-19, 21 and 23** from **Staff's 1st** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of November, 2007.

Monica Lynn Padron
Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

AFFIDAVIT

Sponsor:

C. Dennis Brandt

C. Dennis Brandt

State of Florida)
) ss:
County of Miami-Dade)

I hereby certify that on this 6th day of November, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **C. Dennis Brandt**, who is personally known to me, and he acknowledged before me that he sponsored the answers to **Interrogatory Nos. 9, 10, 11 & 12** from **Staff's 1ST Set of Interrogatories** to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of November, 2007.

Monica Lynn Padron
Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

AFFIDAVIT

Sponsor:

Rosemary Morley

State of Florida)
) ss:
County of Miami-Dade)

I hereby certify that on this 7th day of November, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Rosemary Morley**, who is personally known to me, and she acknowledged before me that she sponsored the answer to **Interrogatory No. 17** from **Staff's 1ST Set of Interrogatories** to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of November, 2007.

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

Monica Lynn Padron
Notary Public
State of Florida, at Large

My Commission Expires:

December 18, 2010

AFFIDAVIT

Sponsor:

Anita Sharma

Anita Sharma

State of Florida)

County of Miami Dade)

I hereby certify that on this 12 day of November, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Anita Sharma, who is personally known to me, and she acknowledged before me that she sponsored the answer to Interrogatory No. 22 from Staff's First Set of Interrogatories Nos. 1-23 to Florida Power & Light Company in Docket No. 070650-EI, and that the response is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12 day of November, 2007.

Monica Lynn Padron

Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

2

FPL's Response to Staff's Third Set of Interrogatories (Nos. 28-30, 32-34, 36-41, 43-52, 54-60)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: December 21, 2007

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S THIRD REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 15) AND THIRD SET OF INTERROGATORIES (NOS. 28-62)

Florida Power & Light Company gives notice of service of its Responses to the Staff of the Florida Public Service Commission's Third Request for Production of Documents (No. 15) and Third Set of Interrogatories (Nos. 28-62) to Katherine E. Fleming, with a copy to all parties on the attached Certificate of Service.

Respectfully submitted this 21st day of December, 2007.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
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Stephen Huntoon
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Rutledge, Ecenia, Purnell & Hoffman, P.A.
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P. O. Box 551
Tallahassee, FL 32302-0551

Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000076

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 21st day of December, 2007, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Charles J. Beck, Deputy Public Counsel*
Office of the Public Counsel
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111 West Madison Street, Room 812
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Jody Lamar Finklea
Daniel B. O'Hagan
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Zoila P. Easterling
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Orlando, FL 32819

Bob Krasowski
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Naples, FL 34103-3857
On Behalf of Jan M. Krasowski and Bob Krasowski**

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Attorney for Orlando Utilities Commission**

William T. Miller
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Vicki Gordon Kaufman
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Barry Moline
Florida Municipal Electric Association**
P.O. Box 10114
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By: *s/Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000077

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: December 21, 2007

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S THIRD REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 15) AND THIRD SET OF INTERROGATORIES (NOS. 28-62)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following responses to the Staff of the Florida Public Service Commission's ("Staff's") Third Request for Production of Documents (No. 15) and Third Set of Interrogatories (Nos. 28-62).

FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in Florida Power & Light Company's Objections to Staff's Third Request for Production of Documents (No. 15) and Third Set of Interrogatories (Nos. 28-62), dated December 19, 2007.

I. Staff's Third Request for Production of Documents (No. 15)

FPL's response is without waiver of its general and specific objections. All documents will be made available by FPL for inspection and review by Staff at FPL's offices at 215 South Monroe Street, Tallahassee Florida, during regular business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

II. Staff's Third Set of Interrogatories (Nos. 28-62)

Attached hereto are FPL's answers to Staff's Third Set of Interrogatories (Nos. 28-62), consistent with its prior objections, together with the affidavits of the persons providing said answers.

Respectfully submitted this 21st day of December, 2007.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
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Stephen Huntoon
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Kenneth A. Hoffman
Rutledge, Ecenia, Purnell & Hoffman, P.A.
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P. O. Box 551
Tallahassee, FL 32302-0551

Attorneys for Florida Power & Light Company

By: _____
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000079

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 21st day of December, 2007, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

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Office of the Public Counsel
c/o The Florida Legislature
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Jody Lamar Finklea
Daniel B. O'Hagan
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Bob Krasowski
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On Behalf of Jan M. Krasowski and Bob Krasowski**

Roy C. Young
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Attorney for Orlando Utilities Commission**

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Attorney for Seminole Electric Cooperative, Inc.**

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Attorney for Seminole Electric Cooperative, Inc.**

Barry Moline
Florida Municipal Electric Association**
P.O. Box 10114
Tallahassee, FL 32302-2114

By: _____
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000080

Q.

On pages 27-30 of his direct testimony, Witness Scroggs discusses the long lead-time procurement items, such as the Reactor Pressure Vessels. Please identify or describe what the other long lead-time procurement items are, and the lead times for each.

A.

FPL has engaged the technology vendors in discussions surrounding the types of items that may need to be procured in advance of a construction contract and the general lead times that should be planned for these items. Based on these discussions and FPL's earliest practical commercial operating date of June 2018, initial payments for the Ultra Heavy Forgings would begin mid-2008. Expenditures are necessary to secure a manufacturing position in the queue at forging manufacturer, Japan Steel Works. These forgings would include the Reactor Pressure vessel, the Pressurizer vessel, Steam Generator vessels, various tanks and the Reactor Coolant Pump casings.

Q.

On page 29 of his direct testimony, Witness Scroggs discusses the procurement of Reactor Pressure Vessels and the value of a production "reservation." Please identify or describe what the potential is of purchasing someone else's reservation as a cost reduction measure, and how much might be saved? If FPL gave up its reservation, please describe what would happen to any advanced payments made by FPL?

A.

FPL is investigating all options available for procurement of long lead items. At present, only a limited number of projects have made long lead component reservations, however, the associated terms of the reservations are confidential and not known to FPL. It is unlikely that any of these projects would relinquish their reservations in the next 6 months, which would have to happen in order for them to be available to FPL in a time frame necessary to support the earliest practical deployment schedule.

If the project schedule was changed after advance payments were made, an evaluation would be conducted to determine the best course of action. The specific course of action available to FPL would be dependent on the terms of the reservation contracts and market supply/demand conditions for the underlying queue positions.

Q.

Please identify or describe how FPL foresees meeting its peak summer loads for the period 2012 through 2018?

A.

It is too early for FPL to commit to definitive resource additions to meet capacity needs in the 2012 through 2018 time frame. Those decisions will be made at later dates when it is appropriate to do so and those decisions will take into account updated forecasts of load, fuel costs, environmental compliance costs, available resources, and resource costs.

For purposes of the analyses presented in this docket, FPL has made use of the most current forecasts and has developed three resource plans in order to analyze the impacts of adding new nuclear units starting in 2018. These three plans are presented in Exhibit SRS-4 of FPL Witness Sim's testimony.

For the 2013 through 2017 time frame, the plans are identical:

- In 2013, 104 MW of nuclear uprates that will be added by 12/2012 will contribute to FPL's reserve margins starting in 2013. No other resources are added in 2013 or 2014;
- In 2015, one 3x1 G combined cycle unit of 1,219 MW (Summer);
- In 2016, one 3x1 G combined cycle unit of 1,219 MW (Summer); and
- In 2017, one 2x1 G combined cycle unit of 812 MW (Summer).

In 2018, the three resource plans differ. The Plan with Nuclear adds the 1,100 MW (Summer) new Turkey Point 6 nuclear unit. The Plan without Nuclear – CC adds a 3x1 G combined cycle (CC) unit of 1,219 MW (Summer). The Plan without Nuclear – IGCC adds two 600 MW (Summer) integrated gasification combined cycle (IGCC) units.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Filed: January 23, 2008

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S SUPPLEMENTAL AND CORRECTED RESPONSES

Florida Power & Light Company gives notice of service of its supplemental response to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories No. 3 and corrected responses to Staff's Third Set of Interrogatories No. 32 and Sixth Set of Interrogatories No. 85, to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 23rd day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420

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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically and by United States mail this 23rd day of January, 2008, to the following:

Katherine E. Fleming
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

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Office of the Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

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Jody Lamar Finklea
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James A. Dickenson
P.G. Para
JEA
21 West Church Street
Jacksonville, FL 32202

By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

Hearing Exhibit 000085

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: January 23, 2008

FLORIDA POWER & LIGHT COMPANY'S
SUPPLEMENTAL AND CORRECTED RESPONSES TO THE
STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S INTERROGATORIES

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following supplemental response to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories No. 3 and corrected responses to Staff's Third Set of Interrogatories No. 32 and Sixth Set of Interrogatories No. 85.

FPL adopts and incorporates by reference, as though fully restated herein, all objections previously provided in response to the interrogatories. Attached hereto are FPL's supplemental and corrected answers, consistent with its prior objections.

Respectfully submitted this 23rd day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
700 Universe Boulevard
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Attorneys for Florida Power & Light Company

By: _____

Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically and by United States mail this 23rd day of January, 2008, to the following:

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Florida Public Service Commission
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James A. Dickenson
P.G. Para
JEA
21 West Church Street
Jacksonville, FL 32202

By: _____
Jessica A. Cano
Florida Bar No. 0037372

Hearing Exhibit 000088

Q.

Please identify or describe what the expected capacity factors are for Turkey Point 6 and 7, compared to the capacity factors for FPL's existing nuclear plants over the past 10 years?

A.

Attachment 1 shows the corrected historical capacity factors for FPL's existing four nuclear units. The expected capacity factors for Turkey Point 6 & 7 are also shown in Attachment 1 and are the capacity factors provided in FPL's previous response to Staff's 3rd Set of Interrogatories No. 32.

Capacity Factor of Existing Nuclear Units (%)

	TP3	TP4	SL1	SL2
1998	89.1	101.8	95.7	91.7
1999	100.7	94.5	88.9	98.1
2000	93.4	91.9	102.0	92.3
2001	91.0	100.6	91.3	91.3
2002	102.4	96.4	94.2	101.0
2003	89.7	91.6	102.1	80.1
2004	77.7	99.9	85.8	92.0
2005	95.5	69.8	82.8	85.5
2006	92.0	88.7	101.6	82.3
2007	84.8	100.1	84.8	70.1

Capacity Factor of New Units(%)

	TURKEY POINT 6	TURKEY POINT 7
2018	56.14	0
2019	90.24	0
2020	95.75	55.98
2021	90.24	90.24
2022	90.24	95.75
2023	95.75	90.24
2024	90.26	90.26
2025	90.24	95.75
2026	95.75	90.24
2027	90.24	90.24
2028	90.26	95.75
2029	95.75	90.24
2030	90.24	90.24
2031	90.24	95.75
2032	95.75	90.26
2033	90.24	90.24
2034	90.24	95.75
2035	95.75	90.24
2036	90.26	90.26
2037	90.24	95.75
2038	95.75	90.24
2039	90.24	90.24
2040	90.26	95.75
2041	95.75	90.24
2042	90.24	90.24
2043	90.24	95.75
2044	95.75	90.26

Q.

Please identify or describe when FPL would need to file a need determination for a comparable combined cycle unit that would begin service in 2018?

A.

Assuming that current regulations and timelines remain unchanged, FPL would need to file for need determination approval of a 2018 combined cycle unit by approximately March, 2015.

Q.

The petition explains that total abandonment of the project immediately prior to commencing construction would expose FPL's customers to minimal economic impact. Please identify or describe what the impact would be.

A.

Witness Scroggs' testimony (pp. 31-32) describes that Preparation phase costs are estimated to range from $163 million to $523 million, depending on the activities undertaken and as deemed prudent and reasonable in the annual cost recovery filing process. The $523 million is composed of $473 million in site selection and pre-construction costs and $50 million in construction costs. If the entire $473 million of pre-construction costs had been expended per schedule, the average impact would equal the amounts identified in the table below. The $50 million of construction costs would be expected to be recovered through inclusion in a subsequent base rate proceeding.

Projection of Approximate Bill Impacts with Turkey Point 6 and 7: 2009-2012

Assumes abandonment of the project immediately prior to commencing construction

	Annual Total Revenue Requirements ($millions, Nominal $)	Projected Total Sales After DSM (GWH at the meter)	Increase in System Average Electric rates (cents/kwh)	Differential in Customer Bill of 1000 kwh $
2009	118	116,870	0.10	1.01
2010	105	120,715	0.09	0.87
2011	111	124,562	0.09	0.89
2012	16	128,243	0.01	0.13

Q.
Please discuss the supply reliability of nuclear fuel to be used in Turkey Point 6 and 7.

A.
There are four steps required to produce and to deliver nuclear fuel to a nuclear plant.

The first step is uranium mining. The recent run up in prices has led to a significant increase in production and new players. Uranium is available from many sources. For a long time, market prices have been driven by excess inventories. In the long-term, we expect the market to be more driven by fundamentals. The fact that it takes less to build a new mine, compared to a new reactor, provides high confidence that uranium production will be added as world demand increases. In addition, new mines would add additional diversity of supply.

The same applies to the other three steps of the fabrication of nuclear fuel such as conversion, enrichment, and fabrication. Moreover, disruption in one part of the production cycle can be made up because of the long time between refueling outages.

Finally, nuclear plants can continue to operate for a while after the optimum shutdown date and further minimize impacts from nuclear fuel supply disruption.

Q.

Please respond to the following questions regarding radioactive waste:

A. How much, if any, increase of radioactive waste will result from the operation of Turkey Point 6 and 7?

B. How will disposal of the radioactive waste from Turkey Point 6 and 7 be handled?

C. Please show how any additional costs associated with the expansion of the radioactive waste storage for Turkey Point 6 and 7 were included in determining the cost-effectiveness of these units.

D. Will any costs of expansion of radioactive waste storage for Turkey Point 6 and 7 benefit Turkey Point 3 and 4?

A.

A. The amount of radioactive waste expected from Turkey Point 6 & 7 will be affected by the technology selected, but is generally expected to be less than the amount currently produced by FPL's existing Turkey Point 3 & 4 nuclear units. Given the larger capacity of the new designs, the amount generated per megawatt is projected to be significantly less than that for the current operating units.

B. FPL will continue to handle disposal of any and all radioactive wastes generated at the plant per applicable regulations and under the strict supervision of the Nuclear Regulatory Commission.

C. Low-level radiological waste storage is a part of the plant design and is included in the capital cost estimate for the facility. As a conservative assumption, the costs for Dry Cask storage of high-level radioactive waste (spent fuel) was included in the economic analysis. A projection of annual fixed operating and maintenance (FOM) costs was developed. This estimate included $12 million in 2029 and 2030 for the licensing and construction of a Dry Cask Storage facility for Turkey Point 6 and 7. An annual cost of $10.7 million was included for each subsequent year to maintain the storage facility and increase capacity as needed. These costs were incorporated with the other FOM costs and a levelized FOM cost was developed and used in the cost analysis presented in the need study.

D. The cost estimate was developed to serve the incremental requirements of Turkey Point 6 and 7 alone. There is no direct benefit to Turkey Point 3 and 4.

Q.

Please refer to page 34 of the petition. Of FPL's current fuel oil and natural gas usage, how much comes from foreign sources? How much comes from domestic sources?

A.

No. 6 Residual Fuel Oil Purchases			
Year	Total Purchases (Barrels)	% Domestic	% Foreign
2004	27,529,119	54.0%	46.0%
2005	31,505,021	34.8%	65.2%
2006	14,896,811	57.5%	42.5%
2007*	15,114,589	73.6%	26.4%

*Note: Data Through November 2007

FPL does not expect the apparent trend of a decline in FPL's percentage of foreign-sourced residual fuel oil to continue. The decline in recent years largely reflects the fact that the BORCO oil terminal in the Bahamas became unavailable to several of FPL's residual fuel oil suppliers for a period of time. However, if the current proposed sale of the BORCO terminal is completed as planned in the first quarter of 2008, FPL (through its suppliers) will once again be able to rely on the flexibility the terminal offers for deliveries of foreign-sourced residual fuel oil.

Natural Gas Consumption			
Year	Total Consumption (MMBtu)	% Domestic	% Foreign
2007*	306,919,559	95.7%	4.3%

*Note: May Through November 2007 Gas Consumption
(Consumption start date coincides with Cypress Pipeline operation date of May 1, 2007)

FPL projects that its percentage of foreign-sourced natural gas will increase as LNG's percentage of total U.S. natural gas supply increases over the next several years.

Q.
Please describe how the CO2 compliance costs, discussed on page 34 of the petition, were determined.

A.
The process used by FPL and its consultants to develop the CO2 environmental compliance costs forecasts is described below:

Step 1 The source document used was the ICF "U.S. Emission & Fuel Markets Outlook" Report, 2006 Edition. The costs provided by ICF in this report were in 2005 real dollars.

Step 2 From this report, three scenarios were chosen:
1. 4P: 4 Pollutant Mild (Bingaman) CO2;
2. 4P: 4 Pollutant Reference Case;
3. 4P Stringent: 4 Pollutant (McCain) CO2.

These scenarios were chosen to cover the broad range of CO2 price outcomes projected by ICF, while keeping the number of scenarios to a manageable level.

Step 3 The ICF projections ended at 2030. For CO2 in the 4P Pollutant Mild Case scenario, the post-2030 values were assumed to stay at the 2030 levels (in real terms). For CO2 in the 4 Pollutant Reference Case scenario, a 2050 projected target price of $35/ton (in real terms) was assumed. Between 2030 and 2050 values were interpolated accordingly. A similar process was used for CO2 in the 4P Stringent scenario, with the 2050 target price set at $50/ton. Target values for 2050 were chosen by consensus by FPL and its consultant. The post-2030 price escalators developed for the three CO2 scenarios in the process described above were also applied to the SO2, NOx and Hg emission prices.

Step 4 The projections were then converted to nominal dollars using a general inflation rate of 2.5%. At this point, FPL had developed Scenarios ENV I, ENV II, and ENV III. The ICF origin of these scenarios is shown below:

ENV I: Based on 4P: 4 Pollutant Mild (Bingaman) CO2;
ENV II: Based on 4P: 4 Pollutant Reference Case;
ENV III: Based on 4P Stringent: 4 Pollutant (McCain) CO2.

Step 5 An additional scenario, ENV IV, was developed. The annual CO2 values ($/ton) in ENV III were increased by 30%.

Q.
Please discuss any action FPL has taken toward encouraging greater customer participation in DSM programs.

A.
FPL has a multi-prong approach to increase participation in its DSM programs. These efforts focus on identifying new DSM programs and measures, modifying existing DSM program measures to meet the changing needs of its customers and the market place, and increasing customer awareness of its DSM programs and their benefits.

In late 2006/2007, FPL implemented the following DSM programs revisions which added new program, added new measures to existing programs, changed program incentives and eligibility/operational requirements:

Business	Revisions/Additions	Incentives Changes
Business Energy Evaluation	° An on-line survey was implemented for small and medium size businesses	
Business Building Envelope	° Add window-related technologies	
	° Program incentive structurechanged from a maximum of $181/kW to:	
	* Ceiling Insulation	Max of $185/kW
	* Roof Insulation	Max of $219/kW
	* Reflective Roofs	Max of $579/kW
	* Window Treatment	Max of $429/kW
Business Efficient Lighting	° Increase maximum incentive	From $101 to $132/kW
Business HVAC	° Updating the minimum qualifying Seasonal Energy Efficiency Ratio (SEER) levels to reflect minimum mandated by U.S. Dept. of Energy Standards	
	° Increase maximum incentive for Direct Expansion (DX)	From $100 to $168/kW
	° Increase maximum incentive for chillers	From $75 to $99/kW
	° Increase maximum incentive for Energy Recovery Ventilators (ERV) units	From $399 to $417/kW
	° Increase maximum incentive for Thermal Storage units and allow additional equipment selections	From $350 to $898/kW
	° Add incentives for air-handler units with electronically commutated motors (ECM)	Max of $102/kW
	° Add incentives for efficient air conditioning room units for DX program	Max of $498/kW
	° Add incentives for demand control ventilation (DCV) systems	Max of $627/kW
Business Water Heating	° New program to add incentives for the installation of qualifying heat recovery units (HRU) or heat pump water heater equipment (HPWH)	Max of $881/kW
Business Refrigeration	° New program to add incentives for the installation of qualifying controls & equipment that reduce electric strip heater usage in refrigeration equipment	Max of $80/kW
Business On Call (Load Management)	° Modifying the cycling interruption schedule for central A/C systems from a total of 15 minutes during a 30 min. period for max of 180 min. per day to 17.5 min. during a 30 min. period for max of 210 min. per day	

Residential	Revisions/Additions	Incentives Changes
Residential HVAC	° Updating the minimum qualifying Seasonal Energy Efficiency Ratio (SEER) levels to reflect minimum mandated by U.S. Dept. of Energy Standards	
	° Expanding the upper range of SEER levels that qualify to encourage customers to install higher efficiency	
	° Add incentives for air-handler units with electronically commutated motors (ECM)	$25 per participant
	° Add incentives for A/C units properly sized using an FPL approved sizing software	$75 per participant
	° Increase average incentive per participant for A/C units	From $260 to $400 per participant
Residential Building Envelope	° Increase maximum incentive for ceiling insulation	From $131 to $352 per participant
	° Increase maximum incentive for reflective roofs	From $240 to $367 per participant
	° Add incentives for light colored roof membranes & reflective roof coatings	Max of $1,200 per participant
Residential Low Income Weatherization	° Expansion of program delivery channels beyond housing authorities and non-profits.	
	° Increase maximum incentive for HVAC maintenance	From $35 to $45 per participant
	° Increase maximum incentive for reduced air infiltration	From $10 to $60 per participant
	° Add incentives for room air conditioning replacement	$25 per participant
Residential On Call (Load Management)	° Modifying the cycling interruption schedule for central A/C systems from a total of 15 minutes during a 30 min. period for max of 180 min. per day to 17.5 min. during a 30 min. period for max of 210 min. per day	
	° Completed On Call incentive pilot and implemented changes to program going forward	

In late 2007, FPL further modified its existing Residential and Business HVAC programs as follows:

- Residential HVAC Program - revising the incentive structure to increase the incentive amounts to better stimulate the market to install equipment that exceeds the minimum required state efficiency code.
- Business HVAC Program - allowing incentives for a wider range of water-and-air cooled chiller efficiencies that are above current Florida Building Efficiency Code requirements; expanding incentives for demand control ventilation (DCV) to include kitchen ventilation controls; expanding the incentive qualification range for single vertical package air conditioners and heat pumps that would be above current ASHRAE (American Society of Heating, Refrigerating, and Air-Conditioning Engineers) Standard 90.1.

These enhancements are effective in January 2008.

In addition, FPL continues to support research and development (R&D) activities for new DSM opportunities. The following is a summary of current R&D:

Conservation Research and Development Program: FPL's Conservation Research and Development (CRD) Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. Many of the technologies examined have resulted in enhancements to existing programs or the development of new programs. FPL is currently investigating the following technologies:

- SmartCool HVAC - This is a field test of a control system which optimizes the cycling pattern of A/C compressors to save energy and possibly reduce peak demand. The operation of many compressors can be coordinated by a central controller. The 15-month test at a Miami drug store began in July 2006 and will continue through October 2007. Analysis results from the University of Miami are expected in early 2008.
- SmartCool Refrigeration - This is a lab test of the Smart Cool compressor optimizer in a refrigeration application. A supermarket refrigerated case identical to the one tested in the Flow Controls research test was used to facilitate comparison of performance results between projects. Data collection was completed in July 2007, and analysis results from the University of South Florida are expected in late 2007 or early 2008.
- Refrigeration Flow Controls - This is a field test of upgrading refrigerant flow control valves for commercial refrigerated cases. Data is being gathered in both a Palatka supermarket and in the University of Florida lab before and after retrofitting each refrigerated case with different types of variable flow refrigerant valves. The cost-effectiveness of these retrofits will be evaluated for both the customer and the electric utility. Data collection will be completed in October 2007, and analysis results are expected in early 2008.
- Business Water Heating - This is a technology search and market opportunity study of alternative electric commercial water heating measures including heat pumps and heat recovery units. Study findings are expected in late 2007.
- Solar Water Heating - Solar water heating can potentially save residential customers approximately 2,000 kWh per year and have a coincident peak reduction value of 0.4 kW per installation. This technology is being evaluated for cost-effectiveness and design as a potential new DSM program.
- Solar PV - Solar photovoltaics (PV) on a typical residential application can potentially produce 3,100 kWh per year and have a coincident peak reduction value of 2.8 kW per installation. This technology is being evaluated for cost-effectiveness and design as a potential new DSM program.
- EPRI Energy Efficiency Collaborative - This research offers a portfolio on advanced technologies and tools to increase end-use energy efficiency and enable demand response. Key program initiatives include developing a web-based energy management tool; assessing and demonstrating smart interconnected motor drives; accelerating commercialization of space-conditioning, water-heating and lighting technologies; and increasing the penetration of demand response.

Residential Thermostat Load Control Pilot Project: On June 15, 2007, FPL filed a petition with the Commission for the Residential Thermostat Load Control Pilot Project. A typical barrier to customer acceptance of utility load control programs is reluctance to surrender control of heating and air conditioning appliances. Consequently, for an initial 24-month period, FPL is evaluating

whether the benefits of the On-Call Program can be expanded through use of a new generation of communication and control technologies that put residential customers in charge of decisions that could lower energy costs, while allowing customers to override FPL control of their heating and air conditioning appliances. The Commission approved FPL's request on August 14, 2007. The demand and energy savings per participant will be evaluated throughout the pilot and are anticipated to be approximately 260 kWh per year and a coincident peak reduction value of 1.0 kW per participant. The pilot will have a maximum of 400 participants.

FPL also has announced plans to install in the future a smart network utilizing state-of-the-art technology that has the potential to provide customers real-time understanding of their energy use and opportunities to conserve. As this technology is deployed, additional opportunities for DSM will be explored.

In addition, there are numerous on-going customer awareness and educational activities to increase customer participation in FPL's DSM programs. See FPL's response to Staff's First Set of Interrogatories No. 12 for a description of these activities.

Q.

Based on FPL's last screening of its DSM measures, please provide a listing of the DSM measures showing the MW potential, the Total Resource Cost Test value, the Rate Impact Measure Test value, and the Participants Test value.

A.

The table below lists all of FPL's DSM measures with their corresponding summer MW potential and cost-effectiveness ratios.

DSM Achievable Potential By Measure - Summer MW @ Meter

Residential

2006-2014 Measures	Rate Class										Cost-Effectiveness Ratios		
		2006	2007	2008	2009	2010	2011	2012	2013	2014	RIM	TRC	Participant
BuildSmart	RS	4.17	5.42	6.50	7.15	7.87	7.87	7.87	7.87	7.87	1.90	2.37	2.19
RHVAC -Grnd	RS	1.96	2.05	2.15	2.25	2.34	2.42	2.50	2.58	2.65	2.10	2.03	1.58
RHVAC -HP	RS	5.71	4.61	4.81	5.01	5.19	5.36	5.52	5.68	5.83	1.04	0.86	1.10
RHVAC -SC	RS	16.98	14.60	15.24	15.86	16.44	16.98	17.49	17.98	18.45	1.05	0.89	1.12
ECM Fan - HP	RS	0.00	0.08	0.13	0.19	0.25	0.31	0.37	0.44	0.51	2.48	2.95	1.81
ECM Fan - SC	RS	0.00	0.25	0.42	0.59	0.78	0.98	1.18	1.40	1.62	2.34	2.59	1.66
AC Sizing - HP	RS	0.00	0.07	0.11	0.16	0.21	0.26	0.32	0.38	0.44	2.24	3.00	1.99
AC Sizing - SC	RS	0.00	0.36	0.59	0.84	1.11	1.39	1.68	1.98	2.30	2.24	3.00	1.99
Plenum Repair - HP	RS	0.25	0.19	0.22	0.25	0.29	0.33	0.38	0.43	0.48	1.69	2.62	2.38
Plenum Repair - SC	RS	0.93	0.71	0.82	0.95	1.08	1.23	1.40	1.59	1.79	1.73	2.68	2.38
Duct- Strip Heat	RS	1.86	1.82	1.85	1.88	1.92	1.95	1.98	2.01	2.04	1.59	2.99	3.27
Duct - HP	RS	0.72	0.71	0.72	0.73	0.75	0.76	0.77	0.78	0.79	1.55	2.75	3.00
RBE Srip heat	RS	0.74	2.34	2.31	1.66	1.62	1.59	1.55	1.51	1.48	1.24	1.97	2.26
RBE HP	RS	0.09	0.27	0.27	0.19	0.19	0.18	0.18	0.17	0.17	1.18	1.81	2.15
Non-Traditional Ceiling Insulation	RS	0.28	1.74	1.72	1.24	1.21	1.18	1.15	1.12	1.10	1.24	1.97	2.26
Refl Roof	RS	0.97	2.07	2.29	1.61	1.83	2.06	2.30	2.54	2.78	1.17	1.84	2.82
Roof Coatings - Condo	RS	0.05	0.12	0.13	0.09	0.10	0.11	0.13	0.14	0.15	1.00	0.82	1.01
White Membrane - Condo	RS	0.05	0.12	0.13	0.09	0.10	0.11	0.13	0.14	0.15	1.00	0.82	1.01
Low Income AC Maintenace	RS	0.05	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	1.57	1.72	1.71
Low Income Infiltration	RS	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	1.32	1.81	2.11
On Call	RS	21.10	117.00	32.96	29.36	30.74	32.03	33.32	34.60	38.07	2.55	6.03	Infinite

Commercial/Industrial

2006-2014 Measures	Rate Class	2006	2007	2008	2009	2010	2011	2012	2013	2014	Cost-Effectiveness Ratios RIM	TRC	Participant
Chiller	GSD	3.34	1.55	1.53	1.51	1.49	1.47	1.46	1.44	1.42	1.51	3.82	3.32
Chiller	GSLD	Combined above									1.48	3.82	3.36
DX	GS	0.12	0.13	0.14	0.15	0.17	0.18	0.19	0.20	0.21	1.51	3.12	2.84
DX	GSD	0.28	0.32	0.35	0.38	0.41	0.43	0.46	0.48	0.51	1.51	3.30	2.84
DX	GSLD	0.21	0.24	0.26	0.28	0.30	0.33	0.34	0.36	0.38	1.48	3.30	2.88
Room AC	GS	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.40	1.81	1.65
Room AC	GSD	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	1.31	1.81	1.65
Room AC	GSLD	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	1.29	1.81	1.67
ERV Strip Heat No Bypass	GSLD	0.58	0.87	1.19	1.57	1.80	2.04	2.30	2.58	2.91	1.75	3.14	2.07
ERV Strip Heat Act Bypass	GSLD										1.69	3.11	2.15
ERV No Heat No Bypass	GSLD										1.38	2.29	1.89
ERV No Heat Act Bypass	GSLD										1.40	2.42	2.03
ERV Strip Heat No Bypass	GSD										1.76	3.14	2.06
ERV Strip Heat Act Bypass	GSD										1.71	3.11	2.14
ERV No Heat No Bypass	GSD					Combined above					1.39	2.29	1.88
ERV No Heat Act Bypass	GSD										1.40	2.42	2.02
ERV Strip Heat No Bypass	GS										2.30	3.18	1.71
ERV Strip Heat Act Bypass	GS										2.08	3.14	1.91
ERV No Heat No Bypass	GS										1.74	2.20	1.52
ERV No Heat Act Bypass	GS										1.64	2.31	1.75
TES	GSD	9.57	8.85	10.41	11.76	12.34	12.68	12.84	12.84	12.70	1.20	1.32	1.11
TES	GSLD	Combined above									1.23	1.35	1.11
Roof Insulation	GS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	1.87	3.69	2.74
Roof Insulation	GSD	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	1.79	3.69	2.66
Roof Insulation	GSLD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.77	3.56	2.58
Reflective Roof Coatings	GS	0.68	0.93	1.01	1.08	1.15	1.22	1.29	1.35	1.41	1.44	2.14	1.90
Reflective Roof Coatings	GSD	2.31	3.16	3.44	3.71	3.97	4.21	4.44	4.66	4.87	1.36	2.21	1.97
Reflective Roof Coatings	GSLD	1.73	2.38	2.59	2.79	2.98	3.16	3.34	3.50	3.66	1.38	2.22	1.95
Ceiling Insulation	GS	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	1.95	3.72	2.65
Ceiling Insulation	GSD	0.10	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	1.72	3.62	2.73
Ceiling Insulation	GSLD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.87	3.72	2.56
Lighting	GS	0.30	0.11	0.13	0.14	0.15	0.16	0.17	0.19	0.20	1.48	3.99	3.70
Lighting	GSD	1.46	0.55	0.63	0.70	0.77	0.83	0.89	0.95	1.00	1.44	4.78	4.38
Lighting	GSLD	1.09	0.41	0.47	0.52	0.57	0.62	0.67	0.71	0.75	1.42	4.79	4.43
DCV - Heat	GS	0.00	0.15	0.18	0.21	0.24	0.27	0.30	0.32	0.34	1.50	2.18	2.14
DCV - Heat	GSD	0.00	0.51	0.61	0.71	0.81	0.90	0.99	1.07	1.15	1.42	2.18	2.09
DCV - Heat	GSLD	0.00	0.38	0.46	0.53	0.60	0.67	0.74	0.80	0.85	1.41	2.18	2.11
DCV - No Heat	GS	0.00	0.04	0.05	0.06	0.06	0.07	0.08	0.08	0.09	1.29	1.69	1.83
DCV - No Heat	GSD	0.00	0.13	0.16	0.18	0.21	0.23	0.26	0.28	0.30	1.28	1.69	1.74
DCV - No Heat	GSLD	0.00	0.10	0.12	0.14	0.16	0.17	0.19	0.21	0.22	1.25	1.69	1.78
ECM Fan	GS	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	1.83	3.62	2.75
ECM Fan	GSD	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.04	1.67	3.62	2.77
ECM Fan	GSLD	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	1.65	3.62	2.80
Window Film	GS	0.00	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	1.24	1.87	2.03
Window Film	GSD	0.00	0.10	0.12	0.13	0.15	0.16	0.17	0.18	0.19	1.23	1.93	1.98
Window Film	GSLD	0.00	0.07	0.07	0.08	0.09	0.10	0.11	0.11	0.12	1.27	1.94	1.92
Heat Recovery Unit	GS	0.00	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.05	1.06	1.14	1.36
Heat Recovery Unit	GSD	0.00	0.07	0.07	0.08	0.08	0.09	0.09	0.10	0.10	1.06	1.46	1.71
Heat Recovery Unit	GSLD	0.00	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	1.06	1.46	1.71
Anti-Condensate Heat Control	GS	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.26	3.53	3.96
Anti-Condensate Heat Control	GSD	0.00	0.16	0.17	0.17	0.17	0.18	0.17	0.17	0.16	1.41	2.57	2.41
Anti-Condensate Heat Control	GSLD	0.00	0.10	0.11	0.11	0.12	0.12	0.11	0.11	0.11	1.38	2.57	2.44
Business Custom Incentive	GSD	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	Done for each project		
Business Custom Incentive	GSLD	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14			
Commercial Demand Reduction	GSLD	16.34	16.34	18.15	6.33	6.33	6.33	6.33	6.33	6.33	2.33	27.12	Infinite
Business On Call	GS/GSD	5.43	15.29	6.25	6.52	6.52	6.52	6.52	6.52	6.52	2.62	7.73	Infinite

Q.

Please refer to page 109 of the Need Study.

A. In FPL's opinion, which fuel and environmental compliance cost scenario is most likely to occur?

B. Please provide a chart of the residential rate impact utilizing the scenario discussed above, for the years 2013-2035.

A.

A. FPL conducted a scenario analysis because of the significant uncertainty regarding future fuel costs, environmental compliance costs, and the interaction between these two sets of costs. It is because of these uncertainties that FPL has not selected a most likely scenario of fuel costs and environmental compliance costs.

B. As explained above in response to part A of this interrogatory, FPL is not projecting a "most likely" scenario of fuel costs and environmental compliance costs. Therefore, FPL is unable to provide a rate impact projection for a "most likely" scenario of these costs. However, FPL did provide a projection of approximate bill impacts for the 2009 – 2021 time frame for one of the nine scenarios evaluated in Exhibit SRS-9 in the testimony of FPL Witness Sim. FPL extended that projection through the year 2035 in supplemental response to Staff's First Set of Interrogatories No. 19.

Q.

In its petition, FPL has identified two design selections for Turkey Point 6 and 7. How and when will the design selection be determined?

A.

Witness Scroggs (p. 19) describes the steps leading to the technology selection. These steps include continued discussions with the technology vendors to evaluate the principal commercial issues (Scroggs, pp. 17-18) and the completion of due diligence investigations at the site to determine the suitability of the design to the specific location. Once these steps are completed, a selection will be made. These steps are expected to be completed by mid-2008.

Q.
Please discuss how selection of the Westinghouse or GE units will affect the amount of nuclear fuel purchased? Would the rate in $/MMBtu be the same for either the Westinghouse or the GE units?

A.
The larger capacity of the GE units would result in the purchase of a larger amount of nuclear fuel.

Historically, the unit fuel cost or rate ($/MMBtu) for boiling water reactors (such as the GE design) has been somewhat higher than that for pressurized water reactors (Westinghouse design). However the anticipated unit fuel costs for the new designs will be influenced by several parameters. The increased economy of scale for the GE (BWR) design may compensate for the historic difference in fuel costs. As it pertains to technology selection, the difference in unit fuel cost is not expected to be a significant factor in the selection process.

Q.
Please discuss how selection of the Westinghouse or GE units will affect O&M (both fixed and variable) costs?

A.
As discussed by Witness Scroggs (p. 17), and based on the limited information available at this time, there is no significant difference in the fixed or variable operating costs of the GE or Westinghouse units. In general, it is presumed that the larger units may provide some benefit from scale economies. Similarly, economies may also be available through industry consortiums, such as owner's groups, to share common costs for either technology.

Q.
Would the Westinghouse unit require less construction time than the GE unit? If yes, how, if at all, will this affect selection?

A.
Currently, the vendors have advised that the technologies would require approximately the same construction duration and, therefore, this is not expected to be a significant factor in technology selection.

Q.
Please discuss the cost impact for additional transmission lines if two 1,520 MW units are selected in lieu of two 1,100 MW units?

A.
Mr. Sanchez presents in his testimony the results of preliminary studies performed by FPL in which a description of the transmission upgrades and new transmission facilities required for Turkey Point 6 & 7 was provided for the interconnection and integration of either two 1,520 MW units or two 1,100 MW units. The results of that preliminary study alternative indicated that upgrades would be necessary for five existing transmission lines to accommodate the larger units. FPL is currently performing a more detailed analysis than the preliminary studies performed earlier to determine with more specificity the transmission upgrades and new transmission facilities that would be required and the attendant cost impact.

Q.

Please discuss the potential impacts, with regards to a unit outage, on the FRCC's import capability if two 1,520 MW units are selected in lieu of two 1,100 MW units?

A.

Based upon preliminary assessments by FPL, in the 2018 time frame, the sudden outage of a unit size of approximately 1,200 MW gross output or less should not adversely impact the FRCC region's import capability from the SERC region. If the unit size increases, more detailed studies will be needed to determine the specific impacts and mitigation alternatives.

Q.

On page 17, lines 9-17 of his direct testimony, Witness Hector Sanchez states that a more detailed study is needed to determine the specific impacts in mitigation alternatives if a unit larger that 1,200 MW is selected. Has FPL started this study? If so, when will the study be completed?

A.

Yes. FPL has initiated preliminary studies to determine the impacts of mitigation alternatives for the larger units. Subsequently, FPL would request through the FRCC that an FRCC/SERC regional/inter-regional study be performed to review the preliminary assessment findings and to determine the requirements, if any, to the transmission systems within the FRCC and SERC regions to accommodate the larger sized units. Such a study would be performed with members of the FRCC, SERC, and FPL. Initial communications with the FRCC are currently underway to prepare for the commencement of this study. It is expected that this study would take up to 24 months to complete.

Q.

On page 4, lines 12-13, of Witness Villard's direct testimony, he discusses the four steps of nuclear fuel development. Please discuss which of the four steps of nuclear fuel development is most prone to cost fluctuation, and why?

A.

The supply of uranium is the most volatile of the four steps. Recent volatility in uranium prices is due to a large extent to speculative demands by hedge funds. As one proceeds to the other steps of the fuel cycle, such as enrichment services, uranium becomes more expensive to carry and also becomes "special nuclear material" where NRC regulations limit ownership to entities with special NRC licences. As a result of limitations on ownership of enriched uranium and fabricated fuel assemblies, these products are much less subject to significant speculative manipulation.

Q.
Please refer to Appendix E, page 13. Why was only one nuclear fuel cost scenario (no low or high) used in the economic analysis?

A.
There are two reasons why a single nuclear fuel cost forecast was used in the economic analyses. First, both the historic and anticipated future variability in nuclear fuel costs is very small compared to other cost uncertainties such as fossil fuel costs and environmental compliance costs that affect the outcome of the analyses to a far greater degree. Second, no reasonable change in future nuclear fuel costs will change the fact that nuclear units will operate at full availability. In other words, varying the nuclear fuel cost forecast would add little additional meaningful information.

Because the projected number of operating hours for Turkey Point 6 & 7 would not change if FPL had used either a low or high nuclear fuel cost forecast, it is possible to estimate the impact of a different nuclear fuel cost forecast on the CPVRR cost of the Plan with Nuclear. This calculation uses the projected annual operating hours for Turkey Point 6 & 7 and multiplies these annual values by the annual difference between the nuclear fuel cost forecast values that were used in the analysis and the values for an alternate (low or high) nuclear fuel cost forecast. The resulting annual changes in nuclear fuel costs can then be summed to determine a CPVRR cost impact for the Plan with Nuclear under both a low and a high nuclear fuel cost compared to that shown in column (3) in Exhibit SRS-6 of FPL Witness Sim for each of the nine scenarios analyzed.

FPL has performed this calculation and the results are presented below in terms of million, CPVRR, 2007$, 2007 -2060.

Projected Change in CPVRR Costs for Plan with Nuclear: w/ Low Nuclear Fuel Costs

Scenario	Plan with Nuclear	Cost Change	% Cost Change
High Gas, Env I	220,904	-228	-0.1%
High Gas, Env II	233,322	-228	-0.1%
High Gas, Env III	242,937	-228	-0.1%
High Gas, Env IV	252,296	-228	-0.1%
Med Gas, Env I	170,391	-228	-0.1%
Med Gas, Env II	182,700	-228	-0.1%
Med Gas, Env III	192,190	-228	-0.1%
Med Gas, Env IV	201,428	-228	-0.1%
Low Gas, Env I	129,850	-228	-0.2%

Projected Change in CPVRR Costs for Plan with Nuclear: w/ High Nuclear Fuel Costs

Scenario	Plan with Nuclear	Cost Change	% Cost Change
High Gas, Env I	220,904	265	0.1%
High Gas, Env II	233,322	265	0.1%
High Gas, Env III	242,937	265	0.1%
High Gas, Env IV	252,296	265	0.1%
Med Gas, Env I	170,391	265	0.1%
Med Gas, Env II	182,700	265	0.1%
Med Gas, Env III	192,190	265	0.1%
Med Gas, Env IV	201,428	265	0.1%
Low Gas, Env I	129,850	265	0.2%

As seen by these results, the impacts of a change in forecasted nuclear fuel costs are negligible in regard to the results of FPL's analyses. A lower nuclear fuel cost forecast only slightly increases the benefits of Turkey Point 6 & 7 while a higher nuclear fuel cost forecast only slightly decreases those benefits.

Q.

In response to Staff's First Set of Interrogatories, No. 5, FPL states that the Southern Company purchased power agreement has been extended through 2015. Please respond to the following:

A. What, if any, renewal provisions are available in this contract?
B. What action is FPL taking to extend this agreement beyond 2015?

A.

A. To be accurate, the Southern Company purchased power agreement that expires in 2010 has not been extended. New contracts with Southern Company, based on primarily new capacity and energy sources, were negotiated in 2004 for the period 2010 through 2015. The contracts have no renewal provisions beyond 2015.

B. FPL has not conducted any further discussions with Southern Company regarding the contracts, primarily due to the fact that the magnitude of FPL's capacity needs in 2016 is uncertain and no decision is needed regarding 2016 at this time. When FPL evaluates alternatives to meet its capacity needs in 2016, it will consider any proposals that Southern Company may offer.

Q.

On page 57 of the Need Study, FPL states that its forecasts are generally consistent with other published contemporary forecasts. Please respond to the following:

A. To what other published contemporary forecasts did FPL compare its fuel price forecasts?
B. Did FPL compare its fuel price forecasts to the fuel price forecast in EIA's Annual Energy Outlook?
C. What did these comparisons reveal?
D. What does FPL mean by "generally consistent"?

A.

A. FPL did not compare its fuel price forecasts to other published contemporary forecasts. FPL's forecast utilizes forward curve commodity prices, escalation rates provided by the Energy Information Administration (EIA) and long-term price projections from both the PIRA Energy Group (PIRA) and JD Energy, Inc. (JD Energy). PIRA, a world-recognized consulting firm with extensive expertise in all aspects of the oil and natural gas industry, supplies FPL with an extensive database to support its short- and long-term projections for future prices of oil and natural gas. JD Energy, a consulting firm retained by many utilities and coal suppliers, and with extensive expertise in all aspects of the coal and petroleum coke industry, supplies FPL with an extensive database to support its short- and long-term projections for future prices of coal and petroleum coke. Because FPL utilizes inputs from renowned energy consultants and industry-accepted rates of escalation, FPL does not believe that comparisons to other contemporary forecasts are necessary as FPL relies on the expertise that each consultant provides.

B. As stated in response to Part A, FPL does not compare its fuel price forecasts to the other published forecasts.

C. Please see responses to Parts A and B.

D. In relying on input from independent sources, including widely recognized energy consulting firms and EIA rates of escalation, FPL believes that its fuel price forecast would, in general, be consistent with other independent fuel price forecasts.

Q.

Please refer to the medium price fuel forecast for natural gas, solid fuel, residual fuel oil, and distillate oil, on pages E5 through E8 of the appendices. Did FPL review or test these fuel price forecasts for reasonableness? Please explain.

A.

As indicated in the response to Staff's 3rd Set of Interrogatories No. 55, FPL relied on independent forecasts from widely recognized energy consulting firms and rates of escalation from the Energy Information Administration (EIA). Therefore, FPL's fuel-price forecasts are already based on recognized, independent sources of forecast information, and there was no need to test those forecasts against additional independent forecasts. FPL believes that its projections are reasonable.

Q.

Please refer to pages 58 and 59 of the Need Study. FPL states that "in order to achieve the maximum fuel supply diversity and delivery flexibility for FPL's customers, FPL assumed that the delivered price of solid fuel for IGCC units in FPL's Plan without Nuclear -- IGCC would he a mix of 25% Central Appalachian coal, 25% South American coal, and 50% petroleum coke." Please explain this assumption.

A.

To achieve the maximum fuel supply diversity, FPL assumed that the IGCC would burn both coal and petroleum coke. For economic evaluation purposes, FPL assumed that the unit would burn an equal share of coal and petroleum; however, depending upon future economics, the actual mix could have a higher or lower percentage of petroleum coke. To enhance fuel delivery flexibility for FPL's customers, FPL assumed, since a solid fuel receiving terminal was required to receive and deliver petroleum coke, that it might be economic in the future to import foreign coal from South America in place of Central Appalachian coal or even petroleum coke. In light of this possibility, for economic evaluation purposes, FPL assumed that half of the coal deliveries would be imported from South America and half would be delivered from the Central Appalachian region. Again, depending upon future economics, the proposed mix of coals could vary over time.

Q.

Please refer to the nuclear price forecast, Exhibit CAV-1, attached to the direct testimony of Claude A. Villard. Please respond to the following:

A. Did FPL review or test this nuclear fuel price forecast for reasonableness? Please explain.
B. Did FPL compare its nuclear fuel price forecast to independent nuclear fuel price forecasts? If yes, please state which independent forecasts were used.
C. If the response to Interrogatory No. 58B is yes, what did that comparison reveal?

A.

A. FPL reviewed various industry forecasts for supply/demand and price projections. This review, along with independent announcements made by suppliers, permitted FPL to compute a reasonable projection for each step of the fuel fabrication process.

B. The reports used by FPL were prepared by Energy Resources International and NAC International.

C. FPL uses a number of reports and its own knowledge of the nuclear fuel market to compute a reasonable price projection. Although there is a wide difference among various sources on price projections in the near future (the next 2-3 years), most experts and FPL agree that the prices of various constituents of the nuclear fuel cycle will return to a level more reflective of market fundamentals.

Q.

On page 8, lines 10 through 20, of his direct testimony, Witness Villard indicates that the market for nuclear fuel will return to fundamentals and that sufficient supply will be available for new nuclear units. Please respond to the following:

A. Why does FPL expect the nuclear fuel markets to return to fundamentals and prices to increase with inflation?
B. What risk analysis has FPL done regarding the assumption that nuclear fuel will return to market fundamentals and that supply will be sufficient over the lifetime of the proposed nuclear plants?

A.

A. The current supply of natural uranium and enrichment services (the largest contributors to nuclear fuel costs) in the market is lower than historical levels, which has caused an increase in price. These higher market prices have motivated additional production, expected to come on line over the next few years, which should bring prices back to a level consistent with market fundamentals.

The current high market price for uranium is due to a combination of factors, such as: (1) recent shutdowns or reduction in major mining operations (a major Australian uranium mine, owned by Energy Resources of Australia, was affected by two cyclones earlier this year); (2) a delay by CAMECO, a Canadian company, in starting production in 2007 at a major mine due to mine flooding; (3) the advent of hedge funds purchasing uranium and artificially increasing demand in the short term; and (4) suppliers unwilling to sell their excess inventories and holding back for higher prices. The higher price has made it economical for a number of players to invest in increasing current and starting new mining operations, which are expected to start in 2-3 years. Although we do not expect the price to return to the $10/lb level for uranium, we expect prices to return to the levels needed to support these new investments in the nuclear fuel cycle.

As for uranium enrichment services, the current restrictions imposed by the U.S. Department of Commerce (DOC) on the import of French and Russian uranium enrichment services have turned the market into a monopoly for the current US supplier, the United States Enrichment Corporation (USEC). USEC uses a technology which is energy intensive (electricity) and USEC has increased its prices to cover these higher costs. The courts have ruled that the DOC restrictions are illegal and requested the DOC to make the appropriate determination consistent with the Court decisions. This should increase the amount of uranium enrichment supply in the US market and modulate price increases. In addition, USEC and a number of suppliers have plans to change the enrichment technology to a centrifuge technology which uses much less electricity and is more capital intensive. These technologies will be deployed within the next 5 years and we expect would create more stability in uranium enrichment prices and cost increases to be tied to production costs.

B. As indicated above, FPL has reviewed a number of market publications and formed its judgment on long-term prices. Of the experts, reviewed, FPL used the higher reference prices to provide a higher confidence in the price of uranium used in its analyses. At these prices, FPL believes there will be sufficient incentive to produce nuclear fuel. Also, it will take far less time to bring on new production facilities compared with the time required for the construction of new nuclear plants. Therefore, the increase in demand can be managed by the markets. In addition, the industry is currently in negotiation with the US government to use part of the large uranium inventory held by the government for new reactors, and if successful, this would provide additional certainty in the supply of nuclear fuel.

Q.

Please refer to page 12, line 22, through page 13, line 2, of the direct testimony of Witness Gerard Yupp.

A. How were the transportation costs forecasts for fuel oil and natural gas developed?
B. Did FPL test the fuel oil and natural gas transportation costs forecasts for reasonableness? Please explain.

A.

FPL's transportation cost forecasts for fuel oil and firm natural gas are primarily based on FPL's existing transportation contracts for each commodity. Additionally, for future natural gas-fired expansions beginning in 2016, FPL estimated a firm demand charge and applied an escalation rate to that charge of 2.5% per year thereafter. FPL's interruptible natural gas transportation forecast is based on FPL's current experience in the procurement of interruptible natural gas transportation in its day-to-day operations. FPL believes that utilizing existing contracts and recent actual experience in developing the transportation cost forecasts is a reasonable methodology.

AFFIDAVIT

Sponsor:

Steven D. Scroggs

Steven D. Scroggs

State of Florida)

County of Miami-Dade)

I hereby certify that on this 12th day of December, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven D. Scroggs**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 28, 29, 34, 37, 42, 44, 45, 46, 47, and 53 from **Staff's Third** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of December, 2007.

Monica Lynn Padron

Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

AFFIDAVIT

Sponsor:

Steven R. Sim

(Steven R. Sim)

State of Florida)

County of Miami-Dade)

I hereby certify that on this 13th day of December 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven R. Sim**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No(s). **30-33, 35, 39, 43, 52, 54** from **Staff's 3rd** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13th day of December, 2007.

Monica Lynn Padron

Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

AFFIDAVIT

Sponsor:

Claude Villard

State of Florida)

County of Palm Beach _)

I hereby certify that on this 17th day of December 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Claude Villard**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 36, 51, 58, and 59 from **Staff's Third** Set of Interrogatories to Florida Power & Light Company in Docket No. *070650-EI*, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 17th day of December, 2007.

Notary Public
State of Florida, at Large

My Commission Expires:

JO NETHA FORBES
Notary Public - State of Florida
My Commission Expires Mar 6, 2010
Commission # DD 606962
Bonded By National Notary Assn.

AFFIDAVIT

Sponsor:

Gerard Yupp

Gerard Yupp

State of Florida)

County of Palm Beach)

I hereby certify that on this 11th day of December 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard Yupp, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 38, 55, 56, 57 and 60 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11th day of December, 2007.

Monica M. Schaefer

Notary Public
State of Florida, at Large

MONICA M SCHAEFER
MY COMMISSION # DD547312
EXPIRES: May 1, 2010
(407) 398-0153 Florida Notary Service.com

My Commission Expires:

5/1/2010

AFFIDAVIT

Sponsor:

C. Dennis Brandt

C. DENNIS BRANDT

State of Florida)

County of MIAMI-DADE)

I hereby certify that on this 11 day of DECEMBER, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **C. Dennis Brandt**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. **40 & 41** from **Staff's 3rd Set of Interrogatories** to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11 day of DECEMBER, 2007.

Debra Ann Dominguez

Notary Public
State of Florida, at Large

My Commission Expires:

APRIL 20, 2008

NOTARY PUBLIC STATE OF FLORIDA
Debra Ann Dominguez
Commission # DD312184
Expires April 20, 2008
Bonded Thru 1-800-350-5161

AFFIDAVIT

Sponsor/

Hector J. Sanchez

State of Florida)

County of DADE)

I hereby certify that on this 14th day of Dec, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Hector J. Sanchez**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No(s). **48, 49 and 50** from **Staff's 3rd** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of December, 2007.

Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC-STATE OF FLORIDA
Mary W. Nicklaus
Commission # DD703671
Expires: SEP. 30, 2011
BONDED THRU ATLANTIC BONDING CO., INC.

AFFIDAVIT

Sponsor:

Anita Sharma

Anita Sharma

State of Florida)

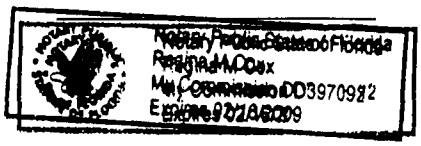
County of Miami Dade)

I hereby certify that on this 18th day of December 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Anita Sharma, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 61 and 62 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of December, 2007.

Notary Public
State of Florida, at Large

My Commission Expires:



3

FPL's Response to Staff's Fourth Set of Interrogatories (Nos. 63-72)

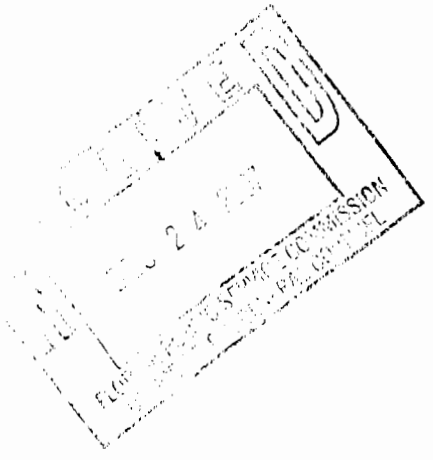
BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Filed: December 21, 2007

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FOURTH SET OF INTERROGATORIES (NOS. 63-74)

Florida Power & Light Company gives notice of service of its Objections and Responses to the Staff of the Florida Public Service Commission's Fourth Set of Interrogatories (Nos. 63-74) to Katherine E. Fleming, with a copy to all parties on the attached Certificate of Service.

Respectfully submitted this 21st day of December, 2007.



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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 21st day of December, 2007, to the following:

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By: *s/Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000132

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: December 21, 2007

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FOURTH SET OF INTERROGATORIES (NOS. 63-74)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following objections and responses to the Staff of the Florida Public Service Commission's ("Staff's") Fourth Set of Interrogatories (Nos. 63-74).

I. General Objections

FPL objects to each and every request for documents that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive such privilege or protection. The nature of the document(s), if any, will be described in a privilege log prepared by FPL.

In certain circumstances, FPL may determine, upon investigation and analysis, that information responsive to certain discovery requests to which objections are not otherwise asserted are confidential and proprietary and should not be produced without provisions in place to protect the confidentiality of the information, if at all. By agreeing to provide such information in response to such request, FPL is not waiving its right to insist upon appropriate protection of confidentiality by means of a protective order or other action to protect the confidential information requested. FPL asserts its right to require such protection of any and all

documents that may qualify for protection under the Florida Rules of Civil Procedure and other applicable statutes, rules and legal principles.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's response. Rather, these responses provide all the information that FPL obtained after a reasonable and diligent search conducted in connection with this discovery request. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to any production location other than FPL's offices at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each request to the extent that it seeks information that is not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests.

FPL objects to each discovery request to the extent that the information requested constitutes "trade secrets" which are privileged pursuant to Sections 90.506 and 366.093(3)(a), Florida Statutes.

Hearing Exhibit 000134

FPL also objects to these discovery requests to the extent they call for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as purporting to expand FPL's obligations under applicable law. FPL will comply with its obligations under the applicable rules of procedure.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to Staff through normal procedures.

FPL objects to each discovery request and any definitions and instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count requests for production of documents and their sub-parts (as permitted under the applicable rules of procedure) in determining whether it is obligated to respond to additional requests served by any party.

Notwithstanding any of the foregoing general objections and without waiving these objections, FPL intends in good faith to respond to Staff's discovery requests.

II. Responses

Attached hereto are FPL's answers to Staff's Fourth Set of Interrogatories (Nos. 63-74), consistent with its prior objections, together with the affidavits of the persons providing said answers.

Hearing Exhibit 000135

Respectfully submitted this 21st day of December, 2007.

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By: _____

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 21st day of December, 2007, to the following:

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Hearing Exhibit 000137

Q.
Please explain or describe the step-by-step process used by FPL and its consultants in the development of the environmental compliance costs forecasts shown in Appendix F of the Need Study For Electrical Power for all years included in the forecasts.

A.
The process used by FPL and its consultants to develop the environmental compliance costs forecasts shown in Appendix F is described below:

Step 1 The source document used was the ICF "U.S. Emission & Fuel Markets Outlook" Report, 2006 Edition. The costs provided by ICF in this report were in 2005 real dollars.

Step 2 From this report, three scenarios were chosen:
1. 4P: 4 Pollutant Mild (Bingaman) CO2;
2. 4P: 4 Pollutant Reference Case;
3. 4P Stringent: 4 Pollutant (McCain) CO2.

These scenarios were chosen to cover the broad range of CO2 price outcomes projected by ICF, while keeping the number of scenarios to a manageable level.

Step 3 The ICF projections ended at 2030. For CO2 in the 4P Pollutant Mild Case scenario, the post-2030 values were assumed to stay at the 2030 levels (in real terms). For CO2 in the 4 Pollutant Reference Case scenario, a 2050 projected target price of 35$/ton (in real terms) was assumed. Between 2030 and 2050, values were interpolated accordingly. A similar process was used for CO2 in the 4P Stringent scenario, with the 2050 target price set at $50/ton. Target values for 2050 were chosen by consensus by FPL and its consultant. The post-2030 price escalators developed for the three CO2 scenarios in the process described above were also applied to the SO2, NOx and Hg emission prices.

Step 4 The projections were then converted to nominal dollars using a general inflation rate of 2.5%. At this point, FPL had developed Scenarios ENV I, ENV II, and ENV III. The ICF origin of these scenarios is shown below:

ENV I: Based on 4P: 4 Pollutant Mild (Bingaman) CO2;
ENV II: Based on 4P: 4 Pollutant Reference Case;
ENV III: Based on 4P Stringent: 4 Pollutant (McCain) CO2.

Step 5 An additional scenario, ENV IV, was developed. The annual CO2 values ($/ton) in ENV III were increased by 30%. Costs for NOx, SO2 and Hg were unchanged from scenario ENV III.

Q.
If not otherwise provided in FPL's Response to Staff's Production Request No. 17, please describe in detail the assumptions utilized in the development of Appendix F of the Need Study regarding existing and future environmental requirements for the control of each of the following emissions as may be expected to impact FPL: SO2, NOx, Hg, and CO2.

A.
The control assumptions identified for each of the cases used in the development of Appendix F were developed by ICF on pages 263 - 281 of their report, which has been provided in response to Staff's 4th Request for Production of Documents No. 16.

Q.
Please explain or describe what probabilities, if any, did FPL assign to the environmental compliance cost scenarios identified in Appendix F of the Need Study For Electrical Power. If no probabilities were assigned, please explain why.

A.
For purposes of FPL's analyses in this docket, FPL assigns no specific probabilities to the four environmental compliance forecasts utilized in the analyses. FPL believes that there are simply too many uncertainties, both in regard to future environmental compliance costs and fuel costs, and in the interaction between them, to assign probabilities to specific forecasts and to designate one such forecast as a "most likely" forecast. Consequently, FPL's analytical approach for both of the nuclear filings is to examine a variety of potential scenarios rather than to assign probabilities.

Q.

Please refer to Page 46, Lines 12-13, of Witness Sim's Direct Testimony. Please explain why FPL assumed that no CO2 allowances would be granted to FPL during the forecast horizon?

A.

FPL currently believes that it is unlikely that the granting of CO2 allowances will be part of any eventual greenhouse gas emission reduction legislation and regulation. Consequently, FPL assumed no such allowances in its analyses.

Q.
Please explain or describe how FPL developed its environmental emissions allowance forecast (number of allowances) for the period 2007 through 2043 for SO2, NOx (both annual & seasonal), Hg, and CO2.

A.
FPL's environmental emissions allowance forecast was developed using the Florida Clean Air Interstate Rule for allocation of SO2 and NOx allowances, and the Florida Clean Air Mercury Rule for allocation of mercury allowances to FPL's affected Florida generating units. The Florida rules adopt the federal CAIR and CAMR provisions with minor changes in the allocations and baseline unit definitions for CAIR and the use of an allowance hold back under CAMR prior to 2017. For allocations of NOx, SO2, and Hg allowances to FPL's ownership share in Georgia, FPL used the EPA final model rules as the Georgia rules proposed to adopt the federal rules but were in draft at the time the analyses were completed. There are no existing or proposed CO2 allocation programs either federally or within the states of Florida or Georgia. It was assumed that any CO2 sensitivity analyses would utilize an auction program similar to that adopted by several states within the RGGI program within the Northeastern US.

The allocation of SO2 allowances under CAIR utilizes the pre-existing Title IV Acid Rain program where allowances have already been allocated in perpetuity to those affected Acid Rain units and no new allocations are allowed under that program. For annual and seasonal NOx allowances, the allowance allocation analysis utilized existing rule language using the existing units within the affected states. To account for future allocations within Florida to new units, the additions through 2017 that had been identified in the 10-year site plans were included. Beyond the 2017 future date for Florida, and for all future years within Georgia, it was assumed that states' EGU needs would grow at their average historical rate and be included as new units and eventually included into baseline allocations as provided in each state's rules. For the purposes of Hg allocations it was assumed that utilities would behave similarly to the acid rain program where excess allowances would be banked for future use. It was assumed that FPL generating units would have sufficient Hg allowances following the installation of applicable Hg controls but that any excess allowances would be banked to mitigate unanticipated future operational issues. The use of a full auction program assumption for CO2 allowances provides the opportunity to evaluate the use of either an auction program or a carbon fee/tax program. There exists a nearly unlimited variety of allowance allocation formulas which could be adopted at the state or federal level to implement subsidies to affected sources. FPL chose to evaluate the impacts of a CO2 program by evaluating the cost of CO2 allowances on the dispatch of generating units rather than arbitrarily choose an allocation method favoring any one of the policy adopted allocation methods.

Q.
For each type of emission, please explain or describe what assumed compliance options (e.g. retirement, retrofit or purchase of the allowance) FPL included in its economic and non-economic analysis.

A.
The evaluation of FPL's compliance options were limited to the existing state and federal rules which will apply to the operation of its generating units. Specific controls were identified for the compliance with the CAIR, CAMR, and applicable Non-attainment Rules applicable to generating units within Florida and Georgia. The compliance options analyzed included only those that have already been included in the testimony of Randall LaBauve for the Environmental Cost Recovery Docket 070007-EI. The calculation of allowance shortfall evaluated FPL's need to purchase future allowances where needed.

Q.
If any allowance purchasing option was assumed, please explain or describe the market prices (in 2007 $) that FPL utilized in developing the economic analysis.

A.
The allowance prices that FPL used in its analysis are shown in Appendix F of the Need Study for Electric Power document. These allowance prices are in nominal dollars, not 2007 dollars. The process used to develop these prices is explained in the response to Staff's 4th Set of Interrogatories No. 63.

As requested in this interrogatory, FPL has converted the prices show in Appendix F to 2007 real dollars. These are shown in the attached table.

SO2 Title IV Allowance Price Trajectories by Scenario (2007$/Ton)	I	II	III	IV
Year	4P Mild CO2	4P	4P Stringent CO2	CO 2-30% x III
2006	908	831	811	811
2007	970	888	867	867
2008	1036	949	927	927
2009	1107	1014	990	990
2010	1182	1082	1057	1057
2011	1263	1156	1129	1129
2012	1350	1236	1207	1207
2013	1443	1321	1290	1290
2014	1542	1411	1378	1378
2015	1647	1509	1472	1472
2016	1760	1612	1573	1573
2017	1880	1721	1679	1679
2018	2007	1838	1793	1793
2019	2142	1962	1915	1915
2020	2287	2095	2045	2045
2021	2445	2239	2185	2185
2022	2612	2392	2336	2336
2023	2792	2556	2495	2495
2024	2983	2731	2666	2666
2025	3188	2919	2849	2849
2026	3233	2927	2764	2764
2027	3279	2935	2682	2682
2028	3326	2944	2601	2601
2029	3374	2952	2524	2524
2030	3422	2961	2448	2448
2031	3422	2983	2482	2482
2032	3422	3005	2516	2516
2033	3422	3028	2551	2551
2034	3422	3050	2586	2586
2035	3422	3073	2622	2622
2036	3422	3096	2658	2658
2037	3422	3119	2695	2695
2038	3422	3143	2732	2732
2039	3422	3166	2770	2770
2040	3422	3190	2808	2808
2041	3422	3214	2847	2847
2042	3422	3238	2886	2886
2043	3422	3262	2926	2926
2044	3422	3286	2966	2966
2045	3422	3311	3007	3007
2046	3422	3336	3049	3049
2047	3422	3361	3091	3091
2048	3422	3386	3134	3134
2049	3422	3411	3177	3177
2050	3422	3436	3221	3221
2051	3422	3462	3265	3265
2052	3422	3488	3311	3311
2053	3422	3514	3356	3356
2054	3422	3540	3403	3403

NOx Annual Allowance Price Trajectories by Scenario (2007$/Ton)

Year	I 4P Mild CO2	II 4P	III 4P Stringent CO2	IV CO 2-30% x III
2006	--	--	--	--
2007	--	--	--	--
2008	--	--	--	--
2009	1670	1594	1554	1554
2010	1645	1696	1659	1659
2011	1620	1804	1771	1771
2012	1732	1929	1893	1893
2013	1851	2061	2024	2024
2014	1978	2203	2163	2163
2015	2114	2353	2310	2310
2016	2258	2514	2468	2468
2017	2411	2684	2636	2636
2018	2574	2866	2815	2815
2019	2748	3060	3005	3005
2020	2934	3268	3209	3209
2021	2720	2362	2540	2540
2022	2520	1707	2011	2011
2023	2336	1233	1592	1592
2024	2164	891	1261	1261
2025	2006	644	998	998
2026	1975	688	--	--
2027	1945	735	--	--
2028	1915	786	--	--
2029	1886	839	--	--
2030	1856	897	--	--
2031	1856	904	--	--
2032	1856	911	--	--
2033	1856	918	--	--
2034	1856	924	--	--
2035	1856	931	--	--
2036	1856	938	--	--
2037	1856	945	--	--
2038	1856	952	--	--
2039	1856	959	--	--
2040	1856	967	--	--
2041	1856	974	--	--
2042	1856	981	--	--
2043	1856	989	--	--
2044	1856	996	--	--
2045	1856	1003	--	--
2046	1856	1011	--	--
2047	1856	1018	--	--
2048	1856	1026	--	--
2049	1856	1034	--	--
2050	1856	1041	--	--
2051	1856	1049	--	--
2052	1856	1057	--	--
2053	1856	1065	--	--
2054	1856	1073	--	--

C02 Allowance Price Trajectories by Scenario (2007$/Ton)

Expected is a weighted probability of all CO2 forecasts

Year	I 4P Mild CO2 (Bingaman)	II 4P (ICF expected)	III 4P Stringent CO2 McCain	IV 30% x D
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	6	0	11	14
2011	6	2	12	15
2012	6	4	13	16
2013	7	7	13	16
2014	7	8	14	18
2015	8	9	15	19
2016	8	11	16	20
2017	8	13	17	22
2018	9	15	18	23
2019	9	16	19	25
2020	9	19	21	27
2021	9	20	22	29
2022	11	22	24	31
2023	11	23	25	33
2024	11	25	27	36
2025	11	26	28	37
2026	11	28	30	40
2027	11	29	33	42
2028	11	29	36	46
2029	11	30	38	49
2030	11	29	40	52
2031	11	30	41	53
2032	11	30	41	54
2033	11	30	42	54
2034	11	30	42	55
2035	11	31	43	56
2036	11	31	44	57
2037	11	31	44	58
2038	11	31	45	58
2039	11	32	46	59
2040	11	32	46	60
2041	11	32	47	61
2042	11	32	47	62
2043	11	32	48	63
2044	11	33	49	63
2045	11	33	49	64
2046	11	33	50	65
2047	11	33	51	66
2048	11	34	51	67
2049	11	34	52	67
2050	11	34	53	68
2051	11	34	53	69
2052	11	35	54	70
2053	11	35	54	71

Hg Allowance Price Trajectories by Scenario (2007$/lb)	I	II	III	IV
Year	4P Mild CO2 (Bingaman)	4P	4P Stringent CO2 McCain	CO 2-30% x III
2006	--	--	--	--
2007	--	--	--	--
2008	--	--	--	--
2009	--	--	--	--
2010	26282	27845	27702	27702
2011	26501	26889	26755	26755
2012	26721	25965	25841	25841
2013	26943	25073	24958	24958
2014	27962	25465	25351	25351
2015	29870	27204	27080	27080
2016	31910	29060	28928	28928
2017	34073	31031	30888	30888
2018	36383	33042	32982	32982
2019	38851	35384	35219	35219
2020	41485	37784	37606	37606
2021	44330	40376	40186	40186
2022	47371	43145	42943	42943
2023	50619	46105	45889	45889
2024	54090	49267	49038	49038
2025	57800	52646	52413	52413
2026	61766	56257	55997	55997
2027	66003	60115	59838	59838
2028	70533	64237	63943	63943
2029	75372	68643	68331	68331
2030	80543	73350	73017	73017
2031	81145	73350	74026	74026
2032	81752	73350	75049	75049
2033	82364	73350	76086	76086
2034	82980	73350	77137	77137
2035	83601	73350	78203	78203
2036	84226	73350	79283	79283
2037	84856	73350	80379	80379
2038	85491	73350	81489	81489
2039	86130	73350	82615	82615
2040	86774	73350	83757	83757
2041	87423	73350	84914	84914
2042	88077	73350	86087	86087
2043	88736	73350	87277	87277
2044	89400	73350	88482	88482
2045	90068	73350	89705	89705
2046	90742	73350	90944	90944
2047	91421	73350	92201	92201
2048	92104	73350	93475	93475
2049	92793	73350	94766	94766
2050	93487	73350	96076	96076
2051	94187	73350	97403	97403
2052	94891	73350	98749	98749
2053	95601	73350	100113	100113
2054	96316	73350	101496	101496

Q.
Please clarify whether FPL included both NOx annual and NOx seasonal emissions in the environmental compliance costs forecasts Env I to Env IV. Please explain or describe whether the numbers presented on Page 2 of Appendix F of the Need Study include both annual and seasonal NOx emissions, or whether the numbers only include annual NOx emission?

A.
The NOx allowance compliance costs represented in Env I to Env IV were for the annual compliance period. The evaluation of compliance costs for NOx under CAIR included control and allowance costs associated with the annual NOx program only as a result of projected seasonal allowance prices which are projected to approach $0 by 2009 when market over-supply of seasonal allowances greatly exceeds demand. ICF has provided a discussion of the NOx Ozone Season analysis on pages 192 and 193 of the 2006 report.

Q.

Please refer to Page 2 of Appendix F of the Need Study. Please explain or describe why the NOx environmental compliance costs shown in forecasts Env III and Env IV dropped from 1557 nominal $ per ton in year 2026 to 0 nominal $ per ton in year 2027 then remained being 0 for the rest of the years within the forecasting horizon, but in contrast the compliance costs shown in forecast Env I and Env II increased every year for the same forecasting period.

A.

The forecasts for Env III and Env IV assume the adoption of stringent CO2 policies which impact the dispatch of coal-fired generating unit through higher CO2 allowance prices creating a low-coal generation scenario. The displacement of uneconomic coal generating units by lower-emitting generating units would create an oversupply of NOx emission allowances that creates significant negative pressure on allowance prices until allowance prices are at $0 in 2027. The allowance price forecast is explained in detail on pages 198 - 201 of the ICF 2006 Report.

Q.
Please refer to Page 3 of Appendix F of the Need Study and respond to the following:

A. Please explain why CO2 emission compliance costs in forecast Env I, Env III and Env IV started to appear (i.e. bigger than zero) in 2010, but in forecast Env II the cost started to appear in 2011.

B. Please explain or describe which year FPL assumed in its analysis for the commencement of a ruling requiring electric utility greenhouse gas reduction in Florida. Please explain why FPL made this assumption.

A.

A. FPL developed its CO2 emission compliance cost forecast based on the 2006 ICF Report "U.S. Emission & Fuel Markets Outlook." FPL's ENV II forecast is based on ICF's Expected CO2 Forecast which has a value of 0 $/ton for 2010. The ICF forecasts used by FPL to model scenarios ENV I, III and IV all did assume CO2 prices starting in 2010.

B. FPL did not make an explict assumption on the commencement of a Florida specific ruling requiring electric utility greenhouse reductions. Instead, FPL relied on the assumption used by ICF in its study that a CO2 allowance price market would start in the year 2010.

AFFIDAVIT

Sponsor:
Barbara P. Linkiewicz

State of Florida)

County of Palm Beach)

I hereby certify that on this 17th day of December, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Barbara P. Linkiewicz, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 63 through 65 and 67 through 73 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 17th day of December, 2007.

Nancy E. Llama
Notary Public
State of Florida, at Large

NOTARY PUBLIC-STATE OF FLORIDA
Nancy E. Llama
Commission # DD708596
NOV. 14, 2011
BONDED THRU ATLANTIC BONDING CO., INC.

NOTARY PUBLIC-STATE OF FLORIDA
Nancy E. Llama
Commission # DD708596
Expires: NOV. 14, 2011
BONDED THRU ATLANTIC BONDING CO., INC.

My Commission Expires:

11/14/2011

AFFIDAVIT

Sponsor:

Steven R. Sim

(Steven R. Sim)

State of Florida)

County of Miami-Dade)

I hereby certify that on this 13th day of December 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven R. Sim**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No(s). **66** from **Staff's 4th** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13th day of December, 2007.

Monica Lynn Padron

Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

AFFIDAVIT

Sponsor:

Anita Sharma

Anita Sharma

State of Florida)

County of Miami Dade)

I hereby certify that on this 18th day of December 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Anita Sharma, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory No.74 from Staff's Fourth Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of December 2007.

Regina M Cox

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Regina M Cox
My Commission DD397092
Expires 02/16/2009

4

FPL's Response to Staff's Fifth Set of Interrogatories (Nos. 75-79, 81-84)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: January 7, 2008

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIFTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 21-26) AND FIFTH SET OF INTERROGATORIES (NOS. 75-84)

Florida Power & Light Company gives notice of service of its responses to the Staff of the Florida Public Service Commission's Fifth Request for Production of Documents (Nos. 21-26) and Fifth Set of Interrogatories (Nos. 75-84) to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 7th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

RECEIVED
JAN - 9 2008
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 7th day of January, 2008, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Charles J. Beck, Deputy Public Counsel*
Office of the Public Counsel
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111 West Madison Street, Room 812
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On Behalf of Jan M. Krasowski and Bob Krasowski

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By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000157

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: January 7, 2008

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIFTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 21-26) AND FIFTH SET OF INTERROGATORIES (NOS. 75-84)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following responses to the Staff of the Florida Public Service Commission's ("Staff's") Fifth Request for Production of Documents (Nos. 21-26) and Fifth Set of Interrogatories (Nos. 75-84).

FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in Florida Power & Light Company's Objections to Staff's Fifth Request for Production of Documents (Nos. 21-26) and Fifth Set of Interrogatories (Nos. 75-84), dated December 21, 2007.

I. Staff's Fifth Request for Production of Documents (Nos. 21-26)

FPL's responses are without waiver of its objections. All documents will be made available by FPL for inspection and review by Staff at FPL's offices at 215 South Monroe Street, Tallahassee Florida, during regular business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

II. Staff's Fifth Set of Interrogatories (Nos. 75-84)

Attached hereto are FPL's answers to Staff's Fifth Set of Interrogatories (Nos. 75-84), consistent with its prior objections, together with the affidavits of the persons providing said answers.

Respectfully submitted this 7th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
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Attorneys for Florida Power & Light Company

By: _____
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000159

Q.
On page 64 of his direct testimony, Witness Scroggs discusses the potential for ownership participation of Turkey Point 6 and 7.

A. Please identify which utilities have expressed an interest in ownership participation of Turkey Point 6&7.

B. Please identify which utilities FPL have discussed, in general terms, the potential for ownership participation of Turkey Point 6 and 7, and what were the results of those discussions?

C. Should the requested determination of need be granted for Turkey Point 6 and 7, please discuss if and how FPL would continue to explore ownership participation with other utilities.

D. Please identify or discuss what other alternatives to ownership participation FPL has considered that might reduce FPL's costs of building and operating Turkey Point 6 and 7.

A.

A. Prior to the filing, FPL held discussions with FMPA and OUC regarding their interest in potential ownership participation. Subsequent to the filing, FPL received an expression of interest from Seminole Electric Cooperative.

B. FPL has discussed potential ownership participation with FMPA and OUC. Discussions have covered the type of relationship (i.e., similar to existing relationships with St. Lucie 2), project status and schedule, and the difficulty to FPL of participating in substantive dialogue given the early stage of the Project.

C. FPL has been and remains willing and interested in discussing joint ownership participation in Turkey Point Units 6 and 7 with other electric utilities at the appropriate time. However, it is premature to hold detailed discussions until FPL is much farther down the road in developing the Project. FPL needs time to resolve many of the regulatory issues facing the Project and further clarify the Project's commercial parameters and schedules. At this point, the Project is necessarily more of a directional approach to developing new nuclear generation, rather than a concrete, detailed commercial arrangement as to which FPL could meaningfully discuss the possibility of participation by others.

D. At this point, FPL has not identified alternatives to joint ownership participation that would be appropriate for spreading the cost of building and operating Turkey Point 6 and 7 with other entities. However, FPL remains open to exploring such alternatives. Of course, any alternative (including joint ownership participation) that spreads the costs of the Project to others is likely also to reduce FPL's share of the benefits, so FPL would have to consider carefully whether any particular form of cost-spreading would be in the ultimate best interests of FPL and its customers.

FPL also intends to remain alert to opportunities to benefit from any future state or federal incentives for the development of new nuclear generation that might help reduce the net cost of the Project to FPL and its customers.

Q.
In response to Staff's First Set of Interrogatories, No. 9, FPL provided a listing of the number of participants in each of FPL's DSM programs. Please expand the listing with another column showing what percentage of total customers eligible for each program is represented by those participating in the DSM programs.

A.
The percent participation of eligible customers was calculated by dividing the cumulative program participation through 2006 by the 2006 eligible customers for each program. The eligible customers for each program is based on customers who can technically participate in each program. It does not consider the economic viability or customer willingness to participate in a specific program.

Program name	Program Participation Through 2006	% Participating of Eligible Customers
Residential Programs		
Residential Building Envelope	732,591	41%
Duct System Testing & Repair	404,859	12%
Residential Air Conditioning	1,093,990	32%
Residential Load Management (On Call)	742,395	19%
BuildSmart	14,487	2%
Residential Low Income Weatherization	476	0.1%
Residential Conservation Service	2,254,528	57%
Business Programs		
Business Air Conditioning	14,178	3%
Business Efficient Lighting	18,540	4%
Business Building Envelope	6,011	1%
Business Custom Incentive	22	0%
Business On Call	19,206	4%
Commercial Demand Reduction/ Commercial Load Control	606	8%
Business Energy Evaluation	105,805	21%

Q.
Please refer to page 16 of the Need Study. FPL mentions that cumulatively 38,169 Gigawatt Hours (GWh) of energy has been saved through Demand Side Management through the year 2006. Please describe how the 38,169 GWh was calculated. How would the 38,169GWh be stated in terms of annual numbers?

A.
The 38,169 GWh of Demand Side Management (DSM) achievement through the year 2006 is calculated as follows:

1. The actual energy saved for each DSM measure implemented in a single year is determined with the assumption that, on average, the measure is implemented for six months of the first year. For example, if a DSM measure saves 600 kwh per year per participant, the first year savings is estimated to be 300 kwh.

2. For each subsequent year, the annual energy saved for the DSM measure implemented in #1 above is 600 kwh.

The total energy saved in each year is the sum of the individual energy savings for all new measures implemented (#1 above) and their on-going savings in each subsequent year (#2 above). The 38,169 GWh is the sum of the total energy saved in each year from when FPL first implemented DSM programs in 1981 through 2006.

The annual energy savings are:

Year	1981	1982	1983	1984	1985	1986	1987	1988	1989
Annual GWh	0.1	6	18	45	96	155	204	244	277
Year	1990	1991	1992	1993	1994	1995	1996	1997	1998
Annual GWh	313	386	491	631	852	1,153	1,602	2,070	2,392
Year	1999	2000	2001	2002	2003	2004	2005	2006	Total
Annual GWh	2,651	2,878	3,093	3,317	3,534	3,727	3,913	4,121	38,169

Q.

Please refer to page 18 of the Need Study in which FPL states "if only natural gas-fueled generation were to be added to FPL's fuel mix, the contribution of natural gas would increase to approximately 75% by 2021 of total electricity delivered to FPL's customers by 2018." Please verify and explain whether this statement is correct. If not, please explain.

A.

This statement in the Need Study is grammatically incorrect and inadvertently confusing. However, the intended message of the statement, that if natural gas-fueled generation is added through 2021 approximately 75% of FPL's fuel mix would be supplied by natural gas, is correct.

In Table VII.D.2.1 on page 117 of the Need Study, and also in Exhibit SRS-10 of FPL Witness Sim's testimony, projections of FPL's system fuel mix are presented for the resource plans analyzed for the years 2018 and 2021 for two scenarios of fuel cost and environmental compliance costs. The projected percentages of system fuel mix supplied by natural gas for the Plan Without Nuclear – CC (the resource plan in which only combined cycle units are added from 2013 through 2021) range from 73.3% to 74.9% for one scenario and range from 74.1% to 75.5% for the other scenario, for the years 2018 through 2021. The portion of the statement on page 18 of the Need Study that refers to "approximately 75%" was based on the range of projected percentages.

Q.

Please refer to page 28 of the Need Study. FPL states that by adding Turkey Point 6 and 7, nuclear generation would represent 27% of FPL's fuel mix portfolio in 2021. Please show a system fuel mix and reserve requirement analysis using both 2200MW and 3040MW capacity additions for Turkey Point 6 and 7 for the period 2018 through 2021.

A.

FPL has evaluated the impact on FPL's reserve requirements as if the TP 6 & 7 nuclear units were 1520 MW each instead of the 1100 MW size used in FPL's analyses for this docket. The projected reserve requirements for the 2018 – 2021 time period for both the 1100 MW and 1520 MW size nuclear units are as follows:

Capacity Needed (MW) to Meet 20%

Year	If no 2018-on addition	If 1100 MW size	If 1520 MW size
2018	353	(747)	(1167)
2019	994	(106)	(526)
2020	1690	(510)	(1350)
2021	2435	235	(650)

The 1100 MW size units would meet FPL's reserve requirements in 2018 through 2020, and would meet all but 235 MW in 2021. The additional 420 MW of capacity per unit for the 1520 MW size units would result in FPL's reserve requirements being met for all four years.

FPL has not performed analyses using its production costing model that evaluated fuel costs or fuel mix assuming that the TP 6 & 7 units were 1520 MW instead of 1100 MW. All analyses have been performed assuming that the new nuclear units were 1100 MW. However, in response to this question a spreadsheet analysis was performed that estimated the annual fuel mix percentages supplied by nuclear energy that would occur if the 2018 and 2020 nuclear additions were 1520 MW each instead of 1100 MW. The values for the 1100 MW size unit are identical to those previously presented in Table VII.D.2.1 of the Need Study on page 117 and in Exhibit SRS-11 of FPL Witness Sim's direct testimony.

Projected Nuclear % of Fuel Mix

Year	If 1100 MW size	If 1520 MW size
2018	20.8	22.1
2019	22.3	24.3
2020	25.7	28.9
2021	26.5	30.3

FPL notes that these projections of reserve margins and fuel mix percentages are subject to change in the future as underlying assumptions (including fuel cost forecasts, load forecasts, etc.) change and as FPL's resource plans may change to adjust to these new assumptions.

Q.

Please refer to pages 104-105 of the Need Study. Why does FPL believe it is not possible to develop a precise projection of the capital costs associated with new nuclear units with an in-service date of 2018 and beyond?

A.

In general, the information necessary for a team of technology vendor/constructor/architect engineer to provide FPL with specific cost estimates for a proposed project at Turkey Point does not currently exist. Moreover, FPL has not finalized selection of a specific technology.

Following such selection, FPL would take two important steps. First, the information necessary to characterize the site specific design would need to be developed. This will occur as the Combined License and Site Certification Applications are completed. Secondly, FPL must then enter into commercial discussions with the technology vendor, constructor and architect/engineer that would allow the preparation of a precise projection of capital costs associated with new nuclear units.

Q.

Please refer to the table on page 117 of the Need Study. Under the Low Gas Cost Environmental I scenario, the plan without nuclear-CC shows that by 2018 FPL's fuel mix will be 74.1% reliant on natural gas. Please respond to the following:

A. Does this amount take into account whether or not the Glades units were built? Please explain.
B. Please explain why the system mix projections leveled off in 2018 and 2019

A.

A. Page 117 of the Need Study does show a projection that 74.1% of FPL's fuel mix in 2018 would be provided by natural gas for one fuel cost and environmental compliance cost scenario. A second fuel cost and environmental compliance cost scenario also provided on page 117 shows a projection that 73.3% of FPL's fuel mix in 2018 would be provided by natural gas. These amounts assume that the Glades units are not built, and are not contained in any of the three resource plans and any of the nine fuel cost and environmental cost scenarios analyzed by FPL including the two scenarios discussed above. The units assumed to be in place prior to 2018 are identical in all three resource plans. These units are shown in Table VII.C.1.a.1 on page 100 of the Need Study and in Exhibit SRS-4 of FPL Witness Sim's direct testimony.

B. Under the Low Gas Cost Environmental I scenario for the Plan Without Nuclear – CC, the projected percentage of annual energy supplied by natural gas is 74.1% in both 2018 and 2019. The projection of the same percentage for both years mainly depends on two factors: the number of months in each year the assumed new CC unit added in 2018 operates and the growth in annual energy usage on the FPL system. Although annual energy usage on the FPL system is projected to grow in 2019 compared to 2018, the new CC unit assumed in this resource plan to be added in June 2018 would be available to operate during only 7 months in 2018, but during all 12 months in 2019. These two factors essentially offset each other which results in the same projection of 74.1% of annual energy supplied by natural gas in both 2018 and 2019.

Q.
Please refer to the chart on Page 119 of the Need Study, and explain the projected drop in CO2 in the plan with nuclear during the 2009-2011 period.

A.
The projected drop in CO2 in 2010 and 2011 compared to 2009 shown on page 119 of the Need Study is actually projected for all three resource plans analyzed in this filing because the three plans are identical through 2017.

There are two main reasons for the projected drop in CO2 in 2010 and 2011 that more than offset increases in net energy for load. First, at the end of May 2010, the existing UPS purchase of approximately 930 MW of coal-fired capacity and energy from Southern Company ends. This 930 MW purchase is replaced through 2015 by a new purchase agreement with Southern in which approximately 170 MW are supplied by coal with the remaining 760 MW being supplied by gas-fired combined cycle units. Because the CO2 emission rates of combined cycle units are approximately one-half that of coal-fired units, the change in fuel type under the new Purchase Agreement with Southern results in a significant reduction in CO2 emissions.

Second, the addition of West County Energy Center (WCEC) combined cycle (CC) units 1 and 2 scheduled for 2009 and 2010, plus the assumed addition of another CC unit in 2011 in the analyses, reduces CO2 emissions on the FPL system by decreasing the operating hours of existing less-efficient gas- and oil-fired units. The greater efficiency of the new combined cycle units compared to the existing units results in lower CO2 emissions, and the lower CO2 emission rates of gas-fired combined cycle units compared to oil-fired units further lower CO2 emissions.

In addition, another contributor to the projection of reduced CO2 emissions in the year 2011 is the addition of approximately 100 MW of additional capacity at FPL's existing St. Lucie 1 nuclear unit that is projected to come in-service in December 2011 as part of FPL's nuclear capacity uprates. Capacity uprates at FPL's three other existing nuclear units are projected to come in-service in 2012.

Q.

In FPL's response to Staff's First Set of Interrogatories No. 18, FPL states that Turkey Point 6 and 7 will require water usage of 43 million gallons per day. Of the overall costs of the units, please identify what percentage is the cost of water.

A.

The percentage of the overall cost of the units that will be related to water will be dependent on the final water requirements and source(s) selected. The selection of water sources will be conducted during the preparation of the Combined License and Site Certification Applications. Characteristics such as raw water quality, treatment required, infrastructure costs, permitting costs and mitigation costs will differ for the various sources that will be investigated.

Some of the costs associated with water supply to the facility are included in line items in Exhibit SDS-6 such as: Cooling Towers, Site Work, and Permits/Licensing. Costs for water could range from 5% to more than 10% of total project capital costs. There will also be differences in the ongoing operational costs (or variable costs) for different sources that may justify selection of a higher capital cost resource to obtain lower life cycle costs.

AFFIDAVIT

Sponsor:

Steven D Scroggs

Steven D. Scroggs

State of Florida)

County of Palm Beach)

I hereby certify that on this 21st day of DEC, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven D. Scroggs**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 75, 80, 81, and 84 from **Staff's Fifth** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21st day of December, 2007.

Beverly A. Mile

Notary Public
State of Florida, at Large

BEVERLY A. MILE
Florida Notary Assn., Inc

My Commission Expires:

7/24/09

AFFIDAVIT

Sponsor:

C Dennis Brandt

C. DENNIS BRANDT

State of Florida)

County of Miami- Dade)

I hereby certify that on this 2ND day of JANUARY, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **C. Dennis Brandt**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. **76 & 77** from **Staff's 5th Set of Interrogatories** to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2nd day of January, 2008.

Cynthia L. Rozek

Notary Public
State of Florida, at Large

My Commission Expires:

CYNTHIA L. ROZEK
MY COMMISSION # DD 334812
EXPIRES: July 12, 2008
Bonded Thru Notary Public Underwriters

AFFIDAVIT

Sponsor:

(Steven R. Sim)

State of Florida)

County of Miami-Dade)

I hereby certify that on this 3rd day of January, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven R. Sim, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No(s). 78, 79, 82, 83 from Staff's 5th Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of January, 2008.

Monica Lynn Padron
Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

5

FPL's Response to Staff's Sixth Set of Interrogatories (Nos. 85, 93-97)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: January 8, 2008

NOTICE OF SERVICE
OF FLORIDA POWER & LIGHT COMPANY'S RESPONSES
TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S
SIXTH SET OF INTERROGATORIES (NOS. 85-98)

Florida Power & Light Company gives notice of service of its responses to the Staff of the Florida Public Service Commission's Sixth Set of Interrogatories (Nos. 85-98) to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 8th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
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Florida Bar No. 0037372

RECEIVED
JAN 11 2008
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 8th day of January, 2008, to the following:

Katherine E. Fleming*
Senior Attorney
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By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: January 8, 2008

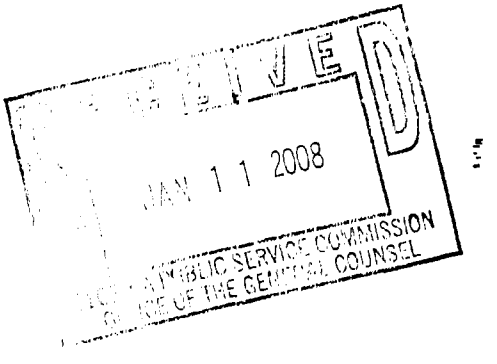
FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S SIXTH SET OF INTERROGATORIES (NOS. 85-98)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following responses to the Staff of the Florida Public Service Commission's ("Staff's") Sixth Set of Interrogatories (Nos. 85-98).

FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in Florida Power & Light Company's Objections to Staff's Sixth Set of Interrogatories (Nos. 85-98), dated January 2, 2008.

Staff's Sixth Set of Interrogatories (Nos. 85-98)

Attached hereto are FPL's answers to Staff's Sixth Set of Interrogatories (Nos. 86-98), consistent with its prior objections, together with the affidavits of the persons providing said answers. Pursuant to an agreement with Staff to extend the time available for responding to Interrogatory No. 85, FPL's answer to Interrogatory No. 85 will be provided by close of business on Thursday, January 10 if possible, and by noon on Friday, January 11 at the latest.



Respectfully submitted this 8th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
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Attorneys for Florida Power & Light Company

By: _____

Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000176

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 8th day of January, 2008, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Charles J. Beck, Deputy Public Counsel*
Office of the Public Counsel
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111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

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Daniel B. O'Hagan
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On Behalf of Jan M. Krasowski and Bob Krasowski

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Barry Moline
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Tallahassee, FL 32302-2114

By: _____
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Filed: January 23, 2008

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S SUPPLEMENTAL AND CORRECTED RESPONSES

Florida Power & Light Company gives notice of service of its supplemental response to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories No. 3 and corrected responses to Staff's Third Set of Interrogatories No. 32 and Sixth Set of Interrogatories No. 85, to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 23rd day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

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I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically and by United States mail this 23rd day of January, 2008, to the following:

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P.G. Para
JEA
21 West Church Street
Jacksonville, FL 32202

By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: January 23, 2008

FLORIDA POWER & LIGHT COMPANY'S
SUPPLEMENTAL AND CORRECTED RESPONSES TO THE
STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S INTERROGATORIES

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following supplemental response to the Staff of the Florida Public Service Commission's ("Staff's") First Set of Interrogatories No. 3 and corrected responses to Staff's Third Set of Interrogatories No. 32 and Sixth Set of Interrogatories No. 85.

FPL adopts and incorporates by reference, as though fully restated herein, all objections previously provided in response to the interrogatories. Attached hereto are FPL's supplemental and corrected answers, consistent with its prior objections.

Respectfully submitted this 23rd day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
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Attorneys for Florida Power & Light Company

By: _____
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Florida Bar No. 0037372

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Hearing Exhibit 000182

Q.

Page 3, lines 10 - 18 of Witness Ousdahl's direct testimony references the Nuclear Filing Requirements (NFRs) that are currently being developed as annual filing requirements for Sections 5(c) and 8 of Rule 25-6.0423, F.A.C. FPL, Progress, Gulf, and TECO proposed the attached set of NFRs on July 5, 2007 to Commission staff (see attached file "NFR True up to Original 070507.pdf") after a June 14, 2007 workshop was held to develop the forms. These forms contain sample data and "0" entries. In the July 5, 2007, cover letter accompanying the forms (see attached file "Cover – 070507 filing.doc"), Alexander Glenn of Progress Energy stated that, while the utilities do not contemplate filing the forms with the need filings, if some or all of the information is needed at the time of the need filing, such information could be provided in discovery. For purposes of this interrogatory, please identify or provide the data necessary to populate these forms (original projected data plus any actual costs incurred to date) for all relevant years (2007 through 2018 for Turkey Point 6 and 2007 through 2020 for Turkey Point 7).

A.

FPL objects to the relevance of this request. Nonetheless, to the extent that FPL has information regarding actual expenditures to date, and projected expenditures for the project, FPL is providing such information in the requested format. Attached please find a revised Attachment A with the following changes:

1. Upon further review, we found a formula error in Attachment A page 11 of 29, Schedule AE-3A for 2009, column G, line 4, which was not including the amount in line 2.b. for that same column. The result of this formula change is reflected in the revised schedules.
2. An incorrect reference in Attachment A page 1 of 29, Schedule TOR-1, Line 7. The reference to the origin of this number was changed to "(TOR2, Line 6)" from "(TOR2, Line 6 + TOR-3A Line 9)."

Turkey Point Units 6&7
Retail Revenue Requirements Summary

Schedule TOR-1 (True Up To Original) [Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the actual to date and projected total retail revenue requirement for the duration of the project.

COMPANY: Florida Power & Light Company

For the Period Ended 12/31/2009

DOCKET NO.: 070650-EI

Line No.		(A) Actual 2006	(B) Actual 2007	(C) Projected 2008	(D) Projected 2009	(E)	(F)	(G)
				Jurisdictional Dollars				
1.	Preconstruction Revenue Requirements (TOR-2, line 5 - line 3d)	$0	$2,547,068	$90,034,506	$183,214,463			
2.	Construction Carrying Cost Revenue Requirements (TOR-3, line 7)	$0	$0	$0	$0			
3.	Recoverable O&M Revenue Requirements (TOR-4, line 14)	$0	$0	$0	$0			
4.	Deferred Tax Asset Carrying Cost (TOR-3A, line 8)	$0	$0	$18,842	$3,982,533			
5.	Other Adjustments	$0	$0	$0	$0			
6.	Total Period Revenue Requirements (Lines 1 through 5)	$0	$2,547,068	$90,053,349	$187,196,997			
7.	Total Revenue Requirements from Original Projection (TOR2, Line 6)	$0	$0	$0	$187,196,997			
8.	Difference (Line 6 - Line 7)	$0	$2,547,068	$90,053,349	$0			
9.	Variance Percentage							

Note 1: Information provided is based upon the best available at the time of the submission of this report.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cos recovery filing by FPL.

Turkey Point Units 6&7
Projection of Preconstruction Costs

Schedule TOR-2 (True Up To Original) [Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the actual to date and projected preconstruction costs for the duration of the project.

COMPANY: Florida Power & Light Company

For the Period Ended 12/31/2009

DOCKET NO.: 070650-EI

Line No.		(A) Beginning of Period	(B) Actual 2006	(C) Actual 2007	(D) Projected 2008	(E) Projected 2009	(F)	(G)	(H)
					Jurisdictional Dollars				
1.	Nuclear CWIP Additions (TOR-6 Line 28)	$0	$0	2,522,693	84,216,330	88,192,867			
2.	Average Base eligible for return (P-2)		$0	$220,914	$29,645,687	$45,026,674			
3.	Return on CWIP Eligible for Return								
	a. Equity Component (a) (P-2)		$0	$12,703	$1,704,627	$2,589,034			
	b. Equity Comp. grossed up for taxes (P-2)		$0	$20,680	$2,775,136	$4,214,951			
	c. Debt Component (P-2)		$0	$3,696	$495,972	$753,296			
	d. Return on Deferred Tax Asset associated with CPI (AE-3A line 8)		$0	$0	$18,842	$3,982,533			
4.	Total Return Requirements (Line 3b + 3c)		$0	$24,376	$3,271,108	$4,968,247			
5.	Total Costs to be Recovered - Recovered in 2009 (Prior + Lines 1 + 3b + 3c + 3d)		$0	2,547,068	90,053,349	187,196,997			
6.	Total Costs Recovered (2009 P2)		$0	$0	$0	187,196,997			
7.	Difference (Line 5 - Line 6)		$0	$2,547,068	$90,053,349	-			
8.	Variance Percentage								

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: 2007 Equity/Debt component shown (Line 3a-c Column C) calculated based on actual for October/November starting 10/16/07 and December estimate.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cos recovery filing by FPL.

Schedule TOR-3A (True Up To Original)

Turkey Point Units 6&7
Deferred Tax Carrying Costs

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the actual to date and projected deferred tax Carrying Costs for the duration of the project.

For the Period Ended 12/31/2009

Line No.			(A) Beginning of Period	(B) Actual 2006	(C) Actual 2007	(D) Projected 2008	(E) Projected 2009	(F)	(G)	(H)
						Jurisdictional Dollars				
1.	Construction Period Interest (TOR-3B, Line 5)			$0	$0	$1,613,628	$7,514,252			
2.	Recovered Costs Excluding AFUDC Recovered in 2009									
	a. 2007-2008 CWIP Base Eligible for Return excluding AFUDC (P2 Line 1)			$0	$0	$0	$86,739,023			
	b. 2009 CWIP Base Eligible for Return excluding AFUDC (P2 Line 1)			$0	$0	$0	$88,192,867			
3.	Other Adjustments			$0	$0	$0	$0			
4.	Tax Basis Less Book Basis (Prior Yr Balance + Line 1 + 2a +2b + 3)		0	$0	$0	$1,613,628	$184,059,769			
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 * Tax Rate)	38.575%	$0	$0	$0	$622,457	$71,001,056			
6.	Average Accumulated DTA ((Prior Period +Current Period)/2)			$0	$0	$311,228	$35,811,756			
7.	Carrying Cost on DTA									
	a. Equity Component (AE-3A Line 7.a)			$0	$0	$9,819	$2,075,362			
	b. Equity Component grossed up for taxes (AE-3A Line7.b)			$0	$0	$15,985	$3,378,693			
	c. Debt Component (AE-3A Line7.c)			$0	$0	$2,857	$603,840			
8.	Total Return Requirements (Line 7b + 7c)			$0	$0	$18,842	$3,982,533			
9.	Total Return Requirements from Original Projections			$0	$0	$18,842	$3,982,533			
10.	Difference (Line 8 - Line 9)			$0	$0	$0	$0			
11.	Variance Percentage									

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: 2007 Equity/Debt component shown (Line 7a-c Column C) calculated based on actual for October/November starting 10/16/07 and December estimate.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule TOR-3B (True Up To Original)

Turkey Point Units 6&7
Construction Period Interest

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the actual to date and projected Construction Period Interest for the duration of the project.

For the Period Ended 12/31/2009

Line No.		(A) Beginning of Period	(B) Actual 2006	(C) Actual 2007	(D) Projected 2008	(E) Projected 2009	(F)	(G)	(H)
					Jurisdictional Dollars				
1.	Beginning Balance		n/a	$0	$2,522,693	$88,352,850			
2.	Additions Site Selection & Preconstruction		n/a	2,522,693	$84,216,330	$88,182,857			
3.	Additions Construction		n/a	$0	$0	$0			
4.	Other Adjustments		n/a	($2,522,693)	$0	$0			
5.	Construction Period Interest for Tax (CPI) (See schedule AE-3B line 6 & 7)		n/a	$0	$1,613,828	$7,514,252			
6.	Ending Balance (Line1+2+3+4+5)	n/a	$0	$0	$88,352,850	$184,059,789			

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 1 Column D, CPI calculation for pre-construction costs started in January 2008 for 2007 pre-construction costs.
Note 3: Line 2 C, Includes pre-construction costs transferred into CWIP as of 11/2007.
Note 4: Line 4 C, Pre-construction costs did not receive CPI in 2007.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule TOR-6 (True Up To Original)

Turkey Point Units 6&7
Monthly Expenditures

[Section (5)(c)1.b.]
[Section (8)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the actual to date and projected monthly expenditures by major tasks performed within Site Selection, Preconstruction and Construction categories for the duration of the project.

For the Period Ended 12/31/2009

Line No.	Description	(A) Actual 2006	(B) Actual 2007	(C) Projected 2008	(D) Projected 2009	(E)	(F)	(G)
1	**Site Selection:**			n/a	n/a			
2	Jurisdictional Factor							
3	Total Jurisdictional Site Selection Costs:	-	-	n/a	n/a			
4	**Pre-Construction:**							
5	Generation:							
6	License Application		1,832,826	26,596,608	20,399,822			
7	Engineering & Design			5,000,000	15,000,000			
8	Long lead procurement advanced payments			50,000,000	50,000,000			
9	Permitting		700,439	2,972,672	3,162,661			
10	Clearing, Grading and Excavation							
11	On-Site Construction Facilities							
12	Total Generation Costs		2,533,265	84,569,280	88,562,483			
13								
14	Jurisdictional Factor		0.9958265	0.9958265	0.9958265			
15								
16	Total Jurisdictional Generation Costs		2,522,693	84,216,330	88,192,867			
17								
18	Transmission:							
19	Line Engineering							
20	Substation Engineering							
21	Clearing							
22	Other							
23	Total Transmission Costs		-	-	-			
24								
25	Jurisdictional Factor							
26								
27	Total Jurisdictional Transmission Costs		-	-	-			
28								
29	Total Jurisdictional Preconstruction Costs	-	2,522,693	84,216,330	88,192,867			
30								

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2 : Line 8 Represents budgeted values for long lead procurements. At present, FPL's discussions with vendors have identified approximately $16 million of long lead procurement payments that would be required in 2008. Additional long lead payments may be identified.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule TOR-6 (True Up To Original)

Turkey Point Units 6&7
Monthly Expenditures

[Section (5)(c)1.b.]
[Section (8)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the actual to date and projected monthly expenditures by major tasks performed within Site Selection, Preconstruction and Construction categories for the duration of the project.

For the Period Ended 12/31/2009

Line No.	Description	(A) Actual 2006	(B) Actual 2007	(C) Projected 2008	(D) Projected 2009	(E)	(F)	(G)
31	Construction:							
32	Generation:							
33	Real Estate Acquisitions							
34	Project Management							
35	Permanent Staff/Training							
36	Site Preparation							
37	On-Site Construction Facilities							
38	Power Block Engineering, Procurement, etc.							
39	Non-Power Block Engineering, Procurement, etc.							
40	Total Generation Costs			0	0	0		
41								
42	Jurisdictional Factor							
43								
44	Total Jurisdictional Generation Costs			0				
45								
46	Transmission:							
47	Line Engineering							
48	Substation Engineering							
49	Real Estate Acquisition							
50	Line Construction							
51	Substation Construction							
52	Other							
53	Total Transmission Costs			0	0	0		
54								
55	Jurisdictional Factor							
56								
57	Total Jurisdictional Transmission Costs			0	0	0		
58								
59	Total Jurisdictional Construction Costs			$0	$0	$0		
60								
61	Total Jurisdictional Construction Costs Original Projection							
62								
63	Difference			$0	$0	$0		
64								
65	Variance Percentage							

Note 1: Information provided is based upon the best available at the time of the submission of this report.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule TOR-6A (True Up To Original)

Turkey Point Units 6&7
Monthly Expenditures

[Section (5)(c)1.a.]
[Section (8)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide a description of the major tasks performed within Site Selection, Preconstruction and Construction categories for the duration of the project.

For the Period Ended 12/31/2009

Line No.	Major Task	Description - Includes, but not limited to:
1	Site Selection Period:	
2	1	Request for Information (RFI) from design vendors
3	2	Engineering review of technology alternatives
4	3	Site identification activities
5	4	Site Selection Analysis
6	5	Fatal flaw geotechnical analyses at candidate site(s)
7	6	Transmission integration studies
8	7	Project planning, industry fees
9	8	Local zoning approvals
10	9	Preparation of need filing
11		
12	Pre-Construction period:	
13	Generation:	
14	1	License Application
15		a. Preparation of NRC Combined License submittal
16		b. Preparation of FDEP Site Certification Application
17		c. Transmission facilities studies, stability analysis, FRCC studies
18		d. Studies required as Conditions of Approval for local zoning
19	2	Engineering and Design
20		a. Site specific civil, mechanical and structural requirements to support design
21		b. Water supply design
22		c. Construction logistical and support planning
23		d. Long lead procurement advanced payments
24	3	Permitting
25		a. Communications outreach
26		b. Legal and application fees
27	4	Clearing, Grading and Excavation
28		a. Site access roads
29		b. Site clearing
30		c. Site fill to grade for construction
31	5	On-Site Construction Facilities
32		a. Warehousing, laydown areas and parking
33		b. Administrative facilities
34		c. Underground infrastructure
35		

Note 1: Information provided is based upon the best available at the time of the submission of this report.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule TOR-6A (True Up To Original)

Turkey Point Units 6&7
Monthly Expenditures

[Section (5)(c)1.a.]
[Section (8)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide a description of the major tasks performed within Site Selection, Preconstruction and Construction categories for the duration of the project.

For the Period Ended 12/31/2009

Line No.	Major Task	Description - Includes, but not limited to:
36	**Transmission:**	
37	1 Line / Substation Engineering	
38		Transmission interconnection design
39		Transmission integration design
40		
41	**Construction period:**	
42	**Generation:**	
43	1 Real Estate Acquisitions - self-explanatory	
44	2 Project Management – FPL and Contractor staff required to oversee/manage project	
45	3 Permanent Staff/Training – Employees of the operational facility hired in advance to assist with system turnover from constructor and obtain training in advance of operations.	
46	4 Site Preparation – preparation costs not expensed within preconstruction period.	
47	5 On-Site Construction Facilities – construction of non-power block facilities.	
48	6 Power Block Engineering, Procurement, etc. – Nuclear Steam Safety System, Long lead procurement advanced payments.	
49	7 Non-Power Block Engineering, Procurement, etc. – Supporting balance of plant facilities (cooling towers, etc.).	
50		
51	**Transmission :**	
52	1 Line Engineering - self-explanatory	
53	2 Substation Engineering - self-explanatory	
54	3 Real Estate Acquisition - self-explanatory	
55	4 Line Construction - self-explanatory	
56	5 Substation Construction - self-explanatory	
57	6 Other – permitting and condition of approval compliance.	

Note 1: Information provided is based upon the best available at the time of the submission of this report.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2009 P-2

Turkey Point Unit 6&7
Projection of Preconstruction Costs

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected preconstruction costs for the subsequent year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2009

DOCKET NO.: 070650-EI

Line No.		(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
					Jurisdictional Dollars				
1.	Nuclear CWIP Additions (2009 AE-6)		$7,307,499	$8,303,344	$8,552,300	$7,307,517	$7,307,517	$8,502,509	$47,280,687
2.	Amortization of CWIP Base Eligible for Return		$7,504,446	$7,504,446	$7,504,446	$7,504,446	$7,504,446	$7,504,446	$45,026,674
3.	Total Costs to be Recovered (Prior Period Balance -line 2)	$90,053,349	$82,548,903	$75,044,457	$67,540,011	$60,035,566	$52,531,120	$45,026,674	
4.	Average Base Eligible for Return		$86,301,126	$78,796,680	$71,292,234	$63,787,789	$56,283,343	$48,778,897	
5.	Return on Deferred Tax Asset associated with CPI (Schedule AE-3A line 8)		$32,250	$87,137	$144,370	$199,979	$253,511	$309,296	
6.	Return on Average Base Eligible for Return								
	a. Equity Component - Note 2 (Line 4 x 5.75% x 1/12)		$413,526	$377,567	$341,609	$305,650	$269,691	$233,732	$1,941,775
	b. Equity Component grossed up for Taxes - Note 3 (Line 6a/61.425%)		$673,221	$614,680	$556,139	$497,598	$439,057	$380,516	$3,161,213
	c. Debt Component (Line 4 x 1.673% x 1/12)		$120,318	$109,856	$99,393	$88,931	$78,468	$68,006	$564,972
7.	Total Return Requirements (Line 6b + 6c)		$793,540	$724,536	$655,533	$586,529	$517,528	$448,522	$3,726,186
8.	Total Costs to be Recovered (Line 1+ 2 + 5 + 7)		$15,637,735	$16,619,463	$16,856,649	$15,598,471	$15,583,000	$16,764,773	$97,060,091

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 6a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 6b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2009 P-2

Turkey Point Unit 6&7
Projection of Preconstruction Costs

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide a summary of the projected preconstruction costs for the subsequent year.

For the Year Ended 12/31/2009

Line No.		(I) Projected July	(J) Projected August	(K) Projected September	(L) Projected October	(M) Projected November	(N) Projected December	(O) 12 Month Total	(P) Monthly Average Base Eligible for return
		Jurisdictional Dollars							
1.	Nuclear CWIP Additions (2009 AE-6)	$6,300,377	$6,300,377	$7,495,369	$6,258,204	$6,258,204	$8,299,649	$88,192,867	
2.	Amortization of CWIP Base Eligible for Return	$7,504,446	$7,504,446	$7,504,446	$7,504,446	$7,504,446	$7,504,446	$90,053,349	
3.	Total Costs to be Recovered (Prior Period Balance -line 2)	$37,522,229	$30,017,783	$22,513,337	$15,008,891	$7,504,446	$0		
4.	Average Base Eligible for Return	$41,274,451	$33,770,006	$26,265,560	$18,761,114	$11,256,669	$3,752,223		$45,026,874.27
5.	Return on Deferred Tax Asset associated with CPI (Schedule AE-3A line 8)	$363,429	$413,778	$466,384	$518,999	$569,559	$623,861	$3,982,533	
6.	Return on Average Base Eligible for Return								
	a. Equity Component - Note 2 (Line 4 x 5.75% x 1/12)	$197,773	$161,815	$125,856	$89,897	$53,938	$17,979	$2,589,034	
	b. Equity Component grossed up for Taxes - Note 3 (Line 6a/61.425%)	$321,975	$263,434	$204,893	$146,352	$87,811	$29,270	$4,214,951	
	c. Debt Component (Line 4 x 1.673% x 1/12)	$57,543	$47,081	$36,619	$26,156	$15,694	$5,231	$753,296	
7.	Total Return Requirements (Line 6b + 6c)	$379,519	$310,515	$241,512	$172,509	$103,505	$34,502	$4,968,247	
8.	Total Costs to be Recovered (Line 1+ 2 + 5 + 7)	$14,547,771	$14,529,116	$15,707,691	$14,454,157	$14,435,713	$16,462,458	$187,196,997	

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 6a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 6b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2009 AE-3A (Actual-Estimate)

Turkey Point U6&7
Deferred Tax Carrying Costs

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated deferred tax Carrying Costs for the current year.

For the Year Ended 12/31/2009

Line No.			(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
						Jurisdictional Dollars				
1.	Construction Period Interest (2009 AE-3B, Line 7)			$421,696	$459,403	$500,136	$538,774	$574,736	$613,602	$3,108,347
2.	a. Recovered Costs Excluding AFUDC			$7,228,252	$7,228,252	$7,228,252	$7,228,252	$7,228,252	$7,228,252	$43,369,511
	b. Recovered Costs Excluding AFUDC (2009 AE-6)			$7,307,499	$8,303,344	$8,552,300	$7,307,517	$7,307,517	$8,502,509	$47,280,687
3.	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4.	Tax Basis Less Book Basis (Includes prior month balance)		1,613,628	16,571,074	32,562,073	48,842,762	63,917,305	79,027,811	95,372,173	$95,372,173
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 * Tax Rate)	38.575%	$622,457	$6,392,292	$12,560,820	$18,841,095	$24,656,101	$30,484,978	$36,789,816	$36,789,816
6.	Average Accumulated DTA			$3,507,374	$9,476,556	$15,700,958	$21,748,598	$27,570,539	$33,637,397	
7.	Carrying Cost on DTA									
	a. Equity Component - Note 2 (Line 6 x 5.75% x 1/12)			$16,806	$45,409	$75,234	$104,212	$132,109	$161,179	$534,948
	b. Equity Component grossed up for taxes - Note 3 (Line 7a/61.425%)			$27,360	$73,925	$122,481	$169,657	$215,073	$262,400	$870,897
	c. Debt Component (Line 6 x 1.673% x 1/12)			$4,890	$13,212	$21,890	$30,321	$38,438	$46,896	$155,647
8.	Total Return Requirements (Line 7b + 7c)			$32,250	$87,137	$144,370	$199,979	$253,511	$309,296	$1,026,544
9.	Total Return Requirements from most recent Projections			$0	$0	$0	$0	$0	$0	$0
10.	Difference (Line 8 - Line 9)			$32,250	$87,137	$144,370	$199,979	$253,511	$309,296	$1,026,544

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Turkey Point U6&7
Deferred Tax Carrying Costs

Schedule 2009 AE-3A (Actual-Estimate) [Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated deferred tax Carrying Costs for the current year.

For the Year Ended 12/31/2009

Line No.			(I) Beginning of Period	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
						Jurisdictional Dollars				
1.	Construction Period Interest (2009 AE-3B, Line 7)			$650,337	$682,195	$716,937	$751,741	$783,870	$820,825	$7,514,252
2.	a. Recovered Costs Excluding AFUDC			$7,228,252	$7,228,252	$7,228,252	$7,228,252	$7,228,252	$7,228,252	$86,738,023
	b. Recovered Costs Excluding AFUDC (2009 AE-6)			$6,300,377	$6,300,377	$7,495,369	$6,258,204	$6,258,204	$8,299,649	$88,192,867
3.	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4.	Tax Basis Less Book Basis (Includes prior month balance)		$95,372,173	$108,551,140	$123,761,963	$139,202,521	$153,440,718	$167,711,044	$184,059,769	$184,059,769
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 * Tax Rate)	38.579%	$36,789,816	$42,259,352	$47,741,177	$53,697,372	$59,189,757	$64,894,535	$71,001,056	$71,001,056
6.	Average Accumulated DTA			$39,524,584	$45,000,265	$50,719,275	$56,443,565	$61,942,146	$67,847,796	
7.	Carrying Cost on DTA									
	a. Equity Component - Note 2 (Line 6 x 5.75% x 1/12)			$189,389	$215,626	$243,030	$270,459	$296,806	$325,104	$2,075,362
	b. Equity Component grossed up for taxes - Note 3 (Line 7a/61.425%)			$308,325	$351,040	$395,653	$440,307	$483,201	$529,270	$3,378,693
	c. Debt Component (Line 6 x 1.673% x 1/12)			$55,104	$62,738	$70,711	$78,692	$86,358	$94,591	$603,840
8.	Total Return Requirements (Line 7b + 7c)			$363,429	$413,778	$466,364	$518,999	$569,559	$623,861	$3,982,533
9.	Total Return Requirements from most recent Projections			$0	$0	$0	$0	$0	$0	$0
10.	Difference (Line 8 - Line 9)			$363,429	$413,778	$466,364	$518,999	$569,559	$623,861	$3,982,533

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2009 AE-3B (Actual-Estimate)

Turkey Point Units 6&7
Construction Period Interest

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated Construction Period Interest for the current year.

For the Year Ended 12/31/2009

Line No.		(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
					Jurisdictional Dollars				
1.	Beginning Balance		$88,352,650	$96,081,845	$104,844,592	$113,897,029	$121,743,320	$129,625,574	
2.	Additions Site Selection & Preconstruction		7,307,499	8,303,344	8,552,300	7,307,517	7,307,517	8,502,509	$47,280,687
3.	Additions Construction		$0	$0	$0	$0	$0	$0	$0
4.	Other Adjustments		$0	$0	$0	$0	$0	$0	
5	Average Balance Eligible for CPI (Line1+[Line2+3+4]/2)		$92,006,400	$100,233,517	$109,120,743	$117,550,788	$125,397,079	$133,878,828	
6.	CPI Rate		0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	
7.	Construction Period Interest for Tax (CPI)		$421,696	$459,403	$500,136	$538,774	$574,736	$613,602	$3,108,347
8.	Ending Balance (Line1+2+3+4+7)	88,352,650	$96,081,845	$104,844,592	$113,897,029	$121,743,320	$129,625,574	$138,741,685	$138,741,685

Note 1: Information provided is based upon the best available at the time of the submission of this report.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2009 AE-3B (Actual-Estimate)

Turkey Point Units 6&7
Construction Period Interest

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated Construction Period Interest for the current year.

For the Year Ended 12/31/2009

Line No.		(I) Beginning of Period	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
					Jurisdictional Dollars				
1.	Beginning Balance		$138,741,685	$145,692,399	$152,674,971	$160,887,277	$167,897,222	$174,939,296	
2.	Additions Site Selection & Preconstruction		6,300,377	6,300,377	7,495,369	6,258,204	6,258,204	8,299,649	88,192,857
3.	Additions Construction		$0	$0	$0	$0	$0	$0	$0
4.	Other Adjustments		$0	$0	$0	$0	$0	$0	
5	Average Balance Eligible for CPI (Line1+[Line2+3+4]/2)		$141,891,873	$148,842,588	$156,422,655	$164,016,379	$171,026,324	$179,089,120	
6.	CPI Rate		0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	
7.	Construction Period Interest for Tax (CPI)		$650,337	$682,195	$716,937	$751,741	$783,870	$820,825	7,514,252
8.	Ending Balance (Line1+2+3+4+7)	$138,741,685	$145,692,399	$152,674,971	$160,887,277	$167,897,222	$174,939,296	$184,059,769	$184,059,769

Note 1: Information provided is based upon the best available at the time of the submission of this report.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Turkey Point Units 6&7
Monthly Expenditures

[Section (5)(c)1.b.]
[Section (8)(d)]

Schedule 2009 AE-6 (Actual-Estimate)

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the actual/estimated monthly expenditures by major tasks performed within Site Selection, Preconstruction and Construction categories for the current year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2009

DOCKET NO.: 070650-EI

Line No.	Description	(A) Actual 2007	(B) Projected 2008	(C) Projected January	(D) Projected February	(E) Projected March	(F) Projected April	(G) Projected May	(H) Projected June	(I) Projected July	(J) Projected August	(K) Projected September	(L) Projected October	(M) Projected November	(O) Projected December	(P) 12Month Total
1	Site Selection:															-
2	Jurisdictional Factor															
3	Total Jurisdictional Site Selection Costs:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Pre-Construction:															
5	Generation:															
6	License Application	1,832,826	26,596,608	1,738,752	2,738,753	2,988,753	1,738,753	1,738,753	2,938,753	699,059	699,059	1,899,059	656,709	656,709	1,906,710	20,399,822
7	Engineering & Design		5,000,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	1,250,000	15,000,000
8	Long lead procurement advanced payments		50,000,000	4,100,000	4,100,000	4,100,000	4,100,000	4,100,000	4,100,000	4,100,000	4,100,000	4,100,000	4,100,000	4,100,000	4,900,000	50,000,000
9	Permitting	700,439	2,972,672	248,373	249,390	249,390	249,390	249,390	249,390	277,723	277,723	277,723	277,723	277,723	277,723	3,162,661
10	On-Site Construction Facilities															
11	Total Generation Costs	2,533,265	84,569,280	7,336,125	8,338,143	8,588,143	7,338,143	7,338,143	8,538,143	6,326,782	6,326,782	7,526,782	6,284,432	6,284,432	8,334,433	88,562,483
12																
13	Jurisdictional Factor	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265
14																
15	Total Jurisdictional Generation Costs	2,522,693	84,216,330	7,307,499	8,303,344	8,552,300	7,307,517	7,307,517	8,502,509	6,300,377	6,300,377	7,495,369	6,258,204	6,258,204	8,299,849	88,192,867
16																
17	Total Jurisdictional Pre-construction Costs:	2,522,693	84,216,330	7,307,499	8,303,344	8,552,300	7,307,517	7,307,517	8,502,509	6,300,377	6,300,377	7,495,369	6,258,204	6,258,204	8,299,849	88,192,867

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2 : Line 8 Represents budgeted values for long lead procurements. At present, FPL's discussions with vendors have identified approximately $16 million of long lead procurement payments that would be required in 2008. Additional long lead payments may be identified.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Hearing Exhibit 000198

Schedule 2008 P-2

Turkey Point Unit 6&7
Projection of Preconstruction Costs

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected preconstruction costs for the subsequent year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2008

DOCKET NO.: 070650-EI

Line No.		(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
					Jurisdictional Dollars				
1.	Nuclear CWIP Additions (2008 AE-6)		$1,947,165	$2,942,992	$3,206,888	$1,962,103	$2,460,016	$3,655,008	$16,174,170
2.	Amortization of CWIP Base Eligible for Return		$0	$0	$0	$0	$0	$0	$0
3.	Total Costs to be Recovered (Prior Period Balance -line 2)	$2,547,068	$4,494,234	$7,469,627	$10,731,622	$12,777,632	$15,348,128	$19,131,039	
4.	Average Base Eligible for Return		$3,520,651	$5,981,930	$9,100,624	$11,754,627	$14,061,880	$17,238,584	$61,658,296
5.	Return on Deferred Tax Asset associated with CPI (Schedule AE-3A line 8)		$28	$105	$227	$396	$604	$856	
6.	Return on Average Base Eligible for Return								
	a. Equity Component - Note 2 (Line 4 x 5.75% x 1/12)		$16,870	$28,663	$43,607	$56,324	$67,380	$82,602	$295,446
	b. Equity Component grossed up for Taxes - Note 3 (Line 6a/61.425%)		$27,464	$46,664	$70,993	$91,696	$109,694	$134,475	$480,987
	c. Debt Component (Line 4 x 1.673% x 1/12)		$4,908	$8,340	$12,688	$16,388	$19,605	$24,033	$85,962
7.	Total Return Requirements (Line 6b + 6c)		$32,372	$55,004	$83,680	$108,084	$129,299	$158,509	$566,949
8.	Total Costs to be Recovered (Line 1+ 2 + 5 + 7)		$4,526,635	$7,524,738	$10,815,529	$12,888,112	$15,478,032	$19,290,405	

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 6a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 6b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2008 P-2

Turkey Point Unit 6&7
Projection of Preconstruction Costs

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected preconstruction costs for the subsequent year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2008

DOCKET NO.: 070650-EI

Line No.		(I) Projected July	(J) Projected August	(K) Projected September	(L) Projected October	(M) Projected November	(N) Projected December	(O) 12 Month Total	(P) Monthly Average Base Eligible for return
		Jurisdictional Dollars							
1.	Nuclear CWIP Additions (2008 AE-6)	$2,460,016	$12,418,281	$13,613,270	$12,436,652	$12,934,567	$14,179,373	$84,216,330	
2.	Amortization of CWIP Base Eligible for Return	$0	$0	$0	$0	$0	$0	$0	
3.	Total Costs to be Recovered (Prior Period Balance -line 2)	$21,750,421	$34,357,814	$48,230,591	$61,049,051	$74,488,911	$89,295,284		
4.	Average Base Eligible for Return	$20,440,730	$28,054,118	$41,294,203	$54,639,821	$67,768,981	$81,892,097		$29,645,687
5.	Return on Deferred Tax Asset associated with CPI (Schedule AE-3A line 8)	$1,160	$1,549	$2,107	$2,879	$3,864	$5,066	$18,842	
6.	Return on Average Base Eligible for Return								
	a. Equity Component - Note 2 (Line 4 x 5.75% x 1/12)	$97,945	$134,426	$197,868	$261,816	$324,726	$392,400	$1,704,627	
	b. Equity Component grossed up for Taxes - Note 3 (Line 6a/61.425%)	$159,455	$218,846	$322,130	$426,237	$528,655	$638,827	$2,775,136	
	c. Debt Component (Line 4 x 1.673% x 1/12)	$28,498	$39,112	$57,571	$76,177	$94,481	$114,171	$495,972	
7.	Total Return Requirements (Line 6b + 6c)	$187,953	$257,958	$379,701	$502,414	$623,136	$752,998	$3,271,108	
8.	Total Costs to be Recovered (Line 1+ 2 + 5 + 7)	$21,939,533	$34,617,321	$48,812,399	$61,554,343	$75,115,911	$90,053,349		

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 6a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 6b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2008 AE-3A (Actual-Estimate)

Turkey Point Units 6&7
Deferred Tax Carrying Costs

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated deferred tax Carrying Costs for the current year.

For the Year Ended 12/31/2008

Line No.			(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
						Jurisdictional Dollars				
1.	Construction Period Interest (2008 AE-3B, Line 7)			$16,025	$27,305	$41,523	$53,569	$63,939	$78,245	$280,596
2.	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3.	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4.	Tax Basis Less Book Basis (Includes prior month balance)		-	$16,025	$43,329	$84,852	$138,412	$202,350	$280,596	$280,596
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 * Tax Rate	38.575%	$0	$6,181	$16,714	$32,732	$53,392	$78,057	$108,240	$108,240
6.	Average Accumulated DTA			$3,091	$11,448	$24,723	$43,062	$65,724	$93,148	
7.	Carrying Cost on DTA									
	a. Equity Component - Note 2 (Line 6 x 5.75% x 1/12)			$15	$55	$118	$206	$315	$446	$1,156
	b. Equity Component grossed up for taxes - Note 3 (Line 7a/61.425%)			$24	$89	$193	$336	$513	$727	$1,882
	c. Debt Component (Line 6 x 1.673% x 1/12)			$4	$16	$34	$60	$92	$130	$336
8.	Total Return Requirements (Line 7b + 7c)			$28	$105	$227	$396	$604	$856	$2,218
9.	Total Return Requirements from most recent Projections			$0	$0	$0	$0	$0	$0	$0
10.	Difference (Line 8 - Line 9)			$28	$105	$227	$396	$604	$856	$2,218

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cos recovery filing by FPL.

Schedule 2008 AE-3A (Actual-Estimate)

Turkey Point Units 6&7
Deferred Tax Carrying Costs

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated deferred tax Carrying Costs for the current year.

For the Year Ended 12/31/2008

Line No.			(I) Beginning of Period	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
						Jurisdictional Dollars				
1.	Construction Period Interest (2008 AE-3B, Line 7)			$92,617	$127,138	$187,376	$247,933	$307,212	$370,756	$1,613,628
2.	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3.	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4.	Tax Basis Less Book Basis (Includes prior month balance)		$280,596	$373,213	$500,351	$687,727	$935,660	$1,242,872	$1,613,628	$1,613,628
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 * Tax Rate	38.575%	$108,240	$143,967	$193,010	$265,291	$360,931	$479,438	$622,457	$622,457
6.	Average Accumulated DTA			$126,103	$168,489	$229,151	$313,111	$420,184	$550,947	
7.	Carrying Cost on DTA									
	a. Equity Component - Note 2 (Line 6 x 5.75% x 1/12)			$604	$807	$1,098	$1,500	$2,013	$2,640	$9,819
	b. Equity Component grossed up for taxes - Note 3 (Line 7a/61.425%)			$984	$1,314	$1,788	$2,443	$3,278	$4,298	$15,985
	c. Debt Component (Line 6 x 1.673% x 1/12)			$176	$235	$319	$437	$586	$768	$2,857
8.	Total Return Requirements (Line 7b + 7c)			$1,160	$1,549	$2,107	$2,879	$3,864	$5,066	$18,842
9.	Total Return Requirements from most recent Projections			$0	$0	$0	$0	$0	$0	$0
10.	Difference (Line 8 - Line 9)			$1,160	$1,548	$2,107	$2,879	$3,864	$5,066	$18,842

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cos recovery filing by FPL.

Turkey Point Units 6&7
Construction Period Interest

Schedule 2008 AE-3B (Actual-Estimate) [Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated Construction Period Interest for the current year.

For the Year Ended 12/31/2008

Line No.		(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
					Jurisdictional Dollars				
1.	Beginning Balance		$2,522,693	$4,485,883	$7,456,179	$10,704,588	$12,720,250	$15,244,205	
2.	Additions Site Selection & Preconstruction		1,947,165	2,942,992	3,206,886	1,962,103	2,460,016	3,655,008	$16,174,170
3.	Additions Construction		$0	$0	$0	$0	$0	$0	$0
4.	Other Adjustments		$0	$0	$0	$0	$0	$0	
5	Average Balance Eligible for CPI (Line1+[Line2+3+4]/2)		$3,496,275	$5,957,379	$9,059,622	$11,685,640	$13,950,259	$17,071,709	
6.	CPI Rate		0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	
7.	Construction Period Interest for Tax (CPI)		$16,025	$27,305	$41,523	$53,559	$63,939	$78,245	$280,596
8.	Ending Balance (Line1+2+3+4+7)	2,522,693	$4,485,883	$7,456,179	$10,704,588	$12,720,250	$15,244,205	$18,977,458	$18,977,458

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: CPI calculation for pre-construction costs started in January 2008 for 2007 pre-construction costs.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2008 AE-3B (Actual-Estimate)

Turkey Point Units 6&7
Construction Period Interest

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated Construction Period Interest for the current year.

For the Year Ended 12/31/2008

Line No.		(I) Beginning of Period	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
					Jurisdictional Dollars				
1.	Beginning Balance		$18,977,458	$21,530,092	$34,075,511	$47,878,157.36	$60,560,742.33	$73,802,521.24	
2.	Additions Site Selection & Preconstruction		2,460,016	12,418,281	13,613,270	12,436,652	12,934,567	14,179,373	84,216,330
3.	Additions Construction		$0	$0	$0	$0	$0	$0	$0
4.	Other Adjustments		$0	$0	$0	$0	$0	$0	
5	Average Balance Eligible for CPI (Line1+[Line2+3+4]/2)		$20,207,466	$27,739,232	$40,882,146	$54,094,483	$67,028,026	$80,892,208	
6.	CPI Rate		0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	
7.	Construction Period Interest for Tax (CPI)		$92,617	$127,138	$187,378	$247,933	$307,212	$370,766	$1,613,628
8.	Ending Balance (Line1+2+3+4+7)	$18,977,458	$21,530,092	$34,075,511	$47,876,157	$60,560,742	$73,802,521	$88,352,650	$88,352,650

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: CPI calculation for pre-construction costs started in January 2008 for 2007 pre-construction costs.

Page 2 of 2

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Turkey Point Units 6&7
Monthly Expenditures

[Section (5)(c)1.b.]
[Section (8)(d)]

Schedule 2008 AE-6 (Actual-Estimate)

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the actual/estimated monthly expenditures by major tasks performed within Site Selection, Preconstruction and Construction categories for the current year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2008

DOCKET NO.: 070650-EI

Line No.	Description	(A) Actual 2007	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) Projected July	(I) Projected August	(J) Projected September	(K) Projected October	(L) Projected November	(M) Projected December	(O) 12Month Total
1	Site Selection:														
2	Jurisdictional Factor														
3	Total Jurisdictional Site Selection Costs:	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Pre-Construction:														
5	Generation:														
6	License Application	1,832,826	1,707,604	2,707,604	2,972,604	1,722,604	1,722,604	2,922,604	1,722,604	1,722,604	2,922,601	1,741,052	1,741,054	2,991,069	26,596,608.00
7	Engineering & Design						500,000	500,000	500,000	500,000	500,000	500,000	1,000,000	1,000,000	5,000,000.00
8	Long lead procurement advanced payments									10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	50,000,000.00
9	Permitting	700,439	247,722	247,722	247,722	247,722	247,722	247,722	247,722	247,722	247,722	247,722	247,722	247,730	2,972,672.00
10	On-Site Construction Facilities														
11	Total Generation Costs	2,533,265	1,955,326	2,955,326	3,220,326	1,970,326	2,470,326	3,670,326	2,470,326	12,470,326	13,670,323	12,488,774	12,988,776	14,238,799	84,569,280
12															
13	Jurisdictional Factor	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265	0.9958265
14															
15	Total Jurisdictional Generation Costs	2,522,693	1,947,165	2,942,992	3,206,886	1,962,103	2,460,016	3,655,008	2,460,016	12,418,281	13,613,270	12,436,652	12,934,567	14,179,373	84,216,330
16															
17	Total Jurisdictional Pre-construction Costs.	2,522,693	1,947,165	2,942,992	3,206,886	1,962,103	2,460,016	3,655,008	2,460,016	12,418,281	13,613,270	12,436,652	12,934,567	14,179,373	84,216,330

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2 : Line 8 Represents budgeted values for long lead procurements. At present, FPL's discussions with vendors have identified approximately $16 million of long lead procurement payments that would be required in 2008. Additional long lead payments may be identified.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Hearing Exhibit 000205

Schedule 2007 P-2

Turkey Point Unit 6&7
Projection of Preconstruction Costs

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected preconstruction costs for the subsequent year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2007

DOCKET NO.: 070650-EI

Line No.		(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
					Jurisdictional Dollars				
1.	Nuclear CWIP Additions (2007 AE-6)		$0	$0	$0	$0	$0	$0	$0
2.	Cumulative Base Eligible for Return		$0	$0	$0	$0	$0	$0	$0
3.	Monthly Return Requirement (See line 7 below)		$0	$0	$0	$0	$0	$0	$0
4.	Cumulative Base Eligible for Return (Line 1 + 2 + 3)	$0	$0	$0	$0	$0	$0	$0	$0
5.	Average Base Eligible for Return		$0	$0	$0	$0	$0	$0	
6.	Return on Deferred Tax Asset associated with CPI (Schedule AE-3A line 8)		$0	$0	$0	$0	$0	$0	$0
7.	Return on Average Base Eligible for return								
	a. Equity Component - Note 2 (Line 5 x 5.75% x 1/12)		$0	$0	$0	$0	$0	$0	$0
	b. Equity Component grossed up for taxes - Note 3 (Line 6a/61.425%)		$0	$0	$0	$0	$0	$0	$0
	c. Debt Component (Line 5 x 1.673% x 1/12)		$0	$0	$0	$0	$0	$0	$0
8.	Total Return Requirements (Line 6b + 6c)		$0	$0	$0	$0	$0	$0	$0

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2007 P-2

Turkey Point Unit 6&7
Projection of Preconstruction Costs

[Section (5)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected preconstruction costs for the subsequent year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2007

DOCKET NO.: 070650-EI

Line No.		(I) Beginning of Period	(J) Actual July	(K) Actual August	(L) Actual September	(M) Actual October	(N) Actual November	(O) Actual December	(P) 12 Month Total	Monthly Average Base Eligible for return
					Jurisdictional Dollars					
1.	Nuclear CWIP Additions (2007 AE-6)		$0	$0	$0	$0	$1,383,258	$1,139,435	$2,522,693	
2.	Cumulative Base Eligible for Return		$0	$0	$0	$0	$0	$1,389,617		
3.	Monthly Return Requirement (See line 7 below)		$0	$0	$0	$0	$6,360	$18,016	$24,376	
4.	Cumulative Base Eligible for Return (Line 1 + 2 + 3)	$0	$0	$0	$0	$0	$1,389,617	$2,547,068	$2,547,068	
5.	Average Base Eligible for Return		$0	$0	$0	$0	$691,629	$1,959,335		$220,913.64
6.	Return on Deferred Tax Asset associated with CPI (Schedule AE-3A line 8)		$0	$0	$0	$0	$0	$0	$0	
7.	Return on Average Base Eligible for return									
	a. Equity Component - Note 2 (Line 5 x 5.75% x 1/12)		$0	$0	$0	$0	$3,314	$9,388	$12,703	
	b. Equity Component grossed up for taxes - Note 3 (Line 6a/61.425%)		$0	$0	$0	$0	$5,395	$15,284	$20,680	
	c. Debt Component (Line 5 x 1.673% x 1/12)		$0	$0	$0	$0	$964	$2,732	$3,696	
8.	Total Return Requirements (Line 6b + 6c)		$0	$0	$0	$0	$6,360	$18,016	$24,376	

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2007 AE-3A (Actual-Estimate)

Turkey Point Units 6&7
Deferred Tax Carrying Costs

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated deferred tax Carrying Costs for the current year.

For the Year Ended 12/31/2007

Line No.			(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
						Jurisdictional Dollars				
1.	Construction Period Interest (2007 AE-3B, Line 7)			$0	$0	$0	$0	$0	$0	$0
2.	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3.	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4.	Tax Basis Less Book Basis (Includes prior month balance)		0	$0	$0	$0	$0	$0	$0	$0
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 * Tax Rate)	38.575%	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Accumulated DTA			$0	$0	$0	$0	$0	$0	
7.	Carrying Cost on DTA									
	a. Equity Component - Note 2 (Line 6 x 5.75% x 1/12)			$0	$0	$0	$0	$0	$0	$0
	b. Equity Component grossed up for taxes - Note 3 (Line 7a/61.425%)			$0	$0	$0	$0	$0	$0	$0
	c. Debt Component (Line 6 x 1.673% x 1/12)			$0	$0	$0	$0	$0	$0	$0
8.	Total Return Requirements (Line 7b + 7c)			$0	$0	$0	$0	$0	$0	$0
9.	Total Return Requirements from most recent Projections			$0	$0	$0	$0	$0	$0	$0
10.	Difference (Line 8 - Line 9)			$0	$0	$0	$0	$0	$0	$0

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Turkey Point Units 6&7
Deferred Tax Carrying Costs

Schedule 2007 AE-3A (Actual-Estimate) [Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated deferred tax Carrying Costs for the current year.

For the Year Ended 12/31/2007

Line No.			(I) Beginning of Period	(J) Actual July	(K) Actual August	(L) Actual September	(M) Actual October	(N) Actual November	(O) Actual December	(P) 12 Month Total
						Jurisdictional Dollars				
1.	Construction Period Interest (2007 AE-3B, Line 7)			$0	$0	$0	$0	$0	$0	$0
2.	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3.	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4.	Tax Basis Less Book Basis (Includes prior month balance)		$0	$0	$0	$0	$0	$0	$0	$0
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 * Tax Rate)	38.575%	$0	$0	$0	$0	$0	$0	$0	$0
6.	Average Accumulated DTA			$0	$0	$0	$0	$0	$0	
7.	Carrying Cost on DTA									
	a. Equity Component - Note 2 (Line 6 x 5.75% x 1/12)			$0	$0	$0	$0	$0	$0	$0
	b. Equity Component grossed up for taxes - Note 3 (Line 7a/61.425%)			$0	$0	$0	$0	$0	$0	$0
	c. Debt Component (Line 6 x 1.673% x 1/12)			$0	$0	$0	$0	$0	$0	$0
8.	Total Return Requirements (Line 7b + 7c)			$0	$0	$0	$0	$0	$0	$0
9.	Total Return Requirements from most recent Projections			$0	$0	$0	$0	$0	$0	$0
10.	Difference (Line 8 - Line 9)			$0	$0	$0	$0	$0	$0	$0

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: Line 7a - The annual Equity Component of 5.75% reflects an 11.0% return on equity.
Note 3: Line 7b - Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2007 AE-3B (Actual-Estimate)

Turkey Point Units 6&7
Construction Period Interest -

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the Actual/Estimated Construction Period Interest for the current year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2007

DOCKET NO.: 070650-EI

Line No.		(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
					Jurisdictional Dollars				
1.	Beginning Balance		$0	$0	$0	$0	$0	$0	
2.	Additions Site Selection & Preconstruction		$0	$0	$0	$0	$0	$0	$0
3.	Additions Construction		$0	$0	$0	$0	$0	$0	$0
4.	Other Adjustments		$0	$0	$0	$0	$0	$0	
5	Average Balance Eligible for CPI (Line1+[Line2+3+4]/2)		$0	$0	$0	$0	$0	$0	
6.	CPI Rate								
7.	Construction Period Interest for Tax (CPI)		$0	$0	$0	$0	$0	$0	
8.	Ending Balance (Line1+2+3+4+7)	$0	$0	$0	$0	$0	$0	$0	$0

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: CPI calculation for pre-construction costs started in January 2008 for 2007 pre-construction costs.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Schedule 2007 AE-3B (Actual-Estimate)

Turkey Point Units 6&7
Construction Period Interest

[Section (5)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 070650-EI

EXPLANATION: Provide the calculation of the Actual/Estimated Construction Period Interest for the current year.

For the Year Ended 12/31/2007

Line No.		(I) Beginning of Period	(J) Actual July	(K) Actual August	(L) Actual September	(M) Actual October	(N) Actual November	(O) Actual December	(P) 12 Month Total
					Jurisdictional Dollars				
1.	Beginning Balance		$0	$0	$0	$0	$0	$0.00	
2.	Additions Site Selection & Preconstruction		$0	$0	$0	$0	1,383,258	1,139,435	2,522,693
3.	Additions Construction		$0	$0	$0	$0	$0	$0	$0
4.	Other Adjustments		$0	$0	$0	$0	(1,383,258)	(1,139,435)	
5	Average Balance Eligible for CPI (Line1+[Line2+3+4]/2)		$0	$0	$0	$0	$0	$0	
6.	CPI Rate								
7.	Construction Period Interest for Tax (CPI)		$0	$0	$0	$0	$0	$0	$0
8.	Ending Balance (Line1+2+3+4+7)	-	$0	$0	$0	$0	$0	$0	$0

Note 1: Information provided is based upon the best available at the time of the submission of this report.
Note 2: CPI calculation for pre-construction costs started in January 2008 for 2007 pre-construction costs.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Turkey Point Units 6&7
Monthly Expenditures

[Section (5)(c)1.b.]
[Section (8)(d)]

Schedule 2007 AE-6 (Actual-Estimate)

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the actual/estimated monthly expenditures by major tasks performed within Site Selection, Preconstruction and Construction categories for the current year.

COMPANY: Florida Power & Light Company

For the Year Ended 12/31/2007

DOCKET NO.: 070650-EI

Line No.	Description	(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) Actual July	(H) Actual August	(I) Actual September	(J) Actual October	(K) Actual November	(L) Actual December	(M) 12Month Total
1	Site Selection:													-
2	Jurisdictional Factor													
3	Total Jurisdictional Site Selection Costs:	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Pre-Construction:													
5	Generation:													
6	License Application											1,185,985	646,841	1,832,826
7	Engineering & Design													
8	Permitting											203,070	497,369	700,439
9	Clearing, Grading and Excavation													
10	On-Site Construction Facilities													
11	Total Generation Costs	-	-	-	-	-	-	-	-	-	-	1,389,055	1,144,210	2,533,265
12														
13	Jurisdictional Factor											0.9958285	0.9958285	0.9958285
14														
15	Total Jurisdictional Generation Costs	-	-	-	-	-	-	-	-	-	-	1,383,258	1,139,435	2,522,693
16														
17	Total Jurisdictional Pre-construction Costs:	-	-	-	-	-	-	-	-	-	-	1,383,258	1,139,435	2,522,693

Note 1: Information provided is based upon the best available at the time of the submission of this report.

The information provided in the attached schedule is based on FPL's current non-binding cost estimate for the Turkey Point Units 6 and 7 project. It is subject to change and should not be considered a formal or binding cost recovery filing by FPL.

Q.

Please respond to the following regarding costs associated with site clearing:

A. Does FPL believe that delays in site clearing would increase preconstruction costs?

B. What additional costs may be considered "preconstruction" costs if any such delay is significant?

C. What are the events which may delay or accelerate key milestones that determine when site clearing can be completed?

D. Is there a way to quantify the range of potential delay or acceleration at this time?

A.

A. Yes, a delay in site clearing would, by definition of Rule 25-6.0423 F.A.C., extend the preconstruction cost period and thereby likely increase the number of expenditures that would meet the definition of preconstruction costs, thus increasing the magnitude of preconstruction costs. However, a delay in the completion of site clearing would not necessarily result in an increase in the overall costs of the project.

B. Per Rule 25-6.0423 F.A.C., costs incurred prior to completion of site clearing would be considered preconstruction costs. Currently site clearing is scheduled to be completed in early 2011. If site clearing were delayed or deferred to early 2012, other milestone activities (e.g., activities identified in Exhibit SDS-5) may become preconstruction costs. These could include expenditures on detailed engineering, the training simulator or a number of material and equipment procurement activities in preparation for construction. Based on current estimates, this could be between $50 and $500 million dollars. The reasonableness of these costs would be reviewed in the NPPCR Rule filing during the preceding year.

If the delay in completing site clearing affects the overall schedule of the project there would be impacts to the overall project costs. Delay in delivery of the project may increase the costs due to escalation of costs or disruptions to project logistical schedules. Delays would also defer the fuel savings and emission compliance costs savings projected for the new plants.

C. Changes in any of three major activities: state regulatory approval, federal regulatory approval, or project design, could delay or accelerate key milestones related to site clearing. Primarily, under Florida's Power Plant Siting Act, site clearing cannot be initiated until a Siting Order has been granted by the Siting Board. Any events that may delay or accelerate receipt of the Siting Order, or otherwise allow initiation of site clearing activities, will impact when site clearing can be completed. Also, delays

or acceleration in the Combined License approval process at the Nuclear Regulatory Commission would have an impact to the overall project schedule, and therefore influence the decision to initiate site clearing. Given that there are several nuclear projects that precede FPL's plans, there may be regulatory or project design information gained from these processes that delay or accelerate the decision to initiate site clearing.

In addition, once site clearing activities are initiated, weather conditions at the site will determine the pace for completing site clearing activities.

D. Due to the number of variables that can affect the pace of obtaining the necessary regulatory approvals, and the detailed engineering and construction planning process FPL is unable to meaningfully quantify the range of potential delay or acceleration at this time.

Q.
For each major long-lead procurement item identified in FPL's response to Staff Interrogatory No. 28, please identify or describe when each item would be purchased and when each item would be installed.

A.
The following example of critical long-lead components is based on maintaining the schedule for 2018 and 2020 commercial operating dates for the two-unit project, and uses the Westinghouse AP1000 as the project design. The long-lead procurement process requires FPL to initiate a series of payments, ultimately resulting in the procurement of the specified components. The initial advanced payment in mid-2008 would secure a manufacturing reservation for the components in a timeframe that supports the project schedule.

Table 88-1. Critical Long Lead Components

Item	Payment Period	Installation Period
Forging Reservation (2 Units with Unit 1 COD in 2018)	mid - 2008	n/a
Reactor Vessel (Unit 1)	2010	2015
Reactor Vessel (Unit 2)	2010	2017
Pressurizer Vessel (Unit 1)	2012	2015
Pressurizer Vessel (Unit 2)	2012	2017
Steam Generator Vessels (Unit 1)	2010	2015
Steam Generator Vessels (Unit 2)	2010	2017
Containment Vessels (Unit 1)	2012	2015
Containment Vessels (Unit 2)	2012	2017
Coolant Pump Casings (Unit 1)	2010	2015
Coolant Pump Casings (Unit 2)	2010	2017

FPL will also be required to make advance payments for other long-lead procurement items later in the process. At this time, the above critical items are the only long-lead procurement items which would require a commitment in advance of completing the 2008 NPPCR Rule process.

Q.

Please identify the range of expenditures necessary to procure long-lead components referenced on page 31, lines 18-23, of Witness Scroggs direct testimony. Please include as much detail regarding the individual components as may be available at this time.

A.

The referenced section of Witness Scroggs' testimony identifies long-lead components as well as other preconstruction cost items such as site preparation costs, detailed engineering and construction of support facilities (training simulator). The following is based on the best available information regarding the range of expenditures for the most critical long lead components described in the FPL's response to Staff's Sixth Set of Interrogatories No. 88 that will require an advance payment prior to the completion of the NPPCR Rule process in 2008. It is noted that commercial negotiations for these components are ongoing and therefore these values are only estimates. It is also noted that additional long-lead items requiring advance payments will be identified as the process develops.

Table 89-1 provides an estimated expenditure schedule for each component by year, beginning with the initial forging reservation payment to delivery at site. The initial forging reservation payment is applicable to all identified critical components required for the two-unit project and would be the only commitment made by FPL prior to initiating Purchase Orders for the components beginning in 2010.

Table 89 – 1. Estimated Payment Schedule for Critical Long Lead Components

Item Description	Estimated Expenditure Schedule (Year Spent $, MM)												Component Total ($MM)
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Forging Reservation Fee	16	0	0	0	0	0	0	0	0	0	0	0	16
Reactor Pressure Vessel (Unit 1)	0	0	6	11	17	18	6	6	0	7	0	0	71
Reactor Pressure Vessel (Unit 2)	0	0	6	0	0	12	18	18	6	7	0	7	74
Pressurizer Vessel (Unit 1)	0	0	0	2	2	2	2	2	0	0	0	0	10
Pressurizer Vessel (Unit 2)	0	0	0	2	2	0	0	2	2	3	0	0	11
Steam Generator Vessels (Unit 1)	0	0	16	22	40	35	24	20	0	13	0	0	170
Steam Generator Vessels (Unit 2)	0	0	16	22	0	0	42	37	25	20	0	14	176
Containment (Unit 1)	0	0	0	1	6	1	6	4	0	0	0	0	18
Containment (Unit 2)	0	0	0	1	6	0	0	1	6	4	0	0	18
Reactor Coolant Pumps (Unit 1)	0	0	16	28	17	18	18	12	0	7	0	0	116
Reactor Coolant Pumps (Unit 2)	0	0	16	11	17	18	18	12	13	7	0	7	119
Annual Total	**16**	**0**	**76**	**100**	**107**	**104**	**134**	**114**	**52**	**68**	**0**	**28**	
Cumulative Total	**16**	**16**	**92**	**192**	**299**	**403**	**537**	**651**	**703**	**771**	**771**	**799**	

Notes:

1) Assumes 2.5% annual escalation from 2007.
2) Forging Reservation Fee applicable to all critical long lead components listed.
3) Reactor Pressure Vessel contains the nuclear fuel and control rods and provides the heat source.
4) Pressurizer Vessel maintains pressure and provides coolant surge volume for the primary system.
5) Steam Generators are heat exchangers using primary system heat to produce steam to drive the turbine generators.
6) Containment Vessel is the primary barrier surrounding the core nuclear plant.
7) Reactor Coolant Pumps provide forced cooling water flow through the primary system.

Q.
Please explain why FPL believes long-lead procurement items are more properly categorized as "preconstruction costs" rather than "construction costs", pursuant to Rule 25-6.0423, F.A.C.?

A.
Long-lead procurement involves reserving manufacturing space and executing the design, purchase and delivery of special heavy forgings and equipment so that they will be prepared and ready to be placed at the appropriate time during the complex construction process. Procurement of an option for certain long-lead items will be required within the first year following an affirmative Need Order to preserve a target Commercial Operating Date of 2018 for the first unit. The current demand for manufacturing capability of this type drives the need to reserve a position to ensure the forgings will be available when the schedule requires. Rule 25-6.0423 F.A.C., Section (2)(c), defines "Pre-construction costs" as "costs that are expended after a site has been selected in the preparation for the construction of a nuclear power plant, incurred up to and including the date the utility completes site clearing work." For the reasons just discussed, advance payments for long-lead procurement items are made "in preparation for the construction of a nuclear power plant" and when those payments occur during the specified time frame they meet the Rule definition of "Pre-construction costs."

Q.
For each major long-lead procurement item subject to recovery as a preconstruction cost item, please explain the need for obtaining the item prior to the completion of site clearing for Turkey Point 6 and 7.

A.
The need to procure any long-lead item in advance of site clearing is driven by the overall schedule for construction. The construction of a project as complex as a nuclear reactor will be meticulously planned with the sequence of construction highly orchestrated to minimize construction time and optimize resource requirements. Necessarily, a detailed design and procurement planning process will be followed for each individual component needed to support the overall construction schedule.

The high-level planning of the construction process has been underway for some time, while the detailed, project-specific planning is just now getting underway. Based on progress to date, equipment providers have identified a list of critical long-lead components and developed an expectation of when each component must be ordered so that it can be designed, fabricated, finished, shipped and prepared on site for installation in a time frame supporting the overall construction schedule. These expectations are based on the cumulative time necessary to conduct each step in the procurement process.

However, the decision to initiate procurement must also reflect the risk to schedule created by a dynamic international material and manufacturing supply market that is affected by a wide range of economic and geo-political factors that can impact the overall project schedule. A key factor in this process is the number of projects with similar material requirements that are planned to occur in a time frame similar to the Turkey Point 6 & 7 project. Because there is limited manufacturing capability for heavy forgings, reservations must be made to secure the specialized manufacturing capability (currently one provider in the world) on a schedule that will support the overall construction schedule. Both, supplier schedules and project needs must be considered.

The critical long-lead components identified by FPL for specific recognition by the Commission are those key components, identified by equipment providers, which require special manufacturing capability that must be reserved and require the most time to procure. These items are pivotal to preserving the ability to deliver the project and its associated benefits at the lowest cost and on the forecasted schedule. It is estimated that the forging reservation payment must be made in 2008 for the first unit in order to support the overall construction schedule.

Q.

Please identify or describe the annual total long lead component costs FPL anticipates recovering in the capacity clause under Rule 25-6.0423, F.A.C. for the period 2009 through 2012 for Turkey Point Units 6 and 7? In addition, please identify or describe the major long lead components which would be included in each year.

A.

Please refer to FPL's response to Staff's 6th Set of Interrogatories No. 89, Table 89-1. Payments made prior to the completion of site clearing in 2011 would be considered preconstruction costs and therefore eligible for recovery under the NPPCR Rule. The annual amounts estimated for recovery in the capacity clause for the period 2009 – 2012, illustrated in the table below, conservatively assume that site clearing occurs in 2011 after the critical long-lead component payments for that year have been made.

Table 92-1. Estimated Critical Long Lead Component Preconstruction Costs

Year	2008	2009	2010	2011	2012
Cost Incurred	$16 MM	$0 MM	$76 MM	$100 MM	$0 MM
Cost Recovered	$0 MM	$16 MM	$76 MM	$100 MM	$0 MM

Cost Recovered does not include an estimate of carrying costs that would be applicable to any advance payment made in 2008 that were not recovered until 2009.

The above table provides an estimated annual recovery amount for the critical long lead components identified in FPL's response to Staff's 6th Set of Interrogatories No. 88, with expenditures more fully described in FPL's response to Staff's 6th Set of Interrogatories No. 89. There will likely be additional long-lead components identified as the project specific planning evolves. Likewise, there will be additional preconstruction cost items such as detailed engineering and training simulator that are not specifically estimated at this time.

Q.

Please refer to FPL's Responses to Staff's 4th Request for Documents, Nos. 16 and 17, and Appendix F of Need Study. Page FPL000389 has notations designating the relationship between the environmental compliance costs Env II (identified in Appendix F) and ICF Expected Case whose formation has been explained in DN10888-07. Given the probabilities presented in FPL000389, please explain whether FPL applied similar probabilities regarding the environmental compliance costs forecasts appearing in the Need Study's Appendix F, page 3. If not, please explain.

A.

FPL did not assign probabilities to the four different environmental compliance cost forecasts utilized in its scenario analysis. Due to uncertainty in future fuel costs, in future environmental compliance costs, and in the interaction between environmental compliance costs and fuel costs, FPL believes there is no sound basis upon which to assign probabilities to any one forecast with any certainty. FPL chose instead to perform a scenario analysis that looked at all reasonable combinations (or scenarios) of the fuel cost and environmental compliance cost forecasts without assigning probabilities.

Q.

Please Refer to page 46, lines 12-13, of Witness Sim's direct testimony. When FPL conducted its economic analysis, FPL assumed no CO2 emission allowances would be granted during the forecast horizon. Please identify or provide the possible economic analysis results of the Total Costs and Total Cost Differentials for all fuel and environmental compliance cost scenarios in the same format as Exhibit SRS-6, using the assumption that 10% of CO2 allowances would be granted to FPL. Please provide this information for each of the three electric power generation alternatives: nuclear, CC and IGCC.

A.

FPL does not believe it is possible to identify or provide "all possible" economic results of the Total Costs and Total Cost Differentials for all fuel and environmental compliance cost scenarios using the assumption that "10% of CO2 allowances would be granted to FPL." There are simply too many possibilities as to the method and timing of how CO2 allowances might be allocated.

However, for purposes of responding to this request, FPL has made the following assumption regarding a potential CO2 allowance allocation regulation: Using actual CO2 system emissions for a given year (in this example assumed to be 2010), FPL would receive allowances for 10% of these allowances and these allowances would be available for FPL to utilize at no cost for each successive year. In this example, FPL's 2010 CO2 allowances are projected to be approximately 58 million tons. Therefore, FPL's annual CO2 allowances would be set at 5.8 million tons.

Using these assumptions, the CPVRR cost for all three resource plans presented in FPL Witness Sim's Exhibit SRS-6 would be lower due to no cost associated with the 5.8 million tons of CO2 each year. For a given fuel cost and environmental compliance cost scenario, the amount by which the CPVRR costs would be lowered would be identical for the three resource plans because the same amount of annual CO2 allowances (5.8 million tons) would be granted to each resource plan. In other words, although the CPVRR costs for all three resource plans would be lowered, the differentials between the three resource plans would not be changed.

The amount by which the CPVRR costs would be lowered is independent of the fuel cost forecast, but increases as the CO2 environmental compliance cost forecast increases. The reduction in CPVRR costs for each resource plan is $784 million with the Env I forecast, $1,629 million with the Env II forecast, $2,313 million with the Env III forecast, and $3,007 million with the Env IV forecast.

These results are shown in attached Table Staff 94.

Table Staff 94

Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

(millions, CPVRR, 2007$, 2007 - 2060) (from Exhibit SRS-6)

(1)	(2)	(3)	(4)	(5)	(6) = (3) - (4)	(7) = (3) - (5)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans			Total Cost Difference Plan with Nuclear - Plan without Nuclear - CC	Total Cost Difference Plan with Nuclear - Plan without Nuclear - IGCC
		Plan with Nuclear	Plan without Nuclear - CC	Plan without Nuclear - IGCC		
High Gas Cost	Env I	220,904	233,052	234,173	(12,148)	(13,269)
High Gas Cost	Env II	233,322	246,544	249,099	(13,222)	(15,777)
High Gas Cost	Env III	242,937	256,648	259,966	(13,711)	(17,029)
High Gas Cost	Env IV	252,296	266,663	270,943	(14,367)	(18,647)
Medium Gas Cost	Env I	170,391	179,356	182,648	(8,965)	(12,257)
Medium Gas Cost	Env II	182,700	192,694	197,474	(9,994)	(14,774)
Medium Gas Cost	Env III	192,190	202,702	208,218	(10,512)	(16,028)
Medium Gas Cost	Env IV	201,428	212,635	219,099	(11,207)	(17,671)
Low Gas Cost	Env I	129,850	136,175	141,533	(6,325)	(11,683)

Note: A negative value in Columns (6) and/or (7) indicates that the Plan with Nuclear is less expensive than the comparative Plan without Nuclear (CC or IGCC). Conversely, a positive value in Columns (6) and/or (7) indicates that the Plan with Nuclear is more expensive than the comparative Plan without Nuclear (CC or IGCC).

Q.

Please refer to page 22, of Witness Kosky's direct testimony. Please clarify whether the environmental compliance costs presented in Appendix F of Need Study are the compliance allowance costs adopted from ICF report or whether the environmental compliance costs are the actual compliance costs described in Witness Sim's direct testimony, on page 46, lines 16 -19.

A.

The environmental compliance costs used in FPL's analyses presented in this docket are those provided in Appendix F of the Need Study. These environmental compliance costs were originally based on ICF's projected costs but have been modified. The modifications that were made were first described by FPL in response to Interrogatory 52 of Staff's 3rd Set of Interrogatories in the FPL's Nuclear Uprates docket. That description is summarized below.

The process used by FPL and its consultants to develop the environmental compliance cost forecasts is described below:

Step 1: The source document used was the ICF "U.S. Emission & Fuel Markets Outlook" Report, 2006 Edition. The costs provided by ICF in this report were in 2005 real dollars.

Step 2: From this report, three scenarios were chosen: (1) 4P: 4 Pollutant Mild (Bingaman) CO2; (2) 4P: 4 Pollutant Reference Case; and (3) 4P Stringent: 4 Pollutant (McCain) CO2. These scenarios were chosen to cover the broad range of CO2 price outcomes projected for ICF, while keeping the number of scenarios to a manageable level.

Step 3: The ICF projections ended at 2030. For CO2 in the 4P Pollutant Mild Case scenario, the post-2030 values were assumed to stay at the 2030 levels (in real terms). For CO2 in the 4 Pollutant Reference Case scenario, a 2050 projected target price of $35/ton (in real terms) was assumed. Between 2030 and 2050 values were interpolated accordingly. A similar process was used for CO2 in the 4P Stringent scenario, with the 2050 target price set at $50/ton. Target values for 2050 were chosen by consensus by FPL and its consultant. The post-2030 price escalators developed for the three CO2 scenarios in the process described above were also applied to the SO2, NOx, and Hg emission compliance costs.

Step 4: The projections were then converted to nominal dollars using a general inflation rate of 2.5% per year. At this point FPL had developed Environmental Compliance Cost scenarios ENV I, ENV II, and ENV III. The ICF origin of these scenarios is shown below:

ENV I: based on 4P: 4 Pollutant Mild (Bingaman) CO2;
ENV II: based on 4P: 4 Pollutant Reference Case;
ENV III: based on 4P Stringent: 4 Pollutant (McCain) CO2.

Step 5: An additional scenario, ENV IV, was developed. The annual CO2 values ($/ton) in ENV III were increased by 30%. Costs for SO2, NOx, and Hg were unchanged from scenario ENV III.

Q.

On pages FPL000328-FPL000335 and FPL000357-FPL000364 responsive to Staff's Fourth Request for Documents, No. 18, FPL presented "FPL CO2 Allowance Allocation" for each year from 2009 to 2024. Please reconcile these allowances with Witness Sim's Direct Testimony (Page 46, Lines 12-13) which stated "FPL assume that no CO2 allowances would be granted to FPL during the forecast horizon".

A.

In response to Staff's Fourth Request for Documents, No. 18, FPL's inclusive response included a projection of CO2 allowance allocations that had been developed based on the possibility that CO2 allowances might be granted as part of future greenhouse gas emission legislation/regulation.

However, FPL currently believes that it is unlikely that free/no cost CO2 allowances will be granted in any such future legislation/regulation. Consequently, as stated in FPL Witness Sim's testimony on page 46, lines 12-13, "For purposes of these analyses, FPL assumed that no CO2 allowances would be granted."

Q.

Please explain how the fixed transportation costs for gas are treated in the calculation of the cumulative present value revenue requirements.

A.

The firm gas transportation costs for FPL's system are treated as a fixed cost, reflecting the firm nature of the contractual commitment necessary to obtain gas transportation, in the calculation of annual system revenue requirements. This approach is consistent with the "fixed" nature of gas transportation contracts. These annual system revenue requirements are then summed and present valued to derive the cumulative present value of revenue requirements.

AFFIDAVIT

Sponsor:

Steven D. Scroggs

State of Florida)

County of Palm Beach)

I hereby certify that on this 3rd day of Jan, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven D. Scroggs**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 85, 86, 87, 88, 89, 91, and 92 from **Staff's Sixth** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of January, 2008.

Notary Public
State of Florida, at Large

Notary Public State of Florida
Jennifer M Payne
My Commission DD439096
Expires 06/09/2009

My Commission Expires:

6/9/09

AFFIDAVIT

Sponsor:

H. Antonio Cuba

State of Florida)

County of Miami-Dade)

I hereby certify that on this 7th day of January, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **H. Antonio Cuba**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No. **90** from **Staff's 6th** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of January, 2008.

Monica Lynn Padron
Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

AFFIDAVIT

Sponsor:

Steven R. Sim

(Steven R. Sim)

State of Florida)

County of Miami- Dade)

I hereby certify that on this 3rd day of January, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven R. Sim**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No(s). **93-98** from **Staff's 6th** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of January, 2008.

Monica Lynn Padron

Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

December 18, 2010

6

FPL's Response to Staff's Eighth Set of Interrogatories (Nos. 107-112, 114)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: January 16, 2008

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S EIGHTH SET OF INTERROGATORIES (NOS. 107-114)

Florida Power & Light Company gives notice of service of its responses to the Staff of the Florida Public Service Commission's Eighth Set of Interrogatories (Nos. 107-114) to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 16th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
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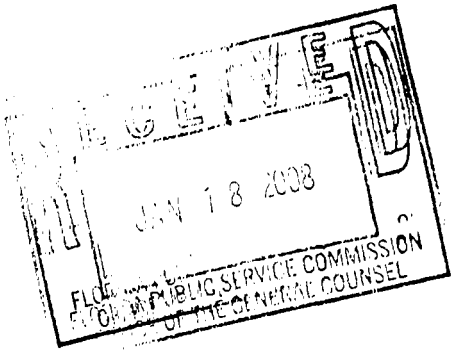

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically and by United States mail this 16th day of January, 2008, to the following:

Katherine E. Fleming
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
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On Behalf of Jan M. Krasowski and Bob Krasowski

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James A. Dickenson
P.G. Para
JEA
21 West Church Street
Jacksonville, FL 32202

By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

Hearing Exhibit 000231

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's	)	Docket No. 070650-EI
Petition to Determine Need for	)	
Turkey Point Nuclear Units 6 and 7	)	
Electrical Power Plant	)	Dated: January 16, 2008

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S EIGHTH SET OF INTERROGATORIES (NOS. 107-114)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following responses to the Staff of the Florida Public Service Commission's ("Staff's") Eighth Set of Interrogatories (Nos. 107-114).

FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in Florida Power & Light Company's Objections to Staff's Eighth Set of Interrogatories (Nos. 107-114), dated January 10, 2008.

Staff's Eighth Set of Interrogatories (Nos. 107-114)

Attached hereto are FPL's answers to Staff's Eighth Set of Interrogatories (Nos. 107-114), consistent with its prior objections, together with the affidavit of the person providing said answers.

Respectfully submitted this 16th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
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Attorneys for Florida Power & Light Company

By: _____
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically and by United States mail this 16th day of January, 2008, to the following:

Katherine E. Fleming
Senior Attorney
Florida Public Service Commission
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2540 Shumard Oak Boulevard
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James A. Dickenson
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JEA
21 West Church Street
Jacksonville, FL 32202

By: _____
Jessica A. Cano
Florida Bar No. 0037372

Hearing Exhibit 000234

Q.
Please identify, list, and explain the need for each long-lead procurement item for which FPL expects to make advance payments.

A.
Please see FPL's response to Staff's 6th Set of Interrogatories Nos. 88, 89 and 91. Each item identified as a critical long-lead component (i.e., requiring advance payment prior to the completion of the NPPCR Rule process in 2008) is a critical component within the core nuclear plant. As such, each item is essential for the safe operation of the facility.

The reactor pressure vessel houses the nuclear fuel that heats the primary system water. The pressurizer vessel acts as a surge volume and maintains the pressure for the primary system. The reactor coolant pumps provide forced flow of primary coolant from the reactor pressure vessel to the steam generator vessels. The heat of the primary system is used to produce steam in the steam generators and that steam is used to drive the turbine generators to produce electricity.

Additional long-lead procurement items will be identified as the project specific planning matures. These long-lead procurement items may require advance payments, which will be identified and reviewed within the NPPCR Rule process.

Q.
Please provide a detailed explanation for the need to make advance payments for each item in order to meet a 2018 - 2020 in-service date for Turkey Point Nuclear Units 6 & 7, including an analysis of the consequences of delay.

A.
Please refer to FPL's response to Staff's 6th Set of Interrogatories Nos. 89 and 91, and FPL's response to Staff's 8th Set of Interrogatories No. 107.

Delays in receiving the critical components necessary to complete construction would translate to construction delays and therefore potentially result in increased project costs in the following areas:

- Increased interest during construction
- Increased equipment and labor escalation impacts
- Increased labor and construction period costs
- Increased long lead component costs (manufacturing, expediting charges)

Additionally, delays would result in the day-for-day deferral of the fuel savings and emission compliance cost savings projected for the new units. Delay would also decrease the reliability of the system unless the capacity could be replaced by purchased power or temporary capacity – likely to be less cost-effective than the new units. In that replacement capacity would almost certainly be fossil-fueled, additional greenhouse gas emissions would result and exposure to fuel supply reliability issues would remain.

The consequences of delay are difficult to estimate given the many variables associated with such projections. However, Witness Scroggs provided two sensitivity analyses on pages 52 and 53 of his direct testimony that are relevant. A six-month delay at the latter stages of the project was estimated to create an increase in interest costs of $400 to $600 million. A one-percent increase in escalation rates was estimated to create an increase in project cost of $415 million. A delay to a key component(s) would manifest itself early in the construction period resulting in a ripple effect creating delays to future schedule milestones. While best efforts would be made to offset and minimize the impacts of such delay, increased project costs from the identified sources would be the likely result.

Q.
Please provide a current cost estimate, by item and in total, of the long-lead procurement items for which FPL expects to make advance payments.

A.
Please refer to FPL's response to Staff's 6th Set of Interrogatories No. 89. Specific information is provided for the critical long-lead components for which payment may be required prior to the completion of the 2008 NPPCR Rule process. Additional long-lead procurement items and preconstruction costs would be identified as the project-specific planning process matures and would be reviewed in the NPPCR Rule process.

Q.
Please provide a cost/benefit analysis identifying the expected cost savings, if any, associated with making advance payments for each long-lead procurement item necessary to meet the 2018 - 2020 in-service dates for Turkey Point Nuclear Units 6 & 7.

A.
The estimated expenditure schedule for the advanced payments associated with critical long-lead procurement items are provided in FPL's response to Staff's 6th Set of Interrogatories No. 89. The alternative to not making the $16 million advance payment in 2008 is to wait until the Purchase Orders would be required in 2010. Doing so would create a significant risk that the target in-service dates of 2018 and 2020 could be met. The limited amount of manufacturing capability and the projected demand from other projects that utilize this capability strongly indicate the need to reserve the queue space.

If the queue space is available in 2010, the $16 million forging reservation fee will have been avoided and the project can proceed per schedule. Based on the best information available, this outcome is highly unlikely.

If the queue space is not available in 2010, then the project will experience a delay that will be determined by manufacturing availability at that time. The magnitude of this delay could range from a year to many years depending on the status of other announced projects.

As an example, assume that the delay is equivalent to the advance period of two years. Based on a 2,200 MW project, using the costs identified in Case A of Witness Scroggs testimony, and assuming a 2.5% annual escalation rate, the increased project costs attributable to escalation alone created by a two-year delay would be approximately $480 million. Of course, escalation would be just one of the incremental project costs created by a delay.

Delay to the project would also result in deferred system economic benefits (fuel savings and emission compliance savings), additional costs for replacement capacity as well as deferred system reliability and environmental benefits (capacity reliability, fuel supply reliability, and reduced greenhouse gas emissions).

This partial and simplified analysis demonstrates the prudence of obtaining a forging reservation to secure the project schedule.

Q.
Please identify the timing, magnitude, and mechanism for cost recovery that FPL expects to request for each long-lead procurement item for which FPL expects to make advance payments.

A.
FPL will file for cost recovery for all projected nuclear costs, including long-lead items strictly in accordance with Rule 25-6.0423, F.A.C., through the annual NPPCR Rule filing process described therein. The annual filings will delineate the actual costs for prior years, the actual/estimated expenditures for the current year and the projected expenditures for the subsequent year. Any projected expenditure to be incurred during the pre-construction period and determined reasonable by review of the Commission would be included for recovery through the capacity cost recovery clause for that projected period. A true-up filing in the following year will affirm the actual costs incurred and the prudence of such expenditures.

Please see FPL's response to Staff's 6th Set of Interrogatories No. 85 for the Company's current projection of 2008 and 2009 nuclear costs.

Q.
Please identify the date on which FPL became aware that advance payments would be required by the manufacturer for each long-lead procurement item necessary to meet the 2018 - 2020 in-service dates for Turkey Point Nuclear Units 6 & 7.

A.
FPL has been a member of the NuStart consortium for several years. During the involvement with that group many of the planning and logistical issues associated with construction of new nuclear generation were formulated at a high level, including the potential for long-lead payments.

Specific to the Turkey Point Unit 6 & 7 project, FPL met with equipment vendors beginning in late 2005 and early 2006 to understand the regulatory, design, procurement and construction process associated with new nuclear generation projects specific to their designs. In those discussions, the vendors identified that certain large forging components would need to be specially fabricated with significant lead times. Implicit in that discussion was the concept that the purchaser would need to enter into some commercial arrangement with the vendor to initiate the procurement process on these time-sensitive items and that such arrangement would involve payments in advance of receiving the components. The dynamic market for heavy forgings and the limited manufacturing capability for these forgings were also identified.

The specific information regarding the timing and payment amounts for critical long-lead components has only been recently developed and is currently provided as a best estimate in advance of a negotiated commercial agreement.

Q.
Please provide a description and cost estimate of any long term capital expenditure that FPL intends to purchase, in whole or in part, during pre-construction.

A.
All estimated costs associated with the project occurring during the pre-construction period are considered long-term capital expenditures. Please refer to FPL's response to Staff's 6th Set of Interrogatories No. 85 that provides draft schedules that are projected as pre-construction expenditures.

AFFIDAVIT

Sponsor:

Steven D Scroggs

Steven D. Scroggs

State of Florida)

County of Palm Beach)

I hereby certify that on this 3rd day of Jan, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven D. Scroggs**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 107, 108, 109, 110, 111, 112, 113, and 114 from **Staff's Eighth** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of January, 2008.

Jennifer M Payne

Notary Public
State of Florida, at Large

Notary Public State of Florida
Jennifer M Payne
My Commission DD439096
Expires 06/09/2009

My Commission Expires:
6/9/09

7

FPL's Response to OPC's First Set of Interrogatories (No. 1)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: December 20, 2007

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE OFFICE OF PUBLIC COUNSEL'S FIRST SET OF INTERROGATORIES (NOS. 1-2) AND FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-13)

Florida Power & Light Company gives notice of service of its Responses to the Office of Public Counsel's First Set of Interrogatories (Nos. 1-2) and First Request for Production of Documents (Nos. 1-13) to Charles J. Beck, with a copy to all parties on the attached Certificate of Service.

Respectfully submitted this 20th day of December, 2007.

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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 20th day of December, 2007, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Charles J. Beck, Deputy Public Counsel*
Office of the Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
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On Behalf of Jan M. Krasowski and Bob Krasowski**

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Attorney for Orlando Utilities Commission**

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Barry Moline
Florida Municipal Electric Association**
P.O. Box 10114
Tallahassee, FL 32302-2114

By: *s/Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing.

Hearing Exhibit 000245

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	)	Docket No. 070650-EI
	)	Dated: December 20, 2007

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE OFFICE OF PUBLIC COUNSEL'S FIRST SET OF INTERROGATORIES (NOS. 1-2) AND FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-13)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following responses to the Office of Public Counsel's ("OPC's") First Set of Interrogatories (Nos. 1-2) and First Request for Production of Documents (Nos. 1-13).

FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in Florida Power & Light Company's Objections to OPC's First Set of Interrogatories (Nos. 1-2) and First Request for Production of Documents (Nos. 1-13), dated December 14, 2007.

I. OPC's First Set of Interrogatories (Nos. 1-2)

Attached hereto are FPL's answers to OPC's First Set of Interrogatories (Nos. 1-2), consistent with its prior general objections, together with the affidavits of the persons providing said answers. Please note that FPL is responding to Interrogatory No. 1, notwithstanding and without waiving its specific objection made on December 14, 2007.

II. OPC's First Request for Production of Documents (Nos. 1-13)

Specific Objection to Nos. 2 and 4

FPL objects to these requests to the extent that they seek confidential, proprietary, business information. By agreeing to provide such information in response to these requests,

FPL is not waiving its right to insist upon appropriate protection of confidentiality by means of a protective order or other action to protect the confidential information requested.

Responses

FPL's responses are without waiver of its general and specific objections. All documents will be made available by FPL for inspection and review by OPC at FPL's offices at 215 South Monroe Street, Tallahassee Florida, during regular business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Respectfully submitted this 20th day of December, 2007.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
700 Universe Boulevard
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Kenneth A. Hoffman
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Attorneys for Florida Power & Light Company

By: _____

Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000247

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 20th day of December, 2007, to the following:

Katherine E. Fleming*
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Attorney for Seminole Electric Cooperative, Inc.**

Barry Moline
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P.O. Box 10114
Tallahassee, FL 32302-2114

By: _____
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000248

Q.

Please provide the charts shown in Table VII.D.!.3 [sic] and VII.D.1.4 of the need study with the low cost gas, env. II, III, and IV results included.

A.

FPL has performed the computations requested by the Office of Public Counsel (OPC) utilizing the gas cost forecast and CO2 environmental compliance cost forecasts specified by OPC's First Set of Interrogatories No. 1. FPL believes that because the combinations specified by OPC are mutually exclusive, they will not occur. Scenario planning is based on the concept of combining assumptions that are expected to co-exist, rather than be (as these are) mutually exclusive. Specifically, a higher cost of CO2 emissions will create greater demand for natural gas because generators will seek to reduce CO2 emissions by utilizing more natural gas. This will cause the price of gas to be significantly higher than envisioned by the low gas cost forecast. Therefore, the computation results provided to accommodate OPC's question are inconsistent with proper scenario planning and not relevant to FPL's decision concerning the addition of Turkey Point 6 and 7.

The computations that utilized OPC's combination of low gas cost and the second lowest, third lowest, and highest environmental compliance costs forecasts, respectively, comparing the Plan with Nuclear and the Plan without Nuclear CC, resulted in breakeven nuclear capital costs of $3,830/kW, $3,975/kW and $4,300/kW, respectively. Similar computations comparing the Plan with Nuclear to the Plan without Nuclear IGCC resulted in breakeven nuclear capital costs of $7,210/kW, $7,800/kW and $8,380/kW.

AFFIDAVIT

Sponsor:

Steven R. Sim

State of Florida)

County of Miami-Dade)

I hereby certify that on this 14th day of December, 2007, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Steven R. Sim**, who is personally known to me, and he/she acknowledged before me that he/she sponsored the answer(s) to Interrogatory No(s). 1 from **OPC's 1st** Set of Interrogatories to Florida Power & Light Company in Docket No. 070650-EI, and that the response(s) is/are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of December, 2007.

Monica Lynn Padron
Notary Public
State of Florida, at Large

MONICA LYNN PADRON
Notary Public - State of Florida
My Commission Expires Dec 18, 2010
Commission # DD 623437
Bonded Through National Notary Assn.

My Commission Expires:

12/18/10

8

FPL's Response to Staff's Fourth Request for Production of Documents (No. 18, including supplemental response)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: December 12, 2007

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 16-20)

Florida Power & Light Company gives notice of service of its Objections and Responses to the Staff of the Florida Public Service Commission's Fourth Request for Production of Documents (Nos. 16-20), to Katherine E. Fleming.

Respectfully submitted this 12th day of December, 2007.

R. Wade Litchfield, Vice President &
Associate General Counsel
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John T. Butler
Bryan S. Anderson
Antonio Fernandez
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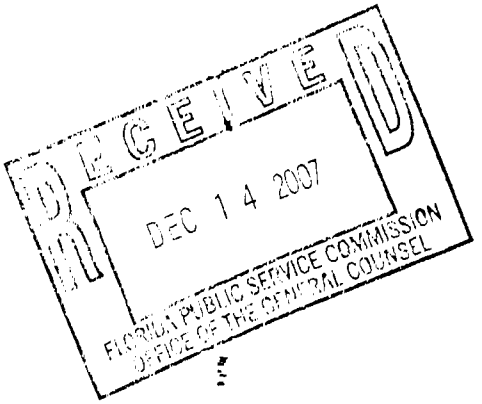

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 12th day of December, 2007, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

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Office of the Public Counsel
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Barry Moline
Florida Municipal Electric Association**
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Tallahassee, FL 32302-2114

By: *s/Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000253

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: December 12, 2007

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 16-20)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following objections and responses to the Staff of the Florida Public Service Commission's ("Staff's") Fourth Request for Production of Documents (Nos. 16-20).

I. General Objections

FPL objects to each and every request for documents that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive such privilege or protection. The nature of the document(s), if any, will be described in a privilege log prepared by FPL.

In certain circumstances, FPL may determine, upon investigation and analysis, that information responsive to certain discovery requests to which objections are not otherwise asserted are confidential and proprietary and should not be produced without provisions in place to protect the confidentiality of the information, if at all. By agreeing to provide such information in response to such request, FPL is not waiving its right to insist upon appropriate protection of confidentiality by means of a protective order or other action to protect the confidential information requested. FPL asserts its right to require such protection of any and all

documents that may qualify for protection under the Florida Rules of Civil Procedure and other applicable statutes, rules and legal principles.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's response. Rather, these responses provide all the information that FPL obtained after a reasonable and diligent search conducted in connection with this discovery request. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to any production location other than FPL's offices at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each request to the extent that it seeks information that is not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests.

FPL objects to each discovery request to the extent that the information requested constitutes "trade secrets" which are privileged pursuant to Sections 90.506 and 366.093(3)(a), Florida Statutes.

FPL also objects to these discovery requests to the extent they call for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as purporting to expand FPL's obligations under applicable law. FPL will comply with its obligations under the applicable rules of procedure.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to Staff through normal procedures.

FPL objects to each discovery request and any definitions and instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count requests for production of documents and their sub-parts (as permitted under the applicable rules of procedure) in determining whether it is obligated to respond to additional requests served by any party.

Notwithstanding any of the foregoing general objections and without waiving these objections, FPL intends in good faith to respond to Staff's discovery requests.

II. Specific Objections

FPL incorporates by reference all of the foregoing General Objections into its Specific Objections set forth below as though fully stated herein:

Staff's Request for Production of Documents Nos. 16 & 17: FPL objects to these requests to the extent they seek confidential, proprietary business information. By agreeing to provide such information in response to these requests, FPL is not waiving its right to insist upon appropriate protection of confidentiality by means of a protective order or other action to protect the confidential information requested.

Hearing Exhibit 000256

III. Responses

FPL incorporates its objections to Staff's Request for Production Nos. 16 and 17 above. FPL's responses are without waiver of those prior objections. All documents will be made available by FPL for inspection and review by Staff at FPL's offices at 215 South Monroe Street, Tallahassee, Florida during regular business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Respectfully submitted this 12th day of December, 2007.

R. Wade Litchfield, Vice President and
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
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Attorneys for Florida Power & Light Company

By: _____
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

Hearing Exhibit 000257

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 12th day of December, 2007, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
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Attorney for Seminole Electric Cooperative, Inc.**

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118 North Gadsden Street
Tallahassee, FL 32301
Attorney for Seminole Electric Cooperative, Inc.**

Barry Moline
Florida Municipal Electric Association**
P.O. Box 10114
Tallahassee, FL 32302-2114

By: _____
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing.

Hearing Exhibit 000258

SO2 Ton ***Total Annual System Emissions***

Expansion Plan / Fuel Forecast / Emission Scenario	With Nuclear Uprates								
	High Gas Cost				Medium Gas Cost				Low Gas Cost
	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	96,952	96,952	96,952	96,952	104,967	104,957	104,998	104,998	94,457
2008	102,583	102,672	102,677	102,677	109,022	109,019	109,022	109,022	101,212
2009	101,217	101,217	101,251	101,251	104,292	104,334	104,429	104,429	98,173
2010	77,177	76,961	77,257	77,324	79,863	79,957	79,830	79,942	76,366
2011	57,204	56,997	57,368	57,422	57,472	57,559	57,202	56,774	57,260
2012	56,892	56,534	56,661	56,766	57,294	57,449	57,009	56,738	56,327
2013	57,908	57,724	57,801	57,862	58,323	58,289	57,979	57,790	57,612
2014	63,593	63,534	63,525	63,506	64,024	64,014	63,513	63,355	63,377
2015	56,908	56,904	56,913	56,910	57,103	56,958	56,764	56,610	54,728
2016	52,032	52,012	52,032	52,033	50,538	50,523	50,551	50,521	48,398
2017	48,335	48,326	48,377	48,378	46,952	46,974	46,974	46,784	44,384
2018	48,923	48,869	48,938	48,943	47,771	47,906	47,871	47,391	43,919
2019	52,351	52,316	52,329	52,344	51,052	50,982	50,977	50,728	47,712
2020	48,276	48,374	48,428	48,319	47,342	47,295	47,259	46,864	44,281
2021	48,304	48,545	48,496	48,273	47,221	47,165	47,264	46,468	44,380
2022	48,375	49,195	49,115	49,027	47,635	47,891	47,647	46,128	43,702
2023	45,555	46,386	46,352	46,276	44,644	45,208	45,105	43,130	40,469
2024	45,514	46,313	46,271	46,209	44,652	45,248	44,983	42,896	40,643
2025	40,767	41,163	41,126	41,090	39,674	39,917	39,796	37,375	36,168
2026	34,949	35,499	36,243	36,244	33,822	34,291	34,518	32,285	30,430
2027	33,557	34,080	34,746	34,747	32,515	33,003	33,573	30,027	30,201
2028	31,831	32,229	32,734	32,735	31,082	31,526	31,715	26,699	28,822
2029	31,912	32,310	32,800	32,801	31,165	31,531	31,873	25,985	29,168
2030	30,741	31,170	31,681	31,682	30,143	30,581	30,927	24,653	28,685
2031	30,093	30,348	30,865	30,860	29,624	29,861	30,279	23,364	28,909
2032	30,093	30,336	30,736	30,735	29,662	29,962	30,125	22,425	29,282
2033	30,396	30,629	31,090	31,075	29,958	30,188	30,605	22,890	29,792
2034	29,895	29,978	30,425	30,420	29,534	29,730	30,079	21,678	29,375
2035	30,232	30,271	30,793	30,794	29,830	30,003	30,569	23,330	29,696
2036	30,382	30,441	30,849	30,849	30,015	30,196	30,679	23,071	29,873
2037	30,053	30,066	30,528	30,521	29,827	29,902	30,343	22,063	29,696
2038	31,661	31,639	32,051	32,060	31,396	31,496	31,916	23,859	31,248
2039	31,723	31,705	32,073	32,079	31,504	31,625	31,895	23,962	31,340
2040	31,821	31,796	32,161	32,152	31,599	31,686	31,932	22,905	31,478
2041	31,662	31,652	31,999	31,990	31,447	31,540	31,787	21,865	31,346
2042	31,666	31,639	32,010	31,994	31,448	31,548	31,788	22,551	31,347
2043	32,251	32,185	32,613	32,612	31,991	32,072	32,434	24,421	31,018
2044	32,384	32,290	32,711	32,710	32,143	32,171	32,481	25,267	31,939

FPL 000291

SO2 Ton

Total Annual System Emissions

Expansion Plan	Without Nuclear Uprates								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	96,952	96,952	96,952	96,952	104,967	104,957	104,998	104,998	94,457
2008	102,583	102,672	102,677	102,677	109,022	109,019	109,022	109,022	101,212
2009	101,217	101,217	101,251	101,251	104,292	104,334	104,429	104,429	98,173
2010	75,609	75,423	75,675	75,746	78,228	78,318	78,175	78,304	74,840
2011	56,338	56,085	56,440	56,494	56,421	56,479	56,183	55,795	56,126
2012	58,300	57,836	58,020	58,144	58,588	58,667	58,270	58,005	57,628
2013	62,027	61,899	61,903	61,998	62,538	62,514	62,143	61,972	61,980
2014	56,419	56,339	56,339	56,377	56,551	56,534	56,178	56,070	56,050
2015	58,744	58,755	58,749	58,753	58,834	58,681	58,446	58,357	56,274
2016	46,708	46,683	46,706	46,692	45,508	45,456	45,510	45,441	43,123
2017	46,975	46,978	47,032	47,037	45,696	45,723	45,715	45,501	42,554
2018	48,761	48,732	48,778	48,796	47,623	47,770	47,729	47,198	43,660
2019	52,167	52,132	52,146	52,174	50,855	50,836	50,833	50,551	47,371
2020	48,120	48,212	48,257	48,143	47,158	47,126	47,093	46,693	44,086
2021	48,146	48,417	48,449	48,120	47,070	47,157	47,101	46,283	44,188
2022	48,256	49,093	48,969	48,922	47,524	47,773	47,518	45,961	43,501
2023	45,445	46,292	46,301	46,223	44,545	45,088	44,994	42,976	40,322
2024	45,470	46,253	46,210	46,138	44,543	45,144	44,889	42,561	40,507
2025	40,696	41,114	41,061	41,033	39,595	39,837	39,704	37,317	35,903
2026	34,895	35,417	36,194	36,194	33,770	34,225	34,430	32,357	30,396
2027	33,515	34,035	34,682	34,682	32,491	32,937	33,565	30,204	30,106
2028	31,801	32,252	32,759	32,761	31,080	31,518	31,738	26,873	28,771
2029	31,893	32,301	32,821	32,821	31,174	31,550	31,835	26,233	29,160
2030	30,765	31,173	31,658	31,659	30,163	30,567	30,914	24,823	28,625
2031	30,147	30,387	30,885	30,884	29,661	29,886	30,304	23,661	28,970
2032	29,972	30,243	30,631	30,630	29,588	29,850	30,165	22,458	29,151
2033	30,847	31,136	31,589	31,588	30,319	30,644	31,087	24,185	30,095
2034	30,278	30,381	30,802	30,802	29,830	30,048	30,274	22,987	29,661
2035	30,065	30,159	30,596	30,601	29,727	29,846	30,366	23,081	29,592
2036	30,547	30,631	31,032	31,035	30,173	30,311	30,733	23,470	30,005
2037	30,217	30,266	30,714	30,720	29,977	30,070	30,514	22,832	29,845
2038	31,503	31,480	31,849	31,849	31,279	31,354	31,696	23,524	31,136
2039	31,571	31,553	31,820	31,820	31,321	31,426	31,699	23,133	31,211
2040	31,640	31,664	31,919	31,916	31,442	31,507	31,745	22,226	31,374
2041	31,494	31,514	31,728	31,723	31,322	31,324	31,527	21,388	31,267
2042	31,507	31,503	31,744	31,740	31,324	31,342	31,575	21,991	31,268
2043	31,991	31,910	32,214	32,207	31,751	31,733	31,986	23,242	31,600
2044	32,105	32,033	32,393	32,366	31,900	31,906	32,084	24,366	31,717

FPL 000292

SO2 Ton **Annual System Emissions Excess / (Shortfall)**

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	With Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007		(96,952)	(96,952)	(96,952)	(96,952)	(104,967)	(104,957)	(104,998)	(104,998)	(94,457)
2008		(102,583)	(102,672)	(102,677)	(102,677)	(109,022)	(109,019)	(109,022)	(109,022)	(101,212)
2009	123,191	21,975	21,974	21,940	21,940	18,899	18,857	18,762	18,762	25,618
2010	118,079	40,903	41,119	40,822	40,755	38,216	38,122	38,250	38,138	41,713
2011	118,079	60,876	61,082	60,712	60,657	60,607	60,521	60,878	61,305	60,819
2012	118,079	61,187	61,545	61,419	61,313	60,785	60,631	61,071	61,342	61,753
2013	118,079	60,171	60,355	60,278	60,218	59,757	59,790	60,101	60,289	60,468
2014	118,079	54,486	54,546	54,554	54,574	54,055	54,066	54,566	54,724	54,703
2015	118,079	61,172	61,176	61,166	61,170	60,976	61,121	61,315	61,469	63,351
2016	118,079	66,048	66,067	66,048	66,046	67,542	67,556	67,529	67,559	69,682
2017	118,079	69,744	69,753	69,703	69,702	71,127	71,106	71,105	71,296	73,695
2018	118,079	69,156	69,210	69,141	69,137	70,309	70,174	70,209	70,689	74,160
2019	118,079	65,729	65,764	65,750	65,736	67,028	67,098	67,102	67,352	70,367
2020	118,079	69,804	69,706	69,651	69,761	70,738	70,784	70,820	71,216	73,799
2021	118,079	69,776	69,535	69,583	69,807	70,858	70,914	70,816	71,611	73,699
2022	118,079	69,704	68,885	68,965	69,053	70,444	70,188	70,432	71,952	74,377
2023	118,079	72,524	71,694	71,727	71,804	73,435	72,872	72,974	74,950	77,610
2024	118,079	72,565	71,766	71,808	71,871	73,428	72,831	73,096	75,384	77,436
2025	118,079	77,313	76,916	76,953	76,989	78,405	78,163	78,283	80,705	81,912
2026	118,079	83,130	82,581	81,837	81,836	84,258	83,788	83,561	85,794	87,650
2027	118,079	84,522	83,999	83,333	83,333	85,564	85,077	84,507	88,052	87,878
2028	118,079	86,248	85,850	85,345	85,344	86,997	86,553	86,365	91,380	89,258
2029	118,079	86,167	85,769	85,280	85,279	86,894	86,548	86,206	92,095	88,912
2030	118,079	87,338	86,909	86,398	86,397	87,936	87,498	87,153	93,427	89,395
2031	118,079	87,987	87,732	87,214	87,219	88,456	88,218	87,800	94,715	89,170
2032	118,079	87,987	87,743	87,344	87,344	88,418	88,118	87,954	95,655	88,797
2033	118,079	87,684	87,450	86,989	87,005	88,121	87,892	87,475	95,190	88,287
2034	118,079	88,185	88,102	87,655	87,660	88,545	88,350	88,000	96,402	88,705
2035	118,079	87,848	87,809	87,286	87,286	88,249	88,076	87,511	94,749	88,383
2036	118,079	87,698	87,638	87,231	87,230	88,065	87,884	87,401	95,008	88,207
2037	118,079	88,026	88,013	87,551	87,558	88,252	88,178	87,736	96,017	88,383
2038	118,079	86,418	86,440	86,028	86,020	86,684	86,583	86,164	94,220	86,832
2039	118,079	86,357	86,374	86,007	86,001	86,575	86,455	86,184	94,118	86,740
2040	118,079	86,258	86,284	85,919	85,927	86,481	86,393	86,147	95,174	86,602
2041	118,079	86,418	86,428	86,080	86,090	86,632	86,540	86,292	96,215	86,734
2042	118,079	86,414	86,440	86,069	86,086	86,632	86,531	86,291	95,528	86,733
2043	118,079	85,829	85,895	85,466	85,468	86,088	86,008	85,645	93,659	86,261
2044	118,079	85,695	85,790	85,369	85,369	85,936	85,908	85,598	92,813	86,141

FPL 000293

SO2 Ton ***Annual System Emissions Excess / (Shortfall)***

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	Without Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007		(96,952)	(96,952)	(96,952)	(96,952)	(104,967)	(104,957)	(104,998)	(104,998)	(94,457)
2008		(102,583)	(102,672)	(102,677)	(102,677)	(109,022)	(109,019)	(109,022)	(109,022)	(99,252)
2009	123,191	21,975	21,974	21,940	21,940	18,899	18,857	18,762	18,762	25,018
2010	118,079	42,470	42,657	42,404	42,334	39,851	39,762	39,905	39,776	43,239
2011	118,079	61,742	61,994	61,640	61,585	61,658	61,601	61,896	62,284	61,953
2012	118,079	59,780	60,243	60,060	59,936	59,491	59,412	59,810	60,075	60,451
2013	118,079	56,052	56,181	56,176	56,082	55,541	55,566	55,937	56,108	56,999
2014	118,079	61,660	61,740	61,740	61,703	61,529	61,545	61,901	62,009	62,030
2015	118,079	59,336	59,325	59,331	59,326	59,246	59,399	59,633	59,722	61,806
2016	118,079	71,372	71,397	71,374	71,387	72,571	72,624	72,570	72,638	74,957
2017	118,079	71,104	71,102	71,048	71,043	72,383	72,356	72,364	72,579	75,525
2018	118,079	69,318	69,348	69,302	69,284	70,457	70,309	70,350	70,882	74,420
2019	118,079	65,913	65,948	65,934	65,906	67,224	67,243	67,246	67,528	70,709
2020	118,079	69,959	69,868	69,822	69,936	70,921	70,953	70,987	71,386	73,994
2021	118,079	69,934	69,663	69,630	69,959	71,009	70,923	70,978	71,796	73,891
2022	118,079	69,824	68,986	69,111	69,158	70,556	70,306	70,561	72,118	74,578
2023	118,079	72,635	71,788	71,778	71,857	73,535	72,992	73,085	75,104	77,758
2024	118,079	72,610	71,826	71,870	71,941	73,536	72,935	73,191	75,519	77,572
2025	118,079	77,384	76,965	77,019	77,046	78,485	78,243	78,375	80,763	82,176
2026	118,079	83,184	82,662	81,886	81,885	84,309	83,854	83,650	85,723	87,683
2027	118,079	84,564	84,044	83,398	83,397	85,588	85,143	84,515	87,875	87,973
2028	118,079	86,279	85,827	85,320	85,318	87,000	86,562	86,342	91,206	89,308
2029	118,079	86,186	85,779	85,259	85,258	86,906	86,530	86,245	91,846	88,919
2030	118,079	87,314	86,906	86,421	86,421	87,917	87,512	87,166	93,256	89,455
2031	118,079	87,933	87,693	87,195	87,195	88,418	88,194	87,776	94,419	89,110
2032	118,079	88,107	87,837	87,449	87,450	88,491	88,229	87,914	95,621	88,928
2033	118,079	87,232	86,943	86,490	86,491	87,760	87,436	86,993	93,895	87,984
2034	118,079	87,802	87,698	87,277	87,278	88,250	88,032	87,805	95,092	88,419
2035	118,079	88,015	87,920	87,484	87,479	88,353	88,233	87,714	94,998	88,488
2036	118,079	87,533	87,449	87,047	87,044	87,907	87,768	87,347	94,609	88,074
2037	118,079	87,862	87,814	87,365	87,359	88,102	88,010	87,566	95,247	88,235
2038	118,079	86,577	86,600	86,230	86,231	86,800	86,726	86,384	94,556	86,944
2039	118,079	86,509	86,526	86,259	86,260	86,758	86,653	86,381	94,946	86,869
2040	118,079	86,439	86,416	86,161	86,163	86,637	86,573	86,335	95,853	86,706
2041	118,079	86,506	86,565	86,352	86,357	86,758	86,755	86,552	96,691	86,813
2042	118,079	86,572	86,577	86,335	86,339	86,756	86,737	86,504	96,089	86,811
2043	118,079	86,088	86,169	85,866	85,873	86,328	86,347	86,093	94,838	86,480
2044	118,079	85,974	86,046	85,687	85,713	86,180	86,174	85,996	93,714	86,363

FPL 000294

NOx Ton ***Total Annual System Emissions***

Expansion Plan	With Nuclear Uprates								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	50,937	50,959	50,959	50,959	51,059	51,095	51,110	51,110	50,766
2008	48,774	48,854	48,850	48,850	48,728	48,763	48,765	48,765	48,640
2009	36,199	36,510	36,751	36,751	34,109	34,353	34,603	34,603	33,442
2010	30,120	29,696	30,418	30,485	28,539	28,205	28,686	28,848	28,121
2011	23,297	22,825	23,289	23,333	22,304	22,091	22,143	22,207	22,112
2012	21,837	21,427	21,639	21,745	21,119	21,102	21,067	21,025	21,018
2013	20,813	20,502	20,637	20,694	20,271	20,282	20,251	20,224	20,158
2014	23,166	22,883	22,997	23,043	22,705	22,696	22,671	22,629	22,278
2015	21,935	21,792	21,893	21,918	21,451	21,441	21,430	21,435	20,950
2016	22,225	22,097	22,090	22,122	21,838	21,780	21,846	21,800	21,278
2017	20,221	20,179	20,168	20,161	19,898	19,811	19,856	19,864	19,453
2018	17,923	17,907	17,943	17,834	17,663	17,626	17,646	17,618	17,360
2019	18,546	18,535	18,539	18,514	18,334	18,268	18,283	18,306	18,076
2020	17,186	17,205	17,209	17,198	17,084	16,982	17,004	16,997	16,830
2021	17,707	18,000	17,858	17,777	17,522	17,493	17,513	17,413	17,313
2022	17,128	18,397	17,905	17,906	17,061	17,811	17,152	17,140	16,772
2023	16,296	18,524	17,682	17,858	16,287	17,428	17,036	16,917	16,114
2024	16,584	18,267	18,065	17,968	16,292	17,722	17,196	17,074	16,084
2025	15,530	16,886	16,733	16,679	15,073	16,424	16,302	16,179	14,861
2026	14,680	15,860	16,579	16,580	14,273	15,408	16,029	15,980	14,035
2027	14,011	14,961	15,604	15,604	13,718	14,552	15,291	15,157	13,561
2028	12,789	13,564	14,043	14,042	12,565	13,258	13,913	13,530	12,409
2029	13,213	14,034	14,589	14,587	12,983	13,737	14,485	13,997	12,794
2030	12,538	13,145	13,658	13,654	12,378	12,887	13,594	13,112	12,234
2031	11,837	12,377	12,792	12,770	11,729	12,155	12,710	12,213	11,641
2032	11,554	11,916	12,329	12,323	11,472	11,798	12,249	11,716	11,435
2033	12,338	12,756	13,211	13,201	12,291	12,601	13,145	12,615	12,220
2034	11,710	12,026	12,369	12,354	11,655	11,949	12,288	11,712	11,618
2035	12,177	12,571	12,982	12,954	12,086	12,489	12,898	12,343	12,043
2036	12,409	12,705	13,074	13,048	12,368	12,657	13,017	12,439	12,309
2037	12,080	12,350	12,652	12,628	12,050	12,309	12,604	11,958	12,023
2038	12,265	12,529	12,862	12,830	12,216	12,511	12,789	12,156	12,179
2039	12,333	12,569	12,850	12,820	12,294	12,588	12,764	12,149	12,266
2040	12,345	12,563	12,890	12,867	12,357	12,600	12,774	12,105	12,312
2041	12,111	12,329	12,652	12,638	12,115	12,377	12,528	11,806	12,080
2042	12,114	12,317	12,650	12,632	12,116	12,380	12,518	11,838	12,082
2043	13,042	13,298	13,694	13,679	13,007	13,361	13,506	12,921	12,940
2044	13,151	13,396	13,775	13,768	13,112	13,454	13,569	13,061	13,037

FPL 000295

NOx Ton ***Total Annual System Emissions***

Expansion Plan	Without Nuclear Uprates								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	50,937	50,959	50,959	50,959	51,059	51,095	51,110	51,110	50,766
2008	48,774	48,854	48,850	48,850	48,728	48,763	48,765	48,765	48,640
2009	36,199	36,510	36,751	30,751	34,109	34,353	34,603	34,603	33,442
2010	28,928	28,545	29,205	29,272	27,445	27,129	27,590	27,734	27,048
2011	22,679	22,207	22,643	22,687	21,677	21,488	21,529	21,592	21,503
2012	22,376	21,910	22,143	22,265	21,586	21,563	21,555	21,514	21,524
2013	22,892	22,507	22,676	22,758	22,220	22,232	22,227	22,179	22,054
2014	21,068	20,842	20,932	20,975	20,637	20,638	20,602	20,591	20,433
2015	21,892	21,753	21,848	21,870	21,372	21,356	21,350	21,351	20,862
2016	20,314	20,198	20,188	20,234	20,016	19,964	20,021	19,977	19,485
2017	19,078	19,038	19,023	19,015	18,773	18,701	18,740	18,745	18,353
2018	18,005	17,984	18,014	17,919	17,742	17,714	17,735	17,708	17,443
2019	18,593	18,581	18,586	18,571	18,416	18,347	18,364	18,381	18,127
2020	17,326	17,338	17,341	17,336	17,209	17,104	17,122	17,111	16,946
2021	17,773	18,069	17,929	17,849	17,623	17,624	17,596	17,500	17,426
2022	17,187	18,482	17,968	17,973	17,112	17,878	17,215	17,204	16,824
2023	16,387	18,619	17,778	17,961	16,377	17,537	17,149	17,027	16,208
2024	16,670	18,334	18,142	18,053	16,390	17,805	17,280	17,155	16,158
2025	15,615	16,974	16,838	16,777	15,171	16,521	16,384	16,263	14,944
2026	14,747	15,936	16,684	16,684	14,353	15,483	16,096	16,057	14,128
2027	14,067	15,014	15,676	15,675	13,774	14,619	15,355	15,263	13,614
2028	12,848	13,643	14,135	14,135	12,628	13,324	13,994	13,633	12,475
2029	13,281	14,107	14,673	14,667	13,042	13,801	14,555	14,085	12,845
2030	12,604	13,215	13,712	13,708	12,439	12,949	13,651	13,173	12,262
2031	11,920	12,438	12,842	12,830	11,793	12,212	12,763	12,277	11,710
2032	11,503	11,860	12,265	12,259	11,447	11,732	12,195	11,659	11,400
2033	12,755	13,239	13,728	13,719	12,668	13,071	13,642	13,144	12,578
2034	12,166	12,580	12,959	12,958	12,088	12,458	12,873	12,342	12,035
2035	12,024	12,381	12,702	12,686	11,941	12,281	12,638	12,117	11,890
2036	12,559	12,901	13,264	13,239	12,501	12,809	13,201	12,637	12,437
2037	12,332	12,607	12,964	12,946	12,290	12,563	12,914	12,302	12,253
2038	11,999	12,212	12,499	12,482	11,967	12,221	12,427	11,814	11,941
2039	12,005	12,226	12,493	12,472	12,002	12,243	12,413	11,778	11,987
2040	12,064	12,247	12,543	12,519	12,063	12,295	12,424	11,733	12,038
2041	11,838	12,018	12,314	12,303	11,841	12,091	12,184	11,463	11,822
2042	11,838	12,013	12,319	12,308	11,844	12,097	12,182	11,487	11,825
2043	12,573	12,794	13,163	13,148	12,556	12,858	12,982	12,358	12,500
2044	12,668	12,881	13,252	13,221	12,645	12,950	13,038	12,507	12,586

FPL 000296

NOx Ton ***Annual System Emissions Excess / (Shortfall)***

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	With Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007		(50,937)	(50,958)	(50,959)	(50,959)	(51,059)	(51,095)	(51,110)	(51,110)	(50,766)
2008		(48,774)	(48,854)	(48,850)	(48,850)	(48,728)	(48,763)	(48,765)	(48,765)	(48,640)
2009	27,452	(8,747)	(9,057)	(9,299)	(9,299)	(6,656)	(6,901)	(7,150)	(7,150)	(6,989)
2010	27,650	(2,470)	(2,045)	(2,768)	(2,834)	(889)	(554)	(1,035)	(1,197)	(470)
2011	27,676	4,379	4,851	4,387	4,343	5,372	5,585	5,533	5,469	5,564
2012	27,403	5,566	5,976	5,704	5,658	6,284	6,301	6,336	6,378	6,385
2013	29,999	9,186	9,497	9,362	9,305	9,728	9,717	9,748	9,775	9,841
2014	30,051	6,885	7,168	7,054	7,008	7,346	7,355	7,380	7,422	7,773
2015	25,704	3,769	3,913	3,812	3,786	4,253	4,263	4,274	4,269	4,754
2016	25,984	3,759	3,887	3,894	3,882	4,146	4,204	4,138	4,184	4,706
2017	25,930	5,709	5,751	5,762	5,769	6,032	6,119	6,074	6,066	6,477
2018	25,879	7,956	7,973	7,937	8,045	8,216	8,253	8,234	8,261	8,519
2019	26,607	8,061	8,072	8,068	8,093	8,274	8,339	8,324	8,301	8,531
2020	26,525	9,339	9,321	9,316	9,327	9,441	9,543	9,521	9,529	9,695
2021	26,454	8,747	8,454	8,596	8,677	8,932	8,961	8,941	9,041	9,141
2022	26,107	8,980	7,711	8,203	8,202	9,047	8,297	8,955	8,968	9,335
2023	26,107	9,811	7,584	8,425	8,250	9,821	8,679	9,071	9,190	9,994
2024	26,107	9,524	7,841	8,043	8,140	9,816	8,386	8,911	9,033	10,023
2025	26,107	10,578	9,222	9,374	9,428	11,034	9,684	9,806	9,928	11,246
2026	26,107	11,427	10,247	9,528	9,528	11,834	10,700	10,079	10,127	12,072
2027	26,107	12,096	11,146	10,503	10,504	12,390	11,555	10,816	10,950	12,547
2028	26,107	13,318	12,544	12,064	12,065	13,542	12,850	12,195	12,578	13,698
2029	26,107	12,894	12,074	11,519	11,520	13,124	12,370	11,622	12,111	13,314
2030	26,107	13,569	12,963	12,450	12,453	13,729	13,221	12,513	12,996	13,873
2031	26,107	14,270	13,730	13,315	13,329	14,379	13,953	13,398	13,895	14,466
2032	26,107	14,553	14,192	13,779	13,785	14,635	14,310	13,859	14,392	14,673
2033	26,107	13,769	13,351	12,896	12,900	13,816	13,507	12,963	13,492	13,888
2034	26,107	14,397	14,081	13,738	13,753	14,453	14,159	13,820	14,396	14,489
2035	26,107	13,930	13,537	13,126	13,153	14,022	13,618	13,209	13,765	14,064
2036	26,107	13,698	13,403	13,033	13,060	13,739	13,450	13,090	13,869	13,798
2037	26,107	14,027	13,757	13,456	13,479	14,057	13,799	13,504	14,150	14,085
2038	26,107	13,843	13,578	13,245	13,277	13,891	13,597	13,319	13,952	13,928
2039	26,107	13,774	13,538	13,257	13,288	13,813	13,519	13,343	13,959	13,841
2040	26,107	13,762	13,545	13,218	13,241	13,750	13,508	13,334	14,003	13,796
2041	26,107	13,997	13,776	13,456	13,472	13,993	13,731	13,580	14,302	14,027
2042	26,107	13,993	13,790	13,457	13,476	13,991	13,728	13,589	14,270	14,026
2043	26,107	13,065	12,810	12,413	12,429	13,100	12,746	12,601	13,187	13,167
2044	26,107	12,956	12,712	12,332	12,340	12,996	12,653	12,539	13,046	13,070

FPL 000297

NOx Ton ***Annual System Emissions Excess / (Shortfall)***

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	Without Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007		(50,937)	(50,959)	(50,959)	(50,959)	(51,059)	(51,085)	(51,110)	(51,110)	(50,766)
2008		(48,774)	(48,854)	(48,850)	(48,850)	(48,728)	(48,763)	(48,765)	(48,765)	(48,640)
2009	27,452	(8,747)	(9,057)	(9,299)	(9,299)	(6,656)	(6,901)	(7,150)	(7,150)	(5,989)
2010	27,650	(1,277)	(694)	(1,595)	(1,621)	205	522	60	(84)	602
2011	27,676	4,997	5,469	5,033	4,989	5,999	6,188	6,147	6,084	6,173
2012	27,403	5,027	5,493	5,260	5,138	5,817	5,840	5,846	5,889	5,879
2013	29,999	7,107	7,492	7,323	7,241	7,779	7,767	7,772	7,820	7,945
2014	30,051	8,983	9,209	9,119	9,076	9,414	9,413	9,449	9,460	9,618
2015	25,704	3,813	3,952	3,856	3,834	4,332	4,349	4,354	4,354	4,843
2016	25,984	5,670	5,786	5,796	5,750	5,968	6,020	5,963	6,007	6,499
2017	25,930	6,852	6,892	6,907	6,915	7,157	7,229	7,190	7,185	7,577
2018	25,879	7,875	7,896	7,866	7,961	8,138	8,166	8,145	8,172	8,436
2019	26,607	8,015	8,026	8,022	8,036	8,192	8,260	8,243	8,226	8,481
2020	26,525	9,200	9,188	9,185	9,190	9,317	9,422	9,404	9,415	9,579
2021	26,454	8,681	8,385	8,525	8,605	8,831	8,830	8,858	8,954	9,028
2022	26,107	8,920	7,625	8,139	8,135	8,996	8,230	8,892	8,903	9,284
2023	26,107	9,720	7,488	8,330	8,146	9,731	8,570	8,958	9,080	9,899
2024	26,107	9,437	7,774	7,965	8,055	9,717	8,302	8,827	8,952	9,949
2025	26,107	10,492	9,133	9,270	9,331	10,937	9,587	9,723	9,845	11,164
2026	26,107	11,361	10,171	9,424	9,423	11,755	10,625	10,012	10,051	11,980
2027	26,107	12,041	11,093	10,432	10,432	12,333	11,489	10,753	10,844	12,494
2028	26,107	13,260	12,464	11,972	11,973	13,479	12,783	12,113	12,475	13,632
2029	26,107	12,826	12,000	11,435	11,440	13,066	12,306	11,552	12,023	13,262
2030	26,107	13,504	12,893	12,396	12,399	13,668	13,158	12,457	12,935	13,826
2031	26,107	14,187	13,670	13,265	13,278	14,314	13,895	13,345	13,831	14,397
2032	26,107	14,605	14,247	13,843	13,849	14,660	14,375	13,913	14,448	14,707
2033	26,107	13,352	12,869	12,380	12,389	13,440	13,037	12,466	12,983	13,529
2034	26,107	13,942	13,527	13,148	13,149	14,020	13,649	13,235	13,766	14,073
2035	26,107	14,084	13,726	13,406	13,421	14,167	13,827	13,469	13,991	14,218
2036	26,107	13,548	13,206	12,843	12,869	13,607	13,299	12,907	13,470	13,671
2037	26,107	13,776	13,500	13,144	13,162	13,817	13,544	13,194	13,805	13,854
2038	26,107	14,108	13,896	13,609	13,625	14,140	13,887	13,680	14,294	14,167
2039	26,107	14,103	13,881	13,614	13,636	14,105	13,864	13,695	14,330	14,121
2040	26,107	14,044	13,861	13,565	13,588	14,044	13,813	13,684	14,375	14,069
2041	26,107	14,269	14,090	13,793	13,804	14,267	14,016	13,923	14,645	14,286
2042	26,107	14,269	14,095	13,788	13,799	14,263	14,010	13,925	14,621	14,282
2043	26,107	13,535	13,314	12,945	12,959	13,551	13,249	13,126	13,751	13,608
2044	26,107	13,440	13,227	12,855	12,886	13,462	13,157	13,070	13,601	13,522

Hearing Exhibit 000266

FPL 000298

CO2 Ton ***Total Annual System Emissions***

Expansion Plan	With Nuclear Uprates								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	57,334,000	57,334,000	57,334,000	57,334,000	57,489,000	57,481,000	57,484,000	57,484,000	56,849,000
2008	58,121,000	58,118,000	58,118,000	58,118,000	58,188,000	58,184,000	58,184,000	58,184,000	57,784,000
2009	59,356,000	59,339,000	59,331,000	59,331,000	59,331,000	59,328,000	59,326,000	59,326,000	59,028,000
2010	58,203,000	58,219,000	58,189,000	58,190,000	58,102,000	58,122,000	58,091,000	58,091,000	57,888,000
2011	56,128,000	56,139,000	56,130,000	56,131,000	55,788,000	55,807,000	55,782,000	55,750,000	55,711,000
2012	56,718,000	56,725,000	56,718,000	56,719,000	56,374,000	56,385,000	56,348,000	56,309,000	56,037,000
2013	57,263,000	57,270,000	57,269,000	57,264,000	56,901,000	56,900,000	56,875,000	56,857,000	56,656,000
2014	59,186,000	59,192,000	59,190,000	59,188,000	58,822,000	58,822,000	58,781,000	58,767,000	58,668,000
2015	60,129,000	60,130,000	60,129,000	60,129,000	59,719,000	59,710,000	59,692,000	59,671,000	59,296,000
2016	59,580,000	59,582,000	59,582,000	59,582,000	59,096,000	59,098,000	59,097,000	59,086,000	58,691,000
2017	60,316,000	60,316,000	60,317,000	60,317,000	59,824,000	59,827,000	59,825,000	59,782,000	59,329,000
2018	59,576,000	59,581,000	59,581,000	59,576,000	59,094,000	59,095,000	59,087,000	59,010,000	58,387,000
2019	60,118,000	60,112,000	60,112,000	60,112,000	59,616,000	59,597,000	59,592,000	59,538,000	58,987,000
2020	58,825,000	58,831,000	58,832,000	58,825,000	58,359,000	58,344,000	58,334,000	58,252,000	57,784,000
2021	59,250,000	59,253,000	59,256,000	59,231,000	58,744,000	58,706,000	58,728,000	58,585,000	58,256,000
2022	60,903,000	60,888,000	60,892,000	60,894,000	60,436,000	60,402,000	60,419,000	60,070,000	59,712,000
2023	62,072,000	62,027,000	62,045,000	62,042,000	61,560,000	61,553,000	61,548,000	61,131,000	60,803,000
2024	64,243,000	64,216,000	64,223,000	64,225,000	63,739,000	63,709,000	63,089,000	63,203,000	63,042,000
2025	64,365,000	64,332,000	64,345,000	64,346,000	63,843,000	63,777,000	63,762,000	63,262,000	63,206,000
2026	64,310,000	64,305,000	64,295,000	64,296,000	63,759,000	63,723,000	63,713,000	63,273,000	63,222,000
2027	66,686,000	66,698,000	66,688,000	66,688,000	66,129,000	66,093,000	66,090,000	65,461,000	65,767,000
2028	68,134,000	68,149,000	68,134,000	68,136,000	67,569,000	67,569,000	67,472,000	66,657,000	67,218,000
2029	69,670,000	69,691,000	69,689,000	69,692,000	69,082,000	69,089,000	69,007,000	68,067,000	68,787,000
2030	71,721,000	71,749,000	71,745,000	71,751,000	71,113,000	71,149,000	71,062,000	70,066,000	70,915,000
2031	73,380,000	73,417,000	73,416,000	73,421,000	72,760,000	72,800,000	72,737,000	71,640,000	72,679,000
2032	76,394,000	76,419,000	76,440,000	76,444,000	75,750,000	75,806,000	75,728,000	74,495,000	75,721,000
2033	81,760,000	81,793,000	81,823,000	81,827,000	81,064,000	81,128,000	81,080,000	79,846,000	81,078,000
2034	84,177,000	84,208,000	84,242,000	84,248,000	83,458,000	83,539,000	83,488,000	82,148,000	83,468,000
2035	86,451,000	86,485,000	86,531,000	86,535,000	85,703,000	85,796,000	85,774,000	84,626,000	85,714,000
2036	91,401,000	91,438,000	91,489,000	91,495,000	90,611,000	90,714,000	90,692,000	89,482,000	90,626,000
2037	93,659,000	93,722,000	93,786,000	93,791,000	92,851,000	92,988,000	92,964,000	91,649,000	92,859,000
2038	95,514,000	95,579,000	95,665,000	95,670,000	94,690,000	94,849,000	94,837,000	93,556,000	94,703,000
2039	97,670,000	97,737,000	97,834,000	97,839,000	96,827,000	97,002,000	96,980,000	95,723,000	96,838,000
2040	100,079,000	100,167,000	100,274,000	100,277,000	99,213,000	99,415,000	99,387,000	97,955,000	99,221,000
2041	99,799,000	99,904,000	100,031,000	100,033,000	98,933,000	99,170,000	99,151,000	97,569,000	98,942,000
2042	99,829,000	99,930,000	100,063,000	100,065,000	98,963,000	99,202,000	99,183,000	97,708,000	98,971,000
2043	101,857,000	101,943,000	102,065,000	102,065,000	100,972,000	101,180,000	101,173,000	99,699,000	100,985,000
2044	102,808,000	102,886,000	102,997,000	102,996,000	101,915,000	102,105,000	102,096,000	100,941,000	101,925,000

Hearing Exhibit 000267

FPL 000299

CO2 Ton ***Total Annual System Emissions***

Expansion Plan	Without Nuclear Uprates								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	57,334,000	57,334,000	57,334,000	57,334,000	57,489,000	57,481,000	57,484,000	57,484,000	56,849,000
2008	58,121,000	58,118,000	58,118,000	58,118,000	58,188,000	58,184,000	58,184,000	58,184,000	57,784,000
2009	59,356,000	59,339,000	59,331,000	59,331,000	59,331,000	59,328,000	59,326,000	59,326,000	59,028,000
2010	57,410,000	57,427,000	57,396,000	57,395,000	57,314,000	57,330,000	57,297,000	57,295,000	57,100,000
2011	55,565,000	55,573,000	55,564,000	55,565,000	55,214,000	55,229,000	55,208,000	55,179,000	55,127,000
2012	57,236,000	57,239,000	57,231,000	57,232,000	56,885,000	56,892,000	56,856,000	56,825,000	56,558,000
2013	59,036,000	59,045,000	59,039,000	59,038,000	58,678,000	58,678,000	58,649,000	58,632,000	58,474,000
2014	59,772,000	59,778,000	59,776,000	59,776,000	59,363,000	59,363,000	59,331,000	59,317,000	59,202,000
2015	61,430,000	61,433,000	61,431,000	61,431,000	61,009,000	60,999,000	60,979,000	60,962,000	60,564,000
2016	60,246,000	60,247,000	60,248,000	60,245,000	59,758,000	59,758,000	59,759,000	59,745,000	59,325,000
2017	61,288,000	61,289,000	61,291,000	61,291,000	60,788,000	60,791,000	60,789,000	60,740,000	60,197,000
2018	60,825,000	60,830,000	60,829,000	60,826,000	60,331,000	60,336,000	60,326,000	60,236,000	59,607,000
2019	61,368,000	61,362,000	61,361,000	61,364,000	60,853,000	60,841,000	60,835,000	60,776,000	60,206,000
2020	60,100,000	60,107,000	60,107,000	60,099,000	59,619,000	59,602,000	59,594,000	59,510,000	59,047,000
2021	60,492,000	60,500,000	60,505,000	60,473,000	59,979,000	59,965,000	59,961,000	59,813,000	59,483,000
2022	62,152,000	62,142,000	62,142,000	62,145,000	61,670,000	61,642,000	61,652,000	61,301,000	60,936,000
2023	63,344,000	63,302,000	63,323,000	63,319,000	62,823,000	62,814,000	62,808,000	62,384,000	62,061,000
2024	65,501,000	65,471,000	65,477,000	65,479,000	64,981,000	64,952,000	64,929,000	64,439,000	64,278,000
2025	65,621,000	65,587,000	65,599,000	65,601,000	65,087,000	65,016,000	64,999,000	64,503,000	64,418,000
2026	65,585,000	65,580,000	65,568,000	65,569,000	65,022,000	64,988,000	64,975,000	64,559,000	64,490,000
2027	67,937,000	67,944,000	67,938,000	67,938,000	67,370,000	67,327,000	67,329,000	66,737,000	66,998,000
2028	69,392,000	69,410,000	69,393,000	69,395,000	68,813,000	68,813,000	68,719,000	67,924,000	68,458,000
2029	70,946,000	70,967,000	70,965,000	70,967,000	70,345,000	70,358,000	70,261,000	69,367,000	70,045,000
2030	72,979,000	73,005,000	72,995,000	73,000,000	72,356,000	72,388,000	72,301,000	71,333,000	72,144,000
2031	74,640,000	74,673,000	74,664,000	74,669,000	74,006,000	74,039,000	73,975,000	72,920,000	73,930,000
2032	77,486,000	77,515,000	77,537,000	77,541,000	76,836,000	76,891,000	76,833,000	75,599,000	76,797,000
2033	82,526,000	82,562,000	82,588,000	82,593,000	81,817,000	81,883,000	81,836,000	80,734,000	81,822,000
2034	84,846,000	84,876,000	84,900,000	84,907,000	84,119,000	84,188,000	84,114,000	82,953,000	84,126,000
2035	86,976,000	87,009,000	87,045,000	87,051,000	86,226,000	86,307,000	86,279,000	85,120,000	86,236,000
2036	91,740,000	91,778,000	91,823,000	91,828,000	90,949,000	91,037,000	91,008,000	89,853,000	90,962,000
2037	93,937,000	93,991,000	94,049,000	94,054,000	93,125,000	93,252,000	93,219,000	92,000,000	93,136,000
2038	95,691,000	95,756,000	95,846,000	95,851,000	94,867,000	95,032,000	95,011,000	93,717,000	94,875,000
2039	97,855,000	97,932,000	98,038,000	98,042,000	97,007,000	97,200,000	97,186,000	95,824,000	97,023,000
2040	100,251,000	100,344,000	100,459,000	100,462,000	99,382,000	99,603,000	99,574,000	98,059,000	99,394,000
2041	99,973,000	100,078,000	100,213,000	100,214,000	99,108,000	99,355,000	99,326,000	97,706,000	99,118,000
2042	100,024,000	100,131,000	100,268,000	100,268,000	99,158,000	99,410,000	99,387,000	97,855,000	99,168,000
2043	101,796,000	101,885,000	102,008,000	102,009,000	100,911,000	101,127,000	101,110,000	99,714,000	100,919,000
2044	102,669,000	102,758,000	102,881,000	102,881,000	101,778,000	101,992,000	101,968,000	100,729,000	101,783,000

FPL 000300

CO2 Ton ***Annual System Emissions Excess / (Shortfall)***

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	With Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	-	(57,334,000)	(57,334,000)	(57,334,000)	(57,334,000)	(57,489,000)	(57,481,000)	(57,484,000)	(57,484,000)	(56,849,000)
2008	-	(58,121,000)	(58,118,000)	(58,118,000)	(58,118,000)	(58,188,000)	(58,184,000)	(58,184,000)	(58,184,000)	(57,784,000)
2009	-	(59,356,000)	(59,339,000)	(59,331,000)	(59,331,000)	(59,331,000)	(59,328,000)	(59,326,000)	(59,326,000)	(59,029,000)
2010	-	(58,203,000)	(58,219,000)	(58,189,000)	(58,190,000)	(58,102,000)	(58,122,000)	(58,091,000)	(58,091,000)	(57,988,000)
2011	-	(56,128,000)	(56,139,000)	(56,130,000)	(56,131,000)	(55,788,000)	(55,807,000)	(55,782,000)	(55,750,000)	(55,711,000)
2012	-	(56,718,000)	(56,725,000)	(56,718,000)	(56,719,000)	(56,374,000)	(56,385,000)	(56,348,000)	(56,309,000)	(56,037,000)
2013	-	(57,263,000)	(57,270,000)	(57,269,000)	(57,264,000)	(56,901,000)	(56,900,000)	(56,875,000)	(56,857,000)	(56,658,000)
2014	-	(59,186,000)	(59,192,000)	(59,190,000)	(59,188,000)	(58,822,000)	(58,822,000)	(58,781,000)	(58,767,000)	(58,668,000)
2015	-	(60,129,000)	(60,130,000)	(60,129,000)	(60,129,000)	(59,719,000)	(59,710,000)	(59,692,000)	(59,671,000)	(59,296,000)
2016	-	(59,580,000)	(59,582,000)	(59,582,000)	(59,582,000)	(59,096,000)	(59,098,000)	(59,097,000)	(59,086,000)	(58,691,000)
2017	-	(60,316,000)	(60,316,000)	(60,317,000)	(60,317,000)	(59,824,000)	(59,827,000)	(59,825,000)	(59,782,000)	(59,329,000)
2018	-	(59,576,000)	(59,581,000)	(59,581,000)	(59,576,000)	(59,094,000)	(59,095,000)	(59,037,000)	(59,010,000)	(58,387,000)
2019	-	(60,118,000)	(60,112,000)	(60,112,000)	(60,112,000)	(59,616,000)	(59,597,000)	(59,592,000)	(59,538,000)	(58,987,000)
2020	-	(58,825,000)	(58,831,000)	(58,832,000)	(58,825,000)	(58,359,000)	(58,344,000)	(58,334,000)	(58,252,000)	(57,784,000)
2021	-	(59,250,000)	(59,253,000)	(59,256,000)	(59,231,000)	(58,744,000)	(58,706,000)	(58,728,000)	(58,585,000)	(58,256,000)
2022	-	(60,903,000)	(60,888,000)	(60,892,000)	(60,894,000)	(60,436,000)	(60,402,000)	(60,419,000)	(60,070,000)	(59,712,000)
2023	-	(62,072,000)	(62,027,000)	(62,045,000)	(62,042,000)	(61,560,000)	(61,553,000)	(61,548,000)	(61,131,000)	(60,803,000)
2024	-	(64,243,000)	(64,216,000)	(64,223,000)	(64,225,000)	(63,739,000)	(63,709,000)	(63,689,000)	(63,203,000)	(63,042,000)
2025	-	(64,365,000)	(64,332,000)	(64,345,000)	(64,348,000)	(63,843,000)	(63,777,000)	(63,762,000)	(63,262,000)	(63,206,000)
2026	-	(64,310,000)	(64,305,000)	(64,295,000)	(64,296,000)	(63,759,000)	(63,723,000)	(63,713,000)	(63,273,000)	(63,222,000)
2027	-	(66,686,000)	(66,698,000)	(66,688,000)	(66,688,000)	(66,129,000)	(66,093,000)	(66,080,000)	(65,461,000)	(65,767,000)
2028	-	(68,134,000)	(68,149,000)	(68,134,000)	(68,136,000)	(67,569,000)	(67,569,000)	(67,472,000)	(66,657,000)	(67,218,000)
2029	-	(69,670,000)	(69,691,000)	(69,689,000)	(69,692,000)	(69,082,000)	(69,089,000)	(69,007,000)	(68,067,000)	(68,787,000)
2030	-	(71,721,000)	(71,749,000)	(71,745,000)	(71,751,000)	(71,113,000)	(71,149,000)	(71,062,000)	(70,066,000)	(70,915,000)
2031	-	(73,380,000)	(73,417,000)	(73,416,000)	(73,421,000)	(72,760,000)	(72,800,000)	(72,737,000)	(71,640,000)	(72,679,000)
2032	-	(76,394,000)	(76,419,000)	(76,440,000)	(76,444,000)	(75,750,000)	(75,806,000)	(75,720,000)	(74,495,000)	(75,721,000)
2033	-	(81,760,000)	(81,793,000)	(81,823,000)	(81,827,000)	(81,064,000)	(81,128,000)	(81,080,000)	(79,846,000)	(81,078,000)
2034	-	(84,177,000)	(84,208,000)	(84,242,000)	(84,248,000)	(83,456,000)	(83,539,000)	(83,488,000)	(82,148,000)	(83,468,000)
2035	-	(86,451,000)	(86,485,000)	(86,531,000)	(86,535,000)	(85,703,000)	(85,796,000)	(85,774,000)	(84,626,000)	(85,714,000)
2036	-	(91,401,000)	(91,438,000)	(91,489,000)	(91,495,000)	(90,611,000)	(90,714,000)	(90,692,000)	(89,482,000)	(90,626,000)
2037	-	(93,650,000)	(93,722,000)	(93,786,000)	(93,791,000)	(92,851,000)	(92,988,000)	(92,964,000)	(91,649,000)	(92,859,000)
2038	-	(95,514,000)	(95,579,000)	(95,665,000)	(95,670,000)	(94,690,000)	(94,849,000)	(94,837,000)	(93,556,000)	(94,703,000)
2039	-	(97,670,000)	(97,737,000)	(97,834,000)	(97,839,000)	(96,827,000)	(97,002,000)	(96,980,000)	(95,723,000)	(96,838,000)
2040	-	(100,079,000)	(100,167,000)	(100,274,000)	(100,277,000)	(99,213,000)	(99,415,000)	(99,387,000)	(97,955,000)	(99,221,000)
2041	-	(99,799,000)	(99,904,000)	(100,031,000)	(100,033,000)	(98,933,000)	(99,170,000)	(99,151,000)	(97,569,000)	(98,942,000)
2042	-	(99,829,000)	(99,930,000)	(100,063,000)	(100,065,000)	(98,963,000)	(99,202,000)	(99,183,000)	(97,708,000)	(98,971,000)
2043	-	(101,857,000)	(101,943,000)	(102,065,000)	(102,065,000)	(100,972,000)	(101,180,000)	(101,173,000)	(99,899,000)	(100,905,000)
2044	-	(102,008,000)	(102,886,000)	(102,997,000)	(102,996,000)	(101,915,000)	(102,105,000)	(102,096,000)	(100,941,000)	(101,925,000)

Hearing Exhibit 000269

FPL 000301

CO2 Ton **Annual System Emissions Excess / (Shortfall)**

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	Without Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	-	(57,334,000)	(57,334,000)	(57,334,000)	(57,334,000)	(57,489,000)	(57,481,000)	(57,484,000)	(57,484,000)	(56,649,000)
2008	-	(58,121,000)	(58,118,000)	(58,118,000)	(58,118,000)	(58,188,000)	(58,184,000)	(58,184,000)	(58,184,000)	(57,784,000)
2009	-	(59,356,000)	(59,339,000)	(59,331,000)	(59,331,000)	(59,331,000)	(59,328,000)	(59,326,000)	(59,326,000)	(58,928,000)
2010	-	(57,410,000)	(57,427,000)	(57,396,000)	(57,395,000)	(57,314,000)	(57,330,000)	(57,297,000)	(57,295,000)	(57,100,000)
2011	-	(55,565,000)	(55,573,000)	(55,564,000)	(55,565,000)	(55,214,000)	(55,229,000)	(55,208,000)	(55,179,000)	(55,127,000)
2012	-	(57,236,000)	(57,239,000)	(57,231,000)	(57,232,000)	(56,885,000)	(56,892,000)	(56,856,000)	(56,825,000)	(56,558,000)
2013	-	(59,036,000)	(59,045,000)	(59,039,000)	(59,038,000)	(58,678,000)	(58,678,000)	(58,649,000)	(58,632,000)	(58,474,000)
2014	-	(59,772,000)	(59,778,000)	(59,778,000)	(59,776,000)	(59,363,000)	(59,363,000)	(59,331,000)	(59,317,000)	(59,202,000)
2015	-	(61,430,000)	(61,433,000)	(61,431,000)	(61,431,000)	(61,009,000)	(60,999,000)	(60,979,000)	(60,962,000)	(60,564,000)
2016	-	(60,246,000)	(60,247,000)	(60,248,000)	(60,245,000)	(59,758,000)	(59,758,000)	(59,759,000)	(59,745,000)	(59,325,000)
2017	-	(61,288,000)	(61,289,000)	(61,291,000)	(61,291,000)	(60,788,000)	(60,791,000)	(60,789,000)	(60,740,000)	(60,197,000)
2018	-	(60,825,000)	(60,830,000)	(60,829,000)	(60,826,000)	(60,331,000)	(60,336,000)	(60,326,000)	(60,236,000)	(59,607,000)
2019	-	(61,368,000)	(61,362,000)	(61,361,000)	(61,364,000)	(60,853,000)	(60,841,000)	(60,835,000)	(60,776,000)	(60,206,000)
2020	-	(60,100,000)	(60,107,000)	(60,107,000)	(60,099,000)	(59,619,000)	(59,602,000)	(59,594,000)	(59,510,000)	(59,047,000)
2021	-	(60,492,000)	(60,500,000)	(60,505,000)	(60,473,000)	(59,979,000)	(59,965,000)	(59,961,000)	(59,813,000)	(59,483,000)
2022	-	(62,152,000)	(62,142,000)	(62,142,000)	(62,145,000)	(61,670,000)	(61,642,000)	(61,652,000)	(61,301,000)	(60,936,000)
2023	-	(63,344,000)	(63,302,000)	(63,323,000)	(63,319,000)	(62,823,000)	(62,814,000)	(62,808,000)	(62,384,000)	(62,061,000)
2024	-	(65,501,000)	(65,471,000)	(65,477,000)	(65,479,000)	(64,981,000)	(64,952,000)	(64,929,000)	(64,439,000)	(64,278,000)
2025	-	(65,621,000)	(65,587,000)	(65,599,000)	(65,601,000)	(65,087,000)	(65,016,000)	(64,999,000)	(64,503,000)	(64,416,000)
2026	-	(65,585,000)	(65,580,000)	(65,568,000)	(65,569,000)	(65,022,000)	(64,988,000)	(64,975,000)	(64,559,000)	(64,490,000)
2027	-	(67,937,000)	(67,944,000)	(67,938,000)	(67,938,000)	(67,370,000)	(67,327,000)	(67,329,000)	(66,737,000)	(66,998,000)
2028	-	(69,392,000)	(69,410,000)	(69,393,000)	(69,395,000)	(68,813,000)	(68,813,000)	(68,719,000)	(67,924,000)	(68,458,000)
2029	-	(70,946,000)	(70,967,000)	(70,965,000)	(70,967,000)	(70,345,000)	(70,358,000)	(70,261,000)	(69,367,000)	(70,045,000)
2030	-	(72,979,000)	(73,005,000)	(72,995,000)	(73,000,000)	(72,356,000)	(72,388,000)	(72,301,000)	(71,333,000)	(72,144,000)
2031	-	(74,640,000)	(74,673,000)	(74,664,000)	(74,669,000)	(74,006,000)	(74,039,000)	(73,975,000)	(72,920,000)	(73,930,000)
2032	-	(77,486,000)	(77,515,000)	(77,537,000)	(77,541,000)	(76,836,000)	(76,891,000)	(76,833,000)	(75,599,000)	(76,797,000)
2033	-	(82,526,000)	(82,562,000)	(82,568,000)	(82,593,000)	(81,817,000)	(81,883,000)	(81,836,000)	(80,734,000)	(81,822,000)
2034	-	(84,846,000)	(84,876,000)	(84,900,000)	(84,907,000)	(84,119,000)	(84,188,000)	(84,114,000)	(82,953,000)	(84,126,000)
2035	-	(86,976,000)	(87,009,000)	(87,045,000)	(87,051,000)	(86,226,000)	(86,307,000)	(86,279,000)	(85,120,000)	(86,236,000)
2036	-	(91,740,000)	(91,778,000)	(91,823,000)	(91,828,000)	(90,949,000)	(91,037,000)	(91,008,000)	(89,853,000)	(90,962,000)
2037	-	(93,937,000)	(93,991,000)	(94,049,000)	(94,054,000)	(93,125,000)	(93,252,000)	(93,219,000)	(92,000,000)	(93,136,000)
2038	-	(95,691,000)	(95,756,000)	(95,846,000)	(95,851,000)	(94,867,000)	(95,032,000)	(95,011,000)	(93,717,000)	(94,875,000)
2039	-	(97,855,000)	(97,932,000)	(98,039,000)	(98,042,000)	(97,007,000)	(97,200,000)	(97,186,000)	(95,824,000)	(97,023,000)
2040	-	(100,251,000)	(100,344,000)	(100,459,000)	(100,462,000)	(99,382,000)	(99,603,000)	(99,574,000)	(98,059,000)	(99,394,000)
2041	-	(99,973,000)	(100,078,000)	(100,213,000)	(100,214,000)	(99,108,000)	(99,355,000)	(99,326,000)	(97,706,000)	(99,118,000)
2042	-	(100,024,000)	(100,131,000)	(100,268,000)	(100,268,000)	(99,158,000)	(99,410,000)	(99,387,000)	(97,855,000)	(99,168,000)
2043	-	(101,796,000)	(101,885,000)	(102,008,000)	(102,009,000)	(100,911,000)	(101,127,000)	(101,110,000)	(99,714,000)	(100,919,000)
2044	-	(102,669,000)	(102,758,000)	(102,881,000)	(102,881,000)	(101,776,000)	(101,992,000)	(101,968,000)	(100,729,000)	(101,783,000)

Hearing Exhibit 000270

FPL 000302

Hg Ton ***Total Annual System Emissions***

Expansion Plan / Fuel Forecast / Emission Scenario	With Nuclear Uprates								
	High Gas Cost				Medium Gas Cost				Low Gas Cost
	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2008	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2009	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2010	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2011	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2012	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2013	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2014	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2015	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2016	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2017	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2018	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2019	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2020	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2021	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2022	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2023	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
2024	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.09
2025	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.09
2026	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
2027	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
2028	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.10
2029	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.10
2030	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.10
2031	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.10
2032	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2033	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2034	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2035	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2036	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2037	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2038	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2039	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2040	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2041	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2042	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2043	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2044	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.11

Hearing Exhibit 000271

FPL 000303

Hg Ton **Total Annual System Emissions**

Expansion Plan / Fuel Forecast / Emission Scenario	Without Nuclear Uprates								
	High Gas Cost				Medium Gas Cost				Low Gas Cost
	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2008	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2009	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2010	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2011	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2012	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2013	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2014	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2015	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2016	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2017	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2018	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2019	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2020	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2021	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2022	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2023	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
2024	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.09
2025	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.09
2026	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
2027	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
2028	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.10
2029	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.10
2030	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.10
2031	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.10
2032	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2033	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2034	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2035	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2036	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2037	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2038	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2039	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2040	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2041	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2042	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2043	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.08	0.11
2044	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.11

Hearing Exhibit 000272

FPL 000304

Hg Ton **Annual System Emissions Excess / (Shortfall)**

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	With Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2008	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2009	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2010	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2011	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2012	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2013	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2014	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2015	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2016	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2017	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2018	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2019	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2020	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2021	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2022	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2023	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2024	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.10)
2025	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.09)
2026	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.09)
2027	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.10)
2028	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.10)
2029	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.10)
2030	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.10)
2031	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.10)
2032	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.10)
2033	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2034	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2035	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2036	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2037	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2038	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2039	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2040	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2041	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2042	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2043	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.08)	(0.11)
2044	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)

Hearing Exhibit 000273

FPL 000305

Hg Ton ***Annual System Emissions Excess / (Shortfall)***

Expansion Plan Fuel Forecast Emission Scenario	Available Allowances	Without Nuclear Uprates								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2008		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2009		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2010		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2011		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2012		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2013		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2014		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2015		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2016		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2017		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2018		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2019		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2020		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2021		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2022		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2023		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2024		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.10)
2025		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.09)
2026		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.09)
2027		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.10)
2028		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)	(0.10)
2029		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.10)
2030		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.10)
2031		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.10)
2032		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.10)
2033		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2034		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2035		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2036		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2037		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2038		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2039		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2040		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2041		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2042		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2043		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)
2044		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.09)	(0.11)

FPL 000306

Hearing Exhibit 000274

Projected FPL Allowance Allocation Bank

	SO2 Ton	NOx Ton	CO2 Ton	Hg Ton
2006	-	-	-	-
2007	-	-	-	-
2008	-	-	-	-
2009	123,191	27,452	-	-
2010	118,079	27,650	-	-
2011	118,079	27,676	-	-
2012	118,079	27,403	-	-
2013	118,079	29,999	-	-
2014	118,079	30,051	-	-
2015	118,079	25,704	-	-
2016	118,079	25,984	-	-
2017	118,079	25,930	-	-
2018	118,079	25,879	-	-
2019	118,079	26,607	-	-
2020	118,079	26,525	-	-
2021	118,079	26,454	-	-
2022	118,079	26,107	-	-
2023	118,079	26,107	-	-
2024	118,079	26,107	-	-
2025	118,079	26,107	-	-
2026	118,079	26,107	-	-
2027	118,079	26,107	-	-
2028	118,079	26,107	-	-
2029	118,079	26,107	-	-
2030	118,079	26,107	-	-
2031	118,079	26,107	-	-
2032	118,079	26,107	-	-
2033	118,079	26,107	-	-
2034	118,079	26,107	-	-
2035	118,079	26,107	-	-
2036	118,079	26,107	-	-
2037	118,079	26,107	-	-
2038	118,079	26,107	-	-
2039	118,079	26,107	-	-
2040	118,079	26,107	-	-
2041	118,079	26,107	-	-
2042	118,079	26,107	-	-
2043	118,079	26,107	-	-
2044	118,079	26,107	-	-

Source: FPL ENV Group

FPL SO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	4,225	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232	4,232
CAPE CANAVERAL PLANT	PCC2	4,963	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969	4,969
CUTLER	PCU5		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
CUTLER	PCU6		9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
FORT MYERS PLANT	1-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT2A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT2B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT2C	-	-			-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT2D	-	-			-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT2E	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT2F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT3A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	FMCT3B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	PFM1	3,189	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194
FORT MYERS PLANT	PFM2	9,460	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475
FPL Manatee	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Martin	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Turkey Point Unit 5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Unsited Combined Cycle 1	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Unsited Combined Cycle 2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL West County 1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL West County 2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL West County 3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LAUDERDALE	1-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LAUDERDALE	13-24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LAUDERDALE	4GT1	948	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
LAUDERDALE	4GT2	948	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
LAUDERDALE	5GT1	948	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
LAUDERDALE	5GT2	948	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
MANATEE	PMT1	13,777	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799	13,799
MANATEE	PMT2	12,701	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716	12,716
MARTIN PLANT	HRSG3A,3ST	1,275	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG3B,3ST	1,275	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4A, 4ST	1,275	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4B, 4ST	1,275	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	PMR1	5,094	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102	5,102
MARTIN PLANT	PMR2	6,041	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049	6,049
PORT EVERGLADES	1-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PORT EVERGLADES	PPE1	2,340	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343
PORT EVERGLADES	PPE2	2,414	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417	2,417
PORT EVERGLADES	PPE3	5,882	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891	5,891
PORT EVERGLADES	PPE4	5,964	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973	5,973
PUTNAM	1GT1/HRSG11	1,644	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647
PUTNAM	1GT2/HRSG12	1,644	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647	1,647
PUTNAM	2GT1/HRSG21	1,568	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570
PUTNAM	2GT2/HRSG22	1,568	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570
RIVIERA PLANT	PRV3	3,574	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580	3,580
RIVIERA PLANT	PRV4	3,546	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551	3,551
SANFORD POWER PLANT	PSN3	1,085	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087
SANFORD POWER PLANT	PSN4	8,615	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323
SANFORD POWER PLANT	PSN5	3,222	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220	3,220
SANFORD POWER PLANT	SNCT4A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT4B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT4C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT4D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT5A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT5B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT5C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT5D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TURKEY POINT PLANT	PTP1	5,870	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879	5,879
TURKEY POINT PLANT	PTP2	5,913	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924	5,924

FPL 000308

Hearing Exhibit 000278

FPL Hg Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances	2024 Allowances

Hearing Exhibit 000279

FPL NOx Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	741	741	741	741	751	751	626	576	576	576	498	498	498	456	456	456
CAPE CANAVERAL PLANT	PCC2	717	717	717	717	727	727	606	558	558	558	482	482	482	442	442	442
CUTLER	PCU5	38	38	38	38	39	39	33	30	30	30	26	26	26	24	24	24
CUTLER	PCU6	83	83	83	83	84	84	70	65	65	65	56	56	56	51	51	51
FORT MYERS PLANT	1 12	67	67	67	67	68	68	56	52	52	52	45	45	45	41	41	41
FORT MYERS PLANT	FMCT2A	320	320	320	320	324	324	270	249	249	249	215	215	215	197	197	197
FORT MYERS PLANT	FMCT2B	317	317	317	317	321	321	267	246	246	246	213	213	213	195	195	195
FORT MYERS PLANT	FMCT2C	322	322	322	322	327	327	272	251	251	251	216	216	216	198	198	198
FORT MYERS PLANT	FMCT2D	339	339	339	339	310	310	259	238	238	238	206	206	206	188	188	188
FORT MYERS PLANT	FMCT2E	338	338	338	338	333	333	278	256	256	256	221	221	221	202	202	202
FORT MYERS PLANT	FMCT2F	334	334	334	334	329	329	274	252	252	252	218	218	218	200	200	200
FORT MYERS PLANT	FMCT3A	70	70	70	70	67	67	56	51	51	51	44	44	44	41	41	41
FORT MYERS PLANT	FMCT3B	84	84	84	84	78	78	65	60	60	60	51	51	51	47	47	47
FORT MYERS PLANT	PFM1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORT MYERS PLANT	PFM2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Manatee	3	728	423	292	259	1,103	1,103	919	847	847	847	731	731	731	670	670	670
FPL Martin	8	723	421	290	257	1,096	1,096	914	841	841	841	727	727	727	665	665	665
FPL Turkey Point Unit 5	5	756	440	303	269	1,146	1,146	955	879	879	879	760	760	760	696	696	696
FPL Unsited Combined Cycle 1	1	-	-	-	-	-	430	325	410	395	381	792	738	690	1,627	1,627	1,627
FPL Unsited Combined Cycle 2	2							165	209	201	194	403	376	351	828	828	828
FPL West County 1	1		1,122	773	686	598	469	354	2,243	2,243	2,243	1,938	1,938	1,938	1,775	1,775	1,775
FPL West County 2	2			773	686	598	469	354	447	431	415	1,938	1,938	1,938	1,775	1,775	1,775
FPL West County 3	3	-	-	-		548	430	325	410	395	381	1,776	1,776	1,776	1,627	1,627	1,627
LAUDERDALE	1-12	52	52	52	52	52	52	44	40	40	40	35	35	35	32	32	32
LAUDERDALE	13 - 24	56	56	56	56	57	57	47	43	43	43	37	37	37	34	34	34
LAUDERDALE	4GT1	335	335	335	335	340	340	283	261	261	261	225	225	225	206	206	206
LAUDERDALE	4GT2	335	335	335	335	339	339	283	260	260	260	225	225	225	206	206	206
LAUDERDALE	5GT1	342	342	342	342	347	347	289	286	266	266	230	230	230	211	211	211
LAUDERDALE	5GT2	328	328	328	328	332	332	277	255	255	255	220	220	220	202	202	202
MANATEE	PMT1	1,317	1,317	1,317	1,317	1,336	1,336	1,113	1,025	1,025	1,025	885	885	885	811	811	811
MANATEE	PMT2	1,361	1,361	1,361	1,361	1,380	1,380	1,150	1,059	1,059	1,059	915	915	915	838	838	838
MARTIN PLANT	HRSG3A,3ST	343	343	343	343	348	348	290	267	267	267	231	231	231	211	211	211
MARTIN PLANT	HRSG3B,3ST	360	360	360	360	365	365	304	280	280	280	242	242	242	221	221	221
MARTIN PLANT	HRSG4A, 4ST	351	351	351	351	356	356	296	273	273	273	236	236	236	216	216	216
MARTIN PLANT	HRSG4B, 4ST	350	350	350	350	355	355	296	272	272	272	235	235	235	215	215	215
MARTIN PLANT	PMR1	1,279	1,279	1,279	1,279	1,297	1,297	1,081	995	995	995	860	860	860	787	787	787
MARTIN PLANT	PMR2	1,345	1,345	1,345	1,345	1,364	1,364	1,137	1,047	1,047	1,047	904	904	904	828	828	828
PORT EVERGLADES	1-12	40	40	40	40	40	40	34	31	31	31	27	27	27	24	24	24
PORT EVERGLADES	PPE1	296	296	296	296	300	300	250	230	230	230	199	199	199	182	182	182
PORT EVERGLADES	PPE2	330	330	330	330	335	335	279	257	257	257	222	222	222	203	203	203
PORT EVERGLADES	PPE3	715	715	715	715	725	725	604	556	556	556	481	481	481	440	440	440
PORT EVERGLADES	PPE4	725	725	725	725	735	735	612	564	564	564	487	487	487	446	446	446
PUTNAM	1GT1/HRSG11	145	145	145	145	147	147	123	113	113	113	98	98	98	89	89	89
PUTNAM	1GT2/HRSG12	144	144	144	144	146	146	122	112	112	112	97	97	97	89	89	89
PUTNAM	2GT1/HRSG21	137	137	137	137	139	139	116	106	106	106	92	92	92	84	84	84
PUTNAM	2GT2/HRSG22	138	138	138	138	139	139	116	107	107	107	92	92	92	85	85	85
RIVIERA PLANT	PRV3	541	541	541	541	549	549	457	421	421	421	364	364	364	333	333	333
RIVIERA PLANT	PRV4	579	579	579	579	587	587	489	451	451	451	389	389	389	357	357	357
SANFORD POWER PLANT	PSN3	173	173	173	173	175	175	146	134	134	134	116	116	116	106	106	106
SANFORD POWER PLANT	PSN4	-				-	-	-	-	-	-	-	-	-	-		
SANFORD POWER PLANT	PSN5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SANFORD POWER PLANT	SNCT4A	338	338	338	338	229	229	191	175	175	175	152	152	152	139	139	139
SANFORD POWER PLANT	SNCT4B	339	339	339	339	230	230	192	177	177	177	153	153	153	140	140	140
SANFORD POWER PLANT	SNCT4C	345	345	345	345	234	234	195	179	179	179	155	155	155	142	142	142
SANFORD POWER PLANT	SNCT4D	351	351	351	351	233	233	194	179	179	179	154	154	154	141	141	141
SANFORD POWER PLANT	SNCT5A	333	333	333	333	317	317	264	243	243	243	210	210	210	192	192	192
SANFORD POWER PLANT	SNCT5B	338	338	338	338	322	322	269	247	247	247	214	214	214	196	196	196
SANFORD POWER PLANT	SNCT5C	347	347	347	347	306	306	255	235	235	235	203	203	203	186	186	186
SANFORD POWER PLANT	SNCT5D	323	323	323	323	309	309	257	237	237	237	205	205	205	187	187	187
TURKEY POINT PLANT	PTP1	667	667	667	667	676	676	564	519	519	519	448	448	448	411	411	411
TURKEY POINT PLANT	PTP2	684	684	684	684	694	694	578	532	532	532	460	460	460	421	421	421
ST JOHNS RIVER POWER PARK	PJK1*	3,810	3,810	3,810	3,810	3,864	3,864	3,220	2,965	2,965	2,965	2,561	2,561	2,561	2,345	2,345	2,345
ST JOHNS RIVER POWER PARK	PJK2*	3,579	3,579	3,579	3,579	3,629	3,629	3,024	2,785	2,785	2,785	2,405	2,405	2,405	2,203	2,203	2,203
SCHERER 4	PSG4*	4,997	4,997	4,997	4,997	4,997	4,997	4,997	4,601	4,601	4,601	4,665	4,665	4,665	4,770	4,770	4,770

FPL 000310

Hearing Exhibit 000280

FPL NOx Seasonal Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	383	383	383	383	389	389	324	298	298	298	258	258	258	236	236	236
CAPE CANAVERAL PLANT	PCC2	374	374	374	374	380	380	316	291	291	291	252	252	252	230	230	230
CUTLER	PCU5	32	32	32	32	33	33	27	25	25	25	22	22	22	20	20	20
CUTLER	PCU6	65	65	65	65	65	65	55	50	50	50	43	43	43	40	40	40
FORT MYERS PLANT	1-12	53	53	53	53	54	54	45	42	42	42	36	36	36	33	33	33
FORT MYERS PLANT	FMCT2A	144	144	144	144	146	146	122	112	112	112	97	97	97	89	89	89
FORT MYERS PLANT	FMCT2B	144	144	144	144	146	146	122	112	112	112	97	97	97	89	89	89
FORT MYERS PLANT	FMCT2C	150	150	150	150	152	152	126	116	116	116	101	101	101	92	92	92
FORT MYERS PLANT	FMCT2D	151	151	151	151	138	138	115	106	106	106	91	91	91	84	84	84
FORT MYERS PLANT	FMCT2E	149	149	149	149	147	147	123	113	113	113	98	98	98	89	89	89
FORT MYERS PLANT	FMCT2F	144	144	144	144	142	142	119	109	109	109	94	94	94	86	86	86
FORT MYERS PLANT	FMCT3A	53	53	53	53	50	50	42	38	38	38	33	33	33	30	30	30
FORT MYERS PLANT	FMCT3B	61	61	61	61	56	56	47	43	43	43	37	37	37	34	34	34
FORT MYERS PLANT	PFM1	70	70	70	70	0	0	0	0	0	0	0	0	0	0	0	0
FORT MYERS PLANT	PFM2	247	247	247	247	0	0	0	0	0	0	0	0	0	0	0	0
FPL Manatee	3	323	188	130	115	490	490	408	376	376	376	320	320	320	287	287	287
FPL Martin	8	321	187	129	114	487	487	405	373	373	373	318	318	318	285	285	285
FPL Turkey Point Unit 5	5	336	195	135	119	509	509	424	390	390	390	333	333	333	298	298	298
FPL Unsited Combined Cycle 1	1	0	0	0	0	0	191	144	182	175	169	347	323	302	696	696	696
FPL Unsited Combined Cycle 2	2	0	0	0	0	0	0	73	93	89	86	177	164	154	356	355	355
FPL West County 1	1	0	498	343	305	249	188	139	996	996	996	848	848	848	760	760	760
FPL West County 2	2	0	0	343	305	249	188	139	189	163	157	848	848	848	760	760	760
FPL West County 3	3	0	0	0	0	243	191	144	182	175	169	778	778	778	696	696	696
LAUDERDALE	1-12	39	39	39	39	39	39	33	30	30	30	26	26	26	24	24	24
LAUDERDALE	13-24	28	28	28	28	28	28	24	22	22	22	19	19	19	17	17	17
LAUDERDALE	4GT1	154	154	154	154	156	156	130	120	120	120	103	103	103	95	95	95
LAUDERDALE	4GT2	152	152	152	152	154	154	128	118	118	118	102	102	102	93	93	93
LAUDERDALE	5GT1	153	153	153	153	155	155	129	119	119	119	103	103	103	94	94	94
LAUDERDALE	5GT2	148	148	148	148	150	150	125	115	115	115	99	99	99	91	91	91
MANATEE	PMT1	649	649	649	649	658	658	549	505	505	505	436	436	436	400	400	400
MANATEE	PMT2	707	707	707	707	717	717	597	550	550	550	475	475	475	435	436	435
MARTIN PLANT	HRSG3A,3ST	150	150	150	150	152	152	127	117	117	117	101	101	101	92	92	92
MARTIN PLANT	HRSG3B,3ST	152	152	152	152	154	154	128	118	118	118	102	102	102	93	93	93
MARTIN PLANT	HRSG4A, 4ST	159	159	159	159	161	161	135	124	124	124	107	107	107	98	98	98
MARTIN PLANT	HRSG4B, 4ST	158	158	158	158	160	160	134	123	123	123	106	106	106	97	97	97
MARTIN PLANT	PMR1	724	724	724	724	735	735	612	564	564	564	487	487	487	446	446	446
MARTIN PLANT	PMR2	676	676	676	676	685	685	571	526	526	526	454	454	454	416	416	416
PORT EVERGLADES	1-12	27	27	27	27	27	27	22	21	21	21	18	18	18	16	16	16
PORT EVERGLADES	PPE1	191	191	191	191	194	194	161	149	149	149	128	128	128	118	118	118
PORT EVERGLADES	PPE2	195	195	195	195	198	198	165	152	152	152	131	131	131	120	120	120
PORT EVERGLADES	PPE3	366	366	366	366	371	371	309	285	285	285	246	246	246	225	226	225
PORT EVERGLADES	PPE4	382	382	382	382	387	387	322	297	297	297	256	256	256	235	236	235
PUTNAM	1GT1/HRSG11	71	71	71	71	72	72	60	55	55	55	47	47	47	43	43	43
PUTNAM [illegible]	1GT2/HRSG12	71	71	71	71	72	72	60	55	55	55	47	47	47	43	43	43
PUTNAM	2GT1/HRSG21	67	67	67	67	68	68	57	52	52	52	45	45	45	41	41	41
PUTNAM	2GT2/HRSG22	69	69	69	69	70	70	58	54	54	54	46	46	46	42	42	42
RIVIERA PLANT	PRV3	281	281	281	281	284	284	237	218	218	218	189	189	189	173	173	173
RIVIERA PLANT	PRV4	284	284	284	284	288	288	240	221	221	221	191	191	191	175	175	175
SANFORD POWER PLANT	PSN3	105	105	105	105	107	107	89	82	82	82	71	71	71	65	66	65
SANFORD POWER PLANT	PSN4	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	SNCT4A	151	151	151	151	102	102	85	78	78	78	67	67	67	62	62	62
SANFORD POWER PLANT	SNCT4B	153	153	153	153	104	104	87	80	80	80	69	69	69	63	63	63
SANFORD POWER PLANT	SNCT4C	152	152	152	152	103	103	86	79	79	79	68	68	68	62	62	62
SANFORD POWER PLANT	SNCT4D	149	149	149	149	99	99	82	76	76	76	66	66	66	60	60	60
SANFORD POWER PLANT	SNCT5A	150	150	150	150	142	142	119	109	109	109	94	94	94	86	86	86
SANFORD POWER PLANT	SNCT5B	150	150	150	150	143	143	119	110	110	110	95	95	95	87	87	87
SANFORD POWER PLANT	SNCT5C	153	153	153	153	135	135	112	103	103	103	89	89	89	82	82	82
SANFORD POWER PLANT	SNCT5D	142	142	142	142	136	136	113	104	104	104	90	90	90	83	83	83
TURKEY POINT PLANT	PTP1	365	365	365	365	370	370	308	284	284	284	245	245	245	224	224	224
TURKEY POINT PLANT	PTP2	360	360	360	360	365	365	304	280	280	280	242	242	242	221	221	221
ST JOHNS RIVER POWER PARK	PJK1	1,706	1,706	1,706	1,706	1,706	1,706	1,571	1,571	1,571	1,571	1,593	1,593	1,593	1,629	1,629	1,629
ST JOHNS RIVER POWER PARK	PJK1	1,559	1,559	1,559	1,559	1,559	1,559	1,435	1,435	1,435	1,435	1,455	1,456	1,455	1,488	1,488	1,488
SCHERER 4	PSG4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		383.26599	383.26599	383.26599	383.26599	394.15225	394.15225	273.71794	232.06586	232.06586	232.06586	173.15211	173.15211	173.15211	145.21774	145.21774	145.21774

FPL 000311

FPL NOx Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
CAPE CANAVERAL PLANT	PCC1	741	741	741	741	751
CAPE CANAVERAL PLANT	PCC2	717	717	717	717	727
CUTLER	PCU5	38	38	38	38	39
CUTLER	PCU6	83	83	83	83	84
FORT MYERS PLANT	1-12	67	67	67	67	68
FORT MYERS PLANT	FMCT2A	320	320	320	320	324
FORT MYERS PLANT	FMCT2B	317	317	317	317	321
FORT MYERS PLANT	FMCT2C	322	322	322	322	327
FORT MYERS PLANT	FMCT2D	339	339	339	339	310
FORT MYERS PLANT	FMCT2E	338	338	338	338	333
FORT MYERS PLANT	FMCT2F	334	334	334	334	329
FORT MYERS PLANT	FMCT3A	70	70	70	70	67
FORT MYERS PLANT	FMCT3B	84	84	84	84	78
FORT MYERS PLANT	PFM1	-	-	-	-	-
FORT MYERS PLANT	PFM2	-	-	-	-	-
FPL Manatee	3	728	423	292	259	1,103
FPL Martin	8	723	421	290	257	1,096
FPL Turkey Point Unit 5	5	756	440	303	269	1,146
FPL Unsited Combined Cycle 1	1	-	-	-	-	-
FPL Unsited Combined Cycle 2	2					
FPL West County 1	1		1,122	773	686	598
FPL West County 2	2			773	686	598
FPL West County 3	3	-	-	-	-	548
LAUDERDALE	1-12	52	52	52	52	52
LAUDERDALE	13 - 24	56	56	56	56	57
LAUDERDALE	4GT1	335	335	335	335	340
LAUDERDALE	4GT2	335	335	335	335	339
LAUDERDALE	5GT1	342	342	342	342	347
LAUDERDALE	5GT2	328	328	328	328	332
MANATEE	PMT1	1,317	1,317	1,317	1,317	1,336
MANATEE	PMT2	1,361	1,361	1,361	1,361	1,380
MARTIN PLANT	HRSG3A,3ST	343	343	343	343	348
MARTIN PLANT	HRSG3B,3ST	360	360	360	360	365
MARTIN PLANT	HRSG4A, 4ST	351	351	351	351	356
MARTIN PLANT	HRSG4B, 4ST	350	350	350	350	355
MARTIN PLANT	PMR1	1,279	1,279	1,279	1,279	1,297
MARTIN PLANT	PMR2	1,345	1,345	1,345	1,345	1,364
PORT EVERGLADES	1-12	40	40	40	40	40
PORT EVERGLADES	PPE1	296	296	296	296	300
PORT EVERGLADES	PPE2	330	330	330	330	335
PORT EVERGLADES	PPE3	715	715	715	715	725
PORT EVERGLADES	PPE4	725	725	725	725	735
PUTNAM	1GT1/HRSG11	145	145	145	145	147
PUTNAM	1GT2/HRSG12	144	144	144	144	146
PUTNAM	2GT1/HRSG21	137	137	137	137	139

FPL NOx Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
PUTNAM	2G~2/HRSG22	138	138	138	138	139
RIVIERA PLANT	PRV3	541	541	541	541	549
RIVIERA PLANT	PRV4	579	579	579	579	587
SANFORD POWER PLANT	PSN3	173	173	173	173	175
SANFORD POWER PLANT	PSN4	-	-	-	-	-
SANFORD POWER PLANT	PSN5	-	-	-	-	-
SANFORD POWER PLANT	SNCT4A	338	338	338	338	229
SANFORD POWER PLANT	SNCT4B	339	339	339	339	230
SANFORD POWER PLANT	SNCT4C	345	345	345	345	234
SANFORD POWER PLANT	SNCT4D	351	351	351	351	233
SANFORD POWER PLANT	SNCT5A	333	333	333	333	317
SANFORD POWER PLANT	SNCT5B	338	338	338	338	322
SANFORD POWER PLANT	SNCT5C	347	347	347	347	306
SANFORD POWER PLANT	SNCT5D	323	323	323	323	309
TURKEY POINT PLANT	PTP1	667	667	667	667	676
TURKEY POINT PLANT	PTP2	684	684	684	684	694
ST JOHNS RIVER POWER PARK	PJK1*	762	762	762	762	773
ST JOHNS RIVER POWER PARK	PJK2*	716	716	716	716	726
SCHERER 4	PSG4*	3,816	3,816	3,816	3,816	3,816

	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
System	27,452	27,650	27,676	27,403	29,999

* Note: Unit allocations for all owners *except*

SCHERER 4 76% owned

ST JOHNS RIVER POWER PARK 20% owned

FPL NOx Allowance A

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
CAPE CANAVERAL PLANT	PCC1	751	626	576	576	576
CAPE CANAVERAL PLANT	PCC2	727	606	558	558	558
CUTLER	PCU5	39	33	30	30	30
CUTLER	PCU6	84	70	65	65	65
FORT MYERS PLANT	1-12	68	56	52	52	52
FORT MYERS PLANT	FMCT2A	324	270	249	249	249
FORT MYERS PLANT	FMCT2B	321	267	246	246	246
FORT MYERS PLANT	FMCT2C	327	272	251	251	251
FORT MYERS PLANT	FMCT2D	310	259	238	238	238
FORT MYERS PLANT	FMCT2E	333	278	256	256	256
FORT MYERS PLANT	FMCT2F	329	274	252	252	252
FORT MYERS PLANT	FMCT3A	67	56	51	51	51
FORT MYERS PLANT	FMCT3B	78	65	60	60	60
FORT MYERS PLANT	PFM1	-	-	-	-	-
FORT MYERS PLANT	PFM2	-	-	-	-	-
FPL Manatee	3	1,103	919	847	847	847
FPL Martin	8	1,096	914	841	841	841
FPL Turkey Point Unit 5	5	1,146	955	879	879	879
FPL Unsited Combined Cycle 1	1	430	325	410	395	381
FPL Unsited Combined Cycle 2	2		165	209	201	194
FPL West County 1	1	469	354	2,243	2,243	2,243
FPL West County 2	2	469	354	447	431	415
FPL West County 3	3	430	325	410	395	381
LAUDERDALE	1-12	52	44	40	40	40
LAUDERDALE	13 - 24	57	47	43	43	43
LAUDERDALE	4GT1	340	283	261	261	261
LAUDERDALE	4GT2	339	283	260	260	260
LAUDERDALE	5GT1	347	289	266	266	266
LAUDERDALE	5GT2	332	277	255	255	255
MANATEE	PMT1	1,336	1,113	1,025	1,025	1,025
MANATEE	PMT2	1,380	1,150	1,059	1,059	1,059
MARTIN PLANT	HRSG3A,3ST	348	290	267	267	267
MARTIN PLANT	HRSG3B,3ST	365	304	280	280	280
MARTIN PLANT	HRSG4A, 4ST	356	296	273	273	273
MARTIN PLANT	HRSG4B, 4ST	355	296	272	272	272
MARTIN PLANT	PMR1	1,297	1,081	995	995	995
MARTIN PLANT	PMR2	1,364	1,137	1,047	1,047	1,047
PORT EVERGLADES	1-12	40	34	31	31	31
PORT EVERGLADES	PPE1	300	250	230	230	230
PORT EVERGLADES	PPE2	335	279	257	257	257
PORT EVERGLADES	PPE3	725	604	556	556	556
PORT EVERGLADES	PPE4	735	612	564	564	564
PUTNAM	1GT1/HRSG11	147	123	113	113	113
PUTNAM	1GT2/HRSG12	145	122	112	112	112
PUTNAM	2GT1/HRSG21	139	116	106	106	106

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
PUTNAM	2GT2/HRSG22	139	116	107	107	107
RIVIERA PLANT	PRV3	549	457	421	421	421
RIVIERA PLANT	PRV4	587	489	451	451	451
SANFORD POWER PLANT	PSN3	175	146	134	134	134
SANFORD POWER PLANT	PSN4	-	-	-	-	-
SANFORD POWER PLANT	PSN5	-	-	-	-	-
SANFORD POWER PLANT	SNCT4A	229	191	175	175	175
SANFORD POWER PLANT	SNCT4B	230	192	177	177	177
SANFORD POWER PLANT	SNCT4C	234	195	179	179	179
SANFORD POWER PLANT	SNCT4D	233	194	179	179	179
SANFORD POWER PLANT	SNCT5A	317	264	243	243	243
SANFORD POWER PLANT	SNCT5B	322	269	247	247	247
SANFORD POWER PLANT	SNCT5C	306	255	235	235	235
SANFORD POWER PLANT	SNCT5D	309	257	237	237	237
TURKEY POINT PLANT	PTP1	676	564	519	519	519
TURKEY POINT PLANT	PTP2	694	578	532	532	532
ST JOHNS RIVER POWER PARK	PJK1*	773	644	593	593	593
ST JOHNS RIVER POWER PARK	PJK2*	726	605	557	557	557
SCHERER 4	PSG4*	3,816	3,816	3,513	3,513	3,513

	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
System	**30,051**	**25,704**	**25,984**	**25,930**	**25,879**

* Note: Unit allocations for all owners *except*

SCHERER 4	76%
ST JOHNS RIVER POWER PARK	20%

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
CAPE CANAVERAL PLANT	PCC1	498	498	498	456	456
CAPE CANAVERAL PLANT	PCC2	482	482	482	442	442
CUTLER	PCU5	26	26	26	24	24
CUTLER	PCU6	56	56	56	51	51
FORT MYERS PLANT	1-12	45	45	45	41	41
FORT MYERS PLANT	FMCT2A	215	215	215	197	197
FORT MYERS PLANT	FMCT2B	213	213	213	195	195
FORT MYERS PLANT	FMCT2C	216	216	216	198	198
FORT MYERS PLANT	FMCT2D	206	206	206	188	188
FORT MYERS PLANT	FMCT2E	221	221	221	202	202
FORT MYERS PLANT	FMCT2F	218	218	218	200	200
FORT MYERS PLANT	FMCT3A	44	44	44	41	41
FORT MYERS PLANT	FMCT3B	51	51	51	47	47
FORT MYERS PLANT	PFM1	-	-	-	-	-
FORT MYERS PLANT	PFM2	-	-	-	-	-
FPL Manatee	3	731	731	731	670	670
FPL Martin	8	727	727	727	665	665
FPL Turkey Point Unit 5	5	760	760	760	696	696
FPL Unsited Combined Cycle 1	1	792	738	690	1,627	1,627
FPL Unsited Combined Cycle 2	2	403	376	351	828	828
FPL West County 1	1	1,938	1,938	1,938	1,775	1,775
FPL West County 2	2	1,938	1,938	1,938	1,775	1,775
FPL West County 3	3	1,776	1,776	1,776	1,627	1,627
LAUDERDALE	1-12	35	35	35	32	32
LAUDERDALE	13 - 24	37	37	37	34	34
LAUDERDALE	4GT1	225	225	225	206	206
LAUDERDALE	4GT2	225	225	225	206	206
LAUDERDALE	5GT1	230	230	230	211	211
LAUDERDALE	5GT2	220	220	220	202	202
MANATEE	PMT1	885	885	885	811	811
MANATEE	PMT2	915	915	915	838	838
MARTIN PLANT	HRSG3A,3ST	231	231	231	211	211
MARTIN PLANT	HRSG3B,3ST	242	242	242	221	221
MARTIN PLANT	HRSG4A, 4ST	236	236	236	216	216
MARTIN PLANT	HRSG4B, 4ST	235	235	235	215	215
MARTIN PLANT	PMR1	860	860	860	787	787
MARTIN PLANT	PMR2	904	904	904	828	828
PORT EVERGLADES	1-12	27	27	27	24	24
PORT EVERGLADES	PPE1	199	199	199	182	182
PORT EVERGLADES	PPE2	222	222	222	203	203
PORT EVERGLADES	PPE3	481	481	481	440	440
PORT EVERGLADES	PPE4	487	487	487	446	446
PUTNAM	1GT1/HRSG11	98	98	98	89	89
PUTNAM	1GT2/HRSG12	97	97	97	89	89
PUTNAM	2GT1/HRSG21	92	92	92	84	84

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
PUTNAM	2GT2/HRSG22	92	92	92	85	85
RIVIERA PLANT	PRV3	364	364	364	333	333
RIVIERA PLANT	PRV4	389	389	389	357	357
SANFORD POWER PLANT	PSN3	116	116	116	106	106
SANFORD POWER PLANT	PSN4	-	-	-	-	-
SANFORD POWER PLANT	PSN5	-	-	-	-	-
SANFORD POWER PLANT	SNCT4A	152	152	152	139	139
SANFORD POWER PLANT	SNCT4B	153	153	153	140	140
SANFORD POWER PLANT	SNCT4C	155	155	155	142	142
SANFORD POWER PLANT	SNCT4D	154	154	154	141	141
SANFORD POWER PLANT	SNCT5A	210	210	210	192	192
SANFORD POWER PLANT	SNCT5B	214	214	214	196	196
SANFORD POWER PLANT	SNCT5C	203	203	203	186	186
SANFORD POWER PLANT	SNCT5D	205	205	205	187	187
TURKEY POINT PLANT	PTP1	448	448	448	411	411
TURKEY POINT PLANT	PTP2	460	460	460	421	421
ST JOHNS RIVER POWER PARK	PJK1*	512	512	512	469	469
ST JOHNS RIVER POWER PARK	PJK2*	481	481	481	441	441
SCHERER 4	PSG4*	3,562	3,562	3,562	3,643	3,643

	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
System	**26,607**	**26,525**	**26,454**	**26,107**	**26,107**

* Note: Unit allocations for all owners *except*

SCHERER 4	76%
ST JOHNS RIVER POWER PARK	20%

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	456
CAPE CANAVERAL PLANT	PCC2	442
CUTLER	PCU5	24
CUTLER	PCU6	51
FORT MYERS PLANT	1-12	41
FORT MYERS PLANT	FMCT2A	197
FORT MYERS PLANT	FMCT2B	195
FORT MYERS PLANT	FMCT2C	198
FORT MYERS PLANT	FMCT2D	188
FORT MYERS PLANT	FMCT2E	202
FORT MYERS PLANT	FMCT2F	200
FORT MYERS PLANT	FMCT3A	41
FORT MYERS PLANT	FMCT3B	47
FORT MYERS PLANT	PFM1	-
FORT MYERS PLANT	PFM2	-
FPL Manatee	3	670
FPL Martin	8	665
FPL Turkey Point Unit 5	5	696
FPL Unsited Combined Cycle 1	1	1,627
FPL Unsited Combined Cycle 2	2	828
FPL West County 1	1	1,775
FPL West County 2	2	1,775
FPL West County 3	3	1,627
LAUDERDALE	1-12	32
LAUDERDALE	13 - 24	34
LAUDERDALE	4GT1	206
LAUDERDALE	4GT2	206
LAUDERDALE	5GT1	211
LAUDERDALE	5GT2	202
MANATEE	PMT1	811
MANATEE	PMT2	838
MARTIN PLANT	HRSG3A,3ST	211
MARTIN PLANT	HRSG3B,3ST	221
MARTIN PLANT	HRSG4A, 4ST	216
MARTIN PLANT	HRSG4B, 4ST	215
MARTIN PLANT	PMR1	787
MARTIN PLANT	PMR2	828
PORT EVERGLADES	1-12	24
PORT EVERGLADES	PPE1	182
PORT EVERGLADES	PPE2	203
PORT EVERGLADES	PPE3	440
PORT EVERGLADES	PPE4	446
PUTNAM	1GT1/HRSG11	89
PUTNAM	1GT2/HRSG12	89
PUTNAM	2GT1/HRSG21	84

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
PUTNAM	2GT2/HRSG22	85
RIVIERA PLANT	PRV3	333
RIVIERA PLANT	PRV4	357
SANFORD POWER PLANT	PSN3	106
SANFORD POWER PLANT	PSN4	-
SANFORD POWER PLANT	PSN5	-
SANFORD POWER PLANT	SNCT4A	139
SANFORD POWER PLANT	SNCT4B	140
SANFORD POWER PLANT	SNCT4C	142
SANFORD POWER PLANT	SNCT4D	141
SANFORD POWER PLANT	SNCT5A	192
SANFORD POWER PLANT	SNCT5B	196
SANFORD POWER PLANT	SNCT5C	186
SANFORD POWER PLANT	SNCT5D	187
TURKEY POINT PLANT	PTP1	411
TURKEY POINT PLANT	PTP2	421
ST JOHNS RIVER POWER PARK	PJK1*	469
ST JOHNS RIVER POWER PARK	PJK2*	441
SCHERER 4	PSG4*	3,643

	2024 Allowances
System	**26,107**

* Note: Unit allocations for all owners *except*

SCHERER 4	75%
ST JOHNS RIVER POWER PARK	20%

FPL NOx Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
CAPE CANAVERAL PLANT	PCC1	383	383	383	383	389
CAPE CANAVERAL PLANT	PCC2	374	374	374	374	380
CUTLER	PCU5	32	32	32	32	33
CUTLER	PCU6	65	65	65	65	65
FORT MYERS PLANT	1-12	53	53	53	53	54
FORT MYERS PLANT	FMCT2A	144	144	144	144	146
FORT MYERS PLANT	FMCT2B	144	144	144	144	146
FORT MYERS PLANT	FMCT2C	150	150	150	150	152
FORT MYERS PLANT	FMCT2D	151	151	151	151	138
FORT MYERS PLANT	FMCT2E	149	149	149	149	147
FORT MYERS PLANT	FMCT2F	144	144	144	144	142
FORT MYERS PLANT	FMCT3A	53	53	53	53	50
FORT MYERS PLANT	FMCT3B	61	61	61	61	56
FORT MYERS PLANT	PFM1	70	70	70	70	0
FORT MYERS PLANT	PFM2	247	247	247	247	0
FPL Manatee	3	323	188	130	115	490
FPL Martin	8	321	187	129	114	487
FPL Turkey Point Unit 5	5	336	195	135	119	509
FPL Unsited Combined Cycle 1	1	0	0	0	0	0
FPL Unsited Combined Cycle 2	2	0	0	0	0	0
FPL West County 1	1	0	498	343	305	249
FPL West County 2	2	0	0	343	305	249
FPL West County 3	3	0	0	0	0	243
LAUDERDALE	1-12	39	39	39	39	39
LAUDERDALE	13-24	28	28	28	28	28
LAUDERDALE	4GT1	154	154	154	154	156
LAUDERDALE	4GT2	152	152	152	152	154
LAUDERDALE	5GT1	153	153	153	153	155
LAUDERDALE	5GT2	148	148	148	148	150
MANATEE	PMT1	649	649	649	649	658
MANATEE	PMT2	707	707	707	707	717
MARTIN PLANT	HRSG3A,3ST	150	150	150	150	152
MARTIN PLANT	HRSG3B,3ST	152	152	152	152	154
MARTIN PLANT	HRSG4A, 4ST	159	159	159	159	161
MARTIN PLANT	HRSG4B, 4ST	158	158	158	158	160
MARTIN PLANT	PMR1	724	724	724	724	735
MARTIN PLANT	PMR2	676	676	676	676	685
PORT EVERGLADES	1-12	27	27	27	27	27
PORT EVERGLADES	PPE1	191	191	191	191	194
PORT EVERGLADES	PPE2	195	195	195	195	198
PORT EVERGLADES	PPE3	366	366	366	366	371
PORT EVERGLADES	PPE4	382	382	382	382	387
PUTNAM	1GT1/HRSG11	71	71	71	71	72
PUTNAM	1GT2/HRSG12	71	71	71	71	72
PUTNAM	2GT1/HRSG21	67	67	67	67	68

FPL NOx Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
PUTNAM	2GT2/HRSG22	69	69	69	69	70
RIVIERA PLANT	PRV3	281	281	281	281	284
RIVIERA PLANT	PRV4	284	284	284	284	288
SANFORD POWER PLANT	PSN3	105	105	105	105	107
SANFORD POWER PLANT	PSN4	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	SNCT4A	151	151	151	151	102
SANFORD POWER PLANT	SNCT4B	153	153	153	153	104
SANFORD POWER PLANT	SNCT4C	152	152	152	152	103
SANFORD POWER PLANT	SNCT4D	149	149	149	149	99
SANFORD POWER PLANT	SNCT5A	150	150	150	150	142
SANFORD POWER PLANT	SNCT5B	150	150	150	150	143
SANFORD POWER PLANT	SNCT5C	153	153	153	153	135
SANFORD POWER PLANT	SNCT5D	142	142	142	142	136
TURKEY POINT PLANT	PTP1	365	365	365	365	370
TURKEY POINT PLANT	PTP2	360	360	360	360	365
ST JOHNS RIVER POWER PARK	PJK1	1,706	1,706	1,706	1,706	1,706
ST JOHNS RIVER POWER PARK	PJK1	1,559	1,559	1,559	1,559	1,559
SCHERER 4	PSG4	-	-	-	-	-
		383.265994	383.265994	383.265994	383.265994	394.152247

* Note: Unit allocations for all owners
except
SCHERER 4 76% owned
ST JOHNS RIVER POWER PARK 20% owned

FPL NOx Allowance A

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
CAPE CANAVERAL PLANT	PCC1	389	324	298	298	298
CAPE CANAVERAL PLANT	PCC2	380	316	291	291	291
CUTLER	PCU5	33	27	25	25	25
CUTLER	PCU6	65	55	50	50	50
FORT MYERS PLANT	1-12	54	45	42	42	42
FORT MYERS PLANT	FMCT2A	146	122	112	112	112
FORT MYERS PLANT	FMCT2B	146	122	112	112	112
FORT MYERS PLANT	FMCT2C	152	126	116	116	116
FORT MYERS PLANT	FMCT2D	138	115	106	106	106
FORT MYERS PLANT	FMCT2E	147	123	113	113	113
FORT MYERS PLANT	FMCT2F	142	119	109	109	109
FORT MYERS PLANT	FMCT3A	50	42	38	38	38
FORT MYERS PLANT	FMCT3B	56	47	43	43	43
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	490	408	376	376	376
FPL Martin	8	487	405	373	373	373
FPL Turkey Point Unit 5	5	509	424	390	390	390
FPL Unsited Combined Cycle 1	1	191	144	182	175	169
FPL Unsited Combined Cycle 2	2	0	73	93	89	86
FPL West County 1	1	188	139	996	996	995
FPL West County 2	2	188	139	169	163	157
FPL West County 3	3	191	144	182	175	169
LAUDERDALE	1-12	39	33	30	30	30
LAUDERDALE	13-24	28	24	22	22	22
LAUDERDALE	4GT1	156	130	120	120	120
LAUDERDALE	4GT2	154	128	118	118	118
LAUDERDALE	5GT1	155	129	119	119	119
LAUDERDALE	5GT2	150	125	115	115	115
MANATEE	PMT1	658	549	505	505	505
MANATEE	PMT2	717	597	550	550	550
MARTIN PLANT	HRSG3A,3ST	152	127	117	117	117
MARTIN PLANT	HRSG3B,3ST	154	128	118	118	118
MARTIN PLANT	HRSG4A, 4ST	161	135	124	124	124
MARTIN PLANT	HRSG4B, 4ST	160	134	123	123	123
MARTIN PLANT	PMR1	735	612	564	564	564
MARTIN PLANT	PMR2	685	571	526	526	526
PORT EVERGLADES	1-12	27	22	21	21	21
PORT EVERGLADES	PPE1	194	161	149	149	149
PORT EVERGLADES	PPE2	198	165	152	152	152
PORT EVERGLADES	PPE3	371	309	285	285	285
PORT EVERGLADES	PPE4	387	322	297	297	297
PUTNAM	1GT1/HRSG11	72	60	55	55	55
PUTNAM	1GT2/HRSG12	72	60	55	55	55
PUTNAM	2GT1/HRSG21	68	57	52	52	52

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
PUTNAM	2GT2/HRSG22	70	58	54	54	54
RIVIERA PLANT	PRV3	284	237	218	218	218
RIVIERA PLANT	PRV4	288	240	221	221	221
SANFORD POWER PLANT	PSN3	107	89	82	82	82
SANFORD POWER PLANT	PSN4	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	SNCT4A	102	85	78	78	78
SANFORD POWER PLANT	SNCT4B	104	87	80	80	80
SANFORD POWER PLANT	SNCT4C	103	86	79	79	79
SANFORD POWER PLANT	SNCT4D	99	82	76	76	76
SANFORD POWER PLANT	SNCT5A	142	119	109	109	109
SANFORD POWER PLANT	SNCT5B	143	119	110	110	110
SANFORD POWER PLANT	SNCT5C	135	112	103	103	103
SANFORD POWER PLANT	SNCT5D	136	113	104	104	104
TURKEY POINT PLANT	PTP1	370	308	284	284	284
TURKEY POINT PLANT	PTP2	365	304	280	280	280
ST JOHNS RIVER POWER PARK	PJK1	1,706	1,571	1,571	1,571	1,571
ST JOHNS RIVER POWER PARK	PJK1	1,559	1,435	1,435	1,435	1,435
SCHERER 4	PSG4	-	-	-	-	-
		394.152247	273.717939	232.06586	232.06586	232.06586

* Note: Unit allocations for all owners
except

SCHERER 4	76%
ST JOHNS RIVER POWER PARK	20%

FPL NOx Allowance A

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
CAPE CANAVERAL PLANT	PCC1	258	258	258	236	236
CAPE CANAVERAL PLANT	PCC2	252	252	252	230	230
CUTLER	PCU5	22	22	22	20	20
CUTLER	PCU6	43	43	43	40	40
FORT MYERS PLANT	1-12	36	36	36	33	33
FORT MYERS PLANT	FMCT2A	97	97	97	89	89
FORT MYERS PLANT	FMCT2B	97	97	97	89	89
FORT MYERS PLANT	FMCT2C	101	101	101	92	92
FORT MYERS PLANT	FMCT2D	91	91	91	84	84
FORT MYERS PLANT	FMCT2E	98	98	98	89	89
FORT MYERS PLANT	FMCT2F	94	94	94	86	86
FORT MYERS PLANT	FMCT3A	33	33	33	30	30
FORT MYERS PLANT	FMCT3B	37	37	37	34	34
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	320	320	320	287	287
FPL Martin	8	318	318	318	285	285
FPL Turkey Point Unit 5	5	333	333	333	298	298
FPL Unsited Combined Cycle 1	1	347	323	302	696	696
FPL Unsited Combined Cycle 2	2	177	164	154	355	355
FPL West County 1	1	848	848	848	760	760
FPL West County 2	2	848	848	848	760	760
FPL West County 3	3	778	778	778	696	696
LAUDERDALE	1-12	26	26	26	24	24
LAUDERDALE	13-24	19	19	19	17	17
LAUDERDALE	4GT1	103	103	103	95	95
LAUDERDALE	4GT2	102	102	102	93	93
LAUDERDALE	5GT1	103	103	103	94	94
LAUDERDALE	5GT2	99	99	99	91	91
MANATEE	PMT1	436	436	436	400	400
MANATEE	PMT2	475	475	475	435	435
MARTIN PLANT	HRSG3A,3ST	101	101	101	92	92
MARTIN PLANT	HRSG3B,3ST	102	102	102	93	93
MARTIN PLANT	HRSG4A, 4ST	107	107	107	98	98
MARTIN PLANT	HRSG4B, 4ST	106	106	106	97	97
MARTIN PLANT	PMR1	487	487	487	446	446
MARTIN PLANT	PMR2	454	454	454	416	416
PORT EVERGLADES	1-12	18	18	18	16	16
PORT EVERGLADES	PPE1	128	128	128	118	118
PORT EVERGLADES	PPE2	131	131	131	120	120
PORT EVERGLADES	PPE3	246	246	246	225	225
PORT EVERGLADES	PPE4	256	256	256	235	235
PUTNAM	1GT1/HRSG11	47	47	47	43	43
PUTNAM	1GT2/HRSG12	47	47	47	43	43
PUTNAM	2GT1/HRSG21	45	45	45	41	41

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
PUTNAM	2GT2/HRSG22	46	46	46	42	42
RIVIERA PLANT	PRV3	189	189	189	173	173
RIVIERA PLANT	PRV4	191	191	191	175	175
SANFORD POWER PLANT	PSN3	71	71	71	65	65
SANFORD POWER PLANT	PSN4	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	SNCT4A	67	67	67	62	62
SANFORD POWER PLANT	SNCT4B	69	69	69	63	63
SANFORD POWER PLANT	SNCT4C	68	68	68	62	62
SANFORD POWER PLANT	SNCT4D	66	66	66	60	60
SANFORD POWER PLANT	SNCT5A	94	94	94	86	86
SANFORD POWER PLANT	SNCT5B	95	95	95	87	87
SANFORD POWER PLANT	SNCT5C	89	89	89	82	82
SANFORD POWER PLANT	SNCT5D	90	90	90	83	83
TURKEY POINT PLANT	PTP1	245	245	245	224	224
TURKEY POINT PLANT	PTP2	242	242	242	221	221
ST JOHNS RIVER POWER PARK	PJK1	1,593	1,593	1,593	1,629	1,629
ST JOHNS RIVER POWER PARK	PJK1	1,455	1,455	1,455	1,488	1,488
SCHERER 4	PSG4	-	-	-	-	-
		173.152111	173.152111	173.152111	145.217742	145.217742

* Note: Unit allocations for all owners except

SCHERER 4	*76%*
ST JOHNS RIVER POWER PARK	*20%*

FPL NOx Allowance A

Facility Name	Federal Unit ID	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	236
CAPE CANAVERAL PLANT	PCC2	230
CUTLER	PCU5	20
CUTLER	PCU6	40
FORT MYERS PLANT	1-12	33
FORT MYERS PLANT	FMCT2A	89
FORT MYERS PLANT	FMCT2B	89
FORT MYERS PLANT	FMCT2C	92
FORT MYERS PLANT	FMCT2D	84
FORT MYERS PLANT	FMCT2E	89
FORT MYERS PLANT	FMCT2F	86
FORT MYERS PLANT	FMCT3A	30
FORT MYERS PLANT	FMCT3B	34
FORT MYERS PLANT	PFM1	0
FORT MYERS PLANT	PFM2	0
FPL Manatee	3	287
FPL Martin	8	285
FPL Turkey Point Unit 5	5	298
FPL Unsited Combined Cycle 1	1	696
FPL Unsited Combined Cycle 2	2	355
FPL West County 1	1	760
FPL West County 2	2	760
FPL West County 3	3	696
LAUDERDALE	1-12	24
LAUDERDALE	13-24	17
LAUDERDALE	4GT1	95
LAUDERDALE	4GT2	93
LAUDERDALE	5GT1	94
LAUDERDALE	5GT2	91
MANATEE	PMT1	400
MANATEE	PMT2	435
MARTIN PLANT	HRSG3A,3ST	92
MARTIN PLANT	HRSG3B,3ST	93
MARTIN PLANT	HRSG4A, 4ST	98
MARTIN PLANT	HRSG4B, 4ST	97
MARTIN PLANT	PMR1	446
MARTIN PLANT	PMR2	416
PORT EVERGLADES	1-12	16
PORT EVERGLADES	PPE1	118
PORT EVERGLADES	PPE2	120
PORT EVERGLADES	PPE3	225
PORT EVERGLADES	PPE4	235
PUTNAM	1GT1/HRSG11	43
PUTNAM	1GT2/HRSG12	43
PUTNAM	2GT1/HRSG21	41

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
PUTNAM	2GT2/HRSG22	42
RIVIERA PLANT	PRV3	173
RIVIERA PLANT	PRV4	175
SANFORD POWER PLANT	PSN3	65
SANFORD POWER PLANT	PSN4	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!
SANFORD POWER PLANT	SNCT4A	62
SANFORD POWER PLANT	SNCT4B	63
SANFORD POWER PLANT	SNCT4C	62
SANFORD POWER PLANT	SNCT4D	60
SANFORD POWER PLANT	SNCT5A	86
SANFORD POWER PLANT	SNCT5B	87
SANFORD POWER PLANT	SNCT5C	82
SANFORD POWER PLANT	SNCT5D	83
TURKEY POINT PLANT	PTP1	224
TURKEY POINT PLANT	PTP2	221
ST JOHNS RIVER POWER PARK	PJK1	1,629
ST JOHNS RIVER POWER PARK	PJK1	1,488
SCHERER 4	PSG4	-
		145.217742

* Note: Unit allocations for all owners
except
SCHERER 4 76%
ST JOHNS RIVER POWER PARK 20%

FPL CO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941	642,941	642,941	642,941	642,941
CAPE CANAVERAL PLANT	PCC2	622,743	622,743	622,743	622,743	622,743
CUTLER	PCU5	33,419	33,419	33,419	33,419	33,419
CUTLER	PCU6	72,274	72,274	72,274	72,274	72,274
FORT MYERS PLANT	1-12	57,963	57,963	57,963	57,963	57,963
FORT MYERS PLANT	FMCT2A	277,652	277,652	277,652	277,652	277,652
FORT MYERS PLANT	FMCT2B	274,807	274,807	274,807	274,807	274,807
FORT MYERS PLANT	FMCT2C	279,574	279,574	279,574	279,574	279,574
FORT MYERS PLANT	FMCT2D	265,577	265,577	265,577	265,577	265,577
FORT MYERS PLANT	FMCT2E	285,394	285,394	285,394	285,394	285,394
FORT MYERS PLANT	FMCT2F	281,522	281,522	281,522	281,522	281,522
FORT MYERS PLANT	FMCT3A	57,213	57,213	57,213	57,213	57,213
FORT MYERS PLANT	FMCT3B	66,390	66,390	66,390	66,390	66,390
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	944,470	944,470	944,470	944,470	944,470
FPL Martin	8	938,498	938,498	938,498	938,498	938,498
FPL Turkey Point Unit 5	5	2,452,893	2,452,893	2,452,893	2,452,893	2,452,893
FPL Unsited Combined Cycle 1	2	0	0	0	0	0
FPL Unsited Combined Cycle 2	1	0	0	0	0	0
FPL West County 1	1	0	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 2	2	0	0	2,559,540	2,559,540	2,559,540
FPL West County 3	1	0	0	0	0	2,559,540
LAUDERDALE	1-12	44,719	44,719	44,719	44,719	44,719
LAUDERDALE	13-24	48,436	48,436	48,436	48,436	48,436
LAUDERDALE	4GT1	291,057	291,057	291,057	291,057	291,057
LAUDERDALE	4GT2	290,436	290,436	290,436	290,436	290,436
LAUDERDALE	5GT1	297,176	297,176	297,176	297,176	297,176
LAUDERDALE	5GT2	284,409	284,409	284,409	284,409	284,409
MANATEE	PMT1	1,143,717	1,143,717	1,143,717	1,143,717	1,143,717
MANATEE	PMT2	1,181,259	1,181,259	1,181,259	1,181,259	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066	298,066	298,066	298,066	298,066
MARTIN PLANT	HRSG3B,3ST	312,358	312,358	312,358	312,358	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439	304,439	304,439	304,439	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614	303,614	303,614	303,614	303,614
MARTIN PLANT	PMR1	1,110,598	1,110,598	1,110,598	1,110,598	1,110,598
MARTIN PLANT	PMR2	1,167,666	1,167,666	1,167,666	1,167,666	1,167,666
PORT EVERGLADES	1-12	34,519	34,519	34,519	34,519	34,519
PORT EVERGLADES	PPE1	256,908	256,908	256,908	256,908	256,908
PORT EVERGLADES	PPE2	286,869	286,869	286,869	286,869	286,869
PORT EVERGLADES	PPE3	620,859	620,859	620,859	620,859	620,859
PORT EVERGLADES	PPE4	629,076	629,076	629,076	629,076	629,076
PUTNAM	1GT1/HRSG11	126,030	126,030	126,030	126,030	126,030
PUTNAM	1GT2/HRSG12	125,170	125,170	125,170	125,170	125,170
PUTNAM	2GT1/HRSG21	118,782	118,782	118,782	118,782	118,782

FPL CO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
PUTNAM	2GT2/HRSG22	119,391	119,391	119,391	119,391	119,391
RIVIERA PLANT	PRV3	469,923	469,923	469,923	469,923	469,923
RIVIERA PLANT	PRV4	502,854	502,854	502,854	502,854	502,854
SANFORD POWER PLANT	PSN3	149,920	149,920	149,920	149,920	149,920
SANFORD POWER PLANT	PSN4	0	0	0	0	0
SANFORD POWER PLANT	PSN5	0	0	0	0	0
SANFORD POWER PLANT	SNCT4A	195,722	195,722	195,722	195,722	195,722
SANFORD POWER PLANT	SNCT4B	197,275	197,275	197,275	197,275	197,275
SANFORD POWER PLANT	SNCT4C	200,268	200,268	200,268	200,268	200,268
SANFORD POWER PLANT	SNCT4D	199,505	199,505	199,505	199,505	199,505
SANFORD POWER PLANT	SNCT5A	271,096	271,096	271,096	271,096	271,096
SANFORD POWER PLANT	SNCT5B	275,989	275,989	275,989	275,989	275,989
SANFORD POWER PLANT	SNCT5C	262,006	262,006	262,006	262,006	262,006
SANFORD POWER PLANT	SNCT5D	264,402	264,402	264,402	264,402	264,402
TURKEY POINT PLANT	PTP1	579,084	579,084	579,084	579,084	579,084
TURKEY POINT PLANT	PTP2	593,797	593,797	593,797	593,797	593,797

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941	642,941	642,941	642,941	642,941
CAPE CANAVERAL PLANT	PCC2	622,743	622,743	622,743	622,743	622,743
CUTLER	PCU5	33,419	33,419	33,419	33,419	33,419
CUTLER	PCU6	72,274	72,274	72,274	72,274	72,274
FORT MYERS PLANT	1-12	57,963	57,963	57,963	57,963	57,963
FORT MYERS PLANT	FMCT2A	277,652	277,652	277,652	277,652	277,652
FORT MYERS PLANT	FMCT2B	274,807	274,807	274,807	274,807	274,807
FORT MYERS PLANT	FMCT2C	279,574	279,574	279,574	279,574	279,574
FORT MYERS PLANT	FMCT2D	265,577	265,577	265,577	265,577	265,577
FORT MYERS PLANT	FMCT2E	285,394	285,394	285,394	285,394	285,394
FORT MYERS PLANT	FMCT2F	281,522	281,522	281,522	281,522	281,522
FORT MYERS PLANT	FMCT3A	57,213	57,213	57,213	57,213	57,213
FORT MYERS PLANT	FMCT3B	66,390	66,390	66,390	66,390	66,390
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	944,470	944,470	944,470	944,470	944,470
FPL Martin	8	938,498	938,498	938,498	938,498	938,498
FPL Turkey Point Unit 5	5	2,452,893	2,452,893	2,452,893	2,452,893	2,452,893
FPL Unsited Combined Cycle 1	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL Unsited Combined Cycle 2	1	0	1,194,452	1,194,452	1,194,452	1,194,452
FPL West County 1	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 2	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 3	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
LAUDERDALE	1-12	44,719	44,719	44,719	44,719	44,719
LAUDERDALE	13-24	48,436	48,436	48,436	48,436	48,436
LAUDERDALE	4GT1	291,057	291,057	291,057	291,057	291,057
LAUDERDALE	4GT2	290,436	290,436	290,436	290,436	290,436
LAUDERDALE	5GT1	297,176	297,176	297,176	297,176	297,176
LAUDERDALE	5GT2	284,409	284,409	284,409	284,409	284,409
MANATEE	PMT1	1,143,717	1,143,717	1,143,717	1,143,717	1,143,717
MANATEE	PMT2	1,181,259	1,181,259	1,181,259	1,181,259	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066	298,066	298,066	298,066	298,066
MARTIN PLANT	HRSG3B,3ST	312,358	312,358	312,358	312,358	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439	304,439	304,439	304,439	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614	303,614	303,614	303,614	303,614
MARTIN PLANT	PMR1	1,110,598	1,110,598	1,110,598	1,110,598	1,110,598
MARTIN PLANT	PMR2	1,167,666	1,167,666	1,167,666	1,167,666	1,167,666
PORT EVERGLADES	1-12	34,519	34,519	34,519	34,519	34,519
PORT EVERGLADES	PPE1	256,908	256,908	256,908	256,908	256,908
PORT EVERGLADES	PPE2	286,869	286,869	286,869	286,869	286,869
PORT EVERGLADES	PPE3	620,859	620,859	620,859	620,859	620,859
PORT EVERGLADES	PPE4	629,076	629,076	629,076	629,076	629,076
PUTNAM	1GT1/HRSG11	126,030	126,030	126,030	126,030	126,030
PUTNAM	1GT2/HRSG12	125,170	125,170	125,170	125,170	125,170
PUTNAM	2GT1/HRSG21	118,782	118,782	118,782	118,782	118,782

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
PUTNAM	2GT2/HRSG22	119,391	119,391	119,391	119,391	119,391
RIVIERA PLANT	PRV3	469,923	469,923	469,923	469,923	469,923
RIVIERA PLANT	PRV4	502,854	502,854	502,854	502,854	502,854
SANFORD POWER PLANT	PSN3	149,920	149,920	149,920	149,920	149,920
SANFORD POWER PLANT	PSN4	0	0	0	0	0
SANFORD POWER PLANT	PSN5	0	0	0	0	0
SANFORD POWER PLANT	SNCT4A	195,722	195,722	195,722	195,722	195,722
SANFORD POWER PLANT	SNCT4B	197,275	197,275	197,275	197,275	197,275
SANFORD POWER PLANT	SNCT4C	200,268	200,268	200,268	200,268	200,268
SANFORD POWER PLANT	SNCT4D	199,505	199,505	199,505	199,505	199,505
SANFORD POWER PLANT	SNCT5A	271,096	271,096	271,096	271,096	271,096
SANFORD POWER PLANT	SNCT5B	275,989	275,989	275,989	275,989	275,989
SANFORD POWER PLANT	SNCT5C	262,006	262,006	262,006	262,006	262,006
SANFORD POWER PLANT	SNCT5D	264,402	264,402	264,402	264,402	264,402
TURKEY POINT PLANT	PTP1	579,084	579,084	579,084	579,084	579,084
TURKEY POINT PLANT	PTP2	593,797	593,797	593,797	593,797	593,797

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941	642,941	642,941	642,941	642,941
CAPE CANAVERAL PLANT	PCC2	622,743	622,743	622,743	622,743	622,743
CUTLER	PCU5	33,419	33,419	33,419	33,419	33,419
CUTLER	PCU6	72,274	72,274	72,274	72,274	72,274
FORT MYERS PLANT	1-12	57,963	57,963	57,963	57,963	57,963
FORT MYERS PLANT	FMCT2A	277,652	277,652	277,652	277,652	277,652
FORT MYERS PLANT	FMCT2B	274,807	274,807	274,807	274,807	274,807
FORT MYERS PLANT	FMCT2C	279,574	279,574	279,574	279,574	279,574
FORT MYERS PLANT	FMCT2D	265,577	265,577	265,577	265,577	265,577
FORT MYERS PLANT	FMCT2E	285,394	285,394	285,394	285,394	285,394
FORT MYERS PLANT	FMCT2F	281,522	281,522	281,522	281,522	281,522
FORT MYERS PLANT	FMCT3A	57,213	57,213	57,213	57,213	57,213
FORT MYERS PLANT	FMCT3B	66,390	66,390	66,390	66,390	66,390
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	944,470	944,470	944,470	944,470	944,470
FPL Martin	8	938,498	938,498	938,498	938,498	938,498
FPL Turkey Point Unit 5	5	2,452,893	2,452,893	2,452,893	2,452,893	2,452,893
FPL Unsited Combined Cycle 1	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL Unsited Combined Cycle 2	1	1,194,452	1,194,452	1,194,452	1,194,452	1,194,452
FPL West County 1	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 2	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 3	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
LAUDERDALE	1-12	44,719	44,719	44,719	44,719	44,719
LAUDERDALE	13-24	48,436	48,436	48,436	48,436	48,436
LAUDERDALE	4GT1	291,057	291,057	291,057	291,057	291,057
LAUDERDALE	4GT2	290,436	290,436	290,436	290,436	290,436
LAUDERDALE	5GT1	297,176	297,176	297,176	297,176	297,176
LAUDERDALE	5GT2	284,409	284,409	284,409	284,409	284,409
MANATEE	PMT1	1,143,717	1,143,717	1,143,717	1,143,717	1,143,717
MANATEE	PMT2	1,181,259	1,181,259	1,181,259	1,181,259	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066	298,066	298,066	298,066	298,066
MARTIN PLANT	HRSG3B,3ST	312,358	312,358	312,358	312,358	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439	304,439	304,439	304,439	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614	303,614	303,614	303,614	303,614
MARTIN PLANT	PMR1	1,110,598	1,110,598	1,110,598	1,110,598	1,110,598
MARTIN PLANT	PMR2	1,167,666	1,167,666	1,167,666	1,167,666	1,167,666
PORT EVERGLADES	1-12	34,519	34,519	34,519	34,519	34,519
PORT EVERGLADES	PPE1	256,908	256,908	256,908	256,908	256,908
PORT EVERGLADES	PPE2	286,869	286,869	286,869	286,869	286,869
PORT EVERGLADES	PPE3	620,859	620,859	620,859	620,859	620,859
PORT EVERGLADES	PPE4	629,076	629,076	629,076	629,076	629,076
PUTNAM	1GT1/HRSG11	126,030	126,030	126,030	126,030	126,030
PUTNAM	1GT2/HRSG12	125,170	125,170	125,170	125,170	125,170
PUTNAM	2GT1/HRSG21	118,782	118,782	118,782	118,782	118,782

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
PUTNAM	2GT2/HRSG22	119,391	119,391	119,391	119,391	119,391
RIVIERA PLANT	PRV3	469,923	469,923	469,923	469,923	469,923
RIVIERA PLANT	PRV4	502,854	502,854	502,854	502,854	502,854
SANFORD POWER PLANT	PSN3	149,920	149,920	149,920	149,920	149,920
SANFORD POWER PLANT	PSN4	0	0	0	0	0
SANFORD POWER PLANT	PSN5	0	0	0	0	0
SANFORD POWER PLANT	SNCT4A	195,722	195,722	195,722	195,722	195,722
SANFORD POWER PLANT	SNCT4B	197,275	197,275	197,275	197,275	197,275
SANFORD POWER PLANT	SNCT4C	200,268	200,268	200,268	200,268	200,268
SANFORD POWER PLANT	SNCT4D	199,505	199,505	199,505	199,505	199,505
SANFORD POWER PLANT	SNCT5A	271,096	271,096	271,096	271,096	271,096
SANFORD POWER PLANT	SNCT5B	275,989	275,989	275,989	275,989	275,989
SANFORD POWER PLANT	SNCT5C	262,006	262,006	262,006	262,006	262,006
SANFORD POWER PLANT	SNCT5D	264,402	264,402	264,402	264,402	264,402
TURKEY POINT PLANT	PTP1	579,084	579,084	579,084	579,084	579,084
TURKEY POINT PLANT	PTP2	593,797	593,797	593,797	593,797	593,797

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941
CAPE CANAVERAL PLANT	PCC2	622,743
CUTLER	PCU5	33,419
CUTLER	PCU6	72,274
FORT MYERS PLANT	1-12	57,963
FORT MYERS PLANT	FMCT2A	277,652
FORT MYERS PLANT	FMCT2B	274,807
FORT MYERS PLANT	FMCT2C	279,574
FORT MYERS PLANT	FMCT2D	265,577
FORT MYERS PLANT	FMCT2E	285,394
FORT MYERS PLANT	FMCT2F	281,522
FORT MYERS PLANT	FMCT3A	57,213
FORT MYERS PLANT	FMCT3B	66,390
FORT MYERS PLANT	PFM1	0
FORT MYERS PLANT	PFM2	0
FPL Manatee	3	944,470
FPL Martin	8	938,498
FPL Turkey Point Unit 5	5	2,452,893
FPL Unsited Combined Cycle 1	2	2,559,540
FPL Unsited Combined Cycle 2	1	1,194,452
FPL West County 1	1	2,559,540
FPL West County 2	2	2,559,540
FPL West County 3	1	2,559,540
LAUDERDALE	1-12	44,719
LAUDERDALE	13-24	48,436
LAUDERDALE	4GT1	291,057
LAUDERDALE	4GT2	290,436
LAUDERDALE	5GT1	297,176
LAUDERDALE	5GT2	284,409
MANATEE	PMT1	1,143,717
MANATEE	PMT2	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066
MARTIN PLANT	HRSG3B,3ST	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614
MARTIN PLANT	PMR1	1,110,598
MARTIN PLANT	PMR2	1,167,666
PORT EVERGLADES	1-12	34,519
PORT EVERGLADES	PPE1	256,908
PORT EVERGLADES	PPE2	286,869
PORT EVERGLADES	PPE3	620,859
PORT EVERGLADES	PPE4	629,076
PUTNAM	1GT1/HRSG11	126,030
PUTNAM	1GT2/HRSG12	125,170
PUTNAM	2GT1/HRSG21	118,782

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
PUTNAM	2GT2/HRSG22	119,391
RIVIERA PLANT	PRV3	469,923
RIVIERA PLANT	PRV4	502,854
SANFORD POWER PLANT	PSN3	149,920
SANFORD POWER PLANT	PSN4	0
SANFORD POWER PLANT	PSN5	0
SANFORD POWER PLANT	SNCT4A	195,722
SANFORD POWER PLANT	SNCT4B	197,275
SANFORD POWER PLANT	SNCT4C	200,268
SANFORD POWER PLANT	SNCT4D	199,505
SANFORD POWER PLANT	SNCT5A	271,096
SANFORD POWER PLANT	SNCT5B	275,989
SANFORD POWER PLANT	SNCT5C	262,006
SANFORD POWER PLANT	SNCT5D	264,402
TURKEY POINT PLANT	PTP1	579,084
TURKEY POINT PLANT	PTP2	593,797

FPL CO2 Allowance A

Facility Name	Federal Unit ID
CAPE CANAVERAL PLANT	PCC1
CAPE CANAVERAL PLANT	PCC2
CUTLER	PCU5
CUTLER	PCU6
FORT MYERS PLANT	1-12
FORT MYERS PLANT	FMCT2A
FORT MYERS PLANT	FMCT2B
FORT MYERS PLANT	FMCT2C
FORT MYERS PLANT	FMCT2D
FORT MYERS PLANT	FMCT2E
FORT MYERS PLANT	FMCT2F
FORT MYERS PLANT	FMCT3A
FORT MYERS PLANT	FMCT3B
FORT MYERS PLANT	PFM1
FORT MYERS PLANT	PFM2
FPL Manatee	3
FPL Martin	8
FPL Turkey Point Unit 5	5
FPL Unsited Combined Cycle 1	2
FPL Unsited Combined Cycle 2	1
FPL West County 1	1
FPL West County 2	2
FPL West County 3	1
LAUDERDALE	1-12
LAUDERDALE	13-24
LAUDERDALE	4GT1
LAUDERDALE	4GT2
LAUDERDALE	5GT1
LAUDERDALE	5GT2
MANATEE	PMT1
MANATEE	PMT2
MARTIN PLANT	HRSG3A,3ST
MARTIN PLANT	HRSG3B,3ST
MARTIN PLANT	HRSG4A, 4ST
MARTIN PLANT	HRSG4B, 4ST
MARTIN PLANT	PMR1
MARTIN PLANT	PMR2
PORT EVERGLADES	1-12
PORT EVERGLADES	PPE1
PORT EVERGLADES	PPE2
PORT EVERGLADES	PPE3
PORT EVERGLADES	PPE4
PUTNAM	1GT1/HRSG11
PUTNAM	1GT2/HRSG12
PUTNAM	2GT1/HRSG21

FPL CO2 Allowance Al

Facility Name	Federal Unit ID
PUTNAM	2GT2/HRSG22
RIVIERA PLANT	PRV3
RIVIERA PLANT	PRV4
SANFORD POWER PLANT	PSN3
SANFORD POWER PLANT	PSN4
SANFORD POWER PLANT	PSN5
SANFORD POWER PLANT	SNCT4A
SANFORD POWER PLANT	SNCT4B
SANFORD POWER PLANT	SNCT4C
SANFORD POWER PLANT	SNCT4D
SANFORD POWER PLANT	SNCT5A
SANFORD POWER PLANT	SNCT5B
SANFORD POWER PLANT	SNCT5C
SANFORD POWER PLANT	SNCT5D
TURKEY POINT PLANT	PTP1
TURKEY POINT PLANT	PTP2

FPL Hg Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances	2014 Allowances

FPL Hg Allowan

Facility Name	Federal Unit ID	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances	2019 Allowances	2020 Allowances

FPL Hg Allowan

Facility Name	Federal Unit ID	2021 Allowances	2022 Allowances	2023 Allowances	2024 Allowances

FPL SO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
CAPE CANAVERAL PLANT	PCC1	4,225	4,232	4,232	4,232	4,232
CAPE CANAVERAL PLANT	PCC2	4,963	4,969	4,969	4,969	4,969
CUTLER	PCU5	-	4	4	4	4
CUTLER	PCU6	-	9	9	9	9
FORT MYERS PLANT	1-12	-	-	-	-	-
FORT MYERS PLANT	FMCT2A	-	-	-	-	-
FORT MYERS PLANT	FMCT2B	-	-	-	-	-
FORT MYERS PLANT	FMCT2C	-	-	-	-	-
FORT MYERS PLANT	FMCT2D	-	-	-	-	-
FORT MYERS PLANT	FMCT2E	-	-	-	-	-
FORT MYERS PLANT	FMCT2F	-	-	-	-	-
FORT MYERS PLANT	FMCT3A	-	-	-	-	-
FORT MYERS PLANT	FMCT3B	-	-	-	-	-
FORT MYERS PLANT	PFM1	3,189	3,194	3,194	3,194	3,194
FORT MYERS PLANT	PFM2	9,460	9,475	9,475	9,475	9,475
FPL Manatee	3	-	-	-	-	-
FPL Martin	8	-	-	-	-	-
FPL Turkey Point Unit 5	5	-	-	-	-	-
FPL Unsited Combined Cycle 1	2	-	-	-	-	-
FPL Unsited Combined Cycle 2	2	-	-	-	-	-
FPL West County 1	1	-	-	-	-	-
FPL West County 2	2	-	-	-	-	-
FPL West County 3	3	-	-	-	-	-
LAUDERDALE	1-12	-	-	-	-	-
LAUDERDALE	13-24	-	-	-	-	-
LAUDERDALE	4GT1	948	950	950	950	950
LAUDERDALE	4GT2	948	950	950	950	950
LAUDERDALE	5GT1	948	950	950	950	950
LAUDERDALE	5GT2	948	950	950	950	950
MANATEE	PMT1	13,777	13,799	13,799	13,799	13,799
MANATEE	PMT2	12,701	12,716	12,716	12,716	12,716
MARTIN PLANT	HRSG3A,3ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG3B,3ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4A, 4ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4B, 4ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	PMR1	5,094	5,102	5,102	5,102	5,102
MARTIN PLANT	PMR2	6,041	6,049	6,049	6,049	6,049
PORT EVERGLADES	1-12	-	-	-	-	-
PORT EVERGLADES	PPE1	2,340	2,343	2,343	2,343	2,343
PORT EVERGLADES	PPE2	2,414	2,417	2,417	2,417	2,417
PORT EVERGLADES	PPE3	5,882	5,891	5,891	5,891	5,891
PORT EVERGLADES	PPE4	5,964	5,973	5,973	5,973	5,973
PUTNAM	1GT1/HRSG11	1,644	1,647	1,647	1,647	1,647
PUTNAM	1GT2/HRSG12	1,644	1,647	1,647	1,647	1,647
PUTNAM	2GT1/HRSG21	1,568	1,570	1,570	1,570	1,570

FPL SO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
PUTNAM	2GT2/HRSG22	1,568	1,570	1,570	1,570	1,570
RIVIERA PLANT	PRV3	3,574	3,580	3,580	3,580	3,580
RIVIERA PLANT	PRV4	3,546	3,551	3,551	3,551	3,551
SANFORD POWER PLANT	PSN3	1,085	1,087	1,087	1,087	1,087
SANFORD POWER PLANT	PSN4	8,615	3,323	3,323	3,323	3,323
SANFORD POWER PLANT	PSN5	3,222	3,220	3,220	3,220	3,220
SANFORD POWER PLANT	SNCT4A	-	-	-	-	-
SANFORD POWER PLANT	SNCT4B	-	-	-	-	-
SANFORD POWER PLANT	SNCT4C	-	-	-	-	-
SANFORD POWER PLANT	SNCT4D	-	-	-	-	-
SANFORD POWER PLANT	SNCT5A	-	-	-	-	-
SANFORD POWER PLANT	SNCT5B	-	-	-	-	-
SANFORD POWER PLANT	SNCT5C	-	-	-	-	-
SANFORD POWER PLANT	SNCT5D	-	-	-	-	-
TURKEY POINT PLANT	PTP1	5,870	5,879	5,879	5,879	5,879
TURKEY POINT PLANT	PTP2	5,913	5,924	5,924	5,924	5,924

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
CAPE CANAVERAL PLANT	PCC1	4,232	4,232	4,232	4,232	4,232
CAPE CANAVERAL PLANT	PCC2	4,969	4,969	4,969	4,969	4,969
CUTLER	PCU5	4	4	4	4	4
CUTLER	PCU6	9	9	9	9	9
FORT MYERS PLANT	1-12	-	-	-	-	-
FORT MYERS PLANT	FMCT2A	-	-	-	-	-
FORT MYERS PLANT	FMCT2B	-	-	-	-	-
FORT MYERS PLANT	FMCT2C	-	-	-	-	-
FORT MYERS PLANT	FMCT2D	-	-	-	-	-
FORT MYERS PLANT	FMCT2E	-	-	-	-	-
FORT MYERS PLANT	FMCT2F	-	-	-	-	-
FORT MYERS PLANT	FMCT3A	-	-	-	-	-
FORT MYERS PLANT	FMCT3B	-	-	-	-	-
FORT MYERS PLANT	PFM1	3,194	3,194	3,194	3,194	3,194
FORT MYERS PLANT	PFM2	9,475	9,475	9,475	9,475	9,475
FPL Manatee	3	-	-	-	-	-
FPL Martin	8	-	-	-	-	-
FPL Turkey Point Unit 5	5	-	-	-	-	-
FPL Unsited Combined Cycle 1	2	-	-	-	-	-
FPL Unsited Combined Cycle 2	2	-	-	-	-	-
FPL West County 1	1	-	-	-	-	-
FPL West County 2	2	-	-	-	-	-
FPL West County 3	3	-	-	-	-	-
LAUDERDALE	1-12	-	-	-	-	-
LAUDERDALE	13-24	-	-	-	-	-
LAUDERDALE	4GT1	950	950	950	950	950
LAUDERDALE	4GT2	950	950	950	950	950
LAUDERDALE	5GT1	950	950	950	950	950
LAUDERDALE	5GT2	950	950	950	950	950
MANATEE	PMT1	13,799	13,799	13,799	13,799	13,799
MANATEE	PMT2	12,716	12,716	12,716	12,716	12,716
MARTIN PLANT	HRSG3A,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG3B,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4A, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4B, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	PMR1	5,102	5,102	5,102	5,102	5,102
MARTIN PLANT	PMR2	6,049	6,049	6,049	6,049	6,049
PORT EVERGLADES	1-12	-	-	-	-	-
PORT EVERGLADES	PPE1	2,343	2,343	2,343	2,343	2,343
PORT EVERGLADES	PPE2	2,417	2,417	2,417	2,417	2,417
PORT EVERGLADES	PPE3	5,891	5,891	5,891	5,891	5,891
PORT EVERGLADES	PPE4	5,973	5,973	5,973	5,973	5,973
PUTNAM	1GT1/HRSG11	1,647	1,647	1,647	1,647	1,647
PUTNAM	1GT2/HRSG12	1,647	1,647	1,647	1,647	1,647
PUTNAM	2GT1/HRSG21	1,570	1,570	1,570	1,570	1,570

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
PUTNAM	2GT2/HRSG22	1,570	1,570	1,570	1,570	1,570
RIVIERA PLANT	PRV3	3,580	3,580	3,580	3,580	3,580
RIVIERA PLANT	PRV4	3,551	3,551	3,551	3,551	3,551
SANFORD POWER PLANT	PSN3	1,087	1,087	1,087	1,087	1,087
SANFORD POWER PLANT	PSN4	3,323	3,323	3,323	3,323	3,323
SANFORD POWER PLANT	PSN5	3,220	3,220	3,220	3,220	3,220
SANFORD POWER PLANT	SNCT4A	-	-	-	-	-
SANFORD POWER PLANT	SNCT4B	-	-	-	-	-
SANFORD POWER PLANT	SNCT4C	-	-	-	-	-
SANFORD POWER PLANT	SNCT4D	-	-	-	-	-
SANFORD POWER PLANT	SNCT5A	-	-	-	-	-
SANFORD POWER PLANT	SNCT5B	-	-	-	-	-
SANFORD POWER PLANT	SNCT5C	-	-	-	-	-
SANFORD POWER PLANT	SNCT5D	-	-	-	-	-
TURKEY POINT PLANT	PTP1	5,879	5,879	5,879	5,879	5,879
TURKEY POINT PLANT	PTP2	5,924	5,924	5,924	5,924	5,924

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
CAPE CANAVERAL PLANT	PCC1	4,232	4,232	4,232	4,232	4,232
CAPE CANAVERAL PLANT	PCC2	4,969	4,969	4,969	4,969	4,969
CUTLER	PCU5	4	4	4	4	4
CUTLER	PCU6	9	9	9	9	9
FORT MYERS PLANT	1-12	-	-	-	-	-
FORT MYERS PLANT	FMCT2A	-	-	-	-	-
FORT MYERS PLANT	FMCT2B	-	-	-	-	-
FORT MYERS PLANT	FMCT2C	-	-	-	-	-
FORT MYERS PLANT	FMCT2D	-	-	-	-	-
FORT MYERS PLANT	FMCT2E	-	-	-	-	-
FORT MYERS PLANT	FMCT2F	-	-	-	-	-
FORT MYERS PLANT	FMCT3A	-	-	-	-	-
FORT MYERS PLANT	FMCT3B	-	-	-	-	-
FORT MYERS PLANT	PFM1	3,194	3,194	3,194	3,194	3,194
FORT MYERS PLANT	PFM2	9,475	9,475	9,475	9,475	9,475
FPL Manatee	3	-	-	-	-	-
FPL Martin	8	-	-	-	-	-
FPL Turkey Point Unit 5	5	-	-	-	-	-
FPL Unsited Combined Cycle 1	2	-	-	-	-	-
FPL Unsited Combined Cycle 2	2	-	-	-	-	-
FPL West County 1	1	-	-	-	-	-
FPL West County 2	2	-	-	-	-	-
FPL West County 3	3	-	-	-	-	-
LAUDERDALE	1-12	-	-	-	-	-
LAUDERDALE	13-24	-	-	-	-	-
LAUDERDALE	4GT1	950	950	950	950	950
LAUDERDALE	4GT2	950	950	950	950	950
LAUDERDALE	5GT1	950	950	950	950	950
LAUDERDALE	5GT2	950	950	950	950	950
MANATEE	PMT1	13,799	13,799	13,799	13,799	13,799
MANATEE	PMT2	12,716	12,716	12,716	12,716	12,716
MARTIN PLANT	HRSG3A,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG3B,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4A, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4B, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	PMR1	5,102	5,102	5,102	5,102	5,102
MARTIN PLANT	PMR2	6,049	6,049	6,049	6,049	6,049
PORT EVERGLADES	1-12	-	-	-	-	-
PORT EVERGLADES	PPE1	2,343	2,343	2,343	2,343	2,343
PORT EVERGLADES	PPE2	2,417	2,417	2,417	2,417	2,417
PORT EVERGLADES	PPE3	5,891	5,891	5,891	5,891	5,891
PORT EVERGLADES	PPE4	5,973	5,973	5,973	5,973	5,973
PUTNAM	1GT1/HRSG11	1,647	1,647	1,647	1,647	1,647
PUTNAM	1GT2/HRSG12	1,647	1,647	1,647	1,647	1,647
PUTNAM	2GT1/HRSG21	1,570	1,570	1,570	1,570	1,570

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
PUTNAM	2GT2/HRSG22	1,570	1,570	1,570	1,570	1,570
RIVIERA PLANT	PRV3	3,580	3,580	3,580	3,580	3,580
RIVIERA PLANT	PRV4	3,551	3,551	3,551	3,551	3,551
SANFORD POWER PLANT	PSN3	1,087	1,087	1,087	1,087	1,087
SANFORD POWER PLANT	PSN4	3,323	3,323	3,323	3,323	3,323
SANFORD POWER PLANT	PSN5	3,220	3,220	3,220	3,220	3,220
SANFORD POWER PLANT	SNCT4A	-	-	-	-	-
SANFORD POWER PLANT	SNCT4B	-	-	-	-	-
SANFORD POWER PLANT	SNCT4C	-	-	-	-	-
SANFORD POWER PLANT	SNCT4D	-	-	-	-	-
SANFORD POWER PLANT	SNCT5A	-	-	-	-	-
SANFORD POWER PLANT	SNCT5B	-	-	-	-	-
SANFORD POWER PLANT	SNCT5C	-	-	-	-	-
SANFORD POWER PLANT	SNCT5D	-	-	-	-	-
TURKEY POINT PLANT	PTP1	5,879	5,879	5,879	5,879	5,879
TURKEY POINT PLANT	PTP2	5,924	5,924	5,924	5,924	5,924

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	4,232
CAPE CANAVERAL PLANT	PCC2	4,969
CUTLER	PCU5	4
CUTLER	PCU6	9
FORT MYERS PLANT	1-12	-
FORT MYERS PLANT	FMCT2A	-
FORT MYERS PLANT	FMCT2B	-
FORT MYERS PLANT	FMCT2C	-
FORT MYERS PLANT	FMCT2D	-
FORT MYERS PLANT	FMCT2E	-
FORT MYERS PLANT	FMCT2F	-
FORT MYERS PLANT	FMCT3A	-
FORT MYERS PLANT	FMCT3B	-
FORT MYERS PLANT	PFM1	3,194
FORT MYERS PLANT	PFM2	9,475
FPL Manatee	3	-
FPL Martin	8	-
FPL Turkey Point Unit 5	5	-
FPL Unsited Combined Cycle 1	2	-
FPL Unsited Combined Cycle 2	2	-
FPL West County 1	1	-
FPL West County 2	2	-
FPL West County 3	3	-
LAUDERDALE	1-12	-
LAUDERDALE	13-24	-
LAUDERDALE	4GT1	950
LAUDERDALE	4GT2	950
LAUDERDALE	5GT1	950
LAUDERDALE	5GT2	950
MANATEE	PMT1	13,799
MANATEE	PMT2	12,716
MARTIN PLANT	HRSG3A,3ST	1,277
MARTIN PLANT	HRSG3B,3ST	1,277
MARTIN PLANT	HRSG4A, 4ST	1,277
MARTIN PLANT	HRSG4B, 4ST	1,277
MARTIN PLANT	PMR1	5,102
MARTIN PLANT	PMR2	5,049
PORT EVERGLADES	1-12	-
PORT EVERGLADES	PPE1	2,343
PORT EVERGLADES	PPE2	2,417
PORT EVERGLADES	PPE3	5,891
PORT EVERGLADES	PPE4	5,973
PUTNAM	1GT1/HRSG11	1,647
PUTNAM	1GT2/HRSG12	1,647
PUTNAM	2GT1/HRSG21	1,570

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
PUTNAM	2GT2/HRSG22	1,570
RIVIERA PLANT	PRV3	3,580
RIVIERA PLANT	PRV4	3,551
SANFORD POWER PLANT	PSN3	1,087
SANFORD POWER PLANT	PSN4	3,323
SANFORD POWER PLANT	PSN5	3,220
SANFORD POWER PLANT	SNCT4A	-
SANFORD POWER PLANT	SNCT4B	-
SANFORD POWER PLANT	SNCT4C	-
SANFORD POWER PLANT	SNCT4D	-
SANFORD POWER PLANT	SNCT5A	-
SANFORD POWER PLANT	SNCT5B	-
SANFORD POWER PLANT	SNCT5C	-
SANFORD POWER PLANT	SNCT5D	-
TURKEY POINT PLANT	PTP1	5,879
TURKEY POINT PLANT	PTP2	5,924

FPL NOx Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
CAPE CANAVERAL PLANT	PCC1	383	383	383	383	389
CAPE CANAVERAL PLANT	PCC2	374	374	374	374	380
CUTLER	PCU5	32	32	32	32	33
CUTLER	PCU6	65	65	65	65	65
FORT MYERS PLANT	1-12	53	53	53	53	54
FORT MYERS PLANT	FMCT2A	144	144	144	144	146
FORT MYERS PLANT	FMCT2B	144	144	144	144	146
FORT MYERS PLANT	FMCT2C	150	150	150	150	152
FORT MYERS PLANT	FMCT2D	151	151	151	151	138
FORT MYERS PLANT	FMCT2E	149	149	149	149	147
FORT MYERS PLANT	FMCT2F	144	144	144	144	142
FORT MYERS PLANT	FMCT3A	53	53	53	53	50
FORT MYERS PLANT	FMCT3B	61	61	61	61	56
FORT MYERS PLANT	PFM1	70	70	70	70	0
FORT MYERS PLANT	PFM2	247	247	247	247	0
FPL Manatee	3	323	188	130	115	490
FPL Martin	8	321	187	129	114	487
FPL Turkey Point Unit 5	5	336	195	135	119	509
FPL Unsited Combined Cycle 1	1	0	0	0	0	0
FPL Unsited Combined Cycle 2	2	0	0	0	0	0
FPL West County 1	1	0	498	343	305	249
FPL West County 2	2	0	0	343	305	249
FPL West County 3	3	0	0	0	0	243
LAUDERDALE	1-12	39	39	39	39	39
LAUDERDALE	13-24	28	28	28	28	28
LAUDERDALE	4GT1	154	154	154	154	156
LAUDERDALE	4GT2	152	152	152	152	154
LAUDERDALE	5GT1	153	153	153	153	155
LAUDERDALE	5GT2	148	148	148	148	150
MANATEE	PMT1	649	649	649	649	658
MANATEE	PMT2	707	707	707	707	717
MARTIN PLANT	HRSG3A,3ST	150	150	150	150	152
MARTIN PLANT	HRSG3B,3ST	152	152	152	152	154
MARTIN PLANT	HRSG4A, 4ST	159	159	159	159	161
MARTIN PLANT	HRSG4B, 4ST	158	158	158	158	160
MARTIN PLANT	PMR1	724	724	724	724	735
MARTIN PLANT	PMR2	676	676	676	676	685
PORT EVERGLADES	1-12	27	27	27	27	27
PORT EVERGLADES	PPE1	191	191	191	191	194
PORT EVERGLADES	PPE2	195	195	195	195	198
PORT EVERGLADES	PPE3	366	366	366	366	371
PORT EVERGLADES	PPE4	382	382	382	382	387
PUTNAM	1GT1/HRSG11	71	71	71	71	72
PUTNAM	1GT2/HRSG12	71	71	71	71	72
PUTNAM	2GT1/HRSG21	67	67	67	67	68

FPL NOx Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
PUTNAM	2GT2/HRSG22	69	69	69	69	70
RIVIERA PLANT	PRV3	281	281	281	281	284
RIVIERA PLANT	PRV4	284	284	284	284	288
SANFORD POWER PLANT	PSN3	105	105	105	105	107
SANFORD POWER PLANT	PSN4	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	SNCT4A	151	151	151	151	102
SANFORD POWER PLANT	SNCT4B	153	153	153	153	104
SANFORD POWER PLANT	SNCT4C	152	152	152	152	103
SANFORD POWER PLANT	SNCT4D	149	149	149	149	99
SANFORD POWER PLANT	SNCT5A	150	150	150	150	142
SANFORD POWER PLANT	SNCT5B	150	150	150	150	143
SANFORD POWER PLANT	SNCT5C	153	153	153	153	135
SANFORD POWER PLANT	SNCT5D	142	142	142	142	136
TURKEY POINT PLANT	PTP1	365	365	365	365	370
TURKEY POINT PLANT	PTP2	360	360	360	360	365
ST JOHNS RIVER POWER PARK	PJK1	1,706	1,706	1,706	1,706	1,706
ST JOHNS RIVER POWER PARK	PJK1	1,559	1,559	1,559	1,559	1,559
SCHERER 4	PSG4	-	-	-	-	-
		383.265994	383.265994	383.265994	383.265994	394.152247

* Note: Unit allocations for all owners
except
SCHERER 4 76% owned
ST JOHNS RIVER POWER PARK 20% owned

FPL 000350

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
CAPE CANAVERAL PLANT	PCC1	389	324	298	298	298
CAPE CANAVERAL PLANT	PCC2	380	316	291	291	291
CUTLER	PCU5	33	27	25	25	25
CUTLER	PCU6	65	55	50	50	50
FORT MYERS PLANT	1-12	54	45	42	42	42
FORT MYERS PLANT	FMCT2A	146	122	112	112	112
FORT MYERS PLANT	FMCT2B	146	122	112	112	112
FORT MYERS PLANT	FMCT2C	152	126	116	116	116
FORT MYERS PLANT	FMCT2D	138	115	106	106	106
FORT MYERS PLANT	FMCT2E	147	123	113	113	113
FORT MYERS PLANT	FMCT2F	142	119	109	109	109
FORT MYERS PLANT	FMCT3A	50	42	38	38	38
FORT MYERS PLANT	FMCT3B	56	47	43	43	43
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	490	408	376	376	376
FPL Martin	8	487	405	373	373	373
FPL Turkey Point Unit 5	5	509	424	390	390	390
FPL Unsited Combined Cycle 1	1	191	144	182	175	169
FPL Unsited Combined Cycle 2	2	0	73	93	89	86
FPL West County 1	1	188	139	996	996	996
FPL West County 2	2	188	139	169	163	157
FPL West County 3	3	191	144	182	175	169
LAUDERDALE	1-12	39	33	30	30	30
LAUDERDALE	13-24	28	24	22	22	22
LAUDERDALE	4GT1	156	130	120	120	120
LAUDERDALE	4GT2	154	128	118	118	118
LAUDERDALE	5GT1	155	129	119	119	119
LAUDERDALE	5GT2	150	125	115	115	115
MANATEE	PMT1	658	549	505	505	505
MANATEE	PMT2	717	597	550	550	550
MARTIN PLANT	HRSG3A,3ST	152	127	117	117	117
MARTIN PLANT	HRSG3B,3ST	154	128	118	118	118
MARTIN PLANT	HRSG4A, 4ST	161	135	124	124	124
MARTIN PLANT	HRSG4B, 4ST	160	134	123	123	123
MARTIN PLANT	PMR1	735	612	564	564	564
MARTIN PLANT	PMR2	685	571	526	526	526
PORT EVERGLADES	1-12	27	22	21	21	21
PORT EVERGLADES	PPE1	194	161	149	149	149
PORT EVERGLADES	PPE2	198	165	152	152	152
PORT EVERGLADES	PPE3	371	309	285	285	285
PORT EVERGLADES	PPE4	387	322	297	297	297
PUTNAM	1GT1/HRSG11	72	60	55	55	55
PUTNAM	1GT2/HRSG12	72	60	55	55	55
PUTNAM	2GT1/HRSG21	68	57	52	52	52

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
PUTNAM	2GT2/HRSG22	70	58	54	54	54
RIVIERA PLANT	PRV3	284	237	218	218	218
RIVIERA PLANT	PRV4	288	240	221	221	221
SANFORD POWER PLANT	PSN3	107	89	82	82	82
SANFORD POWER PLANT	PSN4	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	SNCT4A	102	85	78	78	78
SANFORD POWER PLANT	SNCT4B	104	87	80	80	80
SANFORD POWER PLANT	SNCT4C	103	86	79	79	79
SANFORD POWER PLANT	SNCT4D	99	82	76	76	76
SANFORD POWER PLANT	SNCT5A	142	119	109	109	109
SANFORD POWER PLANT	SNCT5B	143	119	110	110	110
SANFORD POWER PLANT	SNCT5C	135	112	103	103	103
SANFORD POWER PLANT	SNCT5D	136	113	104	104	104
TURKEY POINT PLANT	PTP1	370	308	284	284	284
TURKEY POINT PLANT	PTP2	365	304	280	280	280
ST JOHNS RIVER POWER PARK	PJK1	1,706	1,571	1,571	1,571	1,571
ST JOHNS RIVER POWER PARK	PJK1	1,559	1,435	1,435	1,435	1,435
SCHERER 4	PSG4	-	-	-	-	-
		394.152247	273.717939	232.06586	232.06586	232.06586

• Note: Unit allocations for all owners except

SCHERER 4	76%
ST JOHNS RIVER POWER PARK	20%

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
CAPE CANAVERAL PLANT	PCC1	258	258	258	236	236
CAPE CANAVERAL PLANT	PCC2	252	252	252	230	230
CUTLER	PCU5	22	22	22	20	20
CUTLER	PCU6	43	43	43	40	40
FORT MYERS PLANT	1-12	36	36	36	33	33
FORT MYERS PLANT	FMCT2A	97	97	97	89	89
FORT MYERS PLANT	FMCT2B	97	97	97	89	89
FORT MYERS PLANT	FMCT2C	101	101	101	92	92
FORT MYERS PLANT	FMCT2D	91	91	91	84	84
FORT MYERS PLANT	FMCT2E	98	98	98	89	89
FORT MYERS PLANT	FMCT2F	94	94	94	86	86
FORT MYERS PLANT	FMCT3A	33	33	33	30	30
FORT MYERS PLANT	FMCT3B	37	37	37	34	34
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	320	320	320	287	287
FPL Martin	8	318	318	318	285	285
FPL Turkey Point Unit 5	5	333	333	333	298	298
FPL Unsited Combined Cycle 1	1	347	323	302	696	696
FPL Unsited Combined Cycle 2	2	177	164	154	355	355
FPL West County 1	1	848	848	848	760	760
FPL West County 2	2	848	848	848	760	760
FPL West County 3	3	778	778	778	696	696
LAUDERDALE	1-12	26	26	26	24	24
LAUDERDALE	13-24	19	19	19	17	17
LAUDERDALE	4GT1	103	103	103	95	95
LAUDERDALE	4GT2	102	102	102	93	93
LAUDERDALE	5GT1	103	103	103	94	94
LAUDERDALE	5GT2	99	99	99	91	91
MANATEE	PMT1	436	436	436	400	400
MANATEE	PMT2	475	475	475	435	435
MARTIN PLANT	HRSG3A,3ST	101	101	101	92	92
MARTIN PLANT	HRSG3B,3ST	102	102	102	93	93
MARTIN PLANT	HRSG4A, 4ST	107	107	107	98	98
MARTIN PLANT	HRSG4B, 4ST	106	106	106	97	97
MARTIN PLANT	PMR1	487	487	487	446	446
MARTIN PLANT	PMR2	454	454	454	416	416
PORT EVERGLADES	1-12	18	18	18	16	16
PORT EVERGLADES	PPE1	128	128	128	118	118
PORT EVERGLADES	PPE2	131	131	131	120	120
PORT EVERGLADES	PPE3	246	246	246	225	225
PORT EVERGLADES	PPE4	256	256	256	235	235
PUTNAM	1GT1/HRSG11	47	47	47	43	43
PUTNAM	1GT2/HRSG12	47	47	47	43	43
PUTNAM	2GT1/HRSG21	45	45	45	41	41

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
PUTNAM	2GT2/HRSG22	46	46	46	42	42
RIVIERA PLANT	PRV3	189	189	189	173	173
RIVIERA PLANT	PRV4	191	191	191	175	175
SANFORD POWER PLANT	PSN3	71	71	71	65	65
SANFORD POWER PLANT	PSN4	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
SANFORD POWER PLANT	SNCT4A	67	67	67	62	62
SANFORD POWER PLANT	SNCT4B	69	69	69	63	63
SANFORD POWER PLANT	SNCT4C	68	68	68	62	62
SANFORD POWER PLANT	SNCT4D	66	66	66	60	60
SANFORD POWER PLANT	SNCT5A	94	94	94	86	86
SANFORD POWER PLANT	SNCT5B	95	95	95	87	87
SANFORD POWER PLANT	SNCT5C	89	89	89	82	82
SANFORD POWER PLANT	SNCT5D	90	90	90	83	83
TURKEY POINT PLANT	PTP1	245	245	245	224	224
TURKEY POINT PLANT	PTP2	242	242	242	221	221
ST JOHNS RIVER POWER PARK	PJK1	1,593	1,593	1,593	1,629	1,629
ST JOHNS RIVER POWER PARK	PJK1	1,455	1,455	1,455	1,488	1,488
SCHERER 4	PSG4	-	-	-	-	-
		173.152111	173.152111	173.152111	145.217742	145.217742

* Note: Unit allocations for all owners
except
SCHERER 4 76%
ST JOHNS RIVER POWER PARK 20%

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	236
CAPE CANAVERAL PLANT	PCC2	230
CUTLER	PCU5	20
CUTLER	PCU6	40
FORT MYERS PLANT	1-12	33
FORT MYERS PLANT	FMCT2A	89
FORT MYERS PLANT	FMCT2B	89
FORT MYERS PLANT	FMCT2C	92
FORT MYERS PLANT	FMCT2D	84
FORT MYERS PLANT	FMCT2E	89
FORT MYERS PLANT	FMCT2F	86
FORT MYERS PLANT	FMCT3A	30
FORT MYERS PLANT	FMCT3B	34
FORT MYERS PLANT	PFM1	0
FORT MYERS PLANT	PFM2	0
FPL Manatee	3	287
FPL Martin	8	285
FPL Turkey Point Unit 5	5	298
FPL Unsited Combined Cycle 1	1	696
FPL Unsited Combined Cycle 2	2	355
FPL West County 1	1	760
FPL West County 2	2	760
FPL West County 3	3	696
LAUDERDALE	1-12	24
LAUDERDALE	13-24	17
LAUDERDALE	4GT1	95
LAUDERDALE	4GT2	93
LAUDERDALE	5GT1	94
LAUDERDALE	5GT2	91
MANATEE	PMT1	400
MANATEE	PMT2	435
MARTIN PLANT	HRSG3A,3ST	92
MARTIN PLANT	HRSG3B,3ST	93
MARTIN PLANT	HRSG4A, 4ST	98
MARTIN PLANT	HRSG4B, 4ST	97
MARTIN PLANT	PMR1	446
MARTIN PLANT	PMR2	416
PORT EVERGLADES	1-12	16
PORT EVERGLADES	PPE1	118
PORT EVERGLADES	PPE2	120
PORT EVERGLADES	PPE3	225
PORT EVERGLADES	PPE4	235
PUTNAM	1GT1/HRSG11	43
PUTNAM	1GT2/HRSG12	43
PUTNAM	2GT1/HRSG21	41

FPL NOx Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
PUTNAM	2GT2/HRSG22	42
RIVIERA PLANT	PRV3	173
RIVIERA PLANT	PRV4	175
SANFORD POWER PLANT	PSN3	65
SANFORD POWER PLANT	PSN4	#DIV/0!
SANFORD POWER PLANT	PSN5	#DIV/0!
SANFORD POWER PLANT	SNCT4A	62
SANFORD POWER PLANT	SNCT4B	63
SANFORD POWER PLANT	SNCT4C	62
SANFORD POWER PLANT	SNCT4D	60
SANFORD POWER PLANT	SNCT5A	86
SANFORD POWER PLANT	SNCT5B	87
SANFORD POWER PLANT	SNCT5C	82
SANFORD POWER PLANT	SNCT5D	83
TURKEY POINT PLANT	PTP1	224
TURKEY POINT PLANT	PTP2	221
ST JOHNS RIVER POWER PARK	PJK1	1,629
ST JOHNS RIVER POWER PARK	PJK1	1,488
SCHERER 4	PSG4	-
		145.217742

* *Note: Unit allocations for all owners except*

SCHERER 4	76%
ST JOHNS RIVER POWER PARK	20%

FPL CO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941	642,941	642,941	642,941	642,941
CAPE CANAVERAL PLANT	PCC2	622,743	622,743	622,743	622,743	622,743
CUTLER	PCU5	33,419	33,419	33,419	33,419	33,419
CUTLER	PCU6	72,274	72,274	72,274	72,274	72,274
FORT MYERS PLANT	1-12	57,963	57,963	57,963	57,963	57,963
FORT MYERS PLANT	FMCT2A	277,652	277,652	277,652	277,652	277,652
FORT MYERS PLANT	FMCT2B	274,807	274,807	274,807	274,807	274,807
FORT MYERS PLANT	FMCT2C	279,574	279,574	279,574	279,574	279,574
FORT MYERS PLANT	FMCT2D	265,577	265,577	265,577	265,577	265,577
FORT MYERS PLANT	FMCT2E	285,394	285,394	285,394	285,394	285,394
FORT MYERS PLANT	FMCT2F	281,522	281,522	281,522	281,522	281,522
FORT MYERS PLANT	FMCT3A	57,213	57,213	57,213	57,213	57,213
FORT MYERS PLANT	FMCT3B	66,390	66,390	66,390	66,390	66,390
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	944,470	944,470	944,470	944,470	944,470
FPL Martin	8	938,498	938,498	938,498	938,498	938,498
FPL Turkey Point Unit 5	5	2,452,893	2,452,893	2,452,893	2,452,893	2,452,893
FPL Unsited Combined Cycle 1	2	0	0	0	0	0
FPL Unsited Combined Cycle 2	1	0	0	0	0	0
FPL West County 1	1	0	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 2	2	0	0	2,559,540	2,559,540	2,559,540
FPL West County 3	1	0	0	0	0	2,559,540
LAUDERDALE	1-12	44,719	44,719	44,719	44,719	44,719
LAUDERDALE	13-24	48,436	48,436	48,436	48,436	48,436
LAUDERDALE	4GT1	291,057	291,057	291,057	291,057	291,057
LAUDERDALE	4GT2	290,436	290,436	290,436	290,436	290,436
LAUDERDALE	5GT1	297,176	297,176	297,176	297,176	297,176
LAUDERDALE	5GT2	284,409	284,409	284,409	284,409	284,409
MANATEE	PMT1	1,143,717	1,143,717	1,143,717	1,143,717	1,143,717
MANATEE	PMT2	1,181,259	1,181,259	1,181,259	1,181,259	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066	298,066	298,066	298,066	298,066
MARTIN PLANT	HRSG3B,3ST	312,358	312,358	312,358	312,358	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439	304,439	304,439	304,439	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614	303,614	303,614	303,614	303,614
MARTIN PLANT	PMR1	1,110,598	1,110,598	1,110,598	1,110,598	1,110,598
MARTIN PLANT	PMR2	1,167,666	1,167,666	1,167,666	1,167,666	1,167,666
PORT EVERGLADES	1-12	34,519	34,519	34,519	34,519	34,519
PORT EVERGLADES	PPE1	256,908	256,908	256,908	256,908	256,908
PORT EVERGLADES	PPE2	286,869	286,869	286,869	286,869	286,869
PORT EVERGLADES	PPE3	620,859	620,859	620,859	620,859	620,859
PORT EVERGLADES	PPE4	629,076	629,076	629,076	629,076	629,076
PUTNAM	1GT1/HRSG11	126,030	126,030	126,030	126,030	126,030
PUTNAM	1GT2/HRSG12	125,170	125,170	125,170	125,170	125,170
PUTNAM	2GT1/HRSG21	118,782	118,782	118,782	118,782	118,782

FPL CO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
PUTNAM	2GT2/HRSG22	119,391	119,391	119,391	119,391	119,391
RIVIERA PLANT	PRV3	469,923	469,923	469,923	469,923	469,923
RIVIERA PLANT	PRV4	502,854	502,854	502,854	502,854	502,854
SANFORD POWER PLANT	PSN3	149,920	149,920	149,920	149,920	149,920
SANFORD POWER PLANT	PSN4	0	0	0	0	0
SANFORD POWER PLANT	PSN5	0	0	0	0	0
SANFORD POWER PLANT	SNCT4A	195,722	195,722	195,722	195,722	195,722
SANFORD POWER PLANT	SNCT4B	197,275	197,275	197,275	197,275	197,275
SANFORD POWER PLANT	SNCT4C	200,268	200,268	200,268	200,268	200,268
SANFORD POWER PLANT	SNCT4D	199,505	199,505	199,505	199,505	199,505
SANFORD POWER PLANT	SNCT5A	271,096	271,096	271,096	271,096	271,096
SANFORD POWER PLANT	SNCT5B	275,989	275,989	275,989	275,989	275,989
SANFORD POWER PLANT	SNCT5C	262,006	262,006	262,006	262,006	262,006
SANFORD POWER PLANT	SNCT5D	264,402	264,402	264,402	264,402	264,402
TURKEY POINT PLANT	PTP1	579,084	579,084	579,084	579,084	579,084
TURKEY POINT PLANT	PTP2	593,797	593,797	593,797	593,797	593,797

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941	642,941	642,941	642,941	642,941
CAPE CANAVERAL PLANT	PCC2	622,743	622,743	622,743	622,743	622,743
CUTLER	PCU5	33,419	33,419	33,419	33,419	33,419
CUTLER	PCU6	72,274	72,274	72,274	72,274	72,274
FORT MYERS PLANT	1-12	57,963	57,963	57,963	57,963	57,963
FORT MYERS PLANT	FMCT2A	277,652	277,652	277,652	277,652	277,652
FORT MYERS PLANT	FMCT2B	274,807	274,807	274,807	274,807	274,807
FORT MYERS PLANT	FMCT2C	279,574	279,574	279,574	279,574	279,574
FORT MYERS PLANT	FMCT2D	265,577	265,577	265,577	265,577	265,577
FORT MYERS PLANT	FMCT2E	285,394	285,394	285,394	285,394	285,394
FORT MYERS PLANT	FMCT2F	281,522	281,522	281,522	281,522	281,522
FORT MYERS PLANT	FMCT3A	57,213	57,213	57,213	57,213	57,213
FORT MYERS PLANT	FMCT3B	66,390	66,390	66,390	66,390	66,390
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	944,470	944,470	944,470	944,470	944,470
FPL Martin	8	938,498	938,498	938,498	938,498	938,498
FPL Turkey Point Unit 5	5	2,452,893	2,452,893	2,452,893	2,452,893	2,452,893
FPL Unsited Combined Cycle 1	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL Unsited Combined Cycle 2	1	0	1,194,452	1,194,452	1,194,452	1,194,452
FPL West County 1	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 2	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 3	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
LAUDERDALE	1-12	44,719	44,719	44,719	44,719	44,719
LAUDERDALE	13-24	48,436	48,436	48,436	48,436	48,436
LAUDERDALE	4GT1	291,057	291,057	291,057	291,057	291,057
LAUDERDALE	4GT2	290,436	290,436	290,436	290,436	290,436
LAUDERDALE	5GT1	297,176	297,176	297,176	297,176	297,176
LAUDERDALE	5GT2	284,409	284,409	284,409	284,409	284,409
MANATEE	PMT1	1,143,717	1,143,717	1,143,717	1,143,717	1,143,717
MANATEE	PMT2	1,181,259	1,181,259	1,181,259	1,181,259	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066	298,066	298,066	298,066	298,066
MARTIN PLANT	HRSG3B,3ST	312,358	312,358	312,358	312,358	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439	304,439	304,439	304,439	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614	303,614	303,614	303,614	303,614
MARTIN PLANT	PMR1	1,110,598	1,110,598	1,110,598	1,110,598	1,110,598
MARTIN PLANT	PMR2	1,167,666	1,167,666	1,167,666	1,167,666	1,167,666
PORT EVERGLADES	1-12	34,519	34,519	34,519	34,519	34,519
PORT EVERGLADES	PPE1	256,908	256,908	256,908	256,908	256,908
PORT EVERGLADES	PPE2	286,869	286,869	286,869	286,869	286,869
PORT EVERGLADES	PPE3	620,859	620,859	620,859	620,859	620,859
PORT EVERGLADES	PPE4	629,076	629,076	629,076	629,076	629,076
PUTNAM	1GT1/HRSG11	126,030	126,030	126,030	126,030	126,030
PUTNAM	1GT2/HRSG12	125,170	125,170	125,170	125,170	125,170
PUTNAM	2GT1/HRSG21	118,782	118,782	118,782	118,782	118,782

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
PUTNAM	2GT2/HRSG22	119,391	119,391	119,391	119,391	119,391
RIVIERA PLANT	PRV3	469,923	469,923	469,923	469,923	469,923
RIVIERA PLANT	PRV4	502,854	502,854	502,854	502,854	502,854
SANFORD POWER PLANT	PSN3	149,920	149,920	149,920	149,920	149,920
SANFORD POWER PLANT	PSN4	0	0	0	0	0
SANFORD POWER PLANT	PSN5	0	0	0	0	0
SANFORD POWER PLANT	SNCT4A	195,722	195,722	195,722	195,722	195,722
SANFORD POWER PLANT	SNCT4B	197,275	197,275	197,275	197,275	197,275
SANFORD POWER PLANT	SNCT4C	200,268	200,268	200,268	200,268	200,268
SANFORD POWER PLANT	SNCT4D	199,505	199,505	199,505	199,505	199,505
SANFORD POWER PLANT	SNCT5A	271,096	271,096	271,096	271,096	271,096
SANFORD POWER PLANT	SNCT5B	275,989	275,989	275,989	275,989	275,989
SANFORD POWER PLANT	SNCT5C	262,006	262,006	262,006	262,006	262,006
SANFORD POWER PLANT	SNCT5D	264,402	264,402	264,402	264,402	264,402
TURKEY POINT PLANT	PTP1	579,084	579,084	579,084	579,084	579,084
TURKEY POINT PLANT	PTP2	593,797	593,797	593,797	593,797	593,797

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941	642,941	642,941	642,941	642,941
CAPE CANAVERAL PLANT	PCC2	622,743	622,743	622,743	622,743	622,743
CUTLER	PCU5	33,419	33,419	33,419	33,419	33,419
CUTLER	PCU6	72,274	72,274	72,274	72,274	72,274
FORT MYERS PLANT	1-12	57,963	57,963	57,963	57,963	57,963
FORT MYERS PLANT	FMCT2A	277,652	277,652	277,652	277,652	277,652
FORT MYERS PLANT	FMCT2B	274,807	274,807	274,807	274,807	274,807
FORT MYERS PLANT	FMCT2C	279,574	279,574	279,574	279,574	279,574
FORT MYERS PLANT	FMCT2D	265,577	265,577	265,577	265,577	265,577
FORT MYERS PLANT	FMCT2E	285,394	285,394	285,394	285,394	285,394
FORT MYERS PLANT	FMCT2F	281,522	281,522	281,522	281,522	281,522
FORT MYERS PLANT	FMCT3A	57,213	57,213	57,213	57,213	57,213
FORT MYERS PLANT	FMCT3B	66,390	66,390	66,390	66,390	66,390
FORT MYERS PLANT	PFM1	0	0	0	0	0
FORT MYERS PLANT	PFM2	0	0	0	0	0
FPL Manatee	3	944,470	944,470	944,470	944,470	944,470
FPL Martin	8	938,498	938,498	938,498	938,498	938,498
FPL Turkey Point Unit 5	5	2,452,893	2,452,893	2,452,893	2,452,893	2,452,893
FPL Unsited Combined Cycle 1	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL Unsited Combined Cycle 2	1	1,194,452	1,194,452	1,194,452	1,194,452	1,194,452
FPL West County 1	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 2	2	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
FPL West County 3	1	2,559,540	2,559,540	2,559,540	2,559,540	2,559,540
LAUDERDALE	1-12	44,719	44,719	44,719	44,719	44,719
LAUDERDALE	13-24	48,436	48,436	48,436	48,436	48,436
LAUDERDALE	4GT1	291,057	291,057	291,057	291,057	291,057
LAUDERDALE	4GT2	290,436	290,436	290,436	290,436	290,436
LAUDERDALE	5GT1	297,176	297,176	297,176	297,176	297,176
LAUDERDALE	5GT2	284,409	284,409	284,409	284,409	284,409
MANATEE	PMT1	1,143,717	1,143,717	1,143,717	1,143,717	1,143,717
MANATEE	PMT2	1,181,259	1,181,259	1,181,259	1,181,259	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066	298,066	298,066	298,066	298,066
MARTIN PLANT	HRSG3B,3ST	312,358	312,358	312,358	312,358	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439	304,439	304,439	304,439	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614	303,614	303,614	303,614	303,614
MARTIN PLANT	PMR1	1,110,598	1,110,598	1,110,598	1,110,598	1,110,598
MARTIN PLANT	PMR2	1,167,666	1,167,666	1,167,666	1,167,666	1,167,666
PORT EVERGLADES	1-12	34,519	34,519	34,519	34,519	34,519
PORT EVERGLADES	PPE1	256,908	256,908	256,908	256,908	256,908
PORT EVERGLADES	PPE2	286,869	286,869	286,869	286,869	286,869
PORT EVERGLADES	PPE3	620,859	620,859	620,859	620,859	620,859
PORT EVERGLADES	PPE4	629,076	629,076	629,076	629,076	629,076
PUTNAM	1GT1/HRSG11	126,030	126,030	126,030	126,030	126,030
PUTNAM	1GT2/HRSG12	125,170	125,170	125,170	125,170	125,170
PUTNAM	2GT1/HRSG21	118,782	118,782	118,782	118,782	118,782

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
PUTNAM	2GT2/HRSG22	119,391	119,391	119,391	119,391	119,391
RIVIERA PLANT	PRV3	469,923	469,923	469,923	469,923	469,923
RIVIERA PLANT	PRV4	502,854	502,854	502,854	502,854	502,854
SANFORD POWER PLANT	PSN3	149,920	149,920	149,920	149,920	149,920
SANFORD POWER PLANT	PSN4	0	0	0	0	0
SANFORD POWER PLANT	PSN5	0	0	0	0	0
SANFORD POWER PLANT	SNCT4A	195,722	195,722	195,722	195,722	195,722
SANFORD POWER PLANT	SNCT4B	197,275	197,275	197,275	197,275	197,275
SANFORD POWER PLANT	SNCT4C	200,268	200,268	200,268	200,268	200,268
SANFORD POWER PLANT	SNCT4D	199,505	199,505	199,505	199,505	199,505
SANFORD POWER PLANT	SNCT5A	271,096	271,096	271,096	271,096	271,096
SANFORD POWER PLANT	SNCT5B	275,989	275,989	275,989	275,989	275,989
SANFORD POWER PLANT	SNCT5C	262,006	262,006	262,006	262,006	262,006
SANFORD POWER PLANT	SNCT5D	264,402	264,402	264,402	264,402	264,402
TURKEY POINT PLANT	PTP1	579,084	579,084	579,084	579,084	579,084
TURKEY POINT PLANT	PTP2	593,797	593,797	593,797	593,797	593,797

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
CAPE CANAVERAL PLANT	PCC1	642,941
CAPE CANAVERAL PLANT	PCC2	622,743
CUTLER	PCU5	33,419
CUTLER	PCU6	72,274
FORT MYERS PLANT	1-12	57,963
FORT MYERS PLANT	FMCT2A	277,652
FORT MYERS PLANT	FMCT2B	274,807
FORT MYERS PLANT	FMCT2C	279,574
FORT MYERS PLANT	FMCT2D	265,577
FORT MYERS PLANT	FMCT2E	285,394
FORT MYERS PLANT	FMCT2F	281,522
FORT MYERS PLANT	FMCT3A	57,213
FORT MYERS PLANT	FMCT3B	66,390
FORT MYERS PLANT	PFM1	0
FORT MYERS PLANT	PFM2	0
FPL Manatee	3	944,470
FPL Martin	8	938,498
FPL Turkey Point Unit 5	5	2,452,893
FPL Unsited Combined Cycle 1	2	2,559,540
FPL Unsited Combined Cycle 2	1	1,194,452
FPL West County 1	1	2,559,540
FPL West County 2	2	2,559,540
FPL West County 3	1	2,559,540
LAUDERDALE	1-12	44,719
LAUDERDALE	13-24	48,436
LAUDERDALE	4GT1	291,057
LAUDERDALE	4GT2	290,436
LAUDERDALE	5GT1	297,176
LAUDERDALE	5GT2	284,409
MANATEE	PMT1	1,143,717
MANATEE	PMT2	1,181,259
MARTIN PLANT	HRSG3A,3ST	298,066
MARTIN PLANT	HRSG3B,3ST	312,358
MARTIN PLANT	HRSG4A, 4ST	304,439
MARTIN PLANT	HRSG4B, 4ST	303,614
MARTIN PLANT	PMR1	1,110,598
MARTIN PLANT	PMR2	1,167,666
PORT EVERGLADES	1-12	34,519
PORT EVERGLADES	PPE1	256,908
PORT EVERGLADES	PPE2	286,869
PORT EVERGLADES	PPE3	620,859
PORT EVERGLADES	PPE4	629,076
PUTNAM	1GT1/HRSG11	126,030
PUTNAM	1GT2/HRSG12	125,170
PUTNAM	2GT1/HRSG21	118,782

FPL CO2 Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
PUTNAM	2GT2/HRSG22	119,391
RIVIERA PLANT	PRV3	469,923
RIVIERA PLANT	PRV4	502,854
SANFORD POWER PLANT	PSN3	149,920
SANFORD POWER PLANT	PSN4	0
SANFORD POWER PLANT	PSN5	0
SANFORD POWER PLANT	SNCT4A	195,722
SANFORD POWER PLANT	SNCT4B	197,275
SANFORD POWER PLANT	SNCT4C	200,268
SANFORD POWER PLANT	SNCT4D	199,505
SANFORD POWER PLANT	SNCT5A	271,096
SANFORD POWER PLANT	SNCT5B	275,989
SANFORD POWER PLANT	SNCT5C	262,006
SANFORD POWER PLANT	SNCT5D	264,402
TURKEY POINT PLANT	PTP1	579,084
TURKEY POINT PLANT	PTP2	593,797

FPL CO2 Allowance Al

Facility Name	Federal Unit ID
CAPE CANAVERAL PLANT	PCC1
CAPE CANAVERAL PLANT	PCC2
CUTLER	PCU5
CUTLER	PCU6
FORT MYERS PLANT	1-12
FORT MYERS PLANT	FMCT2A
FORT MYERS PLANT	FMCT2B
FORT MYERS PLANT	FMCT2C
FORT MYERS PLANT	FMCT2D
FORT MYERS PLANT	FMCT2E
FORT MYERS PLANT	FMCT2F
FORT MYERS PLANT	FMCT3A
FORT MYERS PLANT	FMCT3B
FORT MYERS PLANT	PFM1
FORT MYERS PLANT	PFM2
FPL Manatee	3
FPL Martin	8
FPL Turkey Point Unit 5	5
FPL Unsited Combined Cycle 1	2
FPL Unsited Combined Cycle 2	1
FPL West County 1	1
FPL West County 2	2
FPL West County 3	1
LAUDERDALE	1-12
LAUDERDALE	13-24
LAUDERDALE	4GT1
LAUDERDALE	4GT2
LAUDERDALE	5GT1
LAUDERDALE	5GT2
MANATEE	PMT1
MANATEE	PMT2
MARTIN PLANT	HRSG3A,3ST
MARTIN PLANT	HRSG3B,3ST
MARTIN PLANT	HRSG4A, 4ST
MARTIN PLANT	HRSG4B, 4ST
MARTIN PLANT	PMR1
MARTIN PLANT	PMR2
PORT EVERGLADES	1-12
PORT EVERGLADES	PPE1
PORT EVERGLADES	PPE2
PORT EVERGLADES	PPE3
PORT EVERGLADES	PPE4
PUTNAM	1GT1/HRSG11
PUTNAM	1GT2/HRSG12
PUTNAM	2GT1/HRSG21

FPL CO2 Allowance Al

Facility Name	Federal Unit ID
PUTNAM	2GT2/HRSG22
RIVIERA PLANT	PRV3
RIVIERA PLANT	PRV4
SANFORD POWER PLANT	PSN3
SANFORD POWER PLANT	PSN4
SANFORD POWER PLANT	PSN5
SANFORD POWER PLANT	SNCT4A
SANFORD POWER PLANT	SNCT4B
SANFORD POWER PLANT	SNCT4C
SANFORD POWER PLANT	SNCT4D
SANFORD POWER PLANT	SNCT5A
SANFORD POWER PLANT	SNCT5B
SANFORD POWER PLANT	SNCT5C
SANFORD POWER PLANT	SNCT5D
TURKEY POINT PLANT	PTP1
TURKEY POINT PLANT	PTP2

FPL Hg Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances	2014 Allowances

FPL Hg Allowan

Facility Name	Federal Unit ID	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances	2019 Allowances	2020 Allowances

FPL Hg Allowan

Facility Name	Federal Unit ID	2021 Allowances	2022 Allowances	2023 Allowances	2024 Allowances

FPL SO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
CAPE CANAVERAL PLANT	PCC1	4,225	4,232	4,232	4,232	4,232
CAPE CANAVERAL PLANT	PCC2	4,963	4,969	4,969	4,969	4,969
CUTLER	PCU5	-	4	4	4	4
CUTLER	PCU6	-	9	9	9	9
FORT MYERS PLANT	1-12	-	-	-	-	-
FORT MYERS PLANT	FMCT2A	-	-	-	-	-
FORT MYERS PLANT	FMCT2B	-	-	-	-	-
FORT MYERS PLANT	FMCT2C	-	-	-	-	-
FORT MYERS PLANT	FMCT2D	-	-	-	-	-
FORT MYERS PLANT	FMCT2E	-	-	-	-	-
FORT MYERS PLANT	FMCT2F	-	-	-	-	-
FORT MYERS PLANT	FMCT3A	-	-	-	-	-
FORT MYERS PLANT	FMCT3B	-	-	-	-	-
FORT MYERS PLANT	PFM1	3,189	3,194	3,194	3,194	3,194
FORT MYERS PLANT	PFM2	9,460	9,475	9,475	9,475	9,475
FPL Manatee	3	-	-	-	-	-
FPL Martin	8	-	-	-	-	-
FPL Turkey Point Unit 5	5	-	-	-	-	-
FPL Unsited Combined Cycle 1	2	-	-	-	-	-
FPL Unsited Combined Cycle 2	2	-	-	-	-	-
FPL West County 1	1	-	-	-	-	-
FPL West County 2	2	-	-	-	-	-
FPL West County 3	3	-	-	-	-	-
LAUDERDALE	1-12	-	-	-	-	-
LAUDERDALE	13-24	-	-	-	-	-
LAUDERDALE	4GT1	948	950	950	950	950
LAUDERDALE	4GT2	948	950	950	950	950
LAUDERDALE	5GT1	948	950	950	950	950
LAUDERDALE	5GT2	948	950	950	950	950
MANATEE	PMT1	13,777	13,799	13,799	13,799	13,799
MANATEE	PMT2	12,701	12,716	12,716	12,716	12,716
MARTIN PLANT	HRSG3A,3ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG3B,3ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4A, 4ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4B, 4ST	1,275	1,277	1,277	1,277	1,277
MARTIN PLANT	PMR1	5,094	5,102	5,102	5,102	5,102
MARTIN PLANT	PMR2	6,041	6,049	6,049	6,049	6,049
PORT EVERGLADES	1-12	-	-	-	-	-
PORT EVERGLADES	PPE1	2,340	2,343	2,343	2,343	2,343
PORT EVERGLADES	PPE2	2,414	2,417	2,417	2,417	2,417
PORT EVERGLADES	PPE3	5,882	5,891	5,891	5,891	5,891
PORT EVERGLADES	PPE4	5,964	5,973	5,973	5,973	5,973
PUTNAM	1GT1/HRSG11	1,644	1,647	1,647	1,647	1,647
PUTNAM	1GT2/HRSG12	1,644	1,647	1,647	1,647	1,647
PUTNAM	2GT1/HRSG21	1,568	1,570	1,570	1,570	1,570

FPL SO2 Allowance Allocation

Facility Name	Federal Unit ID	2009 Allowances	2010 Allowances	2011 Allowances	2012 Allowances	2013 Allowances
PUTNAM	2GT2/HRSG22	1,568	1,570	1,570	1,570	1,570
RIVIERA PLANT	PRV3	3,574	3,580	3,580	3,580	3,580
RIVIERA PLANT	PRV4	3,546	3,551	3,551	3,551	3,551
SANFORD POWER PLANT	PSN3	1,085	1,087	1,087	1,087	1,087
SANFORD POWER PLANT	PSN4	8,615	3,323	3,323	3,323	3,323
SANFORD POWER PLANT	PSN5	3,222	3,220	3,220	3,220	3,220
SANFORD POWER PLANT	SNCT4A	-	-	-	-	-
SANFORD POWER PLANT	SNCT4B	-	-	-	-	-
SANFORD POWER PLANT	SNCT4C	-	-	-	-	-
SANFORD POWER PLANT	SNCT4D	-	-	-	-	-
SANFORD POWER PLANT	SNCT5A	-	-	-	-	-
SANFORD POWER PLANT	SNCT5B	-	-	-	-	-
SANFORD POWER PLANT	SNCT5C	-	-	-	-	-
SANFORD POWER PLANT	SNCT5D	-	-	-	-	-
TURKEY POINT PLANT	PTP1	5,870	5,879	5,879	5,879	5,879
TURKEY POINT PLANT	PTP2	5,913	5,924	5,924	5,924	5,924

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
CAPE CANAVERAL PLANT	PCC1	4,232	4,232	4,232	4,232	4,232
CAPE CANAVERAL PLANT	PCC2	4,969	4,969	4,969	4,969	4,969
CUTLER	PCU5	4	4	4	4	4
CUTLER	PCU6	9	9	9	9	9
FORT MYERS PLANT	1-12	-	-	-	-	-
FORT MYERS PLANT	FMCT2A	-	-	-	-	-
FORT MYERS PLANT	FMCT2B	-	-	-	-	-
FORT MYERS PLANT	FMCT2C	-	-	-	-	-
FORT MYERS PLANT	FMCT2D	-	-	-	-	-
FORT MYERS PLANT	FMCT2E	-	-	-	-	-
FORT MYERS PLANT	FMCT2F	-	-	-	-	-
FORT MYERS PLANT	FMCT3A	-	-	-	-	-
FORT MYERS PLANT	FMCT3B	-	-	-	-	-
FORT MYERS PLANT	PFM1	3,194	3,194	3,194	3,194	3,194
FORT MYERS PLANT	PFM2	9,475	9,475	9,475	9,475	9,475
FPL Manatee	3	-	-	-	-	-
FPL Martin	8	-	-	-	-	-
FPL Turkey Point Unit 5	5	-	-	-	-	-
FPL Unsited Combined Cycle 1	2	-	-	-	-	-
FPL Unsited Combined Cycle 2	2	-	-	-	-	-
FPL West County 1	1	-	-	-	-	-
FPL West County 2	2	-	-	-	-	-
FPL West County 3	3	-	-	-	-	-
LAUDERDALE	1-12	-	-	-	-	-
LAUDERDALE	13-24	-	-	-	-	-
LAUDERDALE	4GT1	950	950	950	950	950
LAUDERDALE	4GT2	950	950	950	950	950
LAUDERDALE	5GT1	950	950	950	950	950
LAUDERDALE	5GT2	950	950	950	950	950
MANATEE	PMT1	13,799	13,799	13,799	13,799	13,799
MANATEE	PMT2	12,716	12,716	12,716	12,716	12,716
MARTIN PLANT	HRSG3A,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG3B,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4A, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4B, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	PMR1	5,102	5,102	5,102	5,102	5,102
MARTIN PLANT	PMR2	6,049	6,049	6,049	6,049	6,049
PORT EVERGLADES	1-12	-	-	-	-	-
PORT EVERGLADES	PPE1	2,343	2,343	2,343	2,343	2,343
PORT EVERGLADES	PPE2	2,417	2,417	2,417	2,417	2,417
PORT EVERGLADES	PPE3	5,891	5,891	5,891	5,891	5,891
PORT EVERGLADES	PPE4	5,973	5,973	5,973	5,973	5,973
PUTNAM	1GT1/HRSG11	1,647	1,647	1,647	1,647	1,647
PUTNAM	1GT2/HRSG12	1,647	1,647	1,647	1,647	1,647
PUTNAM	2GT1/HRSG21	1,570	1,570	1,570	1,570	1,570

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2014 Allowances	2015 Allowances	2016 Allowances	2017 Allowances	2018 Allowances
PUTNAM	2GT2/HRSG22	1,570	1,570	1,570	1,570	1,570
RIVIERA PLANT	PRV3	3,580	3,580	3,580	3,580	3,580
RIVIERA PLANT	PRV4	3,551	3,551	3,551	3,551	3,551
SANFORD POWER PLANT	PSN3	1,087	1,087	1,087	1,087	1,087
SANFORD POWER PLANT	PSN4	3,323	3,323	3,323	3,323	3,323
SANFORD POWER PLANT	PSN5	3,220	3,220	3,220	3,220	3,220
SANFORD POWER PLANT	SNCT4A	-	-	-	-	-
SANFORD POWER PLANT	SNCT4B	-	-	-	-	-
SANFORD POWER PLANT	SNCT4C	-	-	-	-	-
SANFORD POWER PLANT	SNCT4D	-	-	-	-	-
SANFORD POWER PLANT	SNCT5A	-	-	-	-	-
SANFORD POWER PLANT	SNCT5B	-	-	-	-	-
SANFORD POWER PLANT	SNCT5C	-	-	-	-	-
SANFORD POWER PLANT	SNCT5D	-	-	-	-	-
TURKEY POINT PLANT	PTP1	5,879	5,879	5,879	5,879	5,879
TURKEY POINT PLANT	PTP2	5,924	5,924	5,924	5,924	5,924

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
CAPE CANAVERAL PLANT	PCC1	4,232	4,232	4,232	4,232	4,232
CAPE CANAVERAL PLANT	PCC2	4,969	4,969	4,969	4,969	4,969
CUTLER	PCU5	4	4	4	4	4
CUTLER	PCU6	9	9	9	9	9
FORT MYERS PLANT	1-12	-	-	-	-	-
FORT MYERS PLANT	FMCT2A	-	-	-	-	-
FORT MYERS PLANT	FMCT2B	-	-	-	-	-
FORT MYERS PLANT	FMCT2C	-	-	-	-	-
FORT MYERS PLANT	FMCT2D	-	-	-	-	-
FORT MYERS PLANT	FMCT2E	-	-	-	-	-
FORT MYERS PLANT	FMCT2F	-	-	-	-	-
FORT MYERS PLANT	FMCT3A	-	-	-	-	-
FORT MYERS PLANT	FMCT3B	-	-	-	-	-
FORT MYERS PLANT	PFM1	3,194	3,194	3,194	3,194	3,194
FORT MYERS PLANT	PFM2	9,475	9,475	9,475	9,475	9,475
FPL Manatee	3	-	-	-	-	-
FPL Martin	8	-	-	-	-	-
FPL Turkey Point Unit 5	5	-	-	-	-	-
FPL Unsited Combined Cycle 1	2	-	-	-	-	-
FPL Unsited Combined Cycle 2	2	-	-	-	-	-
FPL West County 1	1	-	-	-	-	-
FPL West County 2	2	-	-	-	-	-
FPL West County 3	3	-	-	-	-	-
LAUDERDALE	1-12	-	-	-	-	-
LAUDERDALE	13-24	-	-	-	-	-
LAUDERDALE	4GT1	950	950	950	950	950
LAUDERDALE	4GT2	950	950	950	950	950
LAUDERDALE	5GT1	950	950	950	950	950
LAUDERDALE	5GT2	950	950	950	950	950
MANATEE	PMT1	13,799	13,799	13,799	13,799	13,799
MANATEE	PMT2	12,716	12,716	12,716	12,716	12,716
MARTIN PLANT	HRSG3A,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG3B,3ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4A, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	HRSG4B, 4ST	1,277	1,277	1,277	1,277	1,277
MARTIN PLANT	PMR1	5,102	5,102	5,102	5,102	5,102
MARTIN PLANT	PMR2	6,049	6,049	6,049	6,049	6,049
PORT EVERGLADES	1-12	-	-	-	-	-
PORT EVERGLADES	PPE1	2,343	2,343	2,343	2,343	2,343
PORT EVERGLADES	PPE2	2,417	2,417	2,417	2,417	2,417
PORT EVERGLADES	PPE3	5,891	5,891	5,891	5,891	5,891
PORT EVERGLADES	PPE4	5,973	5,973	5,973	5,973	5,973
PUTNAM	1GT1/HRSG11	1,647	1,647	1,647	1,647	1,647
PUTNAM	1GT2/HRSG12	1,647	1,647	1,647	1,647	1,647
PUTNAM	2GT1/HRSG21	1,570	1,570	1,570	1,570	1,570

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2019 Allowances	2020 Allowances	2021 Allowances	2022 Allowances	2023 Allowances
PUTNAM	2GT2/HRSG22	1,570	1,570	1,570	1,570	1,570
RIVIERA PLANT	PRV3	3,580	3,580	3,580	3,580	3,580
RIVIERA PLANT	PRV4	3,551	3,551	3,551	3,551	3,551
SANFORD POWER PLANT	PSN3	1,087	1,087	1,087	1,087	1,087
SANFORD POWER PLANT	PSN4	3,323	3,323	3,323	3,323	3,323
SANFORD POWER PLANT	PSN5	3,220	3,220	3,220	3,220	3,220
SANFORD POWER PLANT	SNCT4A	-	-	-	-	-
SANFORD POWER PLANT	SNCT4B	-	-	-	-	-
SANFORD POWER PLANT	SNCT4C	-	-	-	-	-
SANFORD POWER PLANT	SNCT4D	-	-	-	-	-
SANFORD POWER PLANT	SNCT5A	-	-	-	-	-
SANFORD POWER PLANT	SNCT5B	-	-	-	-	-
SANFORD POWER PLANT	SNCT5C	-	-	-	-	-
SANFORD POWER PLANT	SNCT5D	-	-	-	-	-
TURKEY POINT PLANT	PTP1	5,879	5,879	5,879	5,879	5,879
TURKEY POINT PLANT	PTP2	5,924	5,924	5,924	5,924	5,924

FPL SO2 Allowance Al

Facility Name	Federal Unit ID	2024 Allowances
PUTNAM	2GT2/HRSG22	1,570
RIVIERA PLANT	PRV3	3,580
RIVIERA PLANT	PRV4	3,551
SANFORD POWER PLANT	PSN3	1,087
SANFORD POWER PLANT	PSN4	3,323
SANFORD POWER PLANT	PSN5	3,220
SANFORD POWER PLANT	SNCT4A	-
SANFORD POWER PLANT	SNCT4B	-
SANFORD POWER PLANT	SNCT4C	-
SANFORD POWER PLANT	SNCT4D	-
SANFORD POWER PLANT	SNCT5A	-
SANFORD POWER PLANT	SNCT5B	-
SANFORD POWER PLANT	SNCT5C	-
SANFORD POWER PLANT	SNCT5D	-
TURKEY POINT PLANT	PTP1	5,879
TURKEY POINT PLANT	PTP2	5,924

Florida Power & Light Company, 215 S. Monroe St., Suite 810, Tallahassee, FL 32301

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FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

January 3, 2008

VIA HAND DELIVERY
Ms. Katherine Fleming, Esq.
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 070650-EI; FPL's Supplemental Responses to Staff's Fourth Request for Production of Documents Nos. 18 and 19

Dear Ms. Fleming:

Please find enclosed FPL's supplemental responses that you had requested on behalf of the Commission Staff. Enclosed are Excel spreadsheets that provide projections of annual emissions and the excess or shortfall of annual emission allowances by year for the two alternative scenarios to building Turkey Point 6 and 7 that FPL has evaluated (labeled "emission allowances with CC" and "emission allowances with IGCC"). Together with the projections for the "with nuclear uprates" case that were previously provided in response to Staff's Second Request for Production of Documents No. 16 in Docket No. 070602-EI, these spreadsheets fully respond to Staff's Fourth Request for Production of Documents No. 18 in this docket. Staff's Fourth Request for Production of Documents No. 19 in this docket asks for projections of seasonal NOx emissions and the excess or shortfall of seasonal NOx emission allowances by year. FPL did not project that information in Docket No. 070602-EI and has not made such projections in connection with this docket.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Jessica Cano

Enclosures

Projected FPL Allowance Allocation Bank	SO2 Ton		NOx Ton		CO2 Ton		Hg Ton	
	Plan 1	Plan 2	Plan 1	Plan 2	Plan 1	Plan 2	Plan 1	Plan 2
2007	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-
2009		123,191		27,452	-	-	-	-
2010		118,079		27,650	-	-	-	-
2011		118,079		27,676	-	-	-	-
2012		118,079		27,403	-	-	-	-
2013		118,079		29,999	-	-	-	-
2014		118,079		30,051	-	-	-	-
2015		118,079		25,704	-	-	-	-
2016		118,079		25,984	-	-	-	-
2017		118,079		25,930	-	-	-	-
2018		118,079		25,879	-	-		0.011
2019		118,079		26,607	-	-		0.095
2020		118,079		26,525	-	-		0.105
2021		118,079		26,454	-	-		0.175
2022		118,079		26,107	-	-		0.169
2023		118,079		26,107	-	-		0.169
2024		118,079		26,107	-	-		0.169
2025		118,079		26,107	-	-		0.088
2026		118,079		26,107	-	-		0.088
2027		118,079		26,107	-	-		0.088
2028		118,079		26,107	-	-		0.088
2029		118,079		26,107	-	-		0.088
2030		118,079		26,107	-	-		0.088
2031		118,079		26,107	-	-		0.088
2032		118,079		26,107	-	-		0.088
2033		118,079		26,107	-	-		0.088
2034		118,079		26,107	-	-		0.088
2035		118,079		26,107	-	-		0.088
2036		118,079		26,107	-	-		0.088
2037		118,079		26,107	-	-		0.088
2038		118,079		26,107	-	-		0.088
2039		118,079		26,107	-	-		0.088
2040		118,079		26,107	-	-		0.088
2041		118,079		26,107	-	-		0.088
2042		118,079		26,107	-	-		0.088
2043		118,079		26,107	-	-		0.088
2044		118,079		26,107	-	-		0.088

Source: FPL ENV Group

SO2 Ton

Total Annual System Emissions

Expansion Plan	Plan with IGCC								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	96,952	96,952	96,952	96,952	104,967	104,957	104,998	104,998	94,457
2008	102,583	102,672	102,677	102,677	109,022	109,019	109,022	109,022	101,212
2009	101,217	101,217	101,251	101,251	104,292	104,334	104,429	104,429	98,173
2010	77,177	76,961	77,257	77,324	79,863	79,957	79,830	79,942	76,366
2011	57,204	56,997	57,368	57,422	57,472	57,559	57,202	56,774	57,260
2012	56,892	56,534	56,661	56,766	57,294	57,449	57,009	56,738	56,327
2013	57,908	57,724	57,801	57,862	58,323	58,289	57,979	57,790	57,612
2014	63,593	63,534	63,525	63,506	64,024	64,014	63,513	63,355	63,377
2015	56,908	56,904	56,913	56,910	57,103	56,958	56,764	56,610	54,728
2016	52,032	52,012	52,032	52,033	50,538	50,523	50,551	50,521	48,398
2017	48,335	48,326	48,377	48,378	46,952	46,974	46,974	46,784	44,384
2018	50,633	50,550	50,647	50,636	49,395	49,543	49,507	49,044	44,398
2019	54,883	54,861	54,874	54,874	53,653	53,591	53,589	53,307	48,784
2020	52,907	52,838	52,889	52,758	51,404	51,368	51,344	50,962	47,241
2021	57,231	57,530	57,510	57,162	56,096	56,192	56,124	55,384	52,115
2022	53,986	54,820	54,678	54,565	53,027	53,301	53,039	51,499	48,174
2023	53,868	54,619	54,499	54,481	52,732	53,143	53,138	51,145	47,571
2024	52,175	53,140	53,121	53,075	51,012	51,861	51,564	49,388	46,121
2025	46,965	47,546	47,491	47,464	45,722	46,116	46,003	43,771	41,230
2026	40,900	41,471	42,148	42,149	39,559	40,065	40,354	38,509	35,232
2027	38,947	39,509	40,129	40,130	37,688	38,292	39,044	36,012	34,918
2028	39,319	39,819	40,439	40,441	38,186	38,723	39,209	35,019	35,494
2029	37,119	37,518	38,098	38,100	36,116	36,553	37,113	31,948	33,946
2030	35,411	35,785	36,377	36,379	34,625	35,104	35,605	29,858	32,906
2031	36,100	36,335	36,953	36,958	35,222	35,594	36,173	30,494	34,163
2032	35,612	35,786	36,408	36,411	34,873	35,259	35,787	29,922	34,181
2033	34,715	34,945	35,451	35,451	34,143	34,456	34,917	28,308	33,763
2034	34,711	34,856	35,360	35,359	34,051	34,362	34,912	27,993	33,732
2035	34,326	34,431	35,027	35,035	33,878	34,073	34,809	28,575	33,631
2036	35,122	35,158	35,724	35,731	34,600	34,753	35,359	28,943	34,233
2037	34,598	34,656	35,197	35,199	34,112	34,342	34,857	28,090	33,898
2038	35,555	35,493	36,013	36,015	35,212	35,320	35,836	28,845	35,017
2039	35,501	35,418	35,913	35,911	35,218	35,283	35,710	28,234	35,058
2040	35,603	35,562	35,986	35,990	35,316	35,431	35,875	27,484	35,143
2041	35,406	35,380	35,797	35,794	35,148	35,268	35,623	26,495	34,981
2042	35,401	35,335	35,784	35,784	35,137	35,258	35,599	26,903	34,970
2043	36,243	36,112	36,587	36,588	35,864	35,972	36,300	28,494	35,632
2044	36,376	36,238	36,708	36,707	36,024	36,093	36,363	29,680	35,763

SO2 Ton

Total Annual System Emissions Excess / (Shortfall)

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	Plan with IGCC								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	0	(96,952)	(96,952)	(96,952)	(96,952)	(104,967)	(104,957)	(104,998)	(104,998)	(94,457)
2008	0	(102,583)	(102,672)	(102,677)	(102,677)	(109,022)	(109,019)	(109,022)	(109,022)	(101,212)
2009	123,191	21,974	21,974	21,940	21,940	18,899	18,857	18,762	18,762	25,018
2010	118,079	40,902	41,118	40,822	40,755	38,216	38,122	38,249	38,137	41,713
2011	118,079	60,875	61,082	60,711	60,657	60,607	60,520	60,877	61,305	60,819
2012	118,079	61,187	61,545	61,418	61,313	60,785	60,630	61,070	61,341	61,752
2013	118,079	60,171	60,355	60,278	60,217	59,756	59,790	60,100	60,289	60,468
2014	118,079	54,486	54,545	54,554	54,573	54,055	54,065	54,566	54,724	54,702
2015	118,079	61,171	61,175	61,166	61,169	60,976	61,121	61,315	61,469	63,351
2016	118,079	66,047	66,067	66,047	66,046	67,541	67,556	67,528	67,558	69,681
2017	118,079	69,744	69,753	69,702	69,701	71,127	71,105	71,105	71,295	73,695
2018	118,079	67,446	67,529	67,432	67,443	68,684	68,536	68,572	69,035	73,681
2019	118,079	63,196	63,218	63,205	63,205	64,426	64,488	64,490	64,772	69,295
2020	118,079	65,172	65,241	65,190	65,321	66,675	66,711	66,735	67,117	70,838
2021	118,079	60,848	60,549	60,569	60,917	61,983	61,887	61,955	62,695	65,964
2022	118,079	64,093	63,259	63,401	63,514	65,052	64,778	65,040	66,580	69,905
2023	118,079	64,211	63,460	63,580	63,598	65,347	64,936	64,941	66,934	70,508
2024	118,079	65,904	64,939	64,958	65,004	67,067	66,218	66,515	68,691	71,958
2025	118,079	71,114	70,533	70,588	70,615	72,357	71,963	72,076	74,308	76,849
2026	118,079	77,179	76,608	75,931	75,930	78,520	78,014	77,725	79,570	82,847
2027	118,079	79,132	78,570	77,950	77,949	80,391	79,787	79,035	82,067	83,161
2028	118,079	78,760	78,260	77,640	77,638	79,893	79,356	78,870	83,060	82,585
2029	118,079	80,960	80,561	79,981	79,979	81,963	81,526	80,966	86,131	84,133
2030	118,079	82,668	82,294	81,702	81,700	83,454	82,975	82,474	88,221	85,173
2031	118,079	81,979	81,744	81,126	81,121	82,857	82,485	81,906	87,585	83,916
2032	118,079	82,467	82,293	81,671	81,668	83,206	82,820	82,292	88,157	83,898
2033	118,079	83,364	83,134	82,628	82,628	83,936	83,623	83,162	89,771	84,316
2034	118,079	83,368	83,223	82,719	82,720	84,028	83,717	83,167	90,086	84,347
2035	118,079	83,753	83,648	83,052	83,044	84,201	84,006	83,270	89,504	84,448
2036	118,079	82,957	82,921	82,355	82,348	83,479	83,326	82,720	89,136	83,846
2037	118,079	83,481	83,423	82,882	82,880	83,967	83,737	83,222	89,989	84,181
2038	118,079	82,524	82,586	82,066	82,064	82,867	82,759	82,243	89,234	83,062
2039	118,079	82,578	82,661	82,166	82,168	82,861	82,796	82,369	89,845	83,021
2040	118,079	82,476	82,517	82,093	82,089	82,763	82,648	82,204	90,595	82,936
2041	118,079	82,673	82,699	82,282	82,285	82,931	82,811	82,456	91,584	83,098
2042	118,079	82,678	82,744	82,295	82,295	82,942	82,821	82,480	91,176	83,109
2043	118,079	81,836	81,967	81,492	81,491	82,215	82,107	81,779	89,585	82,447
2044	118,079	81,703	81,841	81,371	81,372	82,055	81,986	81,716	88,399	82,316

NOx Ton

Total Annual System Emissions

Expansion Plan	Plan With IGCC								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	50,937	50,959	50,959	50,959	51,059	51,095	51,110	51,110	50,766
2008	48,774	48,854	48,850	48,850	48,728	48,763	48,765	48,765	48,640
2009	36,199	36,510	36,751	36,751	34,109	34,353	34,603	34,603	33,442
2010	30,120	29,696	30,418	30,485	28,539	28,205	28,686	28,848	28,121
2011	23,297	22,825	23,289	23,333	22,304	22,091	22,143	22,207	22,112
2012	21,837	21,427	21,639	21,745	21,119	21,102	21,067	21,025	21,018
2013	20,813	20,502	20,637	20,694	20,271	20,282	20,251	20,224	20,158
2014	23,166	22,883	22,997	23,043	22,705	22,696	22,671	22,629	22,278
2015	21,935	21,792	21,893	21,918	21,451	21,441	21,430	21,435	20,950
2016	22,225	22,097	22,090	22,122	21,838	21,780	21,846	21,800	21,278
2017	20,221	20,179	20,168	20,161	19,898	19,811	19,856	19,864	19,453
2018	19,575	19,554	19,588	19,475	19,297	19,260	19,279	19,257	18,947
2019	21,056	21,047	21,053	21,051	20,898	20,830	20,850	20,844	20,479
2020	21,850	21,779	21,780	21,779	21,456	21,336	21,360	21,351	21,168
2021	24,386	24,780	24,547	24,490	24,146	24,231	24,191	24,092	23,867
2022	23,127	24,568	23,996	24,008	22,988	23,884	23,099	23,137	22,679
2023	22,935	25,500	24,514	24,758	22,833	24,198	23,715	23,619	22,629
2024	23,801	25,845	25,600	25,509	23,399	25,172	24,585	24,478	23,196
2025	22,894	24,514	24,310	24,266	22,326	23,982	23,796	23,716	22,051
2026	21,750	23,166	23,993	23,993	21,243	22,684	23,338	23,333	20,964
2027	20,834	22,022	22,816	22,816	20,352	21,568	22,411	22,298	20,162
2028	20,755	21,898	22,634	22,633	20,368	21,450	22,409	22,132	20,165
2029	20,207	21,281	21,973	21,963	19,877	20,936	21,878	21,417	19,671
2030	18,973	19,722	20,402	20,399	18,731	19,468	20,325	19,835	18,511
2031	19,185	19,912	20,574	20,568	18,961	19,674	20,497	20,031	18,783
2032	18,779	19,434	20,069	20,058	18,589	19,274	19,940	19,517	18,441
2033	18,735	19,269	19,871	19,854	18,564	19,106	19,728	19,257	18,417
2034	18,450	18,996	19,523	19,516	18,305	18,843	19,424	18,906	18,200
2035	18,268	18,759	19,299	19,271	18,156	18,648	19,227	18,738	18,073
2036	18,995	19,511	19,999	19,966	18,902	19,407	19,905	19,383	18,757
2037	18,697	19,120	19,665	19,614	18,615	19,038	19,557	18,943	18,505
2038	18,052	18,412	18,823	18,784	17,990	18,393	18,722	18,160	17,905
2039	17,963	18,318	18,650	18,609	17,875	18,289	18,533	17,947	17,801
2040	18,018	18,289	18,655	18,620	17,967	18,297	18,539	17,889	17,897
2041	17,689	17,955	18,334	18,307	17,644	17,989	18,189	17,498	17,580
2042	17,672	17,913	18,305	18,295	17,625	17,975	18,152	17,494	17,563
2043	18,811	19,161	19,563	19,549	18,749	19,212	19,363	18,769	18,634
2044	18,928	19,259	19,657	19,643	18,855	19,310	19,421	18,937	18,736

NOx Ton

Total Annual System Emissions Excess / (Shortfall)

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	Plan With IGCC								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	0	(50,937)	(50,959)	(50,959)	(50,959)	(51,059)	(51,095)	(51,110)	(51,110)	(50,766)
2008	0	(48,774)	(48,854)	(48,850)	(48,850)	(48,728)	(48,763)	(48,765)	(48,765)	(48,640)
2009	27,452	(8,747)	(9,057)	(9,299)	(9,299)	(6,656)	(6,901)	(7,150)	(7,150)	(5,989)
2010	27,650	(2,470)	(2,045)	(2,768)	(2,834)	(889)	(555)	(1,035)	(1,197)	(470)
2011	27,676	4,379	4,851	4,387	4,342	5,372	5,585	5,533	5,469	5,563
2012	27,403	5,565	5,975	5,764	5,657	6,283	6,301	6,335	6,377	6,384
2013	29,999	9,186	9,497	9,362	9,305	9,728	9,717	9,748	9,775	9,841
2014	30,051	6,884	7,168	7,054	7,008	7,346	7,355	7,380	7,422	7,773
2015	25,704	3,769	3,913	3,812	3,786	4,253	4,263	4,274	4,269	4,754
2016	25,984	3,759	3,887	3,894	3,861	4,146	4,204	4,138	4,184	4,706
2017	25,930	5,709	5,751	5,762	5,768	6,032	6,119	6,074	6,066	6,476
2018	25,879	6,304	6,325	6,291	6,404	6,582	6,619	6,600	6,623	6,932
2019	26,607	5,551	5,560	5,554	5,556	5,709	5,777	5,757	5,763	6,129
2020	26,525	4,675	4,747	4,746	4,746	5,070	5,190	5,166	5,174	5,357
2021	26,454	2,067	1,674	1,907	1,963	2,307	2,223	2,263	2,362	2,587
2022	26,107	2,980	1,540	2,111	2,100	3,119	2,223	3,008	2,970	3,429
2023	26,107	3,172	607	1,593	1,349	3,274	1,909	2,392	2,488	3,478
2024	26,107	2,306	262	508	598	2,708	935	1,522	1,629	2,911
2025	26,107	3,214	1,593	1,797	1,841	3,781	2,126	2,312	2,391	4,056
2026	26,107	4,357	2,941	2,114	2,114	4,865	3,424	2,769	2,774	5,144
2027	26,107	5,273	4,085	3,291	3,291	5,755	4,539	3,697	3,809	5,945
2028	26,107	5,352	4,209	3,473	3,474	5,739	4,657	3,698	3,975	5,942
2029	26,107	5,901	4,826	4,134	4,144	6,230	5,171	4,229	4,690	6,436
2030	26,107	7,134	6,385	5,705	5,709	7,376	6,639	5,782	6,272	7,596
2031	26,107	6,922	6,195	5,533	5,539	7,146	6,434	5,610	6,076	7,325
2032	26,107	7,328	6,673	6,038	6,049	7,518	6,833	6,167	6,591	7,666
2033	26,107	7,373	6,838	6,236	6,253	7,543	7,001	6,379	6,850	7,691
2034	26,107	7,657	7,111	6,584	6,591	7,802	7,264	6,683	7,201	7,907
2035	26,107	7,839	7,349	6,808	6,836	7,951	7,459	6,881	7,369	8,034
2036	26,107	7,112	6,596	6,108	6,141	7,205	6,700	6,202	6,724	7,350
2037	26,107	7,410	6,987	6,442	6,493	7,492	7,069	6,550	7,164	7,602
2038	26,107	8,055	7,695	7,284	7,324	8,117	7,714	7,386	7,947	8,202
2039	26,107	8,144	7,789	7,457	7,498	8,232	7,818	7,574	8,160	8,306
2040	26,107	8,089	7,818	7,452	7,487	8,141	7,810	7,568	8,218	8,210
2041	26,107	8,418	8,152	7,773	7,800	8,464	8,118	7,918	8,609	8,527
2042	26,107	8,435	8,195	7,802	7,812	8,482	8,133	7,955	8,613	8,544
2043	26,107	7,296	6,946	6,544	6,559	7,358	6,895	6,744	7,338	7,473
2044	26,107	7,179	6,848	6,451	6,464	7,252	6,797	6,686	7,170	7,371

CO2 Ton

Total Annual System Emissions

Expansion Plan	Plan with IGCC								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	57,334,000	57,334,000	57,334,000	57,334,000	57,489,000	57,481,000	57,484,000	57,484,000	56,849,000
2008	58,121,000	58,118,000	58,118,000	58,118,000	58,188,000	58,184,000	58,184,000	58,184,000	57,784,000
2009	59,356,000	59,339,000	59,331,000	59,331,000	59,331,000	59,328,000	59,326,000	59,326,000	59,028,000
2010	58,203,000	58,219,000	58,189,000	58,190,000	58,102,000	58,122,000	58,091,000	58,091,000	57,888,000
2011	56,128,000	56,139,000	56,130,000	56,131,000	55,788,000	55,807,000	55,782,000	55,750,000	55,711,000
2012	56,718,000	56,725,000	56,718,000	56,719,000	56,374,000	56,385,000	56,348,000	56,309,000	56,037,000
2013	57,263,000	57,270,000	57,269,000	57,264,000	56,901,000	56,900,000	56,875,000	56,857,000	56,658,000
2014	59,186,000	59,192,000	59,190,000	59,188,000	58,822,000	58,822,000	58,781,000	58,767,000	58,668,000
2015	60,129,000	60,130,000	60,129,000	60,129,000	59,719,000	59,710,000	59,692,000	59,671,000	59,296,000
2016	59,580,000	59,582,000	59,582,000	59,582,000	59,096,000	59,098,000	59,097,000	59,086,000	58,691,000
2017	60,316,000	60,316,000	60,317,000	60,317,000	59,824,000	59,827,000	59,825,000	59,782,000	59,329,000
2018	64,659,000	64,664,000	64,664,000	64,659,000	64,175,000	64,174,000	64,166,000	64,092,000	63,397,000
2019	68,612,000	68,607,000	68,607,000	68,602,000	68,126,000	68,105,000	68,099,000	68,046,000	67,357,000
2020	72,763,000	72,737,000	72,739,000	72,743,000	72,209,000	72,196,000	72,189,000	72,111,000	71,556,000
2021	76,733,000	76,730,000	76,733,000	76,709,000	76,229,000	76,220,000	76,208,000	76,067,000	75,624,000
2022	78,312,000	78,298,000	78,302,000	78,299,000	77,815,000	77,789,000	77,793,000	77,441,000	77,044,000
2023	79,721,000	79,665,000	79,684,000	79,677,000	79,188,000	79,174,000	79,171,000	78,766,000	78,380,000
2024	81,677,000	81,653,000	81,661,000	81,661,000	81,154,000	81,136,000	81,116,000	80,642,000	80,426,000
2025	81,968,000	81,936,000	81,946,000	81,945,000	81,434,000	81,374,000	81,363,000	80,907,000	80,765,000
2026	81,861,000	81,841,000	81,826,000	81,827,000	81,300,000	81,255,000	81,244,000	80,873,000	80,732,000
2027	83,962,000	83,952,000	83,941,000	83,941,000	83,383,000	83,357,000	83,360,000	82,817,000	83,026,000
2028	85,947,000	85,947,000	85,935,000	85,938,000	85,364,000	85,350,000	85,269,000	84,579,000	85,032,000
2029	87,192,000	87,195,000	87,181,000	87,184,000	86,588,000	86,584,000	86,517,000	85,681,000	86,328,000
2030	88,897,000	88,913,000	88,910,000	88,916,000	88,286,000	88,302,000	88,236,000	87,307,000	88,085,000
2031	90,977,000	90,990,000	90,994,000	91,001,000	90,343,000	90,361,000	90,315,000	89,380,000	90,259,000
2032	94,018,000	94,019,000	94,024,000	94,030,000	93,361,000	93,378,000	93,321,000	92,374,000	93,319,000
2033	98,921,000	98,938,000	98,950,000	98,956,000	98,214,000	98,254,000	98,203,000	97,143,000	98,215,000
2034	101,641,000	101,667,000	101,683,000	101,690,000	100,906,000	100,967,000	100,925,000	99,805,000	100,907,000
2035	103,790,000	103,812,000	103,841,000	103,847,000	103,041,000	103,099,000	103,089,000	102,087,000	103,048,000
2036	108,674,000	108,696,000	108,730,000	108,736,000	107,879,000	107,940,000	107,918,000	106,898,000	107,882,000
2037	111,090,000	111,130,000	111,178,000	111,184,000	110,273,000	110,366,000	110,337,000	109,272,000	110,286,000
2038	112,798,000	112,837,000	112,906,000	112,911,000	111,972,000	112,092,000	112,071,000	110,957,000	111,980,000
2039	114,710,000	114,762,000	114,832,000	114,836,000	113,859,000	113,997,000	113,977,000	112,784,000	113,866,000
2040	117,375,000	117,444,000	117,539,000	117,543,000	116,502,000	116,675,000	116,669,000	115,320,000	116,514,000
2041	117,034,000	117,121,000	117,238,000	117,240,000	116,165,000	116,372,000	116,359,000	114,889,000	116,177,000
2042	116,840,000	116,925,000	117,049,000	117,050,000	115,973,000	116,184,000	116,172,000	114,771,000	115,985,000
2043	119,127,000	119,200,000	119,305,000	119,307,000	118,236,000	118,417,000	118,403,000	117,143,000	118,248,000
2044	120,128,000	120,195,000	120,286,000	120,288,000	119,229,000	119,390,000	119,374,000	118,286,000	119,240,000

CO2 Ton

Total Annual System Emissions Excess / (Shortfall)

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	Plan with IGCC								
		High Gas Cost				Medium Gas Cost				Low gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	-	(57,334,000)	(57,334,000)	(57,334,000)	(57,334,000)	(57,489,000)	(57,481,000)	(57,484,000)	(57,484,000)	(56,849,000)
2008	-	(58,121,000)	(58,118,000)	(58,118,000)	(58,118,000)	(58,188,000)	(58,184,000)	(58,184,000)	(58,184,000)	(57,784,000)
2009	-	(59,356,000)	(59,339,000)	(59,331,000)	(59,331,000)	(59,331,000)	(59,328,000)	(59,326,000)	(59,326,000)	(59,028,000)
2010	-	(58,203,000)	(58,219,000)	(58,189,000)	(58,190,000)	(58,102,000)	(58,122,000)	(58,091,000)	(58,091,000)	(57,888,000)
2011	-	(56,128,000)	(56,139,000)	(56,130,000)	(56,131,000)	(55,788,000)	(55,807,000)	(55,782,000)	(55,750,000)	(55,711,000)
2012	-	(56,718,000)	(56,725,000)	(56,718,000)	(56,719,000)	(56,374,000)	(56,385,000)	(56,348,000)	(56,309,000)	(56,037,000)
2013	-	(57,263,000)	(57,270,000)	(57,269,000)	(57,264,000)	(56,901,000)	(56,900,000)	(56,875,000)	(56,857,000)	(56,658,000)
2014	-	(59,186,000)	(59,192,000)	(59,190,000)	(59,188,000)	(58,822,000)	(58,822,000)	(58,781,000)	(58,767,000)	(58,668,000)
2015	-	(60,129,000)	(60,130,000)	(60,129,000)	(60,129,000)	(59,719,000)	(59,710,000)	(59,692,000)	(59,671,000)	(59,296,000)
2016	-	(59,580,000)	(59,582,000)	(59,582,000)	(59,582,000)	(59,096,000)	(59,098,000)	(59,097,000)	(59,086,000)	(58,691,000)
2017	-	(60,316,000)	(60,316,000)	(60,317,000)	(60,317,000)	(59,824,000)	(59,827,000)	(59,825,000)	(59,782,000)	(59,329,000)
2018	-	(64,659,000)	(64,664,000)	(64,664,000)	(64,659,000)	(64,175,000)	(64,174,000)	(64,166,000)	(64,092,000)	(63,397,000)
2019	-	(68,612,000)	(68,607,000)	(68,607,000)	(68,602,000)	(68,126,000)	(68,105,000)	(68,099,000)	(68,046,000)	(67,357,000)
2020	-	(72,763,000)	(72,737,000)	(72,739,000)	(72,743,000)	(72,209,000)	(72,196,000)	(72,189,000)	(72,111,000)	(71,556,000)
2021	-	(76,733,000)	(76,730,000)	(76,733,000)	(76,709,000)	(76,229,000)	(76,220,000)	(76,208,000)	(76,067,000)	(75,624,000)
2022	-	(78,312,000)	(78,298,000)	(78,302,000)	(78,299,000)	(77,815,000)	(77,789,000)	(77,793,000)	(77,441,000)	(77,044,000)
2023	-	(79,721,000)	(79,665,000)	(79,684,000)	(79,677,000)	(79,188,000)	(79,174,000)	(79,171,000)	(78,766,000)	(78,380,000)
2024	-	(81,677,000)	(81,653,000)	(81,661,000)	(81,661,000)	(81,154,000)	(81,136,000)	(81,116,000)	(80,642,000)	(80,426,000)
2025	-	(81,968,000)	(81,936,000)	(81,946,000)	(81,945,000)	(81,434,000)	(81,374,000)	(81,363,000)	(80,907,000)	(80,765,000)
2026	-	(81,861,000)	(81,841,000)	(81,826,000)	(81,827,000)	(81,300,000)	(81,255,000)	(81,244,000)	(80,873,000)	(80,732,000)
2027	-	(83,962,000)	(83,952,000)	(83,941,000)	(83,941,000)	(83,383,000)	(83,357,000)	(83,360,000)	(82,817,000)	(83,026,000)
2028	-	(85,947,000)	(85,947,000)	(85,935,000)	(85,938,000)	(85,364,000)	(85,350,000)	(85,269,000)	(84,579,000)	(85,032,000)
2029	-	(87,192,000)	(87,195,000)	(87,181,000)	(87,184,000)	(86,588,000)	(86,584,000)	(86,517,000)	(85,681,000)	(86,328,000)
2030	-	(88,897,000)	(88,913,000)	(88,910,000)	(88,916,000)	(88,286,000)	(88,302,000)	(88,236,000)	(87,307,000)	(88,085,000)
2031	-	(90,977,000)	(90,990,000)	(90,994,000)	(91,001,000)	(90,343,000)	(90,361,000)	(90,315,000)	(89,380,000)	(90,259,000)
2032	-	(94,018,000)	(94,019,000)	(94,024,000)	(94,030,000)	(93,361,000)	(93,378,000)	(93,321,000)	(92,374,000)	(93,319,000)
2033	-	(98,921,000)	(98,938,000)	(98,950,000)	(98,956,000)	(98,214,000)	(98,254,000)	(98,203,000)	(97,143,000)	(98,215,000)
2034	-	(101,641,000)	(101,667,000)	(101,683,000)	(101,690,000)	(100,906,000)	(100,967,000)	(100,925,000)	(99,805,000)	(100,907,000)
2035	-	(103,790,000)	(103,812,000)	(103,841,000)	(103,847,000)	(103,041,000)	(103,099,000)	(103,089,000)	(102,087,000)	(103,048,000)
2036	-	(108,674,000)	(108,696,000)	(108,730,000)	(108,736,000)	(107,879,000)	(107,940,000)	(107,918,000)	(106,898,000)	(107,882,000)
2037	-	(111,090,000)	(111,130,000)	(111,178,000)	(111,184,000)	(110,273,000)	(110,366,000)	(110,337,000)	(109,272,000)	(110,288,000)
2038	-	(112,798,000)	(112,837,000)	(112,906,000)	(112,911,000)	(111,972,000)	(112,092,000)	(112,071,000)	(110,957,000)	(111,980,000)
2039	-	(114,710,000)	(114,762,000)	(114,832,000)	(114,836,000)	(113,859,000)	(113,997,000)	(113,977,000)	(112,784,000)	(113,866,000)
2040	-	(117,375,000)	(117,444,000)	(117,539,000)	(117,543,000)	(116,502,000)	(116,675,000)	(116,669,000)	(115,320,000)	(116,514,000)
2041	-	(117,034,000)	(117,121,000)	(117,238,000)	(117,240,000)	(116,165,000)	(116,372,000)	(116,359,000)	(114,889,000)	(116,177,000)
2042	-	(116,840,000)	(116,925,000)	(117,049,000)	(117,050,000)	(115,973,000)	(116,184,000)	(116,172,000)	(114,771,000)	(115,985,000)
2043	-	(119,127,000)	(119,200,000)	(119,305,000)	(119,307,000)	(118,236,000)	(118,417,000)	(118,403,000)	(117,143,000)	(118,248,000)
2044	-	(120,128,000)	(120,195,000)	(120,286,000)	(120,288,000)	(119,229,000)	(119,390,000)	(119,374,000)	(118,286,000)	(119,240,000)

Hg Ton

Total Annual System Emissions

Expansion Plan	Plan with IGCC								
Fuel Forecast	High Gas Cost				Medium Gas Cost				Low Gas Cost
Emission Scenario	Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2008	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2009	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2010	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2011	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2012	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2013	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2014	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
2015	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2016	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2017	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
2018	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
2019	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
2020	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
2021	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2022	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2023	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2024	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2025	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2026	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2027	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2028	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2029	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2030	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2031	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2032	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2033	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2034	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2035	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2036	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2037	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2038	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2039	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2040	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2041	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2042	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2043	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2044	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14

Hearing Exhibit 000356

Hg Ton

Total Annual System Emissions Excess / (Shortfall)

Expansion Plan / Fuel Forecast / Emission Scenario	Available Allowances	Plan with IGCC								
		High Gas Cost				Medium Gas Cost				Low Gas Cost
		Env I	Env II	Env III	Env IV	Env I	Env II	Env III	Env IV	Env I
2007	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2008	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2009	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2010	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2011	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2012	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2013	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2014	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2015	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2016	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2017	-	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.10)
2018	0.011	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
2019	0.095	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
2020	0.105	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
2021	0.175	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
2022	0.169	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
2023	0.169	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
2024	0.169	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
2025	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2026	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2027	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2028	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2029	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2030	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2031	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2032	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2033	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2034	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2035	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2036	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2037	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2038	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2039	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2040	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2041	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2042	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2043	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)
2044	0.088	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)

9

FPL's Response to Staff's Fifth Request for Production of Documents (No. 24, 26)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	Docket No. 070650-EI Filed: January 7, 2008

NOTICE OF SERVICE OF FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIFTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 21-26) AND FIFTH SET OF INTERROGATORIES (NOS. 75-84)

Florida Power & Light Company gives notice of service of its responses to the Staff of the Florida Public Service Commission's Fifth Request for Production of Documents (Nos. 21-26) and Fifth Set of Interrogatories (Nos. 75-84) to Katherine E. Fleming, with copies to all parties on the attached Certificate of Service.

Respectfully submitted this 7th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420

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P. O. Box 551
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Attorneys for Florida Power & Light Company

By: *s/ Jessica A. Cano*
Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

RECEIVED
JAN - 9 2008
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 7th day of January, 2008, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Charles J. Beck, Deputy Public Counsel*
Office of the Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

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Orlando Utilities Commission**
500 South Orange Avenue
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Roger Fontes
Florida Municipal Power Agency**
8553 Commodity Circle
Orlando, FL 32819

Bob Krasowski*
1086 Michigan Avenue
Naples, FL 34103-3857
On Behalf of Jan M. Krasowski and Bob Krasowski

Roy C. Young
Young van Assenderp, P.A.
225 South Adams Street, Suite 200
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Attorney for Orlando Utilities Commission**

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Barry Moline
Florida Municipal Electric Association**
P.O. Box 10114
Tallahassee, FL 32302-2114

By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Hearing Exhibit 000360

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant	))))	Docket No. 070650-EI Dated: January 7, 2008

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIFTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 21-26) AND FIFTH SET OF INTERROGATORIES (NOS. 75-84)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, and Rule 28-106.206, Florida Administrative Code, submits the following responses to the Staff of the Florida Public Service Commission's ("Staff's") Fifth Request for Production of Documents (Nos. 21-26) and Fifth Set of Interrogatories (Nos. 75-84).

FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in Florida Power & Light Company's Objections to Staff's Fifth Request for Production of Documents (Nos. 21-26) and Fifth Set of Interrogatories (Nos. 75-84), dated December 21, 2007.

I. Staff's Fifth Request for Production of Documents (Nos. 21-26)

FPL's responses are without waiver of its objections. All documents will be made available by FPL for inspection and review by Staff at FPL's offices at 215 South Monroe Street, Tallahassee Florida, during regular business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

II. Staff's Fifth Set of Interrogatories (Nos. 75-84)

Attached hereto are FPL's answers to Staff's Fifth Set of Interrogatories (Nos. 75-84), consistent with its prior objections, together with the affidavits of the persons providing said answers.

Respectfully submitted this 7th day of January, 2008.

R. Wade Litchfield, Vice President &
Associate General Counsel
Mitchell S. Ross
John T. Butler
Bryan S. Anderson
Antonio Fernandez
Jessica A. Cano
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420

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801 Pennsylvania Avenue, Suite 220
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215 South Monroe Street, Suite 420
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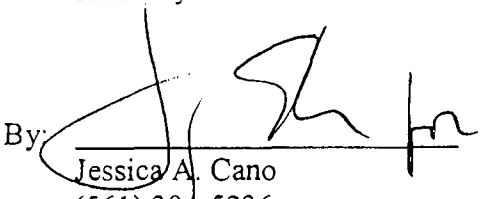
Tallahassee, FL 32302-0551

Attorneys for Florida Power & Light Company

By: 

Jessica A. Cano
(561) 304-5226
Florida Bar No. 0037372

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished electronically (*) and by United States mail this 7th day of January, 2008, to the following:

Katherine E. Fleming*
Senior Attorney
Florida Public Service Commission
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Charles J. Beck, Deputy Public Counsel*
Office of the Public Counsel
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Attorney for Seminole Electric Cooperative, Inc.**

Barry Moline
Florida Municipal Electric Association**
P.O. Box 10114
Tallahassee, FL 32302-2114

By: _____
Jessica A. Cano
Florida Bar No. 0037372

**Indicates not an official party of record as of the date of this filing

Q.
Please provide a copy of the latest available Florida population projections obtained by FPL from BEBR or any other outside source.

A.
Please find enclosed a copy of the latest available Florida population projections from the November Florida Demographic Estimating Conference obtained from the internet site of the Office of Economic & Demographic Research (The Florida Legislature).

FLORIDA DEMOGRAPHIC ESTIMATING CONFERENCE

Tables

Held October 30, 2007

Hearing Exhibit 000365

FPL 001839

Florida Resident Population

	FDEC, 07/07 (As of 4/1)	% Chg	FDEC, 10/07 (As of 4/1)	% Chg
1990	12,938,071	2.27%	12,938,071	2.27%
1991	13,258,732	2.48%	13,258,732	2.48%
1992	13,497,541	1.80%	13,497,541	1.80%
1993	13,730,115	1.72%	13,730,115	1.72%
1994	14,043,757	2.28%	14,043,757	2.28%
1995	14,335,992	2.08%	14,335,992	2.08%
1996	14,623,421	2.00%	14,623,421	2.00%
1997	14,938,314	2.15%	14,938,314	2.15%
1998	15,230,421	1.96%	15,230,421	1.96%
1999	15,580,244	2.30%	15,580,244	2.30%
2000	15,982,824	2.58%	15,982,824	2.58%
2001	16,330,224	2.17%	16,330,224	2.17%
2002	16,674,608	2.11%	16,674,608	2.11%
2003	17,071,508	2.38%	17,071,508	2.38%
2004	17,516,732	2.61%	17,516,732	2.61%
2005	17,918,227	2.29%	17,918,227	2.29%
2006	18,348,624	2.40%	18,349,132	2.40%
2007	18,729,588	2.08%	18,680,367	1.81%
Begins forecast.				
2008	19,132,888	2.15%	18,977,820	1.59%
2009	19,563,430	2.25%	19,278,665	1.59%
2010	19,974,790	2.10%	19,620,532	1.77%
2011	20,365,996	1.96%	19,997,465	1.92%
2012	20,742,470	1.85%	20,360,750	1.82%
2013	21,110,751	1.78%	20,704,460	1.69%
2014	21,473,421	1.72%	21,043,860	1.64%
2015	21,831,512	1.67%	21,386,860	1.63%
2016	22,185,953	1.62%	21,733,970	1.62%
2017	22,536,680	1.58%	22,084,825	1.61%
2020	23,552,138	1.53%	23,146,120	1.59%
2025	25,085,972	1.27%	24,766,129	1.36%
2030	26,513,331	1.11%	26,275,591	1.19%

Source: Florida Demographic Estimating Conference

Held October 30, 2007

Florida Resident Households

	FDEC, 07/07 (As of 4/1)	% Chg	FDEC, 10/07 (As of 4/1)	% Chg
1990	5,134,869	3.40%	5,134,869	3.40%
1991	5,283,154	2.89%	5,283,154	2.89%
1992	5,378,499	1.80%	5,378,499	1.80%
1993	5,478,476	1.86%	5,478,476	1.86%
1994	5,589,093	2.02%	5,589,093	2.02%
1995	5,697,328	1.94%	5,697,328	1.94%
1996	5,806,031	1.91%	5,806,031	1.91%
1997	5,929,613	2.13%	5,929,613	2.13%
1998	6,040,514	1.87%	6,040,514	1.87%
1999	6,182,346	2.35%	6,182,346	2.35%
2000	6,338,075	2.52%	6,338,075	2.52%
2001	6,483,040	2.29%	6,483,040	2.29%
2002	6,620,674	2.12%	6,620,674	2.12%
2003	6,778,804	2.39%	6,778,804	2.39%
2004	6,949,759	2.52%	6,949,759	2.52%
2005	7,109,208	2.29%	7,109,208	2.29%
2006	7,291,013	2.56%	7,291,013	2.56%
2007	7,444,939	2.11%	7,425,143	1.84%
Begins forecast.				
2008	7,607,344	2.18%	7,545,281	1.62%
2009	7,779,123	2.26%	7,665,631	1.60%
2010	7,943,089	2.11%	7,802,160	1.78%
2011	8,099,478	1.97%	7,952,641	1.93%
2012	8,249,821	1.86%	8,097,693	1.82%
2013	8,396,926	1.78%	8,234,963	1.70%
2014	8,541,818	1.73%	8,370,531	1.65%
2015	8,684,914	1.68%	8,507,540	1.64%
2016	8,826,564	1.63%	8,646,187	1.63%
2017	8,966,760	1.59%	8,786,331	1.62%
2020	9,372,636	1.54%	9,210,279	1.60%
2025	9,986,839	1.28%	9,857,755	1.37%
2030	10,558,796	1.12%	10,461,296	1.20%

Source: Florida Demographic Estimating Conference

Held October 30, 2007

FLORIDA DEMOGRAPHIC ESTIMATING CONFERENCE

Held October 30, 2007

	2006-1	2006-2	2006-3	2006-4	2007-1	2007-2	2007-3	2007-4	2008-1	2008-2	2008-3	2008-4	2009-1	2009-2	FISCAL YEAR AVERAGE 2004-05	2005-06	2006-07	2007-08	2008-09
Population																			
FDEC, 07/2007	18,297.4	18,397.3	18,493.1	18,588.0	18,682.3	18,776.9	18,874.0	18,975.3	19,079.4	19,186.3	19,294.8	19,403.2	19,510.5	19,616.4	17,821.6	18,242.5	18,635.1	19,028.8	19,456.2
FDEC, 10/2007	18,296.1	18,394.9	18,482.5	18,563.5	18,642.0	18,718.7	18,793.2	18,867.3	18,941.0	19,014.6	19,088.5	19,163.2	19,239.4	19,317.9	17,819.2	18,240.2	18,601.7	18,904.0	19,202.3
Growth Rate																			
FDEC, 07/2007	2.33	2.20	2.10	2.07	2.04	2.04	2.08	2.16	2.21	2.26	2.28	2.27	2.23	2.19	2.39	2.36	2.15	2.11	2.25
FDEC, 10/2007	2.38	2.18	1.92	1.77	1.70	1.66	1.60	1.59	1.57	1.56	1.56	1.57	1.60	1.64	2.38	2.36	1.98	1.63	1.58
Net Change in Population																			
FDEC, 07/2007	105.2	100.0	95.8	94.9	94.3	94.6	97.1	101.3	104.2	106.9	108.4	108.5	107.3	105.9	403.1	424.2	379.6	409.5	430.6
FDEC, 10/2007	107.1	98.8	87.6	81.0	78.6	76.7	74.5	74.1	73.7	73.6	73.9	74.7	76.2	78.5	404.7	422.8	323.8	295.5	303.3
Households																			
FDEC, 07/2007	7,269.5	7,310.5	7,349.2	7,387.5	7,425.7	7,464.2	7,503.5	7,544.3	7,586.0	7,628.7	7,671.9	7,715.2	7,758.0	7,800.2	7,070.6	7,246.1	7,406.6	7,565.6	7,736.3
FDEC, 10/2007	7,269.3	7,309.5	7,344.9	7,377.7	7,409.6	7,440.7	7,470.9	7,500.9	7,530.5	7,560.0	7,589.6	7,619.5	7,650.0	7,681.3	7,069.7	7,245.3	7,393.2	7,515.6	7,635.1
Growth Rate																			
FDEC, 07/2007	2.47	2.27	2.13	2.10	2.09	2.09	2.13	2.19	2.23	2.27	2.29	2.28	2.24	2.20	2.37	2.48	2.22	2.15	2.26
FDEC, 10/2007	2.51	2.23	1.95	1.80	1.74	1.69	1.63	1.61	1.59	1.58	1.57	1.58	1.61	1.65	2.36	2.48	2.04	1.65	1.59
Net Change in Households																			
FDEC, 07/2007	44.1	41.0	38.7	38.3	38.2	38.5	39.4	40.8	41.7	42.7	43.3	43.3	42.8	42.2	161.9	178.0	153.7	164.5	171.6
FDEC, 10/2007	44.9	40.2	35.4	32.8	31.9	31.1	30.2	30.0	29.7	29.5	29.6	29.9	30.5	31.4	162.5	177.4	131.2	119.3	121.3
Household Size																			
FDEC, 07/2007	2.517	2.517	2.516	2.516	2.516	2.516	2.515	2.515	2.515	2.515	2.515	2.515	2.515	2.515	2.521	2.518	2.516	2.515	2.515
FDEC, 10/2007	2.517	2.517	2.516	2.516	2.516	2.516	2.516	2.515	2.515	2.515	2.515	2.515	2.515	2.515	2.521	2.518	2.516	2.515	2.515
Growth Rate																			
FDEC, 07/2007	-0.13	-0.07	-0.03	-0.03	-0.04	-0.05	-0.04	-0.03	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.02	-0.12	-0.06	-0.05	-0.01
FDEC, 10/2007	-0.13	-0.05	-0.03	-0.03	-0.03	-0.04	-0.03	-0.03	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01	0.02	-0.12	-0.06	-0.05	-0.01
Net Migration																			
FDEC, 07/2007	91.1	85.7	81.4	80.2	79.6	79.9	82.3	86.4	89.3	92.0	93.6	93.6	92.5	91.1	350.8	368.0	321.2	350.0	370.8
FDEC, 10/2007	91.2	82.2	70.2	63.1	60.2	58.0	55.5	55.0	54.4	54.2	54.4	55.2	56.7	58.9	352.5	361.0	251.4	219.2	225.2
Births																			
FDEC, 07/2007	57.1	57.4	57.7	57.9	58.2	58.5	58.8	59.1	59.5	59.8	60.1	60.4	60.8	61.1	221.3	227.8	232.3	237.2	242.4
FDEC, 10/2007	58.3	59.0	59.6	60.2	60.6	61.0	61.2	61.5	61.7	62.0	62.2	62.4	62.6	62.8	221.6	231.7	241.4	246.4	249.9
Deaths																			
FDEC, 07/2007	43.0	43.1	43.2	43.4	43.6	43.8	44.0	44.3	44.6	44.9	45.3	45.6	46.0	46.4	169.0	171.6	173.9	177.8	183.2
FDEC, 10/2007	42.6	42.4	42.3	42.2	42.2	42.3	42.3	42.4	42.4	42.5	42.7	42.8	43.0	43.2	169.3	170.1	169.0	169.7	171.8
Net Natural Increase																			
FDEC, 07/2007	14.1	14.3	14.4	14.6	14.7	14.7	14.8	14.9	14.9	14.9	14.9	14.8	14.8	14.7	52.3	55.3	58.4	59.4	59.2
FDEC, 10/2007	15.8	16.6	17.4	18.0	18.4	18.7	16.9	19.1	19.3	19.4	19.5	19.5	19.5	19.6	52.2	61.6	72.4	70.7	78.2

FPL 001842

Hearing Exhibit 000368

FLORIDA DEMOGRAPHIC ESTIMATING CONFERENCE

Held October 30, 2007

	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
Population														
FDEC, 07/2007	17,405.7	17,821.6	18,242.5	18,635.1	19,028.8	19,456.2	19,872.9	20,269.1	20,649.0	21,019.1	21,383.1	21,742.3	22,097.6	22,449.2
FDEC, 10/2007	17,404.2	17,819.2	18,240.2	18,601.7	18,904.0	19,202.3	19,531.5	19,902.7	20,271.8	20,619.3	20,959.0	21,300.9	21,647.0	21,996.9
Growth Rate														
FDEC, 07/2007	2.58	2.39	2.36	2.15	2.11	2.25	2.14	1.99	1.87	1.79	1.73	1.68	1.63	1.59
FDEC, 10/2007	2.56	2.38	2.36	1.98	1.63	1.58	1.71	1.90	1.85	1.71	1.65	1.63	1.62	1.62
Net Change in Population														
FDEC, 07/2007	444.9	403.1	424.2	379.6	409.5	430.0	407.9	389.6	375.1	367.4	362.1	357.6	354.0	350.2
FDEC, 10/2007	440.8	404.7	422.6	323.8	295.9	303.3	348.7	378.1	359.8	342.4	339.6	343.8	347.6	351.3
Households														
FDEC, 07/2007	6,907.2	7,070.6	7,246.1	7,406.6	7,565.6	7,736.3	7,902.6	8,060.8	8,212.5	8,360.3	8,505.7	8,649.2	8,791.2	8,931.8
FDEC, 10/2007	6,906.6	7,069.7	7,245.3	7,393.2	7,515.6	7,635.1	7,766.6	7,914.8	8,062.2	8,201.0	8,336.6	8,473.2	8,611.4	8,751.2
Growth Rate														
FDEC, 07/2007	2.52	2.37	2.48	2.22	2.15	2.26	2.15	2.00	1.88	1.80	1.74	1.69	1.64	1.60
FDEC, 10/2007	2.49	2.36	2.48	2.04	1.65	1.59	1.72	1.91	1.86	1.72	1.65	1.64	1.63	1.62
Net Change in Households														
FDEC, 07/2007	171.1	161.9	176.0	153.7	164.5	171.6	162.8	155.5	149.8	146.8	144.6	142.9	141.5	140.0
FDEC, 10/2007	169.5	162.5	177.4	131.2	119.3	121.3	139.2	150.9	143.7	136.7	135.6	137.2	138.8	140.3
Household Size														
FDEC, 07/2007	2.520	2.521	2.518	2.516	2.515	2.515	2.515	2.515	2.514	2.514	2.514	2.514	2.514	2.513
FDEC, 10/2007	2.520	2.521	2.518	2.516	2.515	2.515	2.515	2.515	2.514	2.514	2.514	2.514	2.514	2.514
Growth Rate														
FDEC, 07/2007	0.06	0.02	-0.12	-0.06	-0.03	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
FDEC, 10/2007	0.06	0.02	-0.12	-0.06	-0.03	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Net Migration														
FDEC, 07/2007	399.3	350.8	368.0	321.2	350.0	370.8	349.9	332.8	318.9	312.1	307.9	304.8	303.0	301.5
FDEC, 10/2007	393.8	352.5	361.0	251.4	219.2	225.2	270.8	300.8	283.1	266.2	264.2	269.1	274.3	279.5
Births														
FDEC, 07/2007	214.0	221.3	227.8	232.3	237.2	242.4	247.6	252.4	257.3	262.0	266.5	270.8	275.0	278.6
FDEC, 10/2007	215.3	221.6	231.7	241.4	246.4	249.9	252.9	256.0	259.7	263.4	267.1	270.6	274.0	277.2
Deaths														
FDEC, 07/2007	168.4	169.0	171.6	173.9	177.8	183.2	189.6	195.7	201.1	206.6	212.3	218.1	223.9	229.9
FDEC, 10/2007	168.2	169.3	170.1	169.0	169.7	171.8	175.0	178.7	182.9	187.2	191.6	196.1	200.7	205.4
Net Natural Increase														
FDEC, 07/2007	45.6	52.3	56.3	58.4	59.4	59.2	58.0	56.8	56.2	55.3	54.2	52.8	51.0	48.7
FDEC, 10/2007	47.1	52.2	61.6	72.4	76.7	78.2	77.9	77.3	76.8	76.1	75.4	74.5	73.3	71.8

FPL 001843

Staff's Fifth Request POD No. 26
Annual and Cumulative Revenue Requirements for:

1) Plan without Nuclear - CC
2) Plan without Nuclear - IGCC
3) Plan with Nuclear (assuming a $3108/kw capital cost for nuclear)
4) Plan with Nuclear (assuming a $4540/kw capital cost for nuclear)

	(1)			(2)			(3)			(4)		
	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II	Mid. Gas/Env II
Year	Total Annual Costs w/ CC (Millions)	NPV Total Annual Costs w/ CC (Millions)	Cumulative NPV Total Annual Costs w/ CC (Millions)	Total Annual Costs w/ IGCC (Millions)	NPV Total Annual Costs w/ IGCC (Millions)	Cumulative NPV Total Annual Costs w/ IGCC (Millions)	Total Annual Costs w/ Nuclear $3108/kw (Millions)	NPV Total Annual Costs w/ Nuclear $3108/kw (Millions)	Cummulative NPV Total Annual Costs w/ Nuclear $3108/kw (Millions)	Total Annual Costs w/ Nuclear $4540/kw (Millions)	NPV Total Annual Costs w/ Nuclear $4540/kw (Millions)	Cummulative NPV Total Annual Costs w/ Nuclear $4540/kw (Millions)
2007	5,027	5,027	5,027	5,027	5,027	5,027	5,027	5,027	5,027	5,027	5,027	5,027
2008	5,946	5,490	10,517	5,946	5,490	10,517	5,946	5,490	10,517	5,946	5,490	10,517
2009	6,160	5,251	15,769	6,160	5,251	15,769	6,256	5,334	15,851	6,301	5,372	15,889
2010	6,184	4,868	20,637	6,184	4,868	20,637	6,269	4,935	20,787	6,309	4,966	20,856
2011	6,253	4,545	25,181	6,253	4,545	25,181	6,344	4,611	25,398	6,386	4,642	25,497
2012	6,378	4,279	29,460	6,378	4,279	29,460	6,423	4,309	29,707	6,444	4,323	29,821
2013	6,763	4,190	33,650	6,763	4,190	33,650	6,893	4,270	33,977	6,953	4,307	34,128
2014	7,352	4,205	37,856	7,352	4,205	37,856	7,592	4,342	38,319	7,703	4,405	38,532
2015	8,270	4,367	42,223	8,270	4,367	42,223	8,649	4,566	42,885	8,823	4,657	43,190
2016	9,281	4,525	46,747	9,281	4,525	46,747	9,823	4,787	47,672	10,073	4,908	48,098
2017	9,924	4,467	51,214	9,924	4,467	51,214	10,614	4,775	52,447	10,932	4,917	53,015
2018	10,870	4,517	55,731	11,460	4,760	55,974	11,386	4,728	57,175	11,852	4,920	57,934
2019	11,898	4,565	60,296	12,854	4,928	60,902	12,229	4,688	61,863	12,767	4,892	62,827
2020	12,907	4,572	64,868	14,431	5,105	66,007	12,796	4,529	66,392	13,378	4,733	67,560
2021	13,931	4,556	69,425	15,810	5,163	71,170	13,584	4,439	70,831	14,180	4,631	72,191
2022	15,022	4,536	73,961	16,801	5,065	76,235	14,576	4,398	75,228	15,148	4,568	76,760
2023	16,139	4,499	78,461	17,826	4,962	81,197	15,577	4,339	79,567	16,127	4,490	81,250
2024	17,438	4,489	82,949	19,097	4,908	86,106	16,856	4,335	83,902	17,385	4,469	85,719
2025	18,845	4,478	87,427	20,440	4,850	90,956	18,041	4,284	88,186	18,550	4,403	90,122
2026	20,267	4,446	91,873	21,764	4,768	95,724	19,376	4,248	92,434	19,865	4,353	94,476
2027	21,903	4,436	96,309	23,302	4,714	100,438	20,977	4,246	96,680	21,446	4,339	98,815
2028	23,389	4,374	100,683	24,696	4,613	105,051	22,377	4,181	100,861	22,826	4,264	103,079
2029	24,744	4,272	104,955	25,934	4,473	109,523	23,660	4,082	104,943	24,089	4,155	107,233
2030	26,338	4,198	109,153	27,398	4,362	113,886	25,145	4,006	108,949	25,554	4,070	111,303
2031	28,044	4,127	113,280	29,009	4,265	118,151	26,798	3,941	112,890	27,187	3,997	115,300
2032	30,217	4,106	117,386	31,067	4,217	122,368	28,976	3,935	116,824	29,345	3,984	119,284
2033	33,280	4,175	121,560	34,125	4,277	126,645	32,020	4,014	120,839	32,371	4,057	123,341
2034	35,629	4,126	125,686	36,352	4,207	130,852	34,218	3,961	124,799	34,554	3,999	127,340
2035	37,864	4,049	129,735	38,362	4,099	134,951	36,245	3,874	128,673	36,569	3,908	131,247
2036	41,139	4,061	133,797	41,534	4,098	139,048	39,526	3,900	132,573	39,840	3,931	135,178
2037	43,772	3,990	137,786	44,048	4,013	143,061	42,124	3,838	136,411	42,428	3,865	139,043
2038	46,033	3,874	141,660	46,182	3,885	146,946	44,158	3,715	140,126	44,452	3,739	142,782
2039	48,568	3,774	145,434	48,602	3,775	150,720	46,553	3,616	143,742	46,838	3,638	146,419
2040	51,532	3,697	149,131	51,454	3,690	154,410	49,332	3,538	147,280	49,607	3,557	149,976
2041	52,992	3,511	152,642	52,810	3,497	157,907	50,703	3,358	150,638	50,969	3,375	153,351
2042	54,247	3,319	155,961	53,968	3,300	161,208	51,949	3,177	153,815	52,205	3,192	156,544
2043	56,544	3,195	159,155	56,039	3,165	164,373	54,082	3,054	156,869	54,328	3,068	159,612
2044	58,467	3,051	162,206	57,773	3,014	167,387	55,907	2,916	159,785	56,144	2,928	162,540
2045	59,566	2,870	165,076	58,668	2,826	170,213	56,955	2,743	162,528	57,183	2,754	165,293
2046	60,716	2,701	167,777	59,683	2,655	172,868	58,023	2,581	165,109	58,241	2,590	167,884
2047	61,892	2,543	170,320	60,841	2,500	175,368	59,119	2,428	167,537	59,328	2,437	170,320
2048	63,105	2,394	172,714	62,036	2,354	177,722	60,238	2,285	169,822	60,437	2,292	172,612
2049	64,356	2,255	174,969	63,267	2,217	179,939	61,406	2,151	171,973	61,595	2,157	174,769
2050	65,640	2,124	177,093	64,532	2,088	182,026	62,610	2,025	173,998	62,790	2,031	176,800
2051	66,971	2,001	179,094	65,843	1,967	183,994	63,846	1,907	175,905	64,017	1,912	178,712
2052	68,350	1,886	180,980	67,202	1,854	185,848	65,129	1,797	177,702	65,290	1,801	180,513
2053	69,802	1,779	182,759	68,633	1,749	187,597	66,463	1,693	179,395	66,615	1,697	182,210
2054	71,299	1,678	184,436	70,110	1,650	189,246	67,869	1,597	180,992	68,011	1,600	183,810
2055	72,834	1,583	186,019	71,623	1,556	190,803	69,318	1,506	182,498	69,449	1,509	185,319
2056	74,446	1,494	187,513	73,213	1,469	192,272	70,803	1,420	183,918	70,926	1,423	186,741
2057	76,084	1,410	188,922	74,828	1,386	193,658	72,322	1,340	185,258	72,435	1,342	188,083
2058	77,728	1,330	190,252	76,425	1,308	194,966	73,749	1,262	186,520	73,790	1,262	189,346
2059	79,482	1,256	191,508	78,165	1,235	196,201	75,405	1,191	187,711	75,443	1,192	190,537
2060	81,313	1,186	192,694	79,989	1,167	197,474	77,086	1,125	188,836	77,086	1,125	191,662

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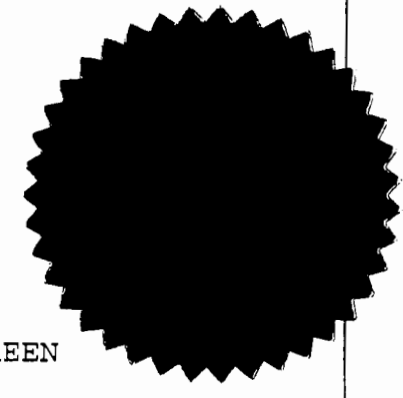
Deposition Transcript of Leonardo E. Green including Deposition Exhibit No. 1 (including errata sheet)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI

In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.
_____/



TELEPHONE DEPOSITION OF: LEONARDO F. GREEN

TAKEN AT THE INSTANCE OF: The FPSC Staff

DATE: January 10, 2008

TIME: Commenced at 2:06 p.m.
Concluded at 2:26 p.m.

LOCATION: 2540 Shumard Oak Boulevard
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR
Notary Public, State
of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
2894 REMINGTON GREEN LANE
TALLAHASSEE, FLORIDA 32308
(850)878-2221

APPEARANCES:

REPRESENTING FLORIDA POWER & LIGHT COMPANY:

STEPHEN L. HUNTOON, ESQUIRE
Florida Power & Light Company
801 Pennsylvania Avenue, N.W., Suite 200
Washington, D.C. 20004

REPRESENTING THE CITIZENS OF THE STATE OF FLORIDA:

CHARLES J. BECK, ESQUIRE
Office of Public Counsel
111 West Madison Street, Suite 812
Tallahassee, Florida 32399-1400

REPRESENTING JAN AND BOB KRASOWSKI:

MR. BOB KRASOWSKI
1086 Michigan Avenue
Naples, Florida 34103-3857

REPRESENTING THE FPSC STAFF:

KATHERINE E. FLEMING, ESQUIRE
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

ALSO PRESENT:

CRAIG HEWITT
MASHIDA KAZADI
ANITA SHARMA
PAUL STALLCUP

Hearing Exhibit 000373

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Hearing Exhibit 000374

STIPULATIONS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

MS. FLEMING: Okay. It looks like our court reporter is ready. Mr. Huntoon, you stated that you had a couple of preliminary matters before we get started?

MR. HUNTOON: Yes. Are we on the record, so to speak?

MS. FLEMING: Yes.

MR. HUNTOON: Okay. Hi, I'm Steve Huntoon, counsel for Florida Power & Light Company. I just was discussing before we went on the record with counsel for staff stipulating to reserve all objections, except with regard to privilege and form. And I understand that's acceptable to counsel; is that right?

MS. FLEMING: Sure.

MR. HUNTOON: At this time, if you want to proceed to administer the oath, I think that's

fine. Dr. Green is prepared for his deposition.

MS. FLEMING: Okay. Is there a notary available to administer the oath?

MR. HUNTOON: Yes. Jennifer?

Thereupon,

LEONARDO F. GREEN

the witness herein, having been first duly sworn by Jennifer DeValario, a notary public in the State of Florida, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. FLEMING:

Q. Good afternoon, Dr. Green. How are you?

A. Good afternoon, everyone. I'm doing very well. And how are you?

Q. We're fine, thank you. I don't know if you remember me. I've deposed you before in several other dockets. I'm Katherine Fleming with the Commission.

A. I sure do.

Q. Okay. Great. I really appreciate you taking the time out of your schedule to appear for us today.

If at any point during this deposition you need a break, just let me know. If you need any clarification on my questions or are not sure, we can try to work through that as well. If we need to go off the record and try to discuss things with staff, we can

Hearing Exhibit 000376

do so as well. Okay?

A. Okay.

Q. I just want to make sure that you have certain documents available. Could you please let me know what you have in front of you today?

A. I have my testimony, my testimony for Nuclear Units 6 and 7. I also have the Petition to Determine Need for Units 6 and 7, and I also have the appendices for the needs study document. I also have a set of Excel spreadsheets that were sent by Commission staff. And I also have a copy of the latest population projections obtained by FPL from BEBR, from the Bureau of Economic and Business Research at the University of Florida.

Q. Is that part of the response to Staff's Request for Production of Documents Number 24?

A. That's correct.

Q. Thank you. We can go ahead and get started. Your name is Dr. Green, is that correct, Dr. Leo E. Green or Leonardo E. Green; correct?

A. That's correct.

Q. And who are you employed by?

A. Currently I'm employed by Texas Utilities. At the time this testimony was prepared, I was employed by Florida Power & Light.

Hearing Exhibit 000377

Q. And when you were employed by Florida Power & Light, in what capacity were you employed by FPL?

A. I was employed as the Manager of Load Forecasting in the Finance Department.

Q. And in that position, you prepared and filed this direct testimony that we're discussing in this docket?

A. That's correct.

Q. At this time, do you have any corrections to your testimony?

A. None, no corrections.

Q. Okay. Great. I would like you to turn to page 14 of your prefiled testimony, please.

A. Okay. I'm there.

Q. I'm looking specifically at lines 12 through 14, in which you were asked what were the basic economic assumptions that were included in FPL's forecast. And you had stated that FPL's economy has continued to grow at a strong pace and is expected to continue this trend into the foreseeable future; is that correct?

A. That's correct.

Q. Let me have you -- in conjunction with that question have you look at the response to POD Number 24 which you referenced earlier.

A. Okay.

Hearing Exhibit 000378

Q. And can you explain this request, please?

A. Yes. This is -- the University of Florida produced a revision of their projections of population, and what I have documented is a comparison of the release that was made on April 1st as compared to the revision that was done in October of '07.

Q. Okay. And so then I take it, based on your response, that you are familiar with this population forecast; is that correct?

A. That's correct.

Q. Okay. Could I have you turn to the page 1840 that's Bates stamped on the bottom right-hand corner, where it shows the Florida resident population? There's a date for July of '07 and also for October of '07.

A. What page was that?

Q. It's at the bottom of the response. It's FPL 001840. It's the Bates stamp number.

MR. HUNTOON: I'm not sure -- Katherine, if I might, I'm not sure we have the one with the Bates stamp number on it. Could you give us just a page reference, what page of the document?

MS. FLEMING: It's probably going to be the second page. It's titled "Florida Resident Population."

THE WITNESS: I have that.

Hearing Exhibit 000379

BY MS. FLEMING:

Q. It shows five columns, and it shows columns of resident population for July of 2007 as well as for October of 2007.

A. That's correct. I have that.

Q. Okay. Great. Is it correct that based on this, that the population forecast dated October 2007 shows that Florida's population is expected to grow more slowly than previously expected in July of 2007?

A. That's what the numbers show, yes.

Q. If Florida's population is expected to grow more slowly, would it be correct to say that FPL's customer growth could be expected to grow more slowly as well?

A. The residential customers could grow slower based on this number. However, I have some concerns with that, in the sense that if you look at 2007, our residential customers slowed quite a bit; however, commercial customers increased by almost 3 percent over 2006. So it's a mixed bag. Yes, the residential customers might be growing slower, but the commercial customers continue to grow strong.

Q. Okay. Thank you. And with that, I would like you to turn to the Excel spreadsheets that were provided by Commission staff.

Hearing Exhibit 000380

A. I do have those. I'm ready.

Q. And as you mentioned earlier, we provided a seven-page document that's entitled "Staff's Analysis of Slowing Customer Growth on FPL's Energy and Demand Forecasts." Have you had an opportunity to review this document?

A. Yes, I have.

Q. Okay. Thank you. Would you agree that page 1 of this document replicates the effect of FPL's customer growth forecast on the company's reserve margin and the number of megawatts needed from 2007 through 2020 assuming that Turkey Point 6 and 7 are not put into service?

A. Yes, it does.

Q. Okay. And looking at pages 2 through 7, would you agree that these pages replicate no customer growth for a period of up to five years on FPL's reserve margins and the number of megawatts needed through 2020?

A. Would you repeat that question, please, Katherine?

Q. Yes. And maybe it would be easier to break it down. For example, on page 3, would you agree that it replicates an effect of no customer growth for a period of one year?

A. That's correct.

Hearing Exhibit 000381

Q. And page 4 would replicate the effects of no growth for a period of two years?

A. That's correct.

Q. And page 5 would replicate the effects of no customer growth for a period of three years?

A. Correct.

Q. Page 6 would replicate no growth for a period of four years?

A. Correct.

Q. Okay. And lastly, page 5 would replicate the effects of no customer growth for a period of five years? I'm sorry. That's page 7, for a period of five years.

A. Correct.

Q. So do you agree that pages 3 through 7 that we just discussed show -- that they replicate FPL's effects of no customer growth for a period of up to five years?

A. Yes, I agree with that.

Q. Okay. And I specifically want to turn to page 7, please, of the spreadsheet.

A. Okay.

Q. We previously discussed that this page assumes no customer growth for a period of five years, and that five-year period is from 2008 through 2012; is that correct?

A. That's correct.

Q. Okay. Would you agree, of course, subject to check, that given the customer growth scenario on this page, that FPL's reserve margin would be about 13.9 percent in 2018 without the addition of Turkey Point 6 and 7?

A. Under this scenario, I agree with that, yes.

Q. Okay. And along the same lines, would you agree, subject to check, given the customer growth scenario on this spreadsheet, that FPL's reserve margin would be about 8.8 percent in 2020 without the addition of Turkey Point 6 and 7?

A. That's correct.

Q. Okay. So would you also agree that given these customer growth assumptions, that FPL would need approximately 1,395 megawatts in 2018 and approximately 2,669 megawatts in 2020 in order to achieve a 20 percent reserve margin?

A. That's correct.

Q. Okay. Given your experience monitoring the economy of FPL's service territory, do you recall a period when FPL experienced five years with no customer growth whatsoever?

A. That has not happened in the -- I would say in the last 50 years, that has not happened.

Hearing Exhibit 000383

Q. Okay. Well, given the current economic climate, whether it's the recession of the housing market or what have you, how realistic is that we would actually see five years with no customer growth?

A. It is not realistic at all. I cannot foresee a scenario where this could happen.

Q. So the basic conclusion then, looking at the extreme scenario of no customer growth whatsoever for five years, FPL would still have a need?

A. That's correct.

MS. FLEMING: Okay. Thank you, Dr. Green. Those are all the questions we have.

MR. BECK: This is Charlie Beck. I have none.

MR. KRASOWSKI: Bob Krasowski. I have none at this time either.

MS. FLEMING: Okay. Does anyone else on the phone have any questions? Mr. Huntoon, redirect?

MR. HUNTOON: Let me just take one moment here.

MS. FLEMING: Okay.

(Pause.)

CROSS-EXAMINATION

BY MR. HUNTOON:

Q. I just have a couple of questions. Dr. Green, has FPL ever had a year in which it has not had a growth

Hearing Exhibit 000384

in customers?

A. Not according to the data that we have, and we go back I think as far as 1948 or something like that.

Q. And just generally, with respect to the scenarios that have been presented in the spreadsheet, could you comment generally about how you view those possible scenarios versus the as-filed forecast of the company?

A. I think the forecast that we produced is still a valid forecast in spite of the fact that we're experiencing a slowdown. To give an example, on page 2, the first scenario talks about a 50 percent reduction in customers, which would give us a growth of approximately 44,000 customers in 2007. But in 2007, FPL experienced a growth of 87,000 customers, which is already way above that.

My comment, my overall comment is that the University of Florida tends to underforecast population in FPL's service territory. And even though there's a slowing down, this is nothing new. The economy and population growth in Florida occurs in cycles. Let me take you back just to the last decade, to the 1990s. In the 1990s, FPL grew by approximately 65,000 customers per year. That was between 1992 and 1999. In the decade of the 2000s, there's a year or so where we're

over 100,000.

When we do a forecast, we do not try to hit those cycles, those high point and low points. We try to give a trend, and our trend of 88,000 or nearby we think is a good trend. So we don't think these scenarios represent reality. I do agree with the conclusions that have been reached in these tables and these scenarios. However, I think the underlying assumption of customer growth is not realistic.

And my final comment towards this is, yes, the economy has slowed, but the fundamentals are there. And what I mean by the fundamentals is this. Tourism and the leisure sector are going to be important in Florida's economy. That has not slowed. Trade has not slowed. Education and health has not slowed. What has slowed has been manufacturing and construction. So basically, the important ones, the most important ones continue to grow.

We created last year a certain number of jobs, and we consider it a slowdown. However, those jobs were more than the jobs created in 2001 or 2003 or 2002. It still is good growth and certainly created more jobs than any other state in the nation with the exception of Texas.

So we do not see these scenarios as being

Hearing Exhibit 000386

realistic. We think that the trend presentation that we have in here is a good one, especially considering that this year, the Baby Boomers turn 62 years old.

Thank you, Steve.

MR. HUNTOON: I don't have any further questions. Katherine, do you have any more questions?

MS. FLEMING: I have nothing further, so I think with that, I think this disposition is concluded.

MR. HUNTOON: Okay. We will send on the certificate of oath to the number you provided to us.

MS. FLEMING: Yes, we've received that. Thank you.

MR. HUNTOON: Oh, okay.

THE REPORTER: And where should I sent the errata sheet? This is the court reporter.

MR. HUNTOON: Can you send it to -- do you have John Butler's contact information handy?

THE REPORTER: I do.

MR. HUNTOON: That would probably be the simplest way.

MR. BECK: Jane, this is Charlie. Can you e-mail me a text version of the deposition when

Hearing Exhibit 000387

it's done?

THE REPORTER: This is Mary. Yes, I can do that.

MR. BECK: I'm really bad today. Thank you, Mary.

MR. KRASOWSKI: I would like one of those as well, if you can. This is Bob Krasowski.

MS. FLEMING: What I will do is, when this deposition is over, I will e-mail the court reporter's contact information, which includes her e-mail address, and you can contact her and let her know. That way, she will have your contact information.

MR. HUNTOON: Katherine, could I ask you a question? Did you wish to mark this spreadsheet as a deposition exhibit, or how did you want to handle that?

MS. FLEMING: If nobody objects to it, yes, we would love to.

MR. HUNTOON: Well, that's fine with us, however you want to mark it.

MS. FLEMING: Okay. Let's do that. Let's just mark it as Deposition Exhibit Number 1, and we'll title it Staff's Analysis of Slowing Customer Growth on FPL's Energy and Demand Forecasts. And

Hearing Exhibit 000388

we'll provide a copy to the court reporter so she can include that, and we'll provide a copy to all the parties.

(Deposition Exhibit Number 1 was marked for identification.)

(Deposition concluded at 2:26 p.m.)

Hearing Exhibit 000389

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1 through 18 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 15th day of January, 2008.

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

Hearing Exhibit 000390

STATE OF Florida

COUNTY OF Palm Beach

CERTIFICATE OF OATH

I, the undersigned authority, certify that Leonardo E. Green personally appeared before me at 700 Universe Boulevard, Juno Beach, FL and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the County of Palm Beach, State of Florida, this 10th day of January, 2008.

Notary Public: State of Florida
Jennifer M Payne
My Commission DD439096
Expires 06/03/2009

Jennifer M Payne DeLabre
Notary Public
State of Florida

My Commission Expires:

Personally known X or who has produced _____.
Type of identification produced _____

ASR ACCURATE STENOTYPE REPORTERS INCORPORATED
CERTIFIED COURT REPORTERS

January 15, 2008

John Butler, Esquire
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420

Re: Need Determination for Turkey Point NU 6 and 7
Docket No. 070650-EI

Dear Mr. Butler:

Enclosed is your copy of the deposition of Leonardo E. Green taken in the above matter on January 10, 2008.

Since reading and signing was not waived, we are enclosing an errata sheet and request that your office make arrangements with the witness to read the deposition and make any corrections on the errata sheet.

Please forward the original completed errata sheet to Jane Faurot at the Commission for attachment to the original transcript and a copy to Charles Beck, Office of Public Counsel. You should also attach a copy to your transcript so that it will be complete.

Thank you for your cooperation in this matter. It was a pleasure working with you.

Sincerely,

Mary A. Neel

/mn
cc: Jane Faurot
Charles Beck, Esq.

ERRATA SHEET

Under penalties of perjury, I declare that I have read the foregoing transcript of my deposition, pages 1 through 19, and that the facts stated therein are true, including any corrections and/or amendments listed below.

1/24/08
Date

LEONARD E. GREEN

Page	Line	Correction or Amendment	Reason for Change
14	3	change 1945 to 1965	Correction

Staff's Analysis of Slowing Customer Growth on FPL's Energy and Demand Forecasts
Docket 070650-EI
Determination of Need for Turkey Point Nuclear Units 6 and 7

Forecast As Filed - 100% of forecasted customer growth

Year	(1) Forecasted Customer Growth (As filed)	(2) Cust. Growth Adjustment Factor	(3) Adjusted Customer Growth (1) * (2)	(4) Prior Year's Total Customers	(5) Forecasted Total Customers (3) + (4)	(6) Forecasted Summer Peak MW (As filed)	(7) Forecasted Summer KW/Cust (6) / (5)	(8) Table III.C.1 of Load Study (Summer) Total Capacity (As filed)	(9) Peak Load (6)	(10) DSM (As filed)	(11) Firm Peak (9) - (10)	(12) Reserves (8) - (11)	(13) Reserve Margin (12) / (11)	(14) MW Needed
2007	88,606	100%	88,606	4,409,563	4,498,169	22,259	4.95	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	92,392	100%	92,392	4,498,169	4,590,561	22,770	4.96	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	93,188	100%	93,188	4,590,561	4,683,749	23,435	5.00	25,932	23,435	2,034	21,401	4,531	21.2%	(251)
2010	91,711	100%	91,711	4,683,749	4,775,460	24,003	5.03	26,794	24,003	2,146	21,857	4,937	22.6%	(566)
2011	89,371	100%	89,371	4,775,460	4,864,831	24,612	5.06	26,844	24,612	2,264	22,348	4,496	20.1%	(26)
2012	87,126	100%	87,126	4,864,831	4,951,957	25,115	5.07	27,092	25,115	2,388	22,727	4,365	19.2%	180
2013	85,470	100%	85,470	4,951,957	5,037,427	25,590	5.08	27,196	25,590	2,516	23,074	4,122	17.9%	493
2014	83,773	100%	83,773	5,037,427	5,121,200	26,100	5.10	27,196	26,100	2,651	23,449	3,747	16.0%	943
2015	82,678	100%	82,678	5,121,200	5,203,878	26,772	5.14	27,196	26,772	2,790	23,982	3,214	13.4%	1,582
2016	81,854	100%	81,854	5,203,878	5,285,732	27,410	5.19	25,885	27,410	2,910	24,500	1,385	5.7%	3,515
2017	81,055	100%	81,055	5,285,732	5,366,787	28,079	5.23	25,885	28,079	3,030	25,049	836	3.3%	4,174
2018	79,537	100%	79,537	5,366,787	5,446,324	28,737	5.28	25,885	28,737	3,150	25,587	298	1.2%	4,819
2019	77,895	100%	77,895	5,446,324	5,524,219	29,391	5.32	25,885	29,391	3,270	26,121	(236)	-0.9%	5,460
2020	75,933	100%	75,933	5,524,219	5,600,152	30,091	5.37	25,885	30,091	3,390	26,701	(816)	-3.1%	6,156

EXHIBIT 1
Witness L. Green
Date 01-10-08
Reporter Mary A Neel

Scenario 1: Slow Customer Growth in 2007 & 2008

Year	(1) Forecasted Customer Growth (As filed)	(2) Cust. Growth Adjustment Factor	(3) Adjusted Customer Growth (1) * (2)	(4) Prior Year's Total Customers	(5) Forecasted Total Customers (3) + (4)	(6) Forecasted Summer KW/Cust (As filed)	(7) Forecasted Summer Peak MW (5) * (6)	(8) Total Capacity (As filed)	(9) Peak Load (7)	(10) DSM (As filed)	(11) Firm Peak (9) - (10)	(12) Reserves (8) - (11)	(13) Reserve Margin (12) / (11)	(14) MW Needed
								Table III.C.1 of Load Study (Summer)						
2007	88,606	50%	44,303	4,409,563	4,453,866	4.95	22,040	25,116	22,040	1,768	20,272	4,844	23.9%	(790)
2008	92,392	50%	46,196	4,453,866	4,500,062	4.96	22,321	25,143	22,321	1,908	20,413	4,730	23.2%	(647)
2009	93,188	100%	93,188	4,500,062	4,593,250	5.00	22,982	25,932	22,982	2,034	20,948	4,984	23.8%	(794)
2010	91,711	100%	91,711	4,593,250	4,684,961	5.03	23,548	26,794	23,548	2,146	21,402	5,392	25.2%	(1,111)
2011	89,371	100%	89,371	4,684,961	4,774,332	5.06	24,154	26,844	24,154	2,264	21,890	4,954	22.6%	(576)
2012	87,126	100%	87,126	4,774,332	4,861,458	5.07	24,656	27,092	24,656	2,388	22,268	4,824	21.7%	(370)
2013	85,470	100%	85,470	4,861,458	4,946,928	5.08	25,130	27,196	25,130	2,516	22,614	4,582	20.3%	(59)
2014	83,773	100%	83,773	4,946,928	5,030,701	5.10	25,639	27,196	25,639	2,651	22,988	4,208	18.3%	389
2015	82,678	100%	82,678	5,030,701	5,113,379	5.14	26,306	27,196	26,306	2,790	23,516	3,680	15.6%	1,024
2016	81,854	100%	81,854	5,113,379	5,195,233	5.19	26,941	25,885	26,941	2,910	24,031	1,854	7.7%	2,952
2017	81,055	100%	81,055	5,195,233	5,276,288	5.23	27,606	25,885	27,606	3,030	24,576	1,309	5.3%	3,606
2018	79,537	100%	79,537	5,276,288	5,355,825	5.28	28,259	25,885	28,259	3,150	25,109	776	3.1%	4,246
2019	77,895	100%	77,895	5,355,825	5,433,720	5.32	28,910	25,885	28,910	3,270	25,640	245	1.0%	4,882
2020	75,933	100%	75,933	5,433,720	5,509,653	5.37	29,605	25,885	29,605	3,390	26,215	(330)	-1.3%	5,573

Scenario 2: Slow Customer Growth in 2007, No Growth in 2008, Slow Growth in 2009

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Table III.C.1 of Load Study (Summer)						
Year	Forecasted Customer Growth (As filed)	Cust. Growth Adjustment Factor	Adjusted Customer Growth (1) * (2)	Prior Year's Total Customers	Forecasted Total Customers (3) + (4)	Forecasted Summer KW/Cust (As filed)	Forecasted Summer Peak MW (5) * (6)	Total Capacity (As filed)	Peak Load (7)	DSM (As filed)	Firm Peak (9) - (10)	Reserves (8) - (11)	Reserve Margin (12) / (11)	MW Needed
2007	88,606	50%	44,303	4,409,563	4,453,866	4.95	22,040	25,116	22,040	1,768	20,272	4,844	23.9%	(790)
2008	92,392	0%	0	4,453,866	4,453,866	4.96	22,092	25,143	22,092	1,908	20,184	4,959	24.6%	(922)
2009	93,188	50%	46,594	4,453,866	4,500,460	5.00	22,518	25,932	22,518	2,034	20,484	5,448	26.6%	(1,351)
2010	91,711	100%	91,711	4,500,460	4,592,171	5.03	23,082	26,794	23,082	2,146	20,936	5,858	28.0%	(1,671)
2011	89,371	100%	89,371	4,592,171	4,681,542	5.06	23,685	26,844	23,685	2,264	21,421	5,423	25.3%	(1,139)
2012	87,126	100%	87,126	4,681,542	4,768,668	5.07	24,185	27,092	24,185	2,388	21,797	5,295	24.3%	(935)
2013	85,470	100%	85,470	4,768,668	4,854,138	5.08	24,659	27,196	24,659	2,516	22,143	5,053	22.8%	(625)
2014	83,773	100%	83,773	4,854,138	4,937,911	5.10	25,166	27,196	25,166	2,651	22,515	4,681	20.8%	(178)
2015	82,678	100%	82,678	4,937,911	5,020,589	5.14	25,829	27,196	25,829	2,790	23,039	4,157	18.0%	451
2016	81,854	100%	81,854	5,020,589	5,102,443	5.19	26,460	25,885	26,460	2,910	23,550	2,335	9.9%	2,374
2017	81,055	100%	81,055	5,102,443	5,183,498	5.23	27,120	25,885	27,120	3,030	24,090	1,795	7.5%	3,023
2018	79,537	100%	79,537	5,183,498	5,263,035	5.28	27,770	25,885	27,770	3,150	24,620	1,265	5.1%	3,659
2019	77,895	100%	77,895	5,263,035	5,340,930	5.32	28,416	25,885	28,416	3,270	25,146	739	2.9%	4,290
2020	75,933	100%	75,933	5,340,930	5,416,863	5.37	29,106	25,885	29,106	3,390	25,716	169	0.7%	4,974

Scenario 3: Slow Customer Growth in 2007, No Growth in 2008-2009, Slow Growth in 2010

Year	(1) Forecasted Customer Growth (As filed)	(2) Cust. Growth Adjustment Factor	(3) Adjusted Customer Growth (1) * (2)	(4) Prior Year's Total Customers	(5) Forecasted Total Customers (3) + (4)	(6) Forecasted Summer KW/Cust (As filed)	(7) Forecasted Summer Peak MW (5) * (6)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Table III.C.1 of Load Study (Summer)						
								Total Capacity (As filed)	Peak Load (7)	DSM (As filed)	Firm Peak (9) - (10)	Reserves (8) - (11)	Reserve Margin (12) / (11)	MW Needed
2007	88,606	50%	44,303	4,409,563	4,453,866	4.95	22,040	25,116	22,040	1,768	20,272	4,844	23.9%	(790)
2008	92,392	0%	0	4,453,866	4,453,866	4.96	22,092	25,143	22,092	1,908	20,184	4,959	24.6%	(922)
2009	93,188	0%	0	4,453,866	4,453,866	5.00	22,285	25,932	22,285	2,034	20,251	5,681	28.1%	(1,631)
2010	91,711	50%	45,856	4,453,866	4,499,722	5.03	22,617	26,794	22,617	2,146	20,471	6,323	30.9%	(2,229)
2011	89,371	100%	89,371	4,499,722	4,589,093	5.06	23,217	26,844	23,217	2,264	20,953	5,891	28.1%	(1,700)
2012	87,126	100%	87,126	4,589,093	4,676,219	5.07	23,717	27,092	23,717	2,388	21,329	5,763	27.0%	(1,498)
2013	85,470	100%	85,470	4,676,219	4,761,689	5.08	24,189	27,196	24,189	2,516	21,673	5,523	25.5%	(1,188)
2014	83,773	100%	83,773	4,761,689	4,845,462	5.10	24,695	27,196	24,695	2,651	22,044	5,152	23.4%	(744)
2015	82,678	100%	82,678	4,845,462	4,928,140	5.14	25,353	27,196	25,353	2,790	22,563	4,633	20.5%	(120)
2016	81,854	100%	81,854	4,928,140	5,009,994	5.19	25,980	25,885	25,980	2,910	23,070	2,815	12.2%	1,799
2017	81,055	100%	81,055	5,009,994	5,091,049	5.23	26,636	25,885	26,636	3,030	23,606	2,279	9.7%	2,443
2018	79,537	100%	79,537	5,091,049	5,170,586	5.28	27,282	25,885	27,282	3,150	24,132	1,753	7.3%	3,074
2019	77,895	100%	77,895	5,170,586	5,248,481	5.32	27,924	25,885	27,924	3,270	24,654	1,231	5.0%	3,700
2020	75,933	100%	75,933	5,248,481	5,324,414	5.37	28,609	25,885	28,609	3,390	25,219	666	2.6%	4,378

Scenario 4: Slow Customer Growth in 2007, No Growth in 2008-2010, Slow Growth in 2011

Year	(1) Forecasted Customer Growth (As filed)	(2) Cust. Growth Adjustment Factor	(3) Adjusted Customer Growth (1) * (2)	(4) Prior Year's Total Customers	(5) Forecasted Total Customers (3) + (4)	(6) Forecasted Summer KW/Cust (As filed)	(7) Forecasted Summer Peak MW (5) * (6)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Table III.C.1 of Load Study (Summer)						
								Total Capacity (As filed)	Peak Load (7)	DSM (As filed)	Firm Peak (9) - (10)	Reserves (8) - (11)	Reserve Margin (12) / (11)	MW Needed
2007	88,606	50%	44,303	4,409,563	4,453,866	4.95	22,040	25,116	22,040	1,768	20,272	4,844	23.9%	(790)
2008	92,392	0%	0	4,453,866	4,453,866	4.96	22,092	25,143	22,092	1,908	20,184	4,959	24.6%	(922)
2009	93,188	0%	0	4,453,866	4,453,866	5.00	22,285	25,932	22,285	2,034	20,251	5,681	28.1%	(1,631)
2010	91,711	0%	0	4,453,866	4,453,866	5.03	22,387	26,794	22,387	2,146	20,241	6,553	32.4%	(2,505)
2011	89,371	50%	44,686	4,453,866	4,498,552	5.06	22,759	26,844	22,759	2,264	20,495	6,349	31.0%	(2,250)
2012	87,126	100%	87,126	4,498,552	4,585,678	5.07	23,257	27,092	23,257	2,388	20,869	6,223	29.8%	(2,049)
2013	85,470	100%	85,470	4,585,678	4,671,148	5.08	23,729	27,196	23,729	2,516	21,213	5,983	28.2%	(1,740)
2014	83,773	100%	83,773	4,671,148	4,754,921	5.10	24,233	27,196	24,233	2,651	21,582	5,614	26.0%	(1,297)
2015	82,678	100%	82,678	4,754,921	4,837,599	5.14	24,888	27,196	24,888	2,790	22,098	5,098	23.1%	(679)
2016	81,854	100%	81,854	4,837,599	4,919,453	5.19	25,511	25,885	25,511	2,910	22,601	3,284	14.5%	1,236
2017	81,055	100%	81,055	4,919,453	5,000,508	5.23	26,163	25,885	26,163	3,030	23,133	2,752	11.9%	1,874
2018	79,537	100%	79,537	5,000,508	5,080,045	5.28	26,804	25,885	26,804	3,150	23,654	2,231	9.4%	2,500
2019	77,895	100%	77,895	5,080,045	5,157,940	5.32	27,442	25,885	27,442	3,270	24,172	1,713	7.1%	3,122
2020	75,933	100%	75,933	5,157,940	5,233,873	5.37	28,123	25,885	28,123	3,390	24,733	1,152	4.7%	3,794

Scenario 5: Slow Customer Growth in 2007, No Growth in 2008-2011, Slow Growth in 2012

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Table III.C.1 of Load Study (Summer)						
Year	Forecasted Customer Growth (As filed)	Cust. Growth Adjustment Factor	Adjusted Customer Growth (1) * (2)	Prior Year's Total Customers	Forecasted Total Customers (3) + (4)	Forecasted Summer KW/Cust (As filed)	Forecasted Summer Peak MW (5) * (6)	Total Capacity (As filed)	Peak Load (7)	DSM (As filed)	Firm Peak (9) - (10)	Reserves (8) - (11)	Reserve Margin (12) / (11)	MW Needed
2007	88,606	50%	44,303	4,409,563	4,453,866	4.95	22,040	25,116	22,040	1,768	20,272	4,844	23.9%	(790)
2008	92,392	0%	0	4,453,866	4,453,866	4.96	22,092	25,143	22,092	1,908	20,184	4,959	24.6%	(922)
2009	93,188	0%	0	4,453,866	4,453,866	5.00	22,285	25,932	22,285	2,034	20,251	5,681	28.1%	(1,631)
2010	91,711	0%	0	4,453,866	4,453,866	5.03	22,387	26,794	22,387	2,146	20,241	6,553	32.4%	(2,505)
2011	89,371	0%	0	4,453,866	4,453,866	5.06	22,533	26,844	22,533	2,264	20,269	6,575	32.4%	(2,521)
2012	87,126	50%	43,563	4,453,866	4,497,429	5.07	22,810	27,092	22,810	2,388	20,422	6,670	32.7%	(2,586)
2013	85,470	100%	85,470	4,497,429	4,582,899	5.08	23,281	27,196	23,281	2,516	20,765	6,431	31.0%	(2,278)
2014	83,773	100%	83,773	4,582,899	4,666,672	5.10	23,784	27,196	23,784	2,651	21,133	6,063	28.7%	(1,837)
2015	82,678	100%	82,678	4,666,672	4,749,350	5.14	24,434	27,196	24,434	2,790	21,644	5,552	25.7%	(1,224)
2016	81,854	100%	81,854	4,749,350	4,831,204	5.19	25,053	25,885	25,053	2,910	22,143	3,742	16.9%	687
2017	81,055	100%	81,055	4,831,204	4,912,259	5.23	25,701	25,885	25,701	3,030	22,671	3,214	14.2%	1,320
2018	79,537	100%	79,537	4,912,259	4,991,796	5.28	26,339	25,885	26,339	3,150	23,189	2,696	11.6%	1,941
2019	77,895	100%	77,895	4,991,796	5,069,691	5.32	26,973	25,885	26,973	3,270	23,703	2,182	9.2%	2,558
2020	75,933	100%	75,933	5,069,691	5,145,624	5.37	27,649	25,885	27,649	3,390	24,259	1,626	6.7%	3,225

Scenario 6: Slow Customer Growth in 2007, No Growth in 2008-2012, Slow Growth in 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Table III.C.1 of Load Study (Summer)						
Year	Forecasted Customer Growth (As filed)	Cust. Growth Adjustment Factor	Adjusted Customer Growth (1) * (2)	Prior Year's Total Customers	Forecasted Total Customers (3) + (4)	Forecasted Summer KW/Cust (As filed)	Forecasted Summer Peak MW (5) * (6)	Total Capacity (As filed)	Peak Load (7)	DSM (As filed)	Firm Peak (9) - (10)	Reserves (8) - (11)	Reserve Margin (12) / (11)	MW Needed
2007	88,606	50%	44,303	4,409,563	4,453,866	4.95	22,040	25,116	22,040	1,768	20,272	4,844	23.9%	(790)
2008	92,392	0%	0	4,453,866	4,453,866	4.96	22,092	25,143	22,092	1,908	20,184	4,959	24.6%	(922)
2009	93,188	0%	0	4,453,866	4,453,866	5.00	22,285	25,932	22,285	2,034	20,251	5,681	28.1%	(1,631)
2010	91,711	0%	0	4,453,866	4,453,866	5.03	22,387	26,794	22,387	2,146	20,241	6,553	32.4%	(2,505)
2011	89,371	0%	0	4,453,866	4,453,866	5.06	22,533	26,844	22,533	2,264	20,269	6,575	32.4%	(2,521)
2012	87,126	0%	0	4,453,866	4,453,866	5.07	22,589	27,092	22,589	2,388	20,201	6,891	34.1%	(2,851)
2013	85,470	50%	42,735	4,453,866	4,496,601	5.08	22,843	27,196	22,843	2,516	20,327	6,869	33.8%	(2,804)
2014	83,773	100%	83,773	4,496,601	4,580,374	5.10	23,344	27,196	23,344	2,651	20,693	6,503	31.4%	(2,365)
2015	82,678	100%	82,678	4,580,374	4,663,052	5.14	23,990	27,196	23,990	2,790	21,200	5,996	28.3%	(1,756)
2016	81,854	100%	81,854	4,663,052	4,744,906	5.19	24,605	25,885	24,605	2,910	21,695	4,190	19.3%	150
2017	81,055	100%	81,055	4,744,906	4,825,961	5.23	25,249	25,885	25,249	3,030	22,219	3,666	16.5%	778
2018	79,537	100%	79,537	4,825,961	4,905,498	5.28	25,883	25,885	25,883	3,150	22,733	3,152	13.9%	1,395
2019	77,895	100%	77,895	4,905,498	4,983,393	5.32	26,514	25,885	26,514	3,270	23,244	2,641	11.4%	2,007
2020	75,933	100%	75,933	4,983,393	5,059,326	5.37	27,185	25,885	27,185	3,390	23,795	2,090	8.8%	2,669

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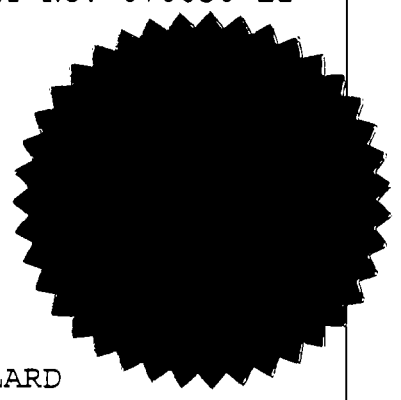
Deposition Transcript of Claude A. Villard

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI

In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.
_____/



TELEPHONE DEPOSITION OF: CLAUDE A. VILLARD

TAKEN AT THE INSTANCE OF: The FPSC Staff

DATE: January 16, 2008

TIME: Commenced at 9:36 a.m.
Concluded at 10:07 a.m.

LOCATION: 2540 Shumard Oak Boulevard
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR
Notary Public, State
of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
2894 REMINGTON GREEN LANE
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(850)878-2221

APPEARANCES:

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ALSO PRESENT:

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MASHINDA KAZADI
BILL McNULTY
DAMARIS RODRIGUEZ
GENE UNGAR
JENNY WU
GERARD YUPP

Hearing Exhibit 000403

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Hearing Exhibit 000404

STIPULATIONS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

Thereupon,

CLAUDE A. VILLARD

the witness herein, having been first duly sworn by Jennifer DeValario, a notary public in the State of Florida, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. FLEMING:

Q. Good morning, Mr. Villard.

A. Good morning.

Q. How are you doing today?

A. Very good, very good.

Q. If you didn't catch my name earlier, I'm Katherine Fleming. I'm the attorney on this docket on behalf of the Commission. I appreciate you taking the time with us this morning.

If at any point during this deposition you need a break, let me know, and if you need any

Hearing Exhibit 000405

clarification on any of my questions or the terms that I use, please let me know. And at some point, if we can't reach some sort of understanding, we may go off the record and have staff explain what they're trying to reach, if that helps.

A. Okay.

Q. Before we get started with the questioning, I just want to make sure you have a copy of your testimony with you.

A. Yes, I do.

Q. And do you also have copies of the need study and appendices?

A. Yes, I do.

Q. And do you also have the responses to Staff Interrogatories Numbers 51 and 59?

A. Fifty-one and 59, yes, correct, I do.

Q. Great. That's really all we need for purposes of your questioning.

So with that, can I have you just state your name and business address for the record, please?

A. Yes. My name is Claude Antoine Villard. I'm Director of Nuclear Fuels for Florida Power & Light. My business address is 700 Universe Boulevard, Juno Beach, Florida.

Q. And in what capacity are you employed by FPL?

A. I'm the Director of Nuclear Fuels.

Q. And can you describe your responsibilities under that position, please?

A. Surely. As Director of Nuclear Fuels, I'm responsible for the procurement and the design of nuclear fuel for the FPL units. My responsibilities include forecasting, initial analysis of nuclear fuel, calculating of nuclear fuel costs, and, of course, design and analysis for nuclear fuel.

Q. And you filed direct testimony in this docket consisting of 11 pages; is that correct?

A. That is correct.

Q. Do you have any changes or corrections to your testimony at this time?

A. No, I don't.

Q. Okay. Thank you. Let me have you turn to page 7 of your testimony, please.

A. Page 7. I'm here.

Q. Okay. When asked what you expect the availability and price for enrichment services to be in the future, in response, on lines 11 to 12, you stated that FPL expects current restrictions to be lifted, at least partially, if not totally. What sort of restrictions are you talking about here?

A. I'm referring to the fact that the Department

of Commerce -- let me back up a little bit. Back in the 1990s, the supply from the Russians was judged to be -- the Russian -- there was an argument that Russia was dumping nuclear fuel in the U.S. market, and since then, there has been a number of restrictions imposed on Russian imports. Eventually, that restriction also encompassed restrictions on enrichment services from western Europe, such as Urenco, which is one of the enrichment suppliers, and Areva, which is one enrichment supplier from France, where Urenco has facilities in the Netherlands, in England, and in Germany. So those cases were brought up in front of the Commerce Department by USEC and by other U.S. uranium miners in trying to -- according to the argument, to stop the dumping of nuclear fuels.

Now, some of those cases have already been resolved, such as Urenco is capable of importing enrichment services into the U.S., or at least we are capable of buying enrichment services from the Urenco facilities for import to the U.S. without any restriction.

The next phase of the legal battle or the legal challenge is for Areva. And in fact, there is -- the case is about to be maybe submitted to the Supreme Court of the U.S., because the U.S. miner and the U.S.

Hearing Exhibit 000408

enricher, the only one, has in fact lost all the appeal case, and the only last obstacle is now whether or not they will file to the U.S. Supreme Court. This is something which is supposed to be imminent within the next one month or two. And we are hopeful that that will not pass, and therefore that will become the law of the land, and therefore importation of enrichment services from Areva will now be acceptable.

There's also litigation going on in the industry with respect to clearing up the import from Russia. And in fact, the court -- USEC and the uranium miner have lost all those cases. Now, it's not as wide as going all the way to the Supreme Court. So the Areva case will affect the precedence as to the import of enrichment services.

So we expect that within the next year or two, those issues will be resolved.

Q. Okay. Thank you, Mr. Villard. It's as if you anticipated my follow-up questions. I appreciate that.

At this point, let me have you turn to page 10 of your testimony, please.

A. Yes, ma'am. I'm here.

Q. Specifically at lines 12 through 15, you discuss that the practice in the nuclear industry has been and continues to be to schedule deliveries of fuel

assemblies no later than two months prior to a refueling outage; is that correct?

A. That is correct.

Q. Can you explain how FPL arrived at two months as the appropriate lead time?

A. Some utilities even use longer times, but we -- it's a compromise between carrying costs and making it -- activities in preparation for the outage. When you have a refueling outage, when we are planning for a refueling outage, there are a number of activities that we plan for, and it is part of the logistical work to try to get those issues, especially delivery of fuel, we need to have fuel inspection when we receive the fuel. There are a number of activities that happen at the site, and of course, we need to prepare and position the fuel for reloading.

All those activities are activities that we would rather not do during a refueling outage, and therefore, it becomes a cost-benefit, and we try to get out of the outage duration all those things that we can do ahead of the outage so that we can have the staff available to focus and have an efficient outage. And that's essentially how that two months came about.

Q. Okay. Thank you very much.

A. You're welcome.

Hearing Exhibit 000410

Q. Further on that page, specifically line 19, starting on line 19, you state that nuclear units have the capability to continue power production beyond the scheduled end of life, end of fuel life; is that correct?

A. That is correct.

Q. Has FPL ever had an experience with their plants where they have extended the nuclear power production beyond the scheduled end of fuel life?

A. Yes.

Q. Okay. Can you describe when that happened and why?

A. Okay. We try to build and design core for a full 18 months. However, we make certain assumptions as to the capacity factor. When we design a core, it's one month -- one year, I'm sorry, one year even before the actual refueling. And it's sometimes uncertain as to how the plant is going to be running for the next two or three years, and therefore, we make the best educated choice as to our assumption. And we typically assume a 97.5 percent capacity factor for operation of the plant between refueling outages.

There are times that the plant runs better than 97.5, and sometimes we've had times when the plant runs at 98 and 95. In those cases, what we do is, we

Hearing Exhibit 000411

don't precisely change the scope of the refueling outage, but we in fact continue to produce, and sometimes with a small reduction in power, and that will allow us to continue to use the fuel a little longer to get to that scheduled refueling date.

Q. So do you view the capability of a nuclear plant to continue the power production beyond the scheduled end life of fuel to be of benefit then to the nuclear plants?

A. Yes, it is. In fact, the way we try to target -- yes, it is. It is a benefit, as I've explained in my testimony, not only from a fuel utilization perspective, because you don't want to overload your core, but also it's a benefit because it will provide additional flexibility in case there are other issues with respect to availability of supply for a fossil plant, and so forth and so on.

Q. Okay. Thank you. At this point I would like you to turn to Interrogatory Number 59, please.

A. Yes, I have 59 in front of me.

Q. I'm looking specific at part B, where FPL was asked if it has completed a risk analysis regarding the assumption that nuclear fuel will return to market fundamentals and that the supply will be sufficient over the lifetime of the proposed nuclear plants. Are you

Hearing Exhibit 000412

there?

A. Yes, I'm there.

Q. And in response, FPL stated that it has reviewed a number of market publications and formed its judgment on long-term prices. And in the last sentence of that response, you also state that the industry is currently in negotiations with the U.S. Government to use part of the large uranium inventory held by the government for new reactors, and that if this is successful, it would provide additional certainty in the supply of nuclear fuel; is that correct?

A. That is correct.

Q. Do you know what the current status of those negotiations are?

A. Yes. I participated in a meeting with the DOE last December along with other utilities, and we have come to an agreement as to making 20 million pounds available for first core in case it's needed. It doesn't obligate the utility to buy it, but just in case there was some issue with trying to procure first core, then it will be available. We met at NEI with the DOE management on that subject.

Q. Okay. Thank you. At this time, I would like you to turn to Interrogatory Number 51, please.

A. I am there.

Hearing Exhibit 000413

Q. In this question, we asked you to discuss which of the four steps of nuclear fuel development is most prone to cost fluctuation, and the response was that the supply of uranium is the most volatile of the four steps and that recent volatility in uranium prices is due to a large extent to speculative demands by hedge funds; is that correct?

A. Well, I can even add. I mean, there have been a number of disruptions in supply also. In my testimony I provide more detail, but there has been a number -- that is correct. That's part of the factor. That is correct.

Q. How has FPL's price forecast for nuclear fuel accounted for this involvement by hedge funds?

A. Well, we do expect periodically to have an imbalance in the fuel supply industry. What happened is the following: For the past 20 years, the market has been driven mostly by inventory, excess inventory, and the pricing that you got for nuclear fuel, for uranium specifically, was about 10 bucks per pound. That has been very stable for a long, long time.

As we are moving toward new nuclear plants, toward optimism in the nuclear power industry to build significantly more nuclear plants, the market is now shifting from a very long, stable period where the

Hearing Exhibit 000414

market price was very low and driven by inventory to one where we now are going to be closer to the fundamentals. By fundamentals I mean closer to what it takes to actually bring new mines on-line and to allow for a decent return on investment for those miners.

So that is our current projection, that right now we have an adjustment period where we're moving from an inventory driven price to a production driven price. And while you're making that adjustment, hedge funds tend to participate in wherever the market is imbalanced. Once the market becomes more balanced, which we expect it will reach equilibrium in the next two or three years, we would expect that to be the long-term trend.

Now, we're not saying that you may not have once every 10 years a spike in uranium prices, but we certainly covered that by being a little bit more conservative in the price that we have proposed to use in our need determination for uranium. In fact, if you look at some of the documents which were produced to you, some of the experts think that the market price will go back all the way down to the fundamentals, which is more like 20 bucks per pound. What we are using is a higher reference price, which we feel would cover on a long-term basis some of those adjustments that we

Hearing Exhibit 000415

currently see.

Q. You stated a few moments ago that you believe there will be a balance in the future, so is it your opinion that the speculative demands by hedge funds will not continue?

A. It is my opinion that in two or three years, yes, because there will be plenty of supply. And hedge funds, in my opinion, in my understanding, only get involved when supplies are imbalanced. And they do serve some purpose, but also disrupt the market periodically.

Q. Please turn to page 11 of your testimony, please.

A. Page 11.

Q. Beginning on line 5, you're asked, "How does FPL intend to address storage of spent nuclear fuel, in view of the delays in DOE's performance in the disposal of spent nuclear fuel?" What sort of delays or what type of delays are we talking about here as far as with respect to DOE's performance?

A. Well, DOE has had some -- I will acknowledge that DOE has had some problems with starting Yucca Mountain, and there also is political opposition to that. But even if you're talking about a significant delay, what we are basically emphasizing is that we do

have storage currently at Turkey Point for Turkey Point 3 and 4, and to add Turkey Point 6 and 7 is not going add any incremental problem.

To store nuclear fuel on a long-term basis is not a scientific issue. The science is there. The foundations are there. And in fact, the industry is moving toward what we call dry cask storage at a facility, where we're simply adding an additional pad and move the fuel from the spent fuel pool into the dry cask storage. The cost for doing that is not that significant, and we expect that we will be able to continue to store the fuel for a very long period of time, on-site for a very long period of time. So we believe that the delay in starting Yucca Mountain, even if it's 10 years or 20 years, can be very well addressed by additional storage at the site.

Q. Okay. You mentioned Yucca Mountain. In your opinion, do you think that Yucca Mountain will ever receive spent nuclear fuel?

A. I would rather say that I believe that the industry will resolve the long-term storage of -- I would like to stay away from the parties of Yucca Mountain. But the industry will resolve the long-term storage of nuclear fuel within the next 20 years. Now, whether it's Yucca Mountain or whether it is some other

Hearing Exhibit 000417

repository that we can move the fuel to, I'm not willing to bet one or the other, but I'm willing to bet that we will resolve the issue one way or the other. It's not a technical issue. It's not -- there are some scientific issues that have to be resolved, and it's quite acceptable that we are challenged as an industry to look into them, but eventually we will find a solution.

Q. Okay. Well, just for my curiosity -- you just stated something, and I'm just curious. You stated whether it's Yucca Mountain or some other repository. Is the industry considering another area to dispose of nuclear fuel, spent nuclear fuel?

A. No.

Q. Okay. I was just curious.

A. Not currently, no.

Q. Okay. With respect to the issue of spent nuclear fuel, you do state that the fuel will either be disposed of by DOE, as it is statutory and contractually obligated to do. Is the disposal by DOE -- is the only method of disposal right now that's considered by DOE Yucca Mountain at this point?

A. Yes. I cannot answer in detail all the consideration that DOE is doing. As far as I know, Yucca Mountain is the primary focus.

Q. Okay. And you stated that DOE is statutory

Hearing Exhibit 000418

and contractually obligated to dispose of the spent nuclear fuel; correct?

A. Correct.

Q. In light of the fact that DOE is statutorily and contractually obligated to do so, is FPL still looking at options for disposing of spent nuclear fuel in the event that they are required to dispose of that fuel?

A. FPL knows of options for interim storage at the site, but FPL is not looking, definitely, at options for eventual final disposal of spent fuel.

Q. Okay. But it is looking as far as disposal or on-site storage; correct?

A. Yes. FPL has a number of alternatives, such as dry cask storage.

Q. Has the cost of storage options such as dry cask storage been included in the project costs for this need determination?

A. My understanding is yes, but I would refer to Steve Scroggs to provide the specifics on that.

MS. FLEMING: Okay. We'll check with him. Those are all the questions that we have.

MR. BECK: This is Charlie Beck. I have none.

MR. BUTLER: Then I believe that --

MR. KRASOWSKI: This is Bob Krasowski. May I

ask a couple of questions?

MS. FLEMING: Did you notice the deposition?

MR. KRASOWSKI: Did I notice the deposition?

MR. BUTLER: Did you cross-notice the deposition? I don't think you did, but --

MR. KRASOWSKI: Well, maybe I didn't. I probably didn't.

MR. BUTLER: Well, I'll tell you what. If you truly have a couple of questions, I will allow that to proceed. Really, you are supposed to. If you have the desire to independently examine the witnesses, you are supposed to be filing your cross-notice of deposition for it. But if it's a small number, I'm not going to object.

MR. KRASOWSKI: Well, I appreciate that, and I apologize for not doing that. I was not aware of that. That's not an excuse, I understand. Yes, I just have a couple of quick questions, if I may, and thank you for allowing it.

CROSS-EXAMINATION

BY MR. KRASOWSKI:

Q. Mr. Villard, how are you today?

A. Very good.

Q. Okay. Nice to meet you. Mr. Villard, how long would dry cask storage serve as a method for

Hearing Exhibit 000420

containing the waste?

A. For a very long time. Dry cask storage uses inert gas, which will allow storage of fuel for a very long time.

Q. With very long being like up to 20 years, or are we talking a longer period of time?

A. We're talking about a much longer period of time.

What I would like to add also is that the fact that you have the current technology and you store fuel in the dry cask, that doesn't mean that 50 or 100 years from now, you would not -- assuming under the worst doom scenario that the government would not pick it up, 100 years from now, that doesn't mean that you could not, as set up -- the technology exists to simply transfer that fuel from that container to another one. It is not a scientific endeavor. The technology exists to practically store fuel for a long, long time, and by moving it from one facility to another one, because the technology does exist for that to happen, including re-encapsulating the cask itself in case it degrades.

So I don't see that as an issue. I don't want to answer your question specifically on dry cask storage, because I view it more as a long-term solution for a long, long time, although we would rather have the

Hearing Exhibit 000421

government pick it up.

Q. Well, I'm working on the information that the fuel will require retention for 10,000 years, or if the newest methods are successful in treating the fuel, it could be reduced to 3,000 years. So I'm wondering if the cost for the storage of the fuel, even with the most optimistic prediction as far as the shortest time being required manage it, are factored into your cost estimates.

A. We do have one mill per kilowatt-hour that we pay the government, and it's factored into our estimate for the eventual disposal of fuel that would be disposed of, whether 10 or 100,000 years, or whatever the scientific community finally decides the repository to be viable for.

Q. Thank you. Could you tell me the dollar amount that was decided upon in your negotiations with the government to access on a first call basis the 20 million pounds of fuel?

A. No, there is no dollar amount. Of course, we would have to pay the government a reasonable price. The government does not give it away, if that's what you mean. But, no, there's no -- it's a policy decision by the government to encourage nuclear power and to make it available. Right now, the government has 150 million

pounds of this inventory that they are sitting on for no other purpose.

Q. 150 million pounds?

A. That's the approximate number, yes.

Q. Thank you. I'm just trying to establish the economic parameters here.

Well, rather than go on too long, I would like to ask you just two more questions. Seeing your education and experience, I certainly believe that you continuously maintain your information base on this issue, so I would like to know first if you are familiar with the writings of Jim Harding, and specifically his paper on the economics of new nuclear power and proliferation risks in a carbon-constrained world. I have that document in front of me. I understand you don't have it in front of you, but I'm asking you if you have that or if you can read it before you appear for cross-examination, if in fact you do.

A. Well, actually, nuclear fuel, this is going beyond my expertise, because it involves a number of other factors. No, I don't know that I would be able to address your question here.

Q. I'll ask the same in a moment to Mr. Yupp, so I'll leave it at that then.

The second and last question would be, are you

Hearing Exhibit 000423

familiar with or have you read the paper by Richard Lance Christie which is entitled "The Economic Cost of Nuclear Power: Free Market v. Subsidized Nuclear Power Economics." Have you read it?

A. No, I haven't read it, no.

Q. Okay. Would you be able to read those two papers before you arrive for testimony on whichever day of the hearing you'll be showing up?

MR. BUTLER: We're not making any commitment to you, Mr. Krasowski, on the extent to which Mr. Villard would be prepared on these papers. As he mentioned, he has a particular role in this case, which is to testify to the nuclear fuel cost projections and issues related to that. I'm suspecting from the titles of these papers that they go to a much broader topic than that.

MR. KRASOWSKI: Okay, Mr. Butler. These papers do serve as documents that help me understand the subject, and they very much relate to the content of Mr. Villard's testimony.

MR. BUTLER: But, Mr. Krasowski, this is an entirely inappropriate form of cross-examination here. If you had wanted Mr. Villard to comment on those, then you certainly should have provided them to him in advance. There's really nothing further

Hearing Exhibit 000424

that you can cover about them, in my mind, in this deposition.

MR. KRASOWSKI: Okay. I appreciate that. I'm just trying to work towards a situation where we can get the most information and move forward. So are you telling me that if I send these to him now, at the hearing he might be able to address them?

MR. BUTLER: I imagine he will give them the attention that his role in the case warrants.

MR. KRASOWSKI: Okay. Well, thank you very much, and I appreciate you not objecting to my questions, Mr. Butler.

MR. BUTLER: My pleasure.

MR. KRASOWSKI: I'm done with my questions, Ms. Fleming, for Mr. Villard.

MR. BUTLER: Let me go off-line for just one second. I don't think I have any redirect, but I just want to be sure.

MS. FLEMING: Okay.

(Off the record briefly.)

MR. BUTLER: We don't have any redirect.

MS. FLEMING: Okay. I think that concludes the deposition of Mr. Villard, and the witness can be excused.

(Deposition concluded at 10:07 a.m.)

Hearing Exhibit 000425

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1 through 24 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 17th day of January, 2008.

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

Hearing Exhibit 000426

CERTIFICATE OF OATH

STATE OF FLORIDA

COUNTY OF PALM BEACH

I, the undersigned authority, certify that **Claude A. Villard** personally appeared before me at **700 Universe Boulevard, Juno Beach, Florida** and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, State of Florida, this 16th day of January, 2008.

Notary Public State of Florida
Jennifer M Payne
My Commission DD439096
Expires 06/09/2009

Notary Public
State of Florida

Personally known K OR produced identification _____.

Type of identification produced _____.

ASR ACCURATE STENOTYPE REPORTERS INCORPORATED
CERTIFIED COURT REPORTERS

January 18, 2008

John Butler, Esquire
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Need Determination for Turkey Point 6 and 7
Docket No. 070650-EI

Dear Mr. Butler:

Enclosed is your copy of the deposition of Claude A. Villard taken in the above matter on January 16, 2008.

Since reading and signing was not waived, we are enclosing an errata sheet and request that your office make arrangements with the witness to read the deposition and make any corrections on the errata sheet.

Please forward the original completed errata sheet to Jane Faurot at the Commission for attachment to the original transcript. You should also attach a copy to your transcript so that it will be complete.

Thank you for your cooperation in this matter. It was a pleasure working with you.

Sincerely,

Mary A. Neel

/mn
cc: Jane Faurot
Enclosures

ERRATA SHEET

Under penalties of perjury, I declare that I have read the foregoing transcript of my deposition, pages 1 through 25, and that the facts stated therein are true, including any corrections and/or amendments listed below.

Date

CLAUDE A. VILLARD

Page	Line	Correction or Amendment	Reason for Change

Deposition taken on 01/16/08, Docket No. 070650-EI

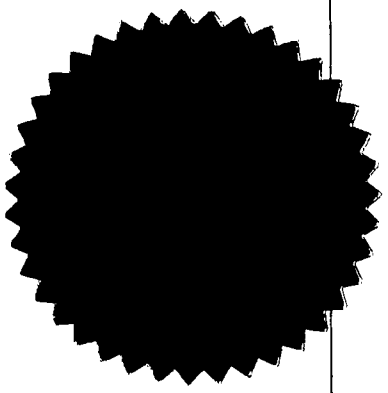
12

Deposition Transcript of Gerard J. Yupp

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI

In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.
_____/



TELEPHONE DEPOSITION OF: GERARD J. YUPP

TAKEN AT THE INSTANCE OF: The FPSC Staff

DATE: January 16, 2008

TIME: Commenced at 10:16 a.m.
Concluded at 11:55 a.m.

LOCATION: 2540 Shumard Oak Boulevard
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR
Notary Public, State
of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
2894 REMINGTON GREEN LANE
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PETE LESTER
MASHINDA KAZADI
BILL McNULTY
DAMARIS RODRIGUEZ
GENE UNGAR
CLAUDE A. VILLARD
JENNY WU

Hearing Exhibit 000432

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Hearing Exhibit 000433

STIPULATIONS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

Thereupon,

GERARD J. YUPP

the witness herein, having been first duly sworn by Jennifer DeValario, a notary public in the State of Florida, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. FLEMING:

Q. Good morning, Mr. Yupp. How are you?

A. Good morning. I'm fine, thanks.

Q. Before we get started, I just want to make sure you have certain documents available to you.

A. Okay.

Q. I'm assuming you have a copy of your testimony; correct?

A. That is correct.

Q. As well as the need study and appendices?

A. That is also correct, yes.

Hearing Exhibit 000434

Q. And the response to Staff's POD Number 13?

A. Yes, I do have that also.

Q. And I believe we provided a copy of the Annual Energy Outlook 2007 and the Annual Energy Outlook 2008, Early Release, Table 13.

A. Right. I have copies of both of those.

Q. In case we need to refer to those.

A. Okay.

Q. Okay. So let's go ahead and get started. For purposes of the record, please state your name and business address.

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

Q. And you're employed by FPL; correct?

A. That is correct.

Q. And what is your position at FPL?

A. I am the Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. And what do your responsibilities include?

A. My responsibilities include overall responsibility for natural gas and fuel oil procurement for the utility, as well as I have overall responsibility for managing our wholesale power transactions.

Q. And you filed 17 pages of direct testimony in

this docket; is that correct?

A. That is correct.

Q. Do you have any corrections to your testimony at this time?

A. No, I do not.

Q. Okay. The first topic I would like to discuss is natural gas prices, so if you could please turn to Appendix E5.

A. Okay. E1 --

MR. BUTLER: E5. You're talking about Fuel Forecast 3, Medium Price, Natural Gas? Is that what you're referring to?

MS. FLEMING: Yes, that's correct.

THE WITNESS: I am there.

MS. FLEMING: John, you just took my first question.

BY MS. FLEMING:

Q. This page refers to the medium price natural gas forecast; correct?

A. That is correct.

Q. Now, there's a column on the far left called the Henry Hub column. Except for that column, the prices on this page include variable transportation costs; is that correct?

MR. BUTLER: Excuse me, Katherine. I think

you meant the right, didn't you?

MS. FLEMING: Oh, yes. I'm sorry. I'm having problems today.

MR. BUTLER: No problem.

A. Yes. To answer your question, all of the other columns except for the Henry Hub column do contain variable transport costs.

Q. Okay. Thank you. Now, I've heard the term "basis" used when we're discussing natural gas prices. Are you familiar with that term?

A. Yes, I am.

Q. Can you explain exactly what that term is or what does it mean?

A. I guess in the simplest sense, we speak of the basis differential, and what that is is, because gas -- let's just take Florida Power & Light, for example. We procure gas in different regions in the Gulf, Florida Gas Transmission Zone 1, Zone 2, and Zone 3. I'll just keep it to that discussion.

The basis differential is the relation of prices in those physical receipt areas versus the Henry Hub. So in other words, there is going to be a price differential between FGT Zone 3 and, let's say, Henry Hub in the example I'm using, and that is referred to as the basis differential.

Hearing Exhibit 000437

Q. So in the columns that you just referred to, for example, the Gulfstream and FGT, there is an allowance for basis in the forecasted prices?

A. Yes, there is.

Q. Okay. And now I'm looking specifically at the two columns in the middle of the page, the Gulfstream Firm, SESH Pipeline, and the Gulfstream Firm, Mobile Bay. Do you see that?

A. Yes, I do.

Q. What is the difference in the prices for these two columns, or what is the reason behind it?

A. The reason for the variance in prices in these two columns is because the gas is assumed to be coming from different locations. For the SESH pipeline column, that is gas that is coming from East Texas. That is a project that we recently executed, or an agreement that we recently executed which will bring gas from East Texas down into the Mobile Bay area and connect with both FGT and Gulfstream pipeline. So the physical receipt of that gas, where we are picking that up and then hauling it on the Southeast Supply Header pipeline, that price will be different than the Gulfstream Mobile Bay price, which historically, gas moving on Gulfstream has always come from the offshore Mobile Bay area. Now we will have this additional supply into that area, part

coming from onshore resources, and then there is a part that still will be coming from offshore resources, and hence the difference in prices.

Q. And you mentioned the Southeast Supply Header pipeline coming into service. So when that pipeline comes in the service, that will lower the basis for the Mobile Bay area?

A. Yes. And that has been -- even as part of executing that transaction or analyzing whether that transaction was good for FPL and its customers, that was taken into account, an assumption being made that the basis in Zone 3, or at least the Mobile Bay area, would get depressed with the introduction of onshore supply into that area.

Q. Okay. Thank you. Now, as far as the column for the Southeast Supply Header pipeline that we've talked about and you have identified the prices on this forecast, has FPL recognized the basis lowering effect of the Southeast Supply Header pipeline in the forecasted natural gas prices on this page?

A. Yes, it has.

Q. Okay. Thank you. At this point, I would like you to turn to the response to POD Number 13. It's an Excel spreadsheet that's titled "070731 Long-term Forecast Methodology." And we're looking specifically

at a tab titled "Gas Forecast Comparison Graph," and the page I have in front of me, the title across the top says "Forecast Comparison: Delivered Firm FGT Natural Gas Dispatch Prices."

MR. BUTLER: And it has a series of curves on it on a graph, Katherine?

MS. FLEMING: Yes, it does. And it's got FGPP medium, low, and high price forecasts, as well as the current updated medium, low, and high price forecasts.

THE WITNESS: Okay. Yes. I've got that open now.

BY MS. FLEMING:

Q. Okay. Just a couple of questions on this. The FGPP that's referenced on this table, is that referring to the Glades project?

A. Yes, that is referring to the Glades project.

Q. Okay. My copy is in black and white, so looking at the FGPP medium case forecast, which is a dark black diamond, along with the updated, current updated medium price forecast, which is a lighter square, it appears as if those two lines or those two prices begin to diverge after about 2030. Would you agree with that analysis?

A. Yes, I do agree with that.

Q. Okay. Can you explain why the current updated prices are higher than the Glades prices after 2030?

A. Yes, I can, and I guess this is a two-part answer. First and foremost, the fuel price forecast for the Turkey Point 6 and 7 case reflects a more updated forecast. As we describe in detail in my testimony, our methodology incorporates numbers from the PIRA Energy Group or data from the PIRA Energy Group to create our fuel price forecast. And so the first thing that is different between the two is that the Turkey Point 6 and 7 contains the latest -- or as of July 31, 2007, when this forecast was done, it contains an update from the PIRA Energy Group on their long-term fuel price forecast. That is the first difference.

The other difference is, we did have a slight change in methodology between forecasts, particularly for the period of 2020 forward, in how we applied a real rate of escalation to prices after 2020, because in our fuel price forecast, the information we receive from the PIRA Energy Group goes out through 2020, and after that, there is no data. At that point in time, in our previous fuel price forecast, that being the one for the Glades project, our methodology was basically looking at the differential from year to year in coal prices, which -- at that point, we do receive coal prices out farther

Hearing Exhibit 000441

in time. So we were looking at the differential from year to year in coal prices, and we were applying that same differential to natural gas prices, making the assumption that the differential between coal and gas would remain equal out in time.

In this new forecast or updated forecast with a slight change in methodology, we felt it was more appropriate for the period 2020 and beyond to use the EIA rate of escalation to escalate our prices out into time. We feel that's more appropriate. And I say more appropriate because the methodology used before, although not wrong -- I mean, a forecast is a forecast, and you can approach it in many different ways. I think as we look out farther in time and at what is going on with coal now, you know, potential environmental regulation and all that, I don't think -- or we don't believe that it warranted this kind of close approximation between coal and natural gas prices. So we felt it was just more appropriate to go with the EIA escalation for this fuel price forecast, and hence you do see a little bit of difference, not only due to that, but also obviously due to the update in the PIRA forecast.

Q. Okay. Thank you. Well, since you've started discussing the forecast methodology, let's turn to that.

A. Okay.

Q. I'll direct to you page 12 of your testimony. And in your response to the previous question, you mentioned that you used the EIA real price forecast. Now, have you provided your calculations of the EIA's real price changes to staff?

A. No, we have not. And I think -- let me make sure I'm clear in my understanding. Have we provided our calculation of what the EIA rate of escalation was in their fuel price forecasts? Is that what you're --

Q. Yes, that's correct. That's what we're asking. Has that been provided to staff, whether it's in discovery or in testimony or anything?

A. No, we have not. The rate that we did use is in -- the calculation of it is not in the documentation that we've provided. A reference to that rate, though, is included in the file that we have been looking at, the long-term price forecast methodology. And it is on -- it's going to take me one second here. It is on the tab titled "PIRA Long-term Gas Backup." It is a hidden tab, unfortunately. A lot of tabs are hidden just because of the sheer size of this file. So it is called "PIRA Long-term Gas Backup." And on that tab in column D -- I'll give you the cell reference, actually. Column D, and the cell reference, it will be D741. And

in that cell there, you can see 1.14 percent as the -- well, the hard part is that it's not flagged EIA rate of escalation, but that is what that cell is referencing.

Q. Okay. Thank you. I appreciate you providing that information to us. Could we also get a late-filed exhibit with the calculation that we discussed?

A. By calculation, you mean how FPL developed the 1.14 percent; is that correct? Or I shouldn't say how FPL developed it, but how FPL obtained that 1.14 percent from the EIA data?

Q. Yes, that's correct.

A. Okay. We can do that, or I can explain it also.

MR. BUTLER: Let's have Mr. Yupp try explaining it and then see if you still need a late-filed exhibit.

MS. FLEMING: Okay. Let's do that, and then if we need to, we can go off the record and confer with staff. Let's do that.

MR. BUTLER: Okay. Go for it.

BY MS. FLEMING:

Q. Go ahead.

A. Actually, to do this, I would refer you to Table 13 in the 2007 Annual Energy Outlook provided, or from the EIA, the 2007 Annual Energy Outlook, not the

Hearing Exhibit 000444

early release for '08.

And the way that we did this, again, we're looking to apply an average annual rate of escalation over a period of time. So what we did is, we looked at the EIA forecast that was in that Annual Energy Outlook. And if you go to natural gas prices, Henry Hub spot price, which is roughly three quarters of the way down the page, we started in 2016. So the first price is $5.56. And I can give everybody a chance to get there. Does everyone see that?

Q. Yes, we see it.

A. Okay. $5.56, and the ending price in 2030 being $6.52. So what we did, trying to back calculate into a number, we continued to apply annual rates of escalation in order to get from 5.56 to 6.52 over that period of time. And if you apply 1.14 percent to the 5.56 in 2016, it would yield a price in 2017 of 5.63. And then if you continue applying 1.14 percent to each of those numbers, by the year 2030, you would get to $6.52. And that is why we made the assumption that on average, the rate of escalation for the EIA over that period of time was 1.14 percent, and that's what we used as an average annual rate in our fuel price forecast.

MS. FLEMING: Okay. Let me confer with staff for a second, so let's go off the record for a

Hearing Exhibit 000445

couple of minutes, if that's okay.

MR. BUTLER: Okay.

(Discussion off the record.)

MS. FLEMING: Mr. Yupp, thank you for that explanation. It really did help clarify a lot of the questions, and we no longer need a late-filed exhibit. I'm getting nods from staff. Yes, that's correct.

MR. BUTLER: Good.

BY MS. FLEMING:

Q. Now that you gave me this long explanation, I do have a few follow-up questions just for clarification. The first question that comes to mind is, why did you use the rate of real price changes from EIA to forecast natural gas prices after 2016?

A. We just felt that was an appropriate source of data, using the EIA rate of escalation. As I said before, we did slightly change -- or not slightly. We changed our methodology for forecasting prices past 2020, because we -- you know, the first reason to change, we felt it was more appropriate given everything that was going on with coal and with potential environmental regulation and all of that. I think our old methodology, where we were taking the rate of increase in coal from year to year and applying that

same rate to natural gas, just -- we thought about that, and it didn't seem to be appropriate anymore, as potentially the differential between coal and gas could widen, depending on what the future holds for environmental regulation. So we simply said, okay, well, how are we going to escalate those rates then from that time forward, because again, the PIRA forecast that we receive goes out through 2020. And at that time, we just decided that EIA was an appropriate data source to use as the rate of escalation. It's very public, can be seen by all, and is a reliable source of data. So that was really the underlying reason for choosing EIA.

Q. You used an escalation rate of 1.14 percent; is that correct?

A. That is correct.

Q. And that was up to 2030?

A. Actually, we -- well, we calculated what that rate is according to the EIA fuel price forecast over that 14-year period, and then we used that rate of escalation, average annual rate as we calculated it, from 2020 forward. We just used that through the life through the fuel price forecast, which goes through 2061.

Q. And you actually anticipated my follow-up question. Thank you.

Hearing Exhibit 000447

Earlier we were discussing Appendix E5 and the Henry Hub column. Do you recall that?

A. Yes, I do.

Q. The Henry Hub column, does that refer -- or does that show FPL's medium natural gas price forecast?

A. I'm not sure I follow the question.

Q. Well, FPL has different gas price forecasts, and the medium natural gas price forecast is shown on Appendix E5. And my question to you is, is FPL's medium natural gas price forecast found in the column shown as the Henry Hub column? Is that what FPL uses as their medium gas price forecast?

A. Oh. Let me see. Maybe I can clarify. Yes, that is the Henry Hub price forecast in the medium price forecast, which is the foundation to create all of the delivered price forecasts which you see in the columns from left to right after you see Zones 1, 2, 3, and so forth. So, yes, that is the Henry Hub forecast, which is the basis for creating all of the delivered price forecasts.

Q. Okay. And I would assume the same would apply on Appendix E9 with the low price gas forecast?

A. That is correct.

Q. Okay. Thank you. Now, turning to your testimony on page 12, lines 21 through 22.

A. Okay. I'm there.

Q. You stated that all constant dollar changes were then converted to nominal dollars using a 2.5 percent annual escalation rate.

A. That is correct.

Q. So in order to get -- the 1.14 escalation rate that you referred to, that's a real price; correct?

A. Right. That is a real dollar escalation rate.

Q. So would you take then the 2.5 percent and add it to the 1.14 percent to get the nominal escalation rate?

A. I guess let me say it maybe a little bit differently. Everything is done on a real price basis. We have all our yearly prices on a real price basis, and then we do escalate from 2020 forward using the real rate of escalation of 1.14 percent to create prices in the years 2021 through 2061. But then once we are done with that, all of our prices are then converted to put them on a nominal dollar basis utilizing a 2.5 percent inflation rate or 2.5 percent annual escalation rate. But that is in relation to putting it into nominal dollars, which may be how you described it. I just wanted to make sure I was clear.

Q. I was just trying to get an understanding of these different rates, and some are in real price and

some are in nominal terms.

A. Right. And the real price escalation rate was used purely to create the forecast, you know, assuming an escalation rate moving forward on a real dollar basis from 2021 through 2061. The inflation rate as described here, the 2.5 percent annual escalation rate, that is then used to convert those real dollars that have been created out through 2061, real dollar price forecast, to nominal dollars.

Q. So how much higher is the price escalation of natural gas for the period -- I think you were referring to 2021 to 2061 -- than the general economy inflation rate that FPL assumed in its price forecast?

MR. BUTLER: I'm sorry. Could you restate that one, Katherine?

BY MS. FLEMING:

Q. The price escalation cost for the natural gas that we're using, I guess, how much higher is that with the general economy inflation rate that FPL assumed? Is there a difference, I guess is what my question is, in those rates, and if there is, what is that difference?

MR. BUTLER: Katherine, I'm not trying to answer for the witness, but it seems like the answer would just be 1.14 percent. That's the real escalation component, and then you have this sort

of general inflation component. But maybe you're asking a different question.

MS. FLEMING: No, that's actually what I was asking. I'm still trying to get my head around the real versus nominal, and so I was just trying to follow up on what he just stated, if there was a difference, what is that, and does that tie back to the 1.14.

MR. BUTLER: May we go off the record for just a second?

MS. FLEMING: Sure. Go ahead.

(Discussion off the record.)

BY MS. FLEMING:

Q. I guess the question is this, Mr. Yupp. And I'll try to phrase this as best I can. You've discussed about having a 1.14 escalation rate; correct?

A. That is correct.

MR. BUTLER: Real escalation.

MS. FLEMING: Excuse me?

MR. BUTLER: Real escalation.

THE WITNESS: Right, real rate of escalation.

BY MS. FLEMING:

Q. Okay. Why is it reasonable to assume that natural gas prices will escalate from 2031 to 2061 at the same rate that the EIA expects natural gas prices

Hearing Exhibit 000451

will escalate from 2016 to 2030?

A. First, you have to assume for our -- for any fuel price forecast, you have to assume some change past the period. In our case, it's past the period where we received data from the PIRA Energy Group. And looking out through history and then applying that on a forward basis, prices will generally tend to increase over time.

So as far as your question -- and maybe now I better understand it -- as to why we would pick a 14-year period in the EIA forecast that showed a 1.14 percent rate of escalation and apply that to a longer period of time, in our case, from 2021 through 2061, the simple answer to that is that that is the best information we have available at the time.

I don't think there's any other source that we could basically use to project that data out over time. Unfortunately, EIA only goes through 2030. You've heard that the fuel forecasts from PIRA only go through 2020. So when you start going out into that far reaching period of time, you do have to make some assumptions. And we thought it was a relatively good assumption or an appropriate assumption to say, "Okay. EIA feels that the annual average rate of escalation through 2030 will be 1.14 percent. Let's just carry that out farther in time for lack of anything that I think could be better,

more concrete, or more definitive." Again, we're talking 30, 40, 50 years out into the future.

Q. So this is the best analysis or the best scenario that FPL could use in order to formulate something that goes out for a 41-year period?

A. Yes, that is correct. We felt this was the best methodology that we could employ for a fuel price forecast that goes out through 2061.

And I guess maybe something to add here, just from an overall sense, is that -- and that's part of the reason that we used the approach we used. Let's say the medium price forecast is what it is, but then we said, okay, for economic evaluation prices, because we are looking at an extremely long period of time, through 2061, we said the banded approach that we used is very appropriate for this type of economic evaluation. Let's put some reasonable bands around the fuel prices, because nothing is certain in a fuel price forecast, particularly ones that go out so far in time, so let's apply some bands developed through real prices that we have seen over the last seven years delivered to FPL's system. And that way, we feel that we have 100 percent covered what we believe to be reasonable fuel price forecast outcomes for economic evaluation purposes.

That's why I say, yes, you do have to make a

lot of assumptions, and there are probably varying consultants and experts that could make different assumptions. We chose the best ones, we felt, and then on top of that, adding in the high and low band, we felt that we covered an appropriate range or a reasonable range of price outcome scenarios, and that was appropriate for economic evaluation purposes of these units.

Q. Okay. And just as a quick follow-up, you started this starting at 2016; is that correct?

A. That is correct.

Q. Why did you choose 2016? Why not start it sooner, like 2012 or 2010? Is there a reason for that?

A. There is reason for it, and I'm going to struggle to explain it, because I don't necessarily do the mechanics of the fuel price forecasts. But when we were evaluating some different methodologies or a methodology that might be more appropriate, the forward curve went out for 10 years, and so what we -- and I know this is going to be difficult to understand, but the forward curve was out for 10 years through 2016. And so as part of it, we were evaluating, well, we do have forward curve prices out through 2016, so then after that, let's take a look from 2016 forward what the EIA rate of escalation is.

That's the best of my understanding. Again, I'm not involved in the specific details of producing the forecast, but that's my general understanding of why it was from 2016 forward. And then obviously, it was through 2030 because that's where the EIA data ended.

Q. Referring back to Table 13 that you were discussing earlier, assuming -- and I'm just looking at numbers here. I'm not a mathematician. But if you had started back in 2010, could one assume that the 1.14 percent would be lower if the forecast had started back at 2010 instead of 2016?

A. Yes, you could make that assumption that the rate of escalation would be lower. But again, I think it is still important to note that there are assumptions that are going to be made, that are made, you know, with keeping in mind what is the most appropriate assumption to make. And at the end of the day, with a banded approach of low and high fuel price forecasts, we feel that we're covering a reasonable range. So there can be tweaks one way or another to the medium price forecast, but the banded approach we used we believe adequately covers what could be, you know, the most likely price outcomes.

Q. Do you know of any other instances where real fuel prices in the U.S. have escalated at the rate of

1.14 percent or a higher rate over a 41-year period for any type of --

A. I do not --

Q. Go ahead.

A. No, I do not know that.

Q. Okay.

A. I know through the last -- you know, from 2000 through 2005, real fuel prices escalated at much higher rate than 1.14 percent. But again, we're talking over a 41-year period. No, I do not know that.

Q. Okay. Thank you. Now I would like to turn to page 10 of your testimony, where you discuss the uncertainties in fossil fuel forecasting. And on pages 10 to 11, you were asked to identify key factors that contribute to uncertainty in forecasting the future price of fossil fuels, and you list a number of drivers behind the natural gas prices; is that correct?

A. Behind all fossil fuel prices, yes.

Q. And on page 11, line 10, you identified the worldwide supply and demand of LNG as one of those drivers; is that correct?

A. That is correct.

Q. Is the future supply of LNG to the U.S. dependent on either the current or planned LNG import terminals?

A. Yes, that does have something to do with it. And by current or future plans, I'm assuming you mean anything that has been approved by FERC at this point or anything that is on the planning horizon. But, yes, that would have something to do with it.

Q. In forecasting the prices for natural gas, whether's the low, medium, or high, were any assumptions made regarding the LNG import terminals?

A. No, but I will -- yes. The answer is actually yes. Again, PIRA, who supplies our long-term forecasts, will have taken all of that into account. They're world renowned energy consultants in the fuel price forecasting business. They have the research people and expertise on staff that when they're creating a forecast, they are looking at all -- you know, they have to develop assumptions, and they are looking at all possible data that is out there, and obviously LNG is a big part of determining future supply-demand balance and all of that.

So the bottom line answer is, yes, that is all taken into account in the forecast. Did FPL specifically? No, because we don't create our forecasts, but we know that the PIRA Energy Group did.

Q. Well, as far as assumptions that the PIRA Energy Group made, are you aware of any specific

Hearing Exhibit 000457

assumptions that they made regarding these LNG import terminals?

A. Specifically regarding LNG import terminals, I do not know. I would have to go back and look through our data. But I can point you to -- at least from a supply perspective of what PIRA sees as the LNG growth in the United States out at least through 2020, I do make reference to that in my testimony. Actually on page 8, beginning on line 8, I say that LNG imports are projected to increase to meet U.S. natural gas demand growth from approximately 1.6 billion cubic feet per day in 2006 to approximately 14.3 BCF per day by 2020. And that is the out of PIRA's assumptions that are behind the forecast.

Q. Do you think these assumptions or projections are based on possibly the fact that they're assuming that the planned terminals will be built on time or according to schedule?

A. I would think that would be a rational assumption to make, yes.

Q. Since you're already on page 8, we're actually going to continue talking a little bit about that. A little further down on the page 8, specifically lines 14 through 16, continuing to talk a little bit more about LNG, you state 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.

A. Correct.

Q. What sort of risks are you talking about here?

A. It's very similar to all the risks we face now on foreign supply fuel, particularly for FPL, residual fuel oil, which in turn is a by-product of crude oil coming from the Middle East. But, you know, risks as far as, just looking at today's environmental, tensions in the Middle East and the politic situation or geopolitics, I guess, of the world, potential supply disruptions due to what's going on in the Middle East now and sabotage attacks on pipelines and all that, you know, supply disruptions caused by those problems will impact prices.

And to the extent that LNG, being a foreign source fuel supply, becomes a more prevalent part of the total U.S. natural gas supply picture, then you do introduce those potential problems. Whether they be political, whether they be political and then result in supply disruptions, whatever it may be, you're at the mercy of what's going on in those particular countries or areas that are supplying the fuel.

Q. So in forecasting the natural gas prices, did

Hearing Exhibit 000459

you take into account these potential risks?

A. Again, this is a natural gas forecast produced by PIRA, and I would make the assumption, without going back through all their data, that those are assumptions that they do make when they are developing their long-term fuel price forecasts, particularly on the oil side. That is something that has to be taken into account when developing a long-term fuel price forecast, because the bottom line is, when you are developing it, you are looking at the supply-demand balance moving forward, not only from what's production going to be versus demand and how the economy fits into all of that, but also what is the situation worldwide from that perspective, from the risks associated with foreign supply. So, yes, bottom line, PIRA would take that account and make some assumptions on it.

Q. In addition to LNG, as far as other alternatives to expanding the existing pipeline system, you address that one alternative could include the addition of a new interstate pipeline; is that correct?

A. Yes. I'm actually looking for the exact words, but yes, I do remember putting that in.

Q. And if you need a specific reference, it's on line 5 on page 8 of your testimony.

A. Okay.

Hearing Exhibit 000460

Q. On that, are you aware of any plans to build a new interstate pipeline that would reach into peninsular Florida?

A. I am not specifically aware of any new plans. Again, I think that was just from a general sense of, you know, potentially one other option in order to address not only the expansion of infrastructure that would be required, but also to potentially address the definite need for supply diversity away from the Gulf of Mexico. An interstate pipeline could be a logical solution, but I have nothing specific behind that comment.

Q. In your opinion, how possible is it to -- would it be to build a new greenfield pipeline in Florida? I mean, what's the likelihood of that actually taking place, in your opinion?

A. I'm not sure I'm qualified to give an opinion on the likelihood of that. Honestly, I really don't know.

Q. Okay. That's fine. That's fair enough.

A. I'm sorry. I don't think I probably have enough information to be able to give an opinion on that.

Q. That's fine. I was just thinking, in order to build a pipeline, you may have right-of-way easements,

Hearing Exhibit 000461

or there may be issues with that, and I just wondered what's the actual probability of obtaining those easements and actually being able to build a pipeline, but that's just more out of curiosity than anything else.

A. Yes. I think I can just add one thing. In my opinion, I don't think it would be easy. It's not necessarily easy to do anything like that with, as you describe, rights-of-way and permitting and all of that. So probably not an easy thing to accomplish, but I don't -- you know, in my opinion, it's not impossible, but definitely not easy.

Q. I don't think there's ever anything that's impossible.

A. Exactly.

Q. Okay. Let's continue on page 8 of your testimony, specifically lines 19 through 21. You state that in an effort to create supply diversity and help strengthen reliability, FPL recently contracted for additional natural gas storage. Is that natural gas storage the Bay Gas and MoBay?

A. Yes. The natural gas storage is the expansion of our Bay Gas agreement from 1 BCF to 2 BCF, which actually should be going into effect sometime roughly, I believe, around April, maybe in the April to June time

frame of '08. And then, yes, as you stated, the MoBay facility, which the last update I had on MoBay was sometime in the fall of '09. But that was for the significant increase in our storage capability of, you know, approximately 6 BCF.

Q. And these natural gas storage facilities will increase the supply reliability for FPL?

A. Yes, they will increase the supply reliability. It's not for over an indefinite period of time, because there is a finite, you know, limitation to the amount of gas we can store. But certainly from where we are at today to where we will be at on our storage capability once both of these arrangements are in place and operational, yes, they will help to mitigate particularly or most primarily the impact of severe weather events and potential supply disruptions to natural gas due to severe weather events in the Gulf of Mexico.

I'm sorry. I'm done.

Q. Okay. Do you believe that by having this gas storage, it will allow FPL to mitigate volatility in gas prices?

A. I think by default, yes, it can help to mitigate volatility, particularly, as I was describing, during severe weather events, where if I have injected

gas into storage during periods of, you know, relatively stable prices, during a severe weather event that results in a supply disruption in the Gulf of Mexico -- or actually, technically, it doesn't even have to result in supply disruptions. Just the mere threat of supply disruptions, potential disruptions in the Gulf of Mexico will greatly impact prices, as we have seen in the past, particularly in 2005.

To the extent that I can use some of that storage to meet some of my requirements without having to go to the market and buy fuel during that heightened price -- you know, price levels being raised, yes, there is a direct correlation. I can help reduce some of the fuel price volatility for natural gas.

Q. Thank you. Continuing with that sentence that we were reading, it also states that FPL recently contracted for firm transportation on a new pipeline. Is this the Southeast Supply Header pipeline?

A. That is correct. That is the Southeast Supply Header pipeline, on which we have contracted for 500,000 MMBTU per day, which will bring the onshore gas into the Gulf of Mexico region.

Q. And so this pipeline will provide FPL an increase in supply reliability and diversity as well?

A. Yes, definitely diversity. With predominantly

a lot of our gas right now coming from offshore, Zone 3 supply in the Gulf of Mexico, definitely diversity with the onshore supply.

And that being said, from a reliability standpoint, yes, very important. During severe weather events or storms such as we had in 2005 in the Gulf of Mexico, we feel confident that our onshore supply, at least this piece coming on the Southeast Supply Header, would be much more reliable than what we would have offshore.

Q. At this point, let me have you turn to page 9 of your testimony, specifically lines 2 through 8, where you discuss that the cost of implementing mitigating strategies will vary depending on the type of alternative being considered.

A. Right.

Q. And you further note that it's important to recognize that this investment in infrastructure and supply alternatives will have to be made in order to maintain today's level of natural gas reliability in the future as the demand for natural gas grows. Do you see that?

A. Yes, I do.

Q. And I guess I'm trying to understand what you're saying here. Are you saying that if FPL doesn't

Hearing Exhibit 000465

build Turkey Point 6 and 7, it will need more investment in gas pipelines and gas storage in order to maintain --

A. I'm not sure if you cut out. Did you finish with "maintain"?

Q. No. I was trying to think of a word. I can't think of a word, so -- are you saying that if for some reason -- let's assume hypothetically that Turkey Point 6 and 7 for some reason aren't approved or can't be built or there are some other issues down the line. Will there need to be more investment in gas pipelines and gas storage in order to meet the demand in the State of Florida?

A. Yes, or, as I say here, or I state here, to maintain. Yes, I think that's definitely a true statement.

And again going back to earlier in my testimony, the natural gas infrastructure into Florida really has proven to be very reliable over the years. It's just that now we have reached a point where the Gulfstream and the FGT pipelines are fully subscribed. Capacity is not available on those pipelines. The introduction of the Cypress pipeline bringing regasified LNG into the State of Florida, something like that I guess is really what I'm referring to here, alternatives like that. That will help.

Hearing Exhibit 000466

But as the demand for gas grows, yes, the bottom line answer is that the investment will have to be made, not only in the infrastructure to move the gas to areas in Florida or to our power plants, but supply diversity becomes a very big issue then. And it's a big issue now. I don't want to trivialize it now. But as your demand for gas grows, it becomes even more important, because we can't continue to rely on just sources in the Gulf of Mexico. We saw how vulnerable that supply is to severe weather events and interruptions. So the effort will have to be made to diversify supply to ensure that during -- whether it be severe weather events or whatever it may be, that we do have sufficient gas to meet the requirements of our customers.

So the bottom line is, yes, I do believe that as the demand for gas grows, an investment will have to be made to maintain, to continue to maintain the reliability that we've had over the years with the current infrastructure that's in place, but then also an investment to really focus on supply diversity.

Q. Okay. Thank you. Now, I would like to turn to the subject of the fuel benefits of nuclear plants versus the total cost of those plants.

A. Okay.

Hearing Exhibit 000467

Q. And I believe in your testimony, you discuss that one of the benefits of Turkey Point 6 and 7 is the reduced reliance on natural gas and fuel oil; is that correct?

A. Yes, I do.

Q. And just considering just the fuel cost alone, FPL's nuclear plants have provided significant benefits; is that correct?

A. Yes.

Q. Okay. Now, would you agree that in dollars per megawatt of capacity, nuclear plants are more capital intensive plants than combined cycle plants?

A. That's not specifically my area of expertise, but I think I can comment that, yes, I would agree with that.

Q. Okay. Would the benefits of nuclear power be less if you look at the total costs, if all costs are considered, not just the fuel costs alone?

A. Could you please repeat that? I think you cut out during the middle of it.

Q. Okay. Well, just a few moments ago we were discussing that the nuclear plants provide significant benefits just considering the fuel costs alone and that nuclear plants are more capital intensive than the gas combined cycle plants. So now my question to you is,

would the benefits of the nuclear plants be less if we're considering the total costs?

A. Would the benefits be less? No, I don't view the benefits to be less. I think there's a tremendous benefit from particularly these two units on the overall fuel mix of FPL, on diversifying its fuel mix, maintaining a more balanced portfolio, helping from a reliability standpoint, from a fuel price volatility mitigation standpoint. So, no.

And I think you're asking, well, okay, if I just don't take fuel by itself, but add all of the costs required, is that a reduction in benefits? I don't believe it is a reduction in benefits. You're not going to reduce any of these reliability or diversification benefits that you're going to get from building these two units.

Q. Okay. Thank you. Let me have you turn to page 11 of your testimony.

A. Okay.

Q. Specifically, on lines 16 and 17, you state that the differential between fuel prices is a key driver in the overall economic outcome of each expansion plan; is that correct?

A. Correct.

Q. So in the case before us that we have here,

Hearing Exhibit 000469

would you agree that the two viable alternatives are either a gas-fired combined cycle plant or a nuclear unit?

A. I would agree with that, I believe, yes.

Q. Okay.

A. Although --

Q. Did you have something to add?

A. Well, I know as part of our -- and I wasn't involved in this particular part of it, but I know as part of this case, it's not only nuclear versus natural gas, but also FPL's plan with nuclear versus IGCC. So I'm not sure how to answer your question. Those alternatives were all evaluated. Are the most likely candidates natural gas and nuclear? I think I could agree with that, sure.

Q. Yes, I do recognize that all alternatives were considered. But the most likely, considering the current state of the environment, would be combined cycle or nuclear?

A. Exactly. And that's how I was answering the question, so I just wanted to clarify it.

Q. Okay. Thank you very much. Let me have you turn to Appendix E9, which is the low price gas forecast.

A. Okay. I'm there.

Q. And the question is along the same lines as the medium price forecast. The column on the far right, the Henry Hub, is that FPL's low price natural gas forecast?

A. Yes, that is correct. And in fact, both low and high price forecasts, this is simply taking the medium price forecast and multiplying by again the low price percentage that we determined through actual fuel prices we have experienced over the last seven years. That was multiplying every column by that percentage to develop what you see on this page here, and likewise, in the high case.

Q. Now, is this forecast data in nominal terms?

A. Yes, these are in nominal dollars.

Q. And I'm looking specifically at the years 2009 through 2012. This forecast seems to show a decline in nominal terms; is that correct?

A. Yes, it does. Yes, it does.

Q. If you know, what are the reasons for this decline?

A. I am not 100 percent sure if there's any specific reason. Well, I don't know of any specific reasons I could give you behind that decline, except to say that our methodology in creating the forecast does change at least in the early years or early period.

Keep in mind that for 2007, '08, and '09, our forecast is based on what the forward curve is at the time. In 2010 and '11, we used a 50 percent mix or 50-50 mix of the forward curve and the PIRA forecast. And then in 2012 through 2020, we used solely the PIRA forecast, and then, as we discussed before, we escalate past that period in time. So that may have something to do with the difference in what the PIRA forecast is in the short term, in the '10 and '11 period, and how that gets combined with what the forward curve is at the time.

Obviously, I think one of the definite take-aways that you could say from this is that the forward curve in the early years of '08 and '09 is most likely higher than what the PIRA forecast is in the '10 and '11 period, and so hence you see the decline, and then you see it start to escalate back up again. Just off the top of my head, that would be what I would think one of the reasons for the decline is.

Q. Thank you. And you anticipated my follow-up question that after 2012, the prices begin to escalate again; correct?

A. That is correct.

Q. Okay. Let me have you at this point turn to your testimony, and I'm trying to find a specific page

Hearing Exhibit 000472

for you. Page 15. We're going to be starting on page 15, lines 18 through 23.

A. Okay.

Q. And here you were asked about future environmental regulations that may impact the price differential between natural gas and other fuel types; correct?

A. That is correct.

Q. Does the natural gas forecast reflect stricter future regulations on carbon emissions?

A. I do not know what the assumptions were that were made by PIRA in the natural gas price forecast. I'm trying to recall. I apologize. I don't believe it was based on strict environmental regulation, but I don't recall what their assumption was at the time that they produced the forecast.

Q. Okay.

A. But if the ultimate question or bottom line question -- hopefully this helps a little bit more. If it was taken into account in their fuel price forecast, I would say yes, it was. The degree to which it was, I do not know that.

Q. Okay. Are you familiar with the testimony of witness Sim?

A. I guess not in depth, and I don't have a copy

Hearing Exhibit 000473

of it in front of me either.

Q. Okay. Well, let me just try to ask you a few questions that are mostly general. I don't think it's very in-depth, because the more detailed questions will be directed to witness Sim. But to the extent that you can answer these, please do so, and if you can't, just let me know.

A. Okay.

Q. Are you aware that FPL combined three fuel forecasts with four environmental compliance cost forecasts to develop a total of 12 initial scenarios for fuel and environmental costs?

A. Well, I am aware that we used three fuel price forecasts and four environmental price forecasts. I happen to have the testimony of witness Silva in front of me, and I see we published nine cases. But I am aware that we did use four environmental and three fuel price.

Q. And that was really my follow-up, because it started with an initial 12 scenarios, and three were removed from further consideration, which leads to the nine that you were talking about.

A. Right.

Q. And it stated that those three scenarios were removed because it's FPL's belief that the medium to

high environmental compliance costs for CO_2 was incompatible with the assumption of low natural gas prices.

A. Okay.

Q. Do you agree with that statement?

A. I do agree with that statement. And I think we were just talking in reference to page 15 of my testimony, and I do address that somewhat. My testimony is careful in the fact that obviously nobody can know what the real outcome of anything is going to be in the future.

However, it is very intuitive or reasonable to make an assumption, and we're making a lot of assumptions here, particularly on the fuel price forecast, but to make an assumption that to the extent that there is a high compliance or there are high or higher compliance costs for CO_2, that that would increase the demand on natural gas, because natural gas-fired generation would come to the forefront, increasing demand. And so the widening effect between gas and coal -- you know, not coal in this particular case, but the demand increasing for natural gas and increasing natural gas costs seems like a logical outcome, a reasonable assumption to make.

And so the thought process behind it would be,

Hearing Exhibit 000475

well, in the high compliance cost case or high environmental compliance cost case, it doesn't really seem appropriate that a very low natural gas price forecast makes a lot of sense as a likely outcome, and hence the removal of those three cases.

Q. You just stated that if there was a scenario with high environmental costs or compliance costs, then the likelihood of having low natural gas costs is very unlikely; is that correct?

A. That is correct, due to potentially the increased demand for natural gas due to the cleaner burning generation.

Q. Okay. What about in a scenario of medium environmental compliance costs? Because you just spoke strictly to the high.

A. Yes, and I'm not necessarily sure I meant high. And again, this starts to get out of my area of what I think I can answer, because I'm not specifically up to speed on what all of the different compliance costs scenarios are. My testimony does address it and is making a rather general statement, one of being intuitive and reasonable to assume that under higher compliance cost cases, you would see an increase in natural gas, and therefore, low natural gas prices would probably be highly unlikely.

Hearing Exhibit 000476

Now, what level of compliance would make that possible, I don't know. I don't think I'm, you know, the appropriate witness for that, just because I don't have that kind of detail. But long story short, I guess -- and I apologize for going into that, but I don't think I can specifically answer that question of medium versus high versus somewhere in between.

Q. Okay. That's fair enough. As far as the increased demand for natural gas, is that the only factor that would impact the natural gas prices?

A. That's what my testimony was referencing. Again, just from a very general perspective, an increase in demand for that commodity would to tend to increase the price of that commodity.

Now, you know, are there other factors that would influence the price? I don't know. I was mainly referring to that increase in demand. You know, just as a fundamental principle of supply and demand, if I increase the demand, I'm going to need to increase supply. That may lead to higher technological costs for finding gas in unconventional places, and so hence you would think it reasonable to assume that there would be an increase in gas prices.

Q. Well, you just mentioned something about supply and demand. Obviously, yes, if there is a big

demand, the prices will increase. But what happens if there's an increase in supply? Wouldn't that balance out the gas prices?

A. Yes, I think over time, you could make that assumption. How much time? Ultimately, supply and demand is always going to be in balance. But there are other factors. You know, what price does it take to get the supply to balance the demand, that being would there be a large investment made in technology in order to find gas in unconventional places as demand grows? And that would tend to raise the price of gas.

But I don't think I -- I can say that over time, supply, you know, it is going to balance. So I think that's why I wanted to say in my testimony that this isn't a 100 percent given case. You know, what I was trying to say was, look, if compliance costs for environmental are higher, one could reasonably assume that gas prices would go up.

Will that necessarily be 100 percent the case? No, but the assumptions behind it seem reasonable. So what happens over a long period of time, it's very difficult to say, I think, looking out that far in time.

Q. Well, earlier we spoke briefly about LNG and how there's the probability of increased supply of LNG. Could the rapid expansion of LNG import capability

Hearing Exhibit 000478

increase supply?

A. Yes, it could. However, one important note, particularly with LNG, is that, you know, the price which we will pay for LNG is largely undetermined. I don't think we can make -- maybe the simplest way to put it is, I don't think we can make a general statement that an influx of LNG will keep our gas prices low because that will beef up our supply whether demand increases for natural gas or not, one of the major reasons being that we will be direct competition for LNG with the rest of the world, particularly the Far East and Pacific Rim countries.

So, you know, depending on what one's own ability is or one's desire is to pay for natural gas, that may not necessarily lower prices just because of an influx of supply. It may increase supply, but you're going to be competing against other entities or other countries that also need that supply. So it's kind of a worldwide type balance, is the way I look at it.

Q. So in your view, you're going to have upward pressure on demand which will increase gas prices. Is it at all possible that other factors, any factors that could affect gas prices could fully counteract the upward pressure on gas prices that can be caused in part due to -- just looking at a medium to high environmental

Hearing Exhibit 000479

compliance cost, we were discussing earlier that that's going to cause upward pressure on demand, because people are going to start going for gas plants and needing more gas. Is there any other possible factor that could fully counteract any upward pressure?

A. It's hard for me to say whether there is or isn't any other counteracting factor.

Q. So in your view, is it possible that the upward pressure that demand will cause on gas prices can be offset? Or, in other words, can supply balance out the demand so that the prices remain leveled out?

A. I think the simplest answer to that is -- and we made reference to it before, that anything is possible. That is not, however, likely in that scenario of higher compliance costs. You know, we were looking purely at what are likely outcomes. I will never say anything is not possible either, but when you're looking at what is most likely, that does not sound reasonable.

Q. Well, I know earlier we were talking about nothing is impossible and there's a possibility for everything. You know, if you had to estimate, how likely would it be? Is it a less than a 1 percent chance, a 5 percent chance? Can you guesstimate?

A. That there would be something that occurs that could totally offset an increase in demand due to higher

Hearing Exhibit 000480

compliance costs that would keep prices at a stable level?

Q. Yes.

A. Or at a stable or at a low level?

Q. Yes.

A. It would be almost impossible for me to put a likelihood on it. I honestly don't know. I don't think it is very likely. What that translates into percentagewise, I would be hard pressed to even venture a guess. But I'm pretty confident in that fact that, you know, those factors coming together, really, the most reasonable outcome is that gas prices are not going to remain -- and we're not even talking here at some kind of medium stable level. We're talking at a low level, so I don't see a very good likelihood to that percentagewise. I just couldn't even venture a guess on that.

Q. That's fair enough. I just wanted to get a guesstimate. I think the terminology "very unlikely" clears it up for me.

A. Okay.

MS. FLEMING: I think that's all we have for Mr. Yupp, so if anyone else has any questions.

MR. BECK: Katherine, this is Charlie. I just have very brief questions.

MS. FLEMING: Okay.

CROSS-EXAMINATION

BY MR. BECK:

Q. Mr. Yupp, this is Charlie Beck with the Office of Public Counsel. Earlier in response to a question by Ms. Fleming, I believe you said something to the effect that for the years 2000 through 2005, there was a real increase in natural gas prices which exceeded the 1.14 percent. Do you recall that?

A. Yes.

Q. Do you know what the average increase was in real terms for natural gas for 2000 through 2005?

A. No, I don't. I don't have it in front of me. That is something -- we do have the data, but it should be significantly higher. I'm trying to recall off the top of my head, but there were a couple of those years where we -- we averaged out, you know, in the 8 to $9 range, I believe, in one of those years from prior levels of 5 to 6, I believe. So significantly higher, but again, only over a short period of time.

MR. BECK: Thank you. That's all I have.

MR. KRASOWSKI: This is Bob Krasowski. Is it okay if I ask a couple of questions?

MR. BUTLER: That's fine.

MR. KRASOWSKI: Okay. Thank you.

Hearing Exhibit 000482

CROSS-EXAMINATION

BY MR. KRASOWSKI:

Q. Mr. Yupp, fascinating discussion. I really appreciate your knowledge. I would like to just move into the realm of improbability, almost impossibility. What if there was a peace in the Middle East? Do you think that would lower prices for oil?

A. That's hard to say. There are numerous factors that impact the price of oil. Obviously, the situation in the Middle East is the main driver of short-term prices. On a day-to-day basis, we see the way the market moved up and down one to two dollars a day up and then one to two dollars a day down.

Would it have an impact of lowering overall prices? It's difficult to say, only from the standpoint that there are other factors, namely, you know, the economy of other countries in the world and how they're growing and what their demand for fuel is. Again, as demand stays relatively steady or increases in some other countries, that's something that tends to put upward pressure on prices and not downward.

So it's hard for me to say. I'm not an expert in fuel forecasting. That's why we do use the PIRA Energy Group to do to our fuel forecasts. They do have that knowledge and expertise. So there are so many

Hearing Exhibit 000483

factors that can move the price of fuel.

But that being said, sure, peace in the Middle East, real peace in that area, yeah, my thought process would be that a reasonable outcome of that could be that, you know, prices at least stabilize.

Q. How about no -- understanding what I do about PIRA, to what extent are you aware of their assessing an increase in the use of renewables as an offset for need for fossil fuels that would then cause a decline in the price of fossil fuels as those interests move to undermine the development of renewables?

A. I believe that I can confidently say --

MR. BUTLER: I'm sorry. I'm going to object to the question. Did I understand your question to be that the oil producers would deliberately lower the prices in order to undermine the development of the renewables? If that's what you're saying, I would object to the question as lacking foundation.

MR. KRASOWSKI: I'm just basing that on basic market principles in a competitive market, but I'll accept your objection. I think it's a business reality.

THE WITNESS: I want to clarify, because I wasn't understanding the question to be that. My understanding was that the question was, you know,

Hearing Exhibit 000484

is the impact of renewables incorporated into PIRA's forecast, or the projected impact of renewables on a long-term basis. With the addition of them and the surge in that, the answer to that would be yes, but not to the question that he was really asking.

BY MR. KRASOWSKI:

Q. That identifies a conspiratory element in market competition?

A. Yes.

Q. Okay. Well, I'll just leave that alone. Fine. I appreciate your answer to that question that you've identified as understanding.

And then economic slowdown. If -- I guess my question would be, at what price of reduction in oil and gas, with oil being $100 a barrel now or whatever it is, might an equalization occur? In the economy slowed down so much that people weren't using as much energy, at what point would that cost of the alternatives cause nuclear not to be as attractive from the economic point of view?

A. I don't know the answer to that question, because I would be just purely speculating on how much of a slowdown in the economy would be required to lower the price level of all of these fuels to a level that

Hearing Exhibit 000485

would ultimately make nuclear not be the economic choice.

But I would say this. I think when you look at our analysis that was done -- and I'll go back to this. I've repeated it a couple of times. That was the reason for using the banded approach to our economic evaluation, because it is very uncertain. There's a lot of uncertainty in forecasting future fuel prices. And so given that, it's important to realize that prices will move in one direction or another or both directions or vary over time.

So the banded approach that we used to look at a low gas cost, low oil cost, and so forth, low coal, and also from a high perspective to really put in perspective what the economic outcome would look like under varying fuel price scenarios -- all being reasonable, though, which is an important note to make. The percentages that we apply to our medium price forecast were developed using fuel prices that FPL had actually experienced over the seven-year period from 2000 to 2007. So that being said, they are reasonable. They can occur.

I think taking that approach covers a lot of maybe what you're asking me, you know, if this changes in the world and that results, will that result in

Hearing Exhibit 000486

downward pressure on prices, or at what level will it result in the economic evaluation being different? The answer to that question is that we've covered what we believe to be a reasonable range of price outcomes, and you can see the economic results from that in our testimony or in our filing.

Q. Okay. Thank you. I appreciate your comments on what you consider to be reasonable based on the PIRA studies and other variables that you brought up. I guess that's the end.

Well, let's see. I have this one document here, and I wanted to ask you if you were familiar with this at all. It's by Richard Lane Christie, and it's "The Economic Costs Of Nuclear Power: Free Market v. Subsidized Nuclear Power Economics." Have you ever read that? Are you familiar with that work?

A. No, I am not.

MR. KRASOWSKI: Okay. Thank you.

MR. BUTLER: Katherine, I need to go to off-line just a minute to see whether I have any redirect.

MS. FLEMING: Okay. That's fine.

(Off the record briefly.)

MR. BUTLER: Katherine, I do have a brief line of redirect for Mr. Yupp.

Hearing Exhibit 000487

CROSS-EXAMINATION

BY MR. BUTLER:

Q. Mr. Yupp, would you turn to Table 13 of the EIA data that you had been discussing earlier? And this was specifically referring to the 2007 data.

A. Okay.

Q. What years did you use -- just to clarify the record here, what records did you use in calculating the average escalation rate of 1.14 percent that you had referred to earlier as a real escalation rate?

A. We began with the Henry Hub spot price in 2016 and carried that forward through 2030.

Q. You were asked about starting the analysis in earlier years by Ms. Fleming. I would like you to look at the prices of -- excuse me, the Henry Hub spot prices for natural gas in the years 2004 through 2010 that are shown on here.

A. Okay.

Q. How would you characterize the volatility of the prices that are shown in that time period?

A. Particularly in the 2004 and '05 time period, I would characterize them as highly volatile, 2004 being 6.08 on average, daily cash prices for the year, and 2005 being 8.60. That is a tremendous difference on a year-to-year basis. And then again, in 2006, they come

back down to 7.07, with a little bit of kind of stabilizing, and then dropping again in '09 and '10, so fairly volatile fuel prices.

Q. Would you consider it appropriate to include volatile years like that as a starting point in the calculation of a long-term escalation rate for fuel prices?

A. No, I wouldn't. I think short-term movement and volatility is very difficult to incorporate in that type of long-term annual average, what we are looking for in developing our long-term forecast out past 2020.

I think one of the things that's very noticeable from that data and why it would not be reasonable or really appropriate to use early data is that when you look at the total strip of prices and you look from whether they show a -- excuse me. I'm going back. I believe that what they calculate this on is based on is 2005 through 2030, and you see a minus 1.1 percent decline in the price over that period of time.

That's not a reasonable rate that we would use in a fuel price forecast for determining prices farther out in time. It's just not intuitive. It's not reasonable to assume that come 2020, natural gas prices are going to begin declining at a rate of 1.1 percent, or whatever that percent may be, a year to a level that

ultimately, you know, through a 40-year period could be one or two dollars for the price of gas. That's not -- and again, nothing is ever impossible, but that's not in a fuel price forecast what I would deem to be a reasonable assumption to make.

The reasonable assumption for us was looking at this period of time of '16 through '30 and looking at that real rate of escalation and saying, okay, we can apply that from 2021 forward over our horizon, and that appears to be a pretty reasonable assumption to make.

MR. BUTLER: Thank you, Mr. Yupp. That's all the questions that I have.

All right. Are we through?

MS. FLEMING: I think so. Does anybody have anything else to add? No? I think we're through.

(Deposition concluded at 11:55 p.m.)

Hearing Exhibit 000490

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that a review of the transcript was requested; that my shorthand notes were thereafter translated under my supervision; and that the foregoing pages numbered 1 through 60 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 17th day of January, 2008.

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

Hearing Exhibit 000491

CERTIFICATE OF OATH

STATE OF FLO RIDA

COUNTY OF P/ LM BEACH

I, the un lersigned authority, certify that **Gerard J. Yupp** personally appeared before me at **700 Universe Boulevard, Juno Beach, Florida** and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, Sta e of Florida, this 16th day of January, 2008.

Notary Public State of Florida
Jennifer M P yne
My Commiss on DD439096
Expires 06/0 /2009

Notary Public
State of Florida

Personally know n X OR produced identification _____.

Type of identifi ation produced _____.

ASR ACCURATE STENOTYPE REPORTERS INCORPORATED
CERTIFIED COURT REPORTERS

January 18, 2008

John Butler, Esquire
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Need Determination for Turkey Point 6 and 7
Docket No. 070650-EI

Dear Mr. Butler:

Enclosed is your copy of the deposition of Gerard J. Yupp taken in the above matter on January 16, 2008.

Since reading and signing was not waived, we are enclosing an errata sheet and request that your office make arrangements with the witness to read the deposition and make any corrections on the errata sheet.

Please forward the original completed errata sheet to Jane Faurot at the Commission for attachment to the original transcript. You should also attach a copy to your transcript so that it will be complete.

Thank you for your cooperation in this matter. It was a pleasure working with you.

Sincerely,

Mary A. Neel

Mary A. Neel

/mn
cc: Jane Faurot
Enclosures

ERRATA SHEET

Under penalties of perjury, I declare that I have read the foregoing transcript of my deposition, pages 1 through 61, and that the facts stated therein are true, including any corrections and/or amendments listed below.

_____ _____

Date GERARD J. YUPP

Page	Line	Correction or Amendment	Reason for Change

13

Deposition Transcript of Kennard F. Kosky (including errata sheet)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

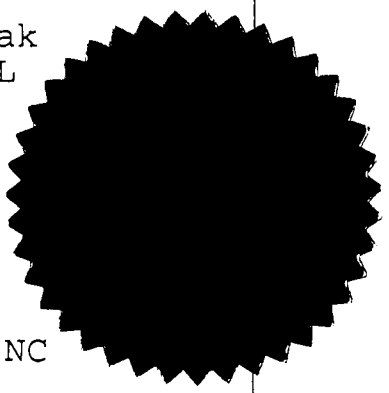
DOCKET NO. 070650-E1

In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.

TELEPHONIC DEPOSITION OF KENNARD F. KOSKY

TAKEN AT THE INSTANCE OF: The PSC

DATE:	January 16, 2008
TIME:	Commenced at 2:00 p.m. Concluded at 2:45 p.m.
LOCATION:	2540 Shumard Oak Tallahassee, FL
REPORTED BY:	JUDY CHIN RPR, CRR



ACCURATE STENOTYPE REPORTERS, INC
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C/O THE FLORIDA LEGISLATURE
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Tallahassee, Florida 32399-1400

ALSO PRESENT:
William McNulty
Jenny Wu
Bob Krasowski

Hearing Exhibit 000497

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Hearing Exhibit 000498

STIPULATIONS

The following deposition of KENNARD F. KOSKY was taken on oral examination, pursuant to notice, for purposes of discovery, and for use as evidence, and for other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing is waived.

* * *

Thereupon,

KENNARD F. KOSKY

was called as a witness, having been first duly sworn by JENNIFER DeVALERIO, notary public, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. KLANCKE

Q Mr. Kosky, I appreciate your time this morning.

I wanted to go over some preliminary matters. If at any point during this deposition you need to take a break or you need me to clarify any of my questions for you, please let me know. Okay?

A Okay.

Q Okay. Let's begin.

Would the deponent please state his full

Hearing Exhibit 000499

A My name is Kennard, K E N N A R D, F, Kosky, K O S K Y. Business address is 6241 Northwest 23 Street, Gainesville, Florida. 32653.

Q Now, Mr. Kosky, you are employed by whom?

A Golder Associates, Inc.

Q In what capacity is Golder Associates working with FPL in the evaluation of the environmental aspects of Turkey Point Units 6 & 7?

A We did preliminary studies related to some of the water issues, air-quality issues on the project, and I had been involved since probably June of this year on the Need case and the environmental aspects of Turkey Point 6 & 7.

Q You have prefiled testimony and exhibits in Docket Number 070650, is that correct?

A That's correct.

Q At this time do you have any additions, deletions or corrections to your prefiled testimony or exhibits?

A No, I do not.

Q In preparation for this deposition, I have asked you to have several documents -- have access to several documents there with you.

Could you please describe the documents

Hearing Exhibit 000500

that you have there with you?

A I have my testimony. I have a staff -- four set of interrogatories and FPL's response, and I have the direct testimony of Steve Sim and his exhibits.

Q Could you please turn to page 11 of your direct testimony. In particular, could you refer to lines two through four on page 11 of your direct testimony.

A Yes, I have it here.

Q In this section you discuss the water supply options for proposed Turkey Point Units 6 & 7, is that correct?

A That's correct. These are water supply options that are being investigated, and that is correct.

Q Okay. Could you describe in more detail the water supply options that are being investigated and are potentially available to FPL within the Turkey Point site?

A The water supply options are currently under unvestigation. In fact, there is also a -- what I would characterize as an intergovernmental consortium looking at water issues for the project.

Hearing Exhibit 000501

As I described in my testimony, there are several options that are being looked at, and these two that are on lines two through four are the ones that are probably one of the more prominent; that's re-use water, or water from Miami-Dade County, and lower quality water from the Floridan aquifer. Both those two sources are sufficient in terms of quantity, and that's being investigated by FPL.

Q Are you also investigating a potential source of water intake in the form of ocean intake?

A Yes. And I believe Mr. Scroggs is probably the best FPL witness of all the alternatives.

I am aware of ocean-type water, ocean intake, or bay water as well.

Q In terms of quantity, what is the estimated total amount of water intake that would be necessary for the supply of Turkey Point Units 6 & 7 to operate on a daily basis?

A It would really depend on the quality of the water. If the water is of good quality, you need less of it. That has been my experience with a lot of different power plants that have worked

Hearing Exhibit 000502

with these types of sources. I believe it's on the order of about 80 million gallons a day for both Units 6 & 7.

Q Now, does that 80 million estimate include water that would be recycled within the plant?

A I don't believe it does. That would generally be the makeup. Obviously the more you can recycle, the lower the demand, which could be -- could include increasing the cycle of the concentration of the cooling tower, for example.

Q Does this estimation --

Well, I would like to get a better idea of the functions that this water supply intake would be used for with regard to Turkey Point 6 & 7.

Could you describe by function the way in which the daily water intake would be utilized within the unit?

MR. ANDERSON: Just to help you out, we want you to get whatever information you would like from Mr. Kosky.

I think the deposition of Mr. Scroggs is scheduled for this week, who is the executive responsible for all of the factual

Hearing Exhibit 000503

investigation involving water supply.

A lot of this evolves around, you know, the size of the unit, the technology type, and all those things, too. So just as you question, please keep in mind Mr. Scroggs may be in a better position to respond to the particulars of FPL's due diligence on water. With that, you know, please ask Mr. Kosky whatever questions you would like.

MS. KLANCKE: That's fine. I just want to get a better picture, since the water intake issue applies to both the testimony of Scroggs and Mr. Kosky. The questions I understand may be somewhat duplicative, but we would like to get answers from both witnesses with regard to their testimony.

MR. ANDERSON: Sure. That's fine.

BY MS. KLANCKE

Q With that, would you like the court reporter to repeat the question that I just asked? Would you like that?

A This is Mr. Kosky. I don't need it repeated.

I haven't seen any water use or water balances from an engineer --

Hearing Exhibit 000504

From my experience, most water consumed in a steam power plant, steam electric, this happens to be nuclear, is the result of evaporation from the cooling towers is probably the majority of its use. There are other uses within the plant.

I don't know exactly what designs FPL ultimately will select.

Any more information you would have to ask Mr. Scroggs.

Q Okay. Well, then let's move on to a primary, secondary source issue.

What will be the primary source of water intake for utilization by the Turkey Point Units 6 & 7?

A I do not believe that's been selected. That's under evaluation by FPL. The alternative that I stated in my testimony are two of several being considered.

Q Could you speak to what are some of the reliability issues with regard to the three potential intake sources that are being investigated for water supply?

A That question probably is best asked of Mr. Scroggs.

Hearing Exhibit 000505

However, based on my experience, and several power plants that I have licensed and completed as a professional engineer managing site certification applications for projects, I can say the reliability of what I have testified to can be reliable depending upon the amount, the analyses that's done.

For example, Turkey Point Unit 5 is using Floridan aquifer water as part of its cooling process. West County Energy Center Units 1 & 2 are also going to be using Floridan aquifer water. The site certification application just submitted for West County Unit 3 is going to be using re-use water. Re-use water is currently used in several power plants in Florida and is reliable as well as the Floridan aquifer.

Q With regard to the infrastructure that FPL intends to install in order to access those potential types of water, can you speak to what type of infrastructure they intend to install?

A No. That's under analysis from my understanding. Mr. Scroggs can give you more information.

Q Could he speak to the potential range of costs with regard to the infrastructure that FPL

Hearing Exhibit 000506

intends to install?

A I do not know that.

Q In that case, I think we can move on.

Let's switch gears here. Could you turn to page 12 of your direct testimony?

Could you refer in particular to line six through eight. In this section --

Are you there, Mr. Kosky?

A Yes, I have it.

Q In this section you refer to the proven technologies for water supply treatment necessary to meet the environmental requirements.

A Yes.

Q Can you identify the primary water supply and treatment technologies required to meet these environmental requirements that you are referring to in this section?

A What I'm testifying here is related to those being looked at for these types of things. For example, water supply, it could be a Floridan well. Floridan aquifer wells are used all over the state. It could be a re-use water pipeline. There are re-use water pipelines that could be developed, different types of water treatment. In fact, one of the projects that I had mentioned,

Hearing Exhibit 000507

West County 1 & 2 is installing water treatment to use Floridan aquifer water so it can maximize its use.

Some of the other environmental controls would be the cooling tower. Cooling tower technology is highly efficient, the types of environmental impact that may be associated with that particular -- particularly cooling tower drift is greatly minimized.

Those are the types of controls that are currently used on existing power plants that are being contemplated for 6 & 7 that could be and could meet environmental requirements.

Q With regard to the support equipment that you refer to in this section that would be needed to meet these environmental requirements, could you describe in addition to the technology what support equipment that you are referring to here?

A Well, support equipment in that context could be more equipment associated with each of the treatment facilities, the port facilities. For example, water treatment may require the use of water treatment chemicals. You need a support facility to use that. They can be constructed in

Hearing Exhibit 000508

an environmentally acceptable matter. You may have a dry powder, you can control the emissions from that in a silo with bag filters.

That's what I was alluding to here, if you have other support equipment, there is equipment that could be installed to meet those kinds of environmental requirements, depending ultimately on what alternative is selected.

Q Are the costs for this support equipment included within FPL's cost estimates that they have provided in this document?

A I do not know that. That's a question to ask Mr. Scroggs. Although that said, in terms of my experience, I have not seen any projects in terms of water use, water supply that any of the costs were so significant that affected the project or its development, including the projects that I had previously mentioned.

Q Could you please turn to staff's fourth set of interrogatories and FPL's answers thereto. In particular, let me turn your attention to question number 69, to staff's set of interrogatories, and your answers thereto, page three of four in particular.

A I have it.

Hearing Exhibit 000509

Q Excellent.

A Question 69, page three of four, I have it.

Q Yes. At the top of this page, in italics, it states, "expected is a weighted probability of all C02 forecasts."

Can you explain the meaning of this statement in the context of the projected C02 price data appearing on this page?

A Well, this particular attachment and the description in italics describes ICF's expected case. Other than just descriptive, it has no other value for this particular document.

Q Who signed the weighted probability in developing the data in column two on this page, ICF or FPL?

A ICF.

Q Are you familiar with ICF's 2006 report entitled U.S. emissions and fuel markets outlook?

A Yes, I am.

Q Did FPL rely to a large extent upon the C02 price projections scenarios provided in this 2006 report?

A Yes. FPL did rely on the C02 price projections as well as the other pollutants and

used that as the initial framework for the estimating environmental compliance cost.

Q In this 2006 report, did ICF include its own C02 price projection scenarios?

A Well, it included several. It included a mild case. It included a more stringent case, depending upon the legislation at the time. ICF provided in that document what they referred to as an expected case.

Q And with regard to that, did ICF assign probabilities to its C02 price projection scenarios and perhaps one in particular?

A They assigned probabilities, depending upon the year of the various projections that they had. Yes, they did.

Q Did FPL assign probabilities to its C02 price projection scenarios?

A No.

Q Could you explain if FPL relied upon ICF in the development of its C02 price projection scenarios, and ICF assigned probabilities to its C02 price projection scenarios, why did FPL choose not to apply probabilities to these scenarios?

A Well, the probability assigned by ICF for specific legislation, and they have provided

Hearing Exhibit 000511

that based on their view at the time in 2006.

The purpose of the estimated environmental cost was not to assign probabilities but to provide a reasonable range of costs that could be expected. And with that, the ICF was used as the initial, I would call it framework, for estimating that reasonable cost of environmental costs for C02 as well as other pollutants that may occur in the future.

Q Isn't FPL's projections the same as ICF's projections through a period until say 2030?

A Yes. Specifically for cases one, two and three.

Q Let's focus our attention back on staff's fourth set of interrogatories and the answer to question 69, page three of four.

A Yes.

Q With respect to the information contained in this document, are any one of the three C02 price projection scenarios shown in this response more indicative of compliance with greenhouse gas reductions called for in Governor Crist's executive order, number 07-127, more than the other two -- in relation to the other two, rather?

Hearing Exhibit 000512

A Not that I'm aware of. Governor Crist's executive orders are specific to Florida. This is a projection made by ICF nationally for legislation that had been proposed as well as what they considered in their analysis.

MS. KLANCKE: That is all of the questions that I have for this witness at this time.

With that, I will open up the floor to other parties that may have questions for the witness.

MR. BECK: This is Charlie Beck. I have some questions.

MS. KLANCKE: Okay.

CROSS EXAMINATION

BY MR. BECK

Q Good afternoon, Mr. Kosky.

A Good afternoon.

Q Let me ask you a few more questions about the ICF study that you were discussing with staff.

The 2006 study that was used in your projections, do you recall what the release date of that study was?

A As I recall, it was late in 2006, maybe

Hearing Exhibit 000513

November, December. Because I had gotten a copy pretty soon after they issued it. I can't recall exactly when the date was, but I believe it was sometime late in 2006.

Q Wasn't it late 2005, if you recall?

A I don't believe so. The 2006 report that -- I wasn't -- it wasn't released until 2005.

Q Is the ICF report you use the most recent one by ICF?

A Yes. This is the most recent one that I'm aware of, or that FPL is aware of that's available.

Q Referring to the staff interrogatory 69, page three of four, there is a scenario four, which is labeled as 30 percent times D?

A That particular case is an additional case, for higher C02 costs, that are 30 percent higher than the stringent C02 costs in case three.

Q That scenario is not included in the ICF study, is it?

A No, it's not.

Q Why did FPL choose to create an ENV IV that's not in the ICF study?

A Well, looking at some of the more current information, it appeared that C02 costs

may be higher, depending upon which scenario or which legislation might be adopted. In order to cover the reasonable range scenario, case three was increased by 30 percent to cover a broader range.

Q I guess I still don't understand. The ICF created a number of different scenarios for emission costs, did it not?

A Yes, it did.

Q FPL relied on those in doing the cases one, two and three, did it not?

A Yes. In part up to 2030; yes it did.

Q Why did you choose to create yet another ENV IV that's not in the ICF study?

A Because information suggested that the C02 cost may be higher. I believe there was an interrogatory that was related to that, and, in fact, I did supply a study done by MIT that projected costs depending upon legislation. It was done actually in 2007. The costs that they project are actually much higher than scenario four. In working with FPL as a consensus, it was agreed that we would increase case three by 30 percent to sort of cover a broader range.

MR. BECK: I think that's all I have,

Mr. Kosky.

Thank you very much.

MR. KRASOWSKI: This is Bob Krasowski. May I ask a question?

CROSS EXAMINATION

BY MR. KRASOWSKI

Q Hi, Mr. Kosky. How are you doing?

A Hi. How are you doing?

Q I'm Bob Krasowski. I'm fine, thank you.

I'm curious to know, were you in Miami for the hearing regarding the local Dade County permitting for the land use for this project?

A No, I was not.

Q You did a lot of the site work, preparatory site work on this project you say in your testimony. I'm kind of paraphrasing here. You are talking about the water, so you were not --

Did you read the transcript of that meeting, maybe?

A No, I did not. In my testimony, I specifically referred to some preliminary studies that we had done for FPL related to some specific issues, one of which was the water issue of primarily the cooling canal system as well as

Hearing Exhibit 000516

cooling tower drift. We had done some preliminary evaluation. But we are not currently involved in any water studies per se at the plant.

Q And so it would be better to ask Mr. Scroggs. He was there. I remember seeing him there. I wouldn't know if I had seen you or not.

That's all the questions I have at this time.

Thank you.

MS. KLANCKE: Okay. I don't believe that anybody else has any further questions, is that correct?

MR. ANDERSON: This is Brian Anderson. I have one question.

CROSS EXAMINATION

BY MR. ANDERSON

Q Mr. Kosky, you were asked some questions a minute ago about the possible use of a single ICF expected case?

A Yes.

Q Mr. Kosky, is it better to use a single ICF expected case based on information available in 2006 or a range of cost as FPL did?

A In my opinion, it's better to use a range of cost that would include a low and a high

cost in evaluating this particular issue, since there hasn't been any legislation or regulations passed specifically regarding C02.

MR. ANDERSON: That's all I have.

MS. KLANCKE: Okay. That seems to be everyone's questions.

Charlie, do you have any follow-up regarding that final question?

MR. BECK: I do not.

MS. KLANCKE: Excellent. With that, I believe this deposition is concluded.

I would like to thank Mr. Kosky for his time.

I would like to thank everyone present.

(Thereupon, the deposition was concluded at 2:45 p.m.)

Hearing Exhibit 000518

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, JUDY CHIN, Registered Professional Reporter, certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1 through 23 are a true and correct record of the aforesaid 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 16th day of January, 2008.

JUDY CHIN, RPR, CRR
Notary Public
1-800-934-9090
850-878-2221

Hearing Exhibit 000519

CERTIFICATE OF OATH

STATE OF FLORIDA

COUNTY OF PALM BEACH

I, the undersigned authority, certify that **Kennard F. Kosky** personally appeared before me at **700 Universe Boulevard, Juno Beach, Florida** and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, State of Florida, this 16th day of January, 2008.

Notary Public State of Florida
Jennifer M Payne
My Commission DD439095
Expires 06/19/2009

Notary Public
State of Florida

Personally known ✓ OR produced identification _____.

Type of identification produced _____.

I have read the transcript of my deposition, pages 1 through 23, and hereby subscribe to same, including any corrections and/or amendments listed below.

1/24/08 Kennard F. Kosky

Date: KENNARD F. KOSKY

Page/Line	Correction/Amendment	Reason for Change
13/22	"port" should be "support"	similar sounding words over phone

Date of Deposition: January 16, 2008.

Reporter: Judy Chin, RPR, CRR

ACCURATE STENOTYPE REPORTERS, INC.
2894 Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

January 16, 2008

BRYAN S. ANDERSON, ESQUIRE
700 Universe Boulevard
Juno Beach, Florida 33

Dear Mr. Anderson:

Re: Docket No. 070650 E1

This is to advise you that your witness did not waive reading and signing of his deposition.

Please have your witness read his copy of your transcript, noting corrections/changes on the errata sheet, or date and sign the errata sheet, **and return the original errata sheet to MS. KLANCKE within the next** 30 days or before the final trial in this matter, whichever comes first.

Sincerely yours,

JUDY SHIN, RPR, CRR

Enclosures (Errata Sheet and Transcript.)

cc Counsel of Record

CERTIFICATE OF OATH

STATE OF FLORIDA

COUNTY OF PALM BEACH

I, the undersigned authority, certify that **Kennard F. Kosky** personally appeared before me at 700 **Universe Boulevard, Juno Beach, Florida** and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, State of Florida, this 16th day of January, 2008.

Notary Public State of Florida
Jennifer M Payne
My Commission DD439096
Expires 06/09/2009

Notary Public
State of Florida

Personally known ✓ OR produced identification _____.

Type of identification produced_____.

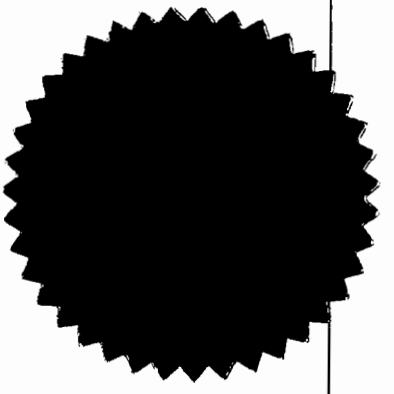
14

Deposition Transcript of Steven R. Sim including Late-Filed Deposition Exhibit Nos. 1-3 (including Errata sheet)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI

In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.
_____/



TELEPHONE DEPOSITION OF: STEVEN R. SIM

TAKEN AT THE INSTANCE OF: The FPSC Staff

DATE: January 17, 2008

TIME: Commenced at 1:32 p.m.
Concluded at 2:05 p.m.

LOCATION: 2540 Shumard Oak Boulevard
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR
Notary Public, State
of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
2894 REMINGTON GREEN LANE
TALLAHASSEE, FLORIDA 32308
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Florida Public Service Commission
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ALSO PRESENT:

SHEVIE BROWN
STEPHEN GARL
ROBERT GRAVES
BILL McNULTY
MICHAEL SPRINGER
JENNY WU

Hearing Exhibit 000526

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Hearing Exhibit 000527

STIPULATIONS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

MS. KLANCKE: Well, I believe everybody is here, so let's begin with the appearances.

As I mentioned, my name is Caroline Klancke with Commission staff, and I'll introduce everybody who's here with me. We have Bill McNulty from Commission staff, Shevie Brown from Commission staff, Stephen Garl from Commission staff, Jenny Wu from Commission staff, and Robert Graves from Commission staff.

MR. ANDERSON: Good afternoon, all. This is Bryan Anderson. I'm an attorney for Florida Power & Light Company. My address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

MR. BECK: My name is Charlie Beck. I'm with the Office of Public Counsel.

MR. ANDERSON: Is there a phone number where we can fax the affidavit of the notary?

Hearing Exhibit 000528

MS. KLANCKE: Absolutely. If you could fax it to area code 850, 413-6250, it would be greatly appreciated.

MR. KRASOWSKI: And I'll mention my identity again. I'm Bob Krasowski.

MS. KLANCKE: Thank you, Mr. Krasowski.

Now that everybody has been identified, Dr. Sim, I appreciate your time this afternoon. I would like to go over some preliminary matters. If at any time during the deposition you need to take a break or you would like me to clarify a question, would you please let me know?

THE WITNESS: I will.

MR. ANDERSON: Caroline, would you like the witness to be sworn?

MS. KLANCKE: Indeed, indeed. Could you please swear in the witness, Madam Notary.

(Witness sworn.)

MS. KLANCKE: Thank you. And if you could provide that to the number I just gave you.

MS. DEVALARIO: Yes, ma'am.

MS. KLANCKE: Thank you.

Thereupon,

STEVEN R. SIM

the witness herein, having been first duly sworn by

Hearing Exhibit 000529

Jennifer DeValario, a notary public in the State of Florida, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. KLANCKE:

Q. Would the deponent please state his name and business address for the record.

A. My name is Steven R. Sim. My business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. Dr. Sim, by whom are you employed, and what position do you hold?

A. I'm employed by Florida Power & Light as a Senior Manager in the Resource Assessment and Planning Business Unit.

Q. Could you briefly describe your duties and responsibilities in that position?

A. Yes. Basically, I have supervised the group that is responsible for determining both the magnitude and the timing of FPL's resource needs and then developing the integrated resource plan with which those needs will be met by FPL.

Q. You have prefiled testimony and exhibits in Docket No. 070650; is that correct?

A. Yes.

Q. At this time, do you have any additions, deletions, or corrections to your prefiled testimony or

exhibits?

A. Yes, I have corrections on three pages.

Q. Could you please describe those corrections or changes to me and what the need for those corrections is?

A. On page 1, line 11, the position I held was Supervisor at the time the testimony was filed. It has since changed to Senior Manager.

Q. Okay.

A. On page 56, there are changes to three lines. On line 12, there's a number of $374 per kW which should read $429 a kW. On line 13, there is a number of $2,836 per kW which should read $2,891 a kW. At the end of that line, the word "low" should be replaced by "high." And then again, on line 15, the first word, "low," should again be replaced by "high." Those were typos.

Q. Okay.

A. And finally, on Exhibit SRS-9, in column 5, all of the values have a dollar sign in front of them. The dollar sign should be removed. Those values are in cents per kilowatt-hour.

Q. Okay. Is that it?

A. Yes.

Q. Okay. If you would, I have asked you to have several documents there with you in preparation for this

deposition. Could you please describe the documents that you have with you?

A. Yes. I have my testimony and exhibits. I have FPL's need study and the appendices to that need study. I have Mr. Scroggs' testimony and exhibits. I have FPL's response to Interrogatory Number 26 from Staff's Fifth Request for Production of Documents. I have three pages from an ICF International report, pages 141 through 143. And I have a file that staff prepared entitled "FPL Customer Growth Sensitivity Analysis."

Q. Okay. Let's start with witness Scroggs' prefiled testimony. Could you please turn to Exhibit SDS-7 of this testimony? It's entitled -- I'll read you the title. "Comparison of Cost Estimate Range to Breakeven Capital Cost Range - Combined Cycle."

A. Just a moment and I'll find it.

Q. Thank you.

A. I have it.

Q. Did the analysis undertaken to derive the breakeven capital cost as shown on Exhibit SDS-7 go through the year 2060?

A. Yes.

Q. What is the expected life in years of Turkey Point 6 and 7?

A. I think for analysis purposes, we assumed a

40-year life.

Q. What analysis is required to calculate a breakeven capital cost for the year 2050?

A. I'm sorry. Can you repeat the question, please?

Q. What analysis would be undertaken to calculate a breakeven capital cost similar to that utilized on this document for the year 2050 as opposed to 2060?

A. There would probably be several approaches one could take to do this. One that comes to mind is simply to take one of the values we calculated for a 2060 breakeven cost and iterate from that starting point back to a breakeven cost for a given scenario of fuel costs and environmental compliance costs.

Q. Staff would like a late-filed exhibit illustrating the calculation that you just went through of a breakeven capital cost for the year 2050. Could you provide staff with that late-filed exhibit?

A. Let me make sure I understand the request. You are asking for the breakeven cost values for a 2050 breakeven value for one or all nine scenarios, and against combined cycle or against IGCC?

Q. All nine, and for CC, combined cycle, rather.

A. So versus combined cycle only, all nine fuel cost and environmental compliance scenarios, provide you

with the breakeven value at 2050?

Q. Yes. Yes, sir.

A. Yes, we can provide that late-filed exhibit and will do so.

Q. Excellent. In the same vein, would a similar analysis be undertaken for the year 2040?

A. Yes. It would be the -- you could use the same methodological approach.

Q. Okay. Let's refer to the first late-filed exhibit as Late-filed Exhibit 1, Breakeven Capital Costs for 2050. And staff would also like a breakeven capital cost analysis for all nine regarding the combined cycle, versus the combined cycle, and we will characterize that as Late-filed Exhibit Number 2, Breakeven Capital Costs for 2040. Would that be possible?

A. Yes, that would be possible.

MS. KLANCKE: Excellent.

(Late-filed Deposition Exhibits Number 1 and 2 were identified.)

BY MS. KLANCKE:

Q. I would like you to turn your attention now to Staff's Fifth Request for Production of Documents and FPL's responses thereto. In particular, please refer to FPL's responses to Staff's Fifth Request for Production of Document Number 26. And for ease of reference, I'm

going to call this POD 26.

A. Okay.

Q. In staff's POD 26, we requested that you provide, quote, the annual and cumulative present value revenue requirements for an analysis in which nuclear, combined cycle, and IGCC units were compared to FP&L's current cost range numbers of nuclear units. In response to POD 26, FPL provided an analysis using the medium gas cost and Env II compliance forecast; is that correct?

A. The medium gas price and Env II; that's correct.

Q. Could you please turn to Exhibit SRS-7 of your testimony, your direct testimony?

A. Yes.

Q. Did you analyze the other eight scenarios depicted in SRS-7 in addition to the medium gas cost and Env II compliance forecast?

A. Yes. FPL analyzed nine fuel and environmental compliance cost forecasts.

Q. But in the answer to POD 26, you only provided us with an analysis reflecting medium gas and Env II; is that correct?

A. That is correct. The question was not specific in regard to how many scenarios information was

Hearing Exhibit 000535

to be supplied for.

Q. That is true. Could you please provide staff with a late-filed exhibit that analyzes all eight scenarios as depicted in SRS-7, the other eight, as it were?

A. Let me make sure I understand. You're asking for the remaining eight scenarios versus combined cycle and the remaining eight versus IGCC?

Q. Yes.

A. And these two nuclear capital cost numbers of 3,108 and 4,540?

Q. Yes.

A. Yes, we can provide that.

MS. KLANCKE: Let's call that Late-filed Exhibit Number 3, Economic Analysis Results for All Fuel and Environmental Compliance Cost Scenarios.

(Late-filed Deposition Exhibit Number 3 was identified.)

BY MS. KLANCKE:

Q. Could you please now turn to pages 40 and 41 of your direct testimony?

A. Yes.

Q. In particular, I would like you to reference lines 16 through 23 on page 40 and lines 1 through 14 on page 41.

A. Okay.

Q. Is it correct that your testimony states here that FPL initially combined three fuel cost forecasts with four environmental cost forecasts in its analysis of alternative generating technologies to develop a total of 12 scenarios of forecasted fuel costs and environmental compliance costs?

A. Yes. There were 12 initial scenarios contemplated, of which three were deemed to be unrealistic and were excluded from the analysis.

Q. Could you identify which three were excluded?

A. Yes. They are the combinations of a low natural gas cost and a mid to high environmental compliance cost. So it would have been a low gas cost, Environmental II, Environmental III, and Environmental IV.

Q. Is it correct that your testimony states that these three scenarios were removed based on FPL's belief that the medium to high environmental compliance costs for CO_2 is incompatible with an assumption of low natural gas prices?

A. Yes, because we believe that medium to high environmental compliance costs for CO_2 will result in upward pressure on natural gas prices, and therefore, combining those CO_2 compliance cost forecasts with low

natural gas costs is just unrealistic.

Q. You characterized these as unrealistic just now. If you were to make an estimate as to the probability, or lack thereof, of a scenario involving low natural gas costs and medium to high environmental compliance costs, what would that estimate be?

A. I'm sorry. Can you restate the question, because I'm not sure what you're asking me to comment on.

Q. Certainly. Would you characterize such a scenario involving low natural gas costs and medium to high environmental compliance costs as very unlikely to highly improbable?

A. I don't know how you differentiate between those two. I would say I believe they are unrealistic, and therefore, most unlikely.

Q. Did you rely on the expertise of any of the other witnesses in this docket for making the determination that these two circumstances are incompatible?

A. I would have to say yes, that it was a consensus opinion among the witnesses and among a number of other folks who had some input into this process that the three scenarios that we deem as most unrealistic, those of low natural gas costs and medium to high CO_2

Hearing Exhibit 000538

costs, should be excluded, because we just do not see that occurring.

Q. Could you identify which witnesses formed this consensus opinion?

A. I would say the primary witnesses in the case who have the same opinion would be FPL witnesses Silva, Yupp, Kosky, Scroggs, and Olivera, at a minimum.

Q. Okay. Did you rely on any additional resources other than the witnesses you have just mentioned in making this determination?

A. No specific resource that I can recall at the moment.

Q. Okay. Turning your attention back to the top of page 41 of your testimony, you state that it's FPL's belief that medium to high environmental compliance costs for CO_2 will result in upward pressure on natural gas prices; is that correct?

A. That's correct.

Q. Is it possible that other factors affecting gas price, such as gas supply, could fully counteract the upward pressure on gas prices which may be caused by medium to high environmental compliance costs?

A. If I understand the question to mean is it theoretically possible that other factors could overcome this, I would have to say yes, anything is possible in

Hearing Exhibit 000539

theory. FPL just views it as highly unlikely and therefore not worthy of inclusion in the analysis in this case.

Q. What other factors -- I'll say if differently. What are the factors that determine FP&L's natural gas commodity price?

A. I believe that would be more appropriately addressed, that question, to FPL witness Yupp.

Q. All right. Is it possible that increased demand for natural gas, perhaps caused by medium to high CO_2 costs, could occur at the same time that the real price of natural gas decreases based on an interaction of other possible factors, such as natural gas supply growth, geographical events, weather, improvements in drilling, storage technology, et cetera? Would it be possible that that -- would that be possible?

A. Again, if I understand your question to be is it theoretically possible to have natural gas prices, the movement be downward due to other unforeseen factors or unlikely factors that overcome the medium to high environmental compliance costs for CO_2, I would have to say in theory, yes, it's possible. But again, FPL views it as highly unlikely.

Q. Let me turn your attention back to Exhibit SRS-7. Are you there, Dr. Sim?

A. Yes, I am.

Q. Good. Is it correct that FP&L assigned no probabilities to either its natural gas price forecasts or its environmental cost forecasts which were used to produce the matrix of cost differentials appearing in this exhibit?

A. Yes, that's correct. FPL views the situation of both forecasting of fuel prices and the forecasting of environmental compliance costs each on their own as having a high level of uncertainty associated with them. Then when you combine the interactive effects between the two, that uncertainty level rises even further.

Therefore, FPL's approach for its analysis for this docket was to create a scenario approach in which we provided a broad range of possible fuel and environmental compliance costs without assigning probabilities.

Q. So it's also correct that there were no probabilities assigned to any of the combinations of scenarios that appear on this exhibit?

A. That is correct, for the reasons just stated.

MS. KLANCKE: Absolutely. I would like to go off the record momentarily at this point to allow staff, Commission staff to talk with the witness about a potential additional late-filed exhibit.

Hearing Exhibit 000541

MR. ANDERSON: We have no objection to that.

MS. KLANCKE: Excellent. We're now off the record.

(Discussion off the record.)

MS. KLANCKE: All right. We are now back on the record. With that, Commission staff have no further questions for this witness at this time. At this point, I would like to ask whether any of the other parties present have any questions for the witness. Charlie, do you have any questions?

MR. BECK: No, I do not. Thank you, Caroline.

MS. KLANCKE: Mr. Krasowski, do you have any questions?

MR. KRASOWSKI: Yes, I have two questions.

CROSS-EXAMINATION

BY MR. KRASOWSKI:

Q. Hello, Dr. Sim.

A. Yes, sir. How are you this afternoon?

Q. Very well, thank you.

On page 17 of your testimony -- and I will apologize in advance if the answer is contained in your material and I've missed it or forgotten it, but I would like to ask you this question. On page 17, line 11, the question regards what is mentioned here, that the projections you've made rely upon FP&L's IRP 2006 load

Hearing Exhibit 000542

forecast that was developed in September 2006. My question would be, to what extent are your projections based on this forecast, and what updates or -- I won't use "uprates." What updates or other information might have been added -- well, let me start with one thing at a time. I'm sorry. Is it accurate that your projections rely upon the IRP 2006 load forecast?

A. Yes. Both the projections of capacity needs and all of FPL's analysis are based on the forecast of load and energy that was developed in the September 2006 load forecast.

Q. Okay. Do you have any updates from that time that you'll be applying to refining your analysis one way or the other?

A. In terms of the analysis that FPL has provided in this docket, we have no change in FPL's official load forecast, and therefore, we will not be updating it for this analysis. However, as we have indicated in our filing, FPL intends this to be an ongoing analysis on an annual basis, at which time all of the assumptions, including the load forecast, will be updated.

Q. Okay. Thank you. One other question. On page 18, I'm at lines 20 and 21. The end of line 20 says, "At the time of this filing, FPL is analyzing these three firm capacity proposals." Could you say

what those proposals are?

A. We've indicated in lines 17 and 18 that one is from the waste-to-energy facility and two are from biomass facilities. Beyond that, I do not believe FPL has publicly given out information regarding who the bidders are or where they are located, so I would respectfully not like to comment further on those proposals.

MR. KRASOWSKI: What you've said is adequate, thank you, as far as identifying what the three of them are. That's all the questions I have for the moment. Thank you very much.

MS. KLANCKE: Bryan, do you have any redirect for the witness at this time?

MR. ANDERSON: No, we do not. Thank you.

MS. KLANCKE: Well, Commission staff has no further questions for the witness, and as such, I thank you all for your time. I would like you to apprise the court reporter, Mary, who would like a copy of this transcript.

MR. ANDERSON: FPL would, please.

MR. BECK: Mary, this is Charlie. I do not. Thank you.

MR. KRASOWSKI: Nor do I. Bob Krasowski.

MS. KLANCKE: Well, thank you all for your

Hearing Exhibit 000544

time. Thank you, Dr. Sim, for your answers today and for your time. We appreciate your candor.

THE WITNESS: You're welcome.

MR. ANDERSON: Thank you all very much. Have a good afternoon.

(Deposition concluded at 2:05 p.m.)

Hearing Exhibit 000545

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1 through 21 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 17th day of January, 2008.

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

Hearing Exhibit 000546

CERTIFICATE OF OATH

STATE OF FLORIDA

COUNTY OF PALM BEACH

I, the undersigned authority, certify that **Steven R. Sim** personally appeared before me at **700 Universe Boulevard, Juno Beach, Florida** and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, State of Florida, this 17th day of January, 2008.

Notary Public State of Florida
Jennifer M Payne
My Commission DD439096
Expires 05/09/2009

Notary Public
State of Florida

Personally known X OR produced identification _____.

Type of identification produced _____.

ASR ACCURATE STENOTYPE REPORTERS INCORPORATED
CERTIFIED COURT REPORTERS

January 18, 2008

Bryan Anderson, Esquire
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Need Determination for Turkey Point 6 and 7
Docket No. 070650-EI

Dear Mr. Butler:

Enclosed is your copy of the deposition of Steven R. Sim taken in the above matter on January 17, 2008.

Since reading and signing was not waived, we are enclosing an errata sheet and request that your office make arrangements with the witness to read the deposition and make any corrections on the errata sheet.

Please forward the original completed errata sheet to Jane Faurot at the Commission for attachment to the original transcript. You should also attach a copy to your transcript so that it will be complete.

Thank you for your cooperation in this matter. It was a pleasure working with you.

Sincerely,

Mary A. Neel

Mary A. Neel

/mn
cc: Jane Faurot
Enclosures

ERRATA SHEET

Under penalties of perjury, I declare that I have read the foregoing transcript of my deposition, pages 1 through 22, and that the facts stated therein are true, including any corrections and/or amendments listed below.

1/23/08
Date

STEVEN R SIM

Page	Line	Correction or Amendment	Reason for Change
20	3	Change "the" to "a"	Typo

Deposition taken on 01/17/08 Docket No 070650-EI

Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios

(from Exhibit SRS-8)

Plan with Nuclear vs. Plan without Nuclear-CC

Breakeven Nuclear Capital Costs
($/kw in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
Env I	6,157	4,543	3,206
Env II	6,701	5,065	
Env III	6,949	5,327	
Env IV	7,281	5,680	

Plan with Nuclear vs. Plan without Nuclear-CC

Year 2050 Breakeven Nuclear Capital Costs
($/kw in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
Env I	5,692	4,223	3,003
Env II	6,178	4,690	
Env III	6,386	4,909	
Env IV	6,681	5,211	

Notes:
(1) The breakeven costs in the left-hand matrix show that the breakeven costs are higher than, or within, the $3,108/kw - to - $4,540/kw (2007$) current cost estimate for nuclear in 9 of 9 scenarios (8 higher and 1 within).
(2) The breakeven costs in the right hand matrix show that the breakeven costs are higher than, or within the $3,108/kw - to - $4,540/kw (2007$) current cost estimate for nuclear in 8 of 9 scenarios (7 higher and 1 within) and slightly lower than the range in one scenario.
(3) Breakeven cost values are calculated assuming no carbon capture and sequestration (CCS) costs for CC units. Inclusion of such costs would increase breakeven costs.

Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios

(from Exhibit SRS-8)

Plan with Nuclear vs. Plan without Nuclear-CC

Breakeven Nuclear Capital Costs
($/kw in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
Env I	6,157	4,543	3,206
Env II	6,701	5,065	
Env III	6,949	5,327	
Env IV	7,281	5,680	

Plan with Nuclear vs. Plan without Nuclear-CC

Year 2040 Breakeven Nuclear Capital Costs
($/kw in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
Env I	4,953	3,705	2,668
Env II	5,349	4,092	
Env III	5,500	4,247	
Env IV	5,740	4,489	

Notes:
(1) The breakeven costs in the left-hand matrix show that the breakeven costs are higher than, or within, the $3,108/kw - to - $4,540/kw (2007$) current cost estimate for nuclear in 9 of 9 scenarios (8 higher and 1 within).
(2) The breakeven costs in the right hand matrix show that the breakeven costs are higher than, or within the $3,108/kw - to - $4,540/kw (2007$) current cost estimate for nuclear in 8 of 9 scenarios (4 are higher and 4 within) and lower than the range in one scenario.
(3) Breakeven cost values are calculated assuming no carbon capture and sequestration (CCS) costs for CC units. Inclusion of such costs would increase breakeven costs.

Plan With Nuclear @, $3,108/kw
Total Annual Costs(Millions)

Fuel Cost Forecast	*High Gas Cost*											
Environmental Compliance Cost Forecast	*Env I*			*Env II*			*Env III*			*Env IV*		
Year	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	6,785	6,785	6,785	6,777	6,777	6,777	6,775	6,775	6,775	6,775	6,775	6,775
2008	8,056	7,438	14,223	8,046	7,429	14,206	8,044	7,427	14,202	8,044	7,427	14,202
2009	8,423	7,181	21,404	8,421	7,179	21,385	8,419	7,178	21,380	8,419	7,178	21,380
2010	8,766	6,901	28,305	8,379	6,596	27,981	9,034	7,111	28,491	9,230	7,266	28,646
2011	8,598	6,250	34,555	8,334	6,058	34,039	8,933	6,493	34,984	9,148	6,650	35,296
2012	8,441	5,664	40,218	8,304	5,572	39,611	8,854	5,940	40,925	9,098	6,104	41,400
2013	8,914	5,522	45,741	8,869	5,494	45,105	9,273	5,745	46,670	9,523	5,900	47,300
2014	9,748	5,576	51,316	9,768	5,587	50,692	10,201	5,835	52,504	10,489	6,000	53,299
2015	10,938	5,775	57,091	11,011	5,814	56,506	11,411	6,025	58,529	11,734	6,196	59,495
2016	12,435	6,061	63,152	12,614	6,148	62,654	12,996	6,335	64,864	13,348	6,507	66,002
2017	13,166	5,924	69,077	13,504	6,077	68,731	13,830	6,223	71,088	14,219	6,399	72,400
2018	13,918	5,781	74,858	14,333	5,953	74,684	14,592	6,061	77,149	15,010	6,235	78,636
2019	14,834	5,688	80,546	15,384	5,900	80,584	15,613	5,988	83,137	16,072	6,164	84,800
2020	15,231	5,392	85,938	15,987	5,660	86,244	16,187	5,731	88,868	16,699	5,913	90,712
2021	16,037	5,242	91,180	16,948	5,540	91,785	17,120	5,597	94,465	17,667	5,776	96,488
2022	17,090	5,158	96,338	18,140	5,475	97,260	18,325	5,531	99,996	18,964	5,724	102,212
2023	18,104	5,044	101,382	19,325	5,385	102,645	19,492	5,432	105,427	20,185	5,625	107,838
2024	19,431	4,999	106,381	20,905	5,379	108,024	21,112	5,432	110,859	21,913	5,639	113,476
2025	20,750	4,929	111,310	22,388	5,318	113,342	22,588	5,366	116,225	23,442	5,569	119,045
2026	22,219	4,872	116,182	24,040	5,273	118,615	24,353	5,341	121,567	25,294	5,548	124,593
2027	23,944	4,848	121,030	25,997	5,264	123,879	26,463	5,359	126,926	27,531	5,575	130,169
2028	25,457	4,758	125,788	27,691	5,177	129,056	28,471	5,323	132,249	29,699	5,553	135,722
2029	26,943	4,650	130,438	29,307	5,059	134,115	30,370	5,243	137,491	31,733	5,479	141,200
2030	28,698	4,573	135,011	31,178	4,969	139,084	32,602	5,196	142,688	34,122	5,439	146,639
2031	30,578	4,499	139,510	33,206	4,886	143,970	34,750	5,114	147,802	36,369	5,353	151,992
2032	33,081	4,493	144,003	35,905	4,878	148,848	37,608	5,110	152,912	39,362	5,349	157,341
2033	36,638	4,595	148,598	39,767	4,988	153,836	41,688	5,230	158,141	43,641	5,475	162,816
2034	39,167	4,535	153,133	42,497	4,922	158,758	44,588	5,164	163,306	46,681	5,407	168,224
2035	41,536	4,441	157,574	45,076	4,820	163,578	47,343	5,063	168,369	49,578	5,303	173,526
2036	45,378	4,480	162,054	49,247	4,862	168,441	51,769	5,112	173,481	54,226	5,355	178,882
2037	48,348	4,406	166,460	52,467	4,783	173,224	55,196	5,032	178,514	57,816	5,272	184,153
2038	50,702	4,267	170,727	55,047	4,633	177,857	57,990	4,882	183,395	60,768	5,116	189,270
2039	53,510	4,158	174,885	58,107	4,516	182,373	61,274	4,763	188,158	64,228	4,993	194,263
2040	56,733	4,071	178,956	61,623	4,422	186,796	65,042	4,668	192,827	68,186	4,894	199,157
2041	58,342	3,865	182,821	63,404	4,201	190,997	66,996	4,440	197,267	70,252	4,656	203,814
2042	59,873	3,663	186,484	65,114	3,984	194,982	68,889	4,216	201,483	72,274	4,424	208,237
2043	62,506	3,532	190,015	68,028	3,844	198,826	72,064	4,073	205,555	75,648	4,276	212,513
2044	64,750	3,378	193,394	70,509	3,679	202,505	74,777	3,903	209,458	78,532	4,099	216,612
2045	65,972	3,179	196,572	71,922	3,466	205,971	76,383	3,681	213,139	80,274	3,869	220,481
2046	67,217	2,991	199,563	73,365	3,265	209,236	78,026	3,472	216,612	82,058	3,652	224,133
2047	68,493	2,814	202,377	74,845	3,076	212,312	79,714	3,276	219,888	83,894	3,448	227,581
2048	69,794	2,648	205,025	76,358	2,898	215,209	81,445	3,091	222,979	85,776	3,255	230,837
2049	71,147	2,493	207,518	77,929	2,731	217,940	83,243	2,917	225,896	87,731	3,075	233,912
2050	72,540	2,347	209,865	79,547	2,574	220,514	85,097	2,754	228,650	89,749	2,905	236,816
2051	73,967	2,210	212,075	81,208	2,427	222,941	87,004	2,600	231,250	91,825	2,744	239,561
2052	75,444	2,082	214,156	82,925	2,288	225,229	88,978	2,455	233,705	93,974	2,594	242,154
2053	76,975	1,961	216,118	84,705	2,158	227,387	91,026	2,320	236,025	96,203	2,452	244,606
2054	78,581	1,849	217,967	86,568	2,037	229,424	93,168	2,192	238,218	98,533	2,319	246,925
2055	80,232	1,743	219,710	88,484	1,923	231,347	95,375	2,073	240,290	100,936	2,193	249,118
2056	81,923	1,644	221,353	90,450	1,815	233,162	97,643	1,959	242,249	103,406	2,075	251,193
2057	83,651	1,550	222,903	92,461	1,713	234,875	99,970	1,852	244,102	105,942	1,963	253,156
2058	85,289	1,459	224,363	94,392	1,615	236,490	102,230	1,749	245,851	108,420	1,855	255,012
2059	87,160	1,377	225,740	96,565	1,526	238,016	104,747	1,655	247,506	111,161	1,757	256,768
2060	89,058	1,299	227,039	98,776	1,441	239,457	107,314	1,566	249,072	113,962	1,663	258,431

Plan With Nuclear @ $3,108/kw
Total Annual Costs(Millions)

Fuel Cost Forecast	Medium Gas Cost												Low Gas Cost		
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV			Env I		
Year	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	5,037	5,037	5,037	5,027	5,027	5,027	5,025	5,025	5,025	5,025	5,025	5,025	3,718	3,718	3,718
2008	5,957	5,500	10,537	5,946	5,490	10,517	5,944	5,488	10,513	5,944	5,488	10,513	4,394	4,058	7,775
2009	6,254	5,332	15,869	6,256	5,334	15,851	6,256	5,334	15,846	6,256	5,334	15,846	4,615	3,935	11,710
2010	6,658	5,241	21,110	6,269	4,935	20,787	6,925	5,452	21,298	7,122	5,606	21,453	4,954	3,900	15,610
2011	6,608	4,803	25,913	6,344	4,611	25,398	6,939	5,043	26,342	7,150	5,197	26,650	4,928	3,582	19,192
2012	6,560	4,401	30,314	6,423	4,309	29,707	6,969	4,675	31,017	7,207	4,836	31,486	4,991	3,348	22,540
2013	6,940	4,299	34,613	6,893	4,270	33,977	7,292	4,517	35,534	7,540	4,671	36,157	5,302	3,284	25,824
2014	7,574	4,331	38,944	7,592	4,342	38,319	8,017	4,585	40,119	8,302	4,748	40,905	5,796	3,314	29,139
2015	8,577	4,528	43,472	8,649	4,566	42,885	9,043	4,774	44,893	9,363	4,943	45,848	6,617	3,492	32,631
2016	9,645	4,700	48,172	9,823	4,787	47,672	10,202	4,972	49,865	10,551	5,142	50,990	7,480	3,644	36,275
2017	10,278	4,624	52,796	10,614	4,775	52,447	10,937	4,920	54,785	11,324	5,095	56,085	8,013	3,604	39,878
2018	10,977	4,558	57,354	11,386	4,728	57,175	11,644	4,835	59,621	12,057	5,007	61,092	8,689	3,606	43,485
2019	11,685	4,479	61,833	12,229	4,688	61,863	12,457	4,776	64,396	12,911	4,950	66,042	9,271	3,552	47,037
2020	12,051	4,265	66,098	12,796	4,529	66,392	12,996	4,600	68,996	13,502	4,779	70,821	9,570	3,385	50,422
2021	12,690	4,146	70,244	13,584	4,439	70,831	13,758	4,496	73,492	14,305	4,675	75,496	10,083	3,293	53,715
2022	13,533	4,083	74,326	14,576	4,398	75,228	14,758	4,453	77,944	15,388	4,643	80,139	10,752	3,242	56,957
2023	14,353	3,998	78,324	15,577	4,339	79,567	15,736	4,383	82,328	16,424	4,575	84,714	11,391	3,170	60,127
2024	15,392	3,958	82,282	16,856	4,335	83,902	17,063	4,388	86,716	17,851	4,592	89,306	12,185	3,131	63,258
2025	16,417	3,897	86,179	18,041	4,284	88,186	18,237	4,330	91,047	19,079	4,531	93,837	12,954	3,073	66,332
2026	17,571	3,851	90,030	19,376	4,248	92,434	19,692	4,317	95,364	20,617	4,520	98,357	13,839	3,031	69,363
2027	18,947	3,834	93,864	20,977	4,246	96,680	21,445	4,341	99,704	22,492	4,553	102,910	14,912	3,015	72,378
2028	20,167	3,767	97,632	22,377	4,181	100,861	23,154	4,327	104,031	24,353	4,552	107,462	15,877	2,964	75,342
2029	21,321	3,678	101,309	23,660	4,082	104,943	24,718	4,265	108,296	26,049	4,495	111,957	16,765	2,889	78,231
2030	22,691	3,614	104,923	25,145	4,006	108,949	26,559	4,231	112,528	28,038	4,468	116,425	17,806	2,833	81,064
2031	24,200	3,558	108,481	26,798	3,941	112,890	28,332	4,167	116,695	29,906	4,400	120,825	19,006	2,792	83,857
2032	26,178	3,554	112,034	28,976	3,935	116,824	30,660	4,164	120,859	32,365	4,396	125,221	20,553	2,786	86,644
2033	28,926	3,625	115,659	32,020	4,014	120,839	33,923	4,253	125,112	35,826	4,493	129,713	22,638	2,835	89,479
2034	30,918	3,578	119,237	34,218	3,961	124,799	36,286	4,201	129,313	38,324	4,437	134,151	24,187	2,796	92,275
2035	32,734	3,497	122,734	36,245	3,874	128,673	38,482	4,114	133,427	40,667	4,348	138,498	25,554	2,728	95,003
2036	35,690	3,521	126,255	39,526	3,900	132,573	42,017	4,147	137,574	44,417	4,384	142,883	27,780	2,738	97,740
2037	38,043	3,465	129,720	42,124	3,838	136,411	44,814	4,084	141,657	47,373	4,317	147,200	29,620	2,695	100,435
2038	39,840	3,350	133,070	44,158	3,715	140,126	47,048	3,958	145,616	49,762	4,188	151,388	30,967	2,602	103,037
2039	41,985	3,260	136,330	46,553	3,616	143,742	49,659	3,858	149,474	52,546	4,083	155,471	32,564	2,526	105,563
2040	44,470	3,188	139,518	49,332	3,538	147,280	52,679	3,779	153,253	55,752	4,000	159,471	34,446	2,467	108,030
2041	45,671	3,024	142,542	50,703	3,358	150,638	54,214	3,591	156,844	57,393	3,802	163,273	35,312	2,335	110,366
2042	46,740	2,858	145,400	51,949	3,177	153,815	55,640	3,403	160,247	58,946	3,606	166,879	36,000	2,199	112,565
2043	48,593	2,744	148,143	54,082	3,054	156,869	58,034	3,278	163,525	61,544	3,477	170,356	37,224	2,100	114,664
2044	50,185	2,617	150,760	55,907	2,916	159,785	60,091	3,135	166,660	63,775	3,327	173,683	38,282	1,994	116,659
2045	51,043	2,458	153,218	56,955	2,743	162,528	61,328	2,954	169,614	65,158	3,139	176,823	38,843	1,869	118,527
2046	51,915	2,308	155,526	58,023	2,581	165,109	62,594	2,785	172,399	66,575	2,962	179,785	39,409	1,751	120,278
2047	52,808	2,168	157,695	59,119	2,428	167,537	63,896	2,625	175,024	68,034	2,795	182,580	39,990	1,641	121,919
2048	53,717	2,037	159,732	60,238	2,285	169,822	65,229	2,475	177,498	69,532	2,638	185,218	40,578	1,538	123,457
2049	54,668	1,914	161,646	61,406	2,151	171,973	66,621	2,334	179,832	71,094	2,491	187,709	41,201	1,442	124,899
2050	55,649	1,800	163,446	62,610	2,025	173,998	68,059	2,202	182,034	72,708	2,352	190,061	41,844	1,352	126,251
2051	56,654	1,692	165,138	63,846	1,907	175,905	69,538	2,077	184,112	74,371	2,222	192,283	42,504	1,269	127,520
2052	57,698	1,591	166,729	65,129	1,797	177,702	71,075	1,961	186,072	76,099	2,100	194,383	43,194	1,191	128,710
2053	58,785	1,497	168,226	66,463	1,693	179,395	72,674	1,852	187,924	77,896	1,985	196,368	43,919	1,118	129,828
2054	59,936	1,410	169,636	67,869	1,597	180,992	74,355	1,749	189,673	79,783	1,877	198,245	44,698	1,051	130,879
2055	61,121	1,328	170,964	69,318	1,506	182,498	76,091	1,653	191,326	81,733	1,776	200,021	45,501	988	131,867
2056	62,334	1,250	172,214	70,803	1,420	183,918	77,876	1,562	192,889	83,741	1,680	201,701	46,324	929	132,796
2057	63,572	1,178	173,392	72,322	1,340	185,258	79,706	1,477	194,366	85,803	1,590	203,291	47,161	873	133,669
2058	64,708	1,107	174,499	73,749	1,262	186,520	81,459	1,394	195,759	87,796	1,502	204,793	47,887	819	134,488
2059	66,064	1,044	175,542	75,405	1,191	187,711	83,454	1,319	197,078	90,041	1,423	206,216	48,823	771	135,259
2060	67,435	984	176,526	77,086	1,125	188,836	85,487	1,247	198,325	92,334	1,347	207,563	49,762	726	135,985

Hearing Exhibit 000553

Plan With Nuclear @ $4,540/kw
Total Annual Costs(Millions)

Fuel Cost Forecast	*High Gas Cost*											
Environmental Compliance Cost Forecast	*Env I*			*Env II*			*Env III*			*Env IV*		
Year	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	6,785	6,785	6,785	6,777	6,777	6,777	6,775	6,775	6,775	6,775	6,775	6,775
2008	8,056	7,438	14,223	8,046	7,429	14,206	8,044	7,427	14,202	8,044	7,427	14,202
2009	8,467	7,219	21,442	8,465	7,217	21,423	8,464	7,216	21,418	8,464	7,216	21,418
2010	8,805	6,932	28,374	8,418	6,627	28,050	9,073	7,142	28,560	9,270	7,297	28,715
2011	8,640	6,280	34,654	8,376	6,088	34,138	8,975	6,524	35,084	9,190	6,680	35,395
2012	8,462	5,678	40,332	8,325	5,586	39,724	8,875	5,954	41,039	9,119	6,118	41,513
2013	8,974	5,559	45,891	8,929	5,531	45,255	9,333	5,782	46,820	9,583	5,937	47,450
2014	9,859	5,639	51,530	9,879	5,650	50,905	10,312	5,897	52,718	10,600	6,062	53,513
2015	11,112	5,867	57,396	11,186	5,905	56,811	11,585	6,117	58,834	11,909	6,287	59,800
2016	12,685	6,182	63,578	12,864	6,269	63,080	13,246	6,456	65,290	13,598	6,628	66,427
2017	13,483	6,066	69,644	13,822	6,219	69,299	14,148	6,365	71,655	14,537	6,541	72,968
2018	14,384	5,973	75,617	14,799	6,146	75,444	15,058	6,253	77,909	15,477	6,427	79,396
2019	15,372	5,893	81,510	15,923	6,104	81,548	16,151	6,192	84,101	16,610	6,368	85,764
2020	15,813	5,596	87,107	16,569	5,864	87,413	16,770	5,936	90,036	17,281	6,117	91,881
2021	16,632	5,434	92,541	17,543	5,733	93,145	17,716	5,789	95,825	18,263	5,968	97,849
2022	17,662	5,328	97,869	18,712	5,646	98,791	18,897	5,702	101,527	19,536	5,895	103,744
2023	18,654	5,196	103,065	19,875	5,537	104,328	20,042	5,583	107,110	20,735	5,776	109,520
2024	19,960	5,133	108,198	21,434	5,513	109,841	21,641	5,566	112,676	22,442	5,773	115,293
2025	21,259	5,048	113,246	22,897	5,437	115,278	23,097	5,485	118,161	23,951	5,688	120,981
2026	22,708	4,978	118,224	24,529	5,378	120,656	24,842	5,447	123,608	25,782	5,653	126,635
2027	24,413	4,941	123,165	26,466	5,358	126,014	26,932	5,452	129,060	28,000	5,669	132,304
2028	25,906	4,841	128,006	28,140	5,260	131,274	28,920	5,406	134,466	30,147	5,636	137,939
2029	27,372	4,723	132,729	29,736	5,132	136,405	30,799	5,316	139,782	32,162	5,551	143,490
2030	29,107	4,637	137,366	31,587	5,033	141,438	33,011	5,260	145,042	34,531	5,503	148,994
2031	30,967	4,555	141,920	33,595	4,942	146,381	35,139	5,170	150,212	36,758	5,409	154,402
2032	33,450	4,543	146,463	36,275	4,927	151,308	37,977	5,159	155,371	39,731	5,398	159,800
2033	36,989	4,638	151,101	40,118	5,031	156,339	42,039	5,273	160,644	43,992	5,518	165,319
2034	39,503	4,573	155,674	42,833	4,960	161,299	44,925	5,203	165,847	47,018	5,446	170,764
2035	41,860	4,475	160,149	45,399	4,854	166,153	47,667	5,097	170,944	49,902	5,337	176,101
2036	45,691	4,510	164,658	49,560	4,893	171,046	52,082	5,142	176,086	54,540	5,386	181,487
2037	48,651	4,433	169,092	52,771	4,810	175,856	55,500	5,059	181,145	58,120	5,299	186,785
2038	50,996	4,291	173,383	55,341	4,658	180,513	58,284	4,906	186,051	61,062	5,140	191,926
2039	53,795	4,180	177,563	58,392	4,538	185,051	61,559	4,785	190,836	64,513	5,015	196,940
2040	57,008	4,090	181,652	61,898	4,442	189,492	65,317	4,688	195,523	68,461	4,914	201,854
2041	58,607	3,882	185,535	63,670	4,219	193,711	67,261	4,457	199,980	70,518	4,673	206,527
2042	60,129	3,678	189,213	65,370	4,000	197,711	69,145	4,231	204,212	72,530	4,439	210,966
2043	62,752	3,545	192,758	68,274	3,858	201,568	72,311	4,086	208,298	75,895	4,289	215,256
2044	64,987	3,390	196,148	70,746	3,691	205,260	75,014	3,915	212,213	78,769	4,111	219,367
2045	66,200	3,189	199,337	72,150	3,476	208,736	76,610	3,692	215,905	80,501	3,880	223,246
2046	67,435	3,000	202,337	73,583	3,274	212,011	78,244	3,482	219,386	82,276	3,662	226,908
2047	68,701	2,822	205,160	75,054	3,084	215,094	79,923	3,284	222,671	84,102	3,456	230,364
2048	69,993	2,655	207,815	76,557	2,905	217,999	81,644	3,098	225,769	85,975	3,263	233,627
2049	71,337	2,499	210,314	78,119	2,737	220,736	83,432	2,924	228,692	87,921	3,081	236,708
2050	72,720	2,353	212,667	79,727	2,580	223,316	85,277	2,760	231,452	89,928	2,910	239,618
2051	74,137	2,215	214,882	81,378	2,432	225,748	87,174	2,605	234,057	91,995	2,749	242,368
2052	75,605	2,086	216,968	83,086	2,293	228,040	89,139	2,460	236,517	94,135	2,598	244,965
2053	77,126	1,965	218,933	84,856	2,162	230,202	91,177	2,323	238,840	96,355	2,455	247,421
2054	78,723	1,852	220,785	86,709	2,040	232,242	93,309	2,196	241,036	98,675	2,322	249,743
2055	80,364	1,746	222,531	88,616	1,925	234,168	95,507	2,075	243,111	101,068	2,196	251,939
2056	82,046	1,646	224,177	90,572	1,817	235,985	97,766	1,962	245,073	103,529	2,077	254,017
2057	83,764	1,552	225,729	92,574	1,715	237,700	100,083	1,854	246,927	106,055	1,965	255,982
2058	85,330	1,460	227,189	94,433	1,616	239,316	102,272	1,750	248,677	108,461	1,856	257,838
2059	87,198	1,378	228,566	96,603	1,526	240,843	104,785	1,656	250,333	111,199	1,757	259,595
2060	89,058	1,299	229,866	98,776	1,441	242,284	107,314	1,566	251,899	113,962	1,663	261,258

Plan With Nuclear @, $4,540/kw
Total Annual Costs(Millions)

Fuel Cost Forecast	Medium Gas Cost												Low Gas Cost		
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV			Env I		
Year	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	5,037	5,037	5,037	5,027	5,027	5,027	5,025	5,025	5,025	5,025	5,025	5,025	3,718	3,718	3,718
2008	5,957	5,500	10,537	5,946	5,490	10,517	5,944	5,488	10,513	5,944	5,488	10,513	4,394	4,058	7,775
2009	6,299	5,370	15,907	6,301	5,372	15,889	6,300	5,372	15,884	6,300	5,372	15,884	4,660	3,973	11,748
2010	6,697	5,272	21,179	6,309	4,966	20,856	6,965	5,483	21,367	7,161	5,638	21,522	4,994	3,931	15,679
2011	6,650	4,833	26,013	6,386	4,642	25,497	6,981	5,074	26,441	7,192	5,228	26,750	4,970	3,613	19,292
2012	6,581	4,415	30,428	6,444	4,323	29,821	6,990	4,689	31,130	7,228	4,850	31,599	5,012	3,362	22,654
2013	7,000	4,336	34,764	6,953	4,307	34,128	7,352	4,554	35,684	7,600	4,708	36,307	5,362	3,321	25,975
2014	7,685	4,394	39,158	7,703	4,405	38,532	8,128	4,648	40,332	8,413	4,811	41,118	5,907	3,377	29,352
2015	8,751	4,619	43,777	8,823	4,657	43,190	9,218	4,866	45,198	9,537	5,034	46,153	6,791	3,584	32,936
2016	9,895	4,821	48,598	10,073	4,908	48,098	10,452	5,093	50,291	10,801	5,263	51,416	7,730	3,765	36,701
2017	10,596	4,765	53,364	10,932	4,917	53,015	11,255	5,062	55,353	11,642	5,236	56,652	8,331	3,745	40,446
2018	11,443	4,750	58,114	11,852	4,920	57,934	12,110	5,027	60,380	12,524	5,199	61,852	9,155	3,798	44,244
2019	12,223	4,684	62,797	12,767	4,892	62,827	12,995	4,980	65,360	13,449	5,154	67,006	9,809	3,757	48,001
2020	12,634	4,469	67,266	13,378	4,733	67,560	13,578	4,804	70,164	14,084	4,983	71,989	10,152	3,589	51,590
2021	13,285	4,339	71,605	14,180	4,631	72,191	14,353	4,688	74,852	14,900	4,867	76,857	10,679	3,485	55,075
2022	14,105	4,253	75,858	15,148	4,568	76,760	15,330	4,623	79,476	15,960	4,814	81,670	11,324	3,412	58,488
2023	14,903	4,149	80,007	16,127	4,490	81,250	16,286	4,535	84,010	16,974	4,727	86,397	11,941	3,322	61,810
2024	15,921	4,092	84,099	17,385	4,469	85,719	17,592	4,523	88,533	18,380	4,726	91,123	12,714	3,266	65,075
2025	16,925	4,016	88,115	18,550	4,403	90,122	18,745	4,450	92,983	19,568	4,650	95,773	13,463	3,192	68,268
2026	18,060	3,957	92,072	19,865	4,353	94,476	20,181	4,423	97,405	21,106	4,626	100,399	14,328	3,137	71,404
2027	19,416	3,927	95,999	21,446	4,339	98,815	21,914	4,434	101,839	22,961	4,647	105,045	15,381	3,109	74,513
2028	20,616	3,850	99,849	22,826	4,264	103,079	23,603	4,410	106,249	24,802	4,634	109,679	16,326	3,046	77,559
2029	21,750	3,750	103,599	24,089	4,155	107,233	25,147	4,338	110,587	26,478	4,568	114,248	17,193	2,962	80,521
2030	23,100	3,678	107,277	25,554	4,070	111,303	26,968	4,295	114,882	28,447	4,532	118,779	18,215	2,897	83,419
2031	24,589	3,614	110,891	27,187	3,997	115,300	28,721	4,224	119,106	30,297	4,456	123,235	19,395	2,848	86,267
2032	26,547	3,603	114,494	29,345	3,984	119,284	31,029	4,213	123,319	32,734	4,445	127,680	20,922	2,837	89,104
2033	29,277	3,668	118,162	32,371	4,057	123,341	34,274	4,297	127,615	36,177	4,536	132,216	22,989	2,878	91,981
2034	31,254	3,616	121,778	34,554	3,999	127,340	36,622	4,239	131,854	38,660	4,475	136,691	24,523	2,834	94,815
2035	33,058	3,531	125,309	36,569	3,908	131,247	38,806	4,147	136,001	40,990	4,382	141,073	25,878	2,762	97,577
2036	36,003	3,551	128,860	39,840	3,931	135,178	42,331	4,177	140,178	44,731	4,415	145,488	28,093	2,768	100,345
2037	38,347	3,492	132,352	42,428	3,865	139,043	45,118	4,111	144,289	47,677	4,344	149,832	29,924	2,722	103,067
2038	40,134	3,374	135,726	44,452	3,739	142,782	47,342	3,983	148,272	50,056	4,212	154,044	31,261	2,626	105,693
2039	42,269	3,282	139,008	46,838	3,638	146,419	49,944	3,880	152,151	52,831	4,105	158,148	32,848	2,548	108,241
2040	44,746	3,208	142,215	49,607	3,557	149,976	52,954	3,798	155,949	56,027	4,019	162,167	34,722	2,486	110,727
2041	45,937	3,041	145,256	50,969	3,375	153,351	54,480	3,608	159,557	57,659	3,819	165,987	35,578	2,353	113,080
2042	46,996	2,873	148,129	52,205	3,192	156,544	55,896	3,419	162,976	59,202	3,621	169,608	36,256	2,214	115,294
2043	48,839	2,757	150,886	54,328	3,068	159,612	58,280	3,292	166,268	61,790	3,491	173,099	37,471	2,113	117,407
2044	50,422	2,629	153,514	56,144	2,928	162,540	60,328	3,147	169,415	64,012	3,339	176,438	38,519	2,006	119,413
2045	51,271	2,468	155,983	57,183	2,754	165,293	61,556	2,965	172,380	65,385	3,150	179,588	39,070	1,879	121,293
2046	52,133	2,318	158,301	58,241	2,590	167,884	62,812	2,794	175,173	66,793	2,971	182,559	39,627	1,760	123,053
2047	53,016	2,177	160,477	59,328	2,437	170,320	64,104	2,633	177,807	68,243	2,803	185,363	40,198	1,649	124,702
2048	53,916	2,044	162,522	60,437	2,292	172,612	65,428	2,482	180,288	69,731	2,645	188,008	40,777	1,545	126,247
2049	54,858	1,921	164,443	61,595	2,157	174,769	66,810	2,340	182,629	71,283	2,497	190,505	41,390	1,448	127,695
2050	55,828	1,805	166,248	62,790	2,031	176,800	68,238	2,207	184,836	72,888	2,358	192,863	42,024	1,358	129,053
2051	56,824	1,697	167,945	64,017	1,912	178,712	69,708	2,082	186,919	74,541	2,227	195,090	42,674	1,274	130,327
2052	57,858	1,596	169,540	65,290	1,801	180,513	71,236	1,965	188,884	76,259	2,104	197,194	43,355	1,195	131,521
2053	58,936	1,501	171,041	66,615	1,697	182,210	72,825	1,855	190,739	78,047	1,988	199,183	44,070	1,122	132,643
2054	60,077	1,413	172,454	68,011	1,600	183,810	74,497	1,753	192,491	79,925	1,880	201,063	44,839	1,054	133,697
2055	61,253	1,330	173,785	69,449	1,509	185,319	76,223	1,656	194,147	81,865	1,779	202,842	45,633	991	134,688
2056	62,457	1,253	175,037	70,926	1,423	186,741	77,998	1,565	195,712	83,863	1,683	204,524	46,446	931	135,619
2057	63,685	1,180	176,217	72,435	1,342	188,083	79,819	1,479	197,191	85,916	1,592	206,116	47,274	875	136,494
2058	64,749	1,108	177,325	73,790	1,262	189,346	81,500	1,394	198,585	87,837	1,503	207,619	47,928	820	137,314
2059	66,102	1,044	178,369	75,443	1,192	190,537	83,492	1,319	199,904	90,079	1,423	209,042	48,861	772	138,086
2060	67,435	984	179,353	77,086	1,125	191,662	85,487	1,247	201,152	92,334	1,347	210,390	49,762	726	138,812

Plan Without Nuclear - CC
Total Annual Costs(Millions)

Fuel Cost Forecast	*High Gas Cost*											
Environmental Compliance Cost Forecast	*Env I*			*Env II*			*Env III*			*Env IV*		
Year	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	6,785	6,785	6,785	6,777	6,777	6,777	6,775	6,775	6,775	6,775	6,775	6,775
2008	8,056	7,438	14,223	8,046	7,429	14,206	8,044	7,427	14,202	8,044	7,427	14,202
2009	8,326	7,098	21,322	8,324	7,097	21,303	8,322	7,095	21,297	8,322	7,095	21,297
2010	8,680	6,833	28,155	8,293	6,528	27,831	8,948	7,044	28,341	9,145	7,199	28,496
2011	8,507	6,184	34,338	8,243	5,992	33,823	8,842	6,427	34,768	9,057	6,583	35,079
2012	8,396	5,633	39,972	8,259	5,541	39,364	8,808	5,910	40,678	9,052	6,074	41,153
2013	8,784	5,442	45,414	8,739	5,414	44,778	9,143	5,664	46,343	9,393	5,820	46,973
2014	9,508	5,439	50,853	9,528	5,450	50,228	9,961	5,698	52,041	10,249	5,863	52,836
2015	10,559	5,577	56,429	10,633	5,615	55,844	11,032	5,827	57,867	11,356	5,997	58,833
2016	11,892	5,799	62,228	12,071	5,886	61,730	12,454	6,073	63,940	12,806	6,244	65,077
2017	12,476	5,616	67,844	12,815	5,769	67,499	13,140	5,915	69,855	13,529	6,091	71,168
2018	13,499	5,610	73,455	13,927	5,789	73,287	14,196	5,900	75,756	14,628	6,080	77,248
2019	14,665	5,628	79,082	15,246	5,851	79,138	15,487	5,943	81,699	15,970	6,129	83,377
2020	15,617	5,533	84,615	16,444	5,826	84,964	16,664	5,904	87,604	17,224	6,103	89,480
2021	16,761	5,483	90,098	17,775	5,815	90,779	17,967	5,878	93,481	18,584	6,080	95,559
2022	17,887	5,402	95,501	19,061	5,757	96,536	19,266	5,819	99,301	19,980	6,035	101,595
2023	19,058	5,314	100,815	20,417	5,694	102,230	20,605	5,746	105,047	21,381	5,963	107,557
2024	20,359	5,241	106,056	21,990	5,662	107,891	22,221	5,721	110,768	23,104	5,949	113,506
2025	21,907	5,207	111,263	23,724	5,639	113,531	23,944	5,692	116,459	24,889	5,916	119,422
2026	23,465	5,149	116,412	25,479	5,591	119,122	25,826	5,668	122,127	26,867	5,896	125,318
2027	25,225	5,110	121,522	27,482	5,568	124,690	27,991	5,671	127,798	29,166	5,910	131,228
2028	26,879	5,028	126,550	29,342	5,489	130,179	30,199	5,649	133,448	31,557	5,904	137,132
2029	28,428	4,909	131,459	31,024	5,358	135,537	32,189	5,560	139,007	33,689	5,819	142,951
2030	30,298	4,830	136,289	33,002	5,262	140,799	34,553	5,510	144,517	36,215	5,775	148,726
2031	32,279	4,752	141,041	35,155	5,176	145,975	36,839	5,424	149,942	38,616	5,686	154,412
2032	34,798	4,729	145,770	37,886	5,150	151,125	39,731	5,401	155,343	41,651	5,663	160,075
2033	38,375	4,815	150,586	41,767	5,242	156,367	43,834	5,502	160,844	45,954	5,768	165,843
2034	41,089	4,760	155,346	44,703	5,180	161,546	46,944	5,440	166,284	49,214	5,703	171,546
2035	43,672	4,671	160,017	47,500	5,082	166,628	49,925	5,341	171,625	52,343	5,601	177,147
2036	47,516	4,692	164,709	51,686	5,105	171,733	54,374	5,371	176,997	57,020	5,633	182,780
2037	50,566	4,611	169,320	55,000	5,016	176,749	57,905	5,281	182,278	60,725	5,539	188,319
2038	53,156	4,475	173,795	57,830	4,869	181,618	60,951	5,133	187,411	63,934	5,385	193,704
2039	56,099	4,361	178,156	61,034	4,745	186,363	64,392	5,007	192,418	67,550	5,253	198,957
2040	59,547	4,274	182,429	64,796	4,651	191,015	68,424	4,912	197,330	71,792	5,155	204,111
2041	61,268	4,060	186,490	66,706	4,422	195,436	70,513	4,674	202,004	74,001	4,906	209,017
2042	62,806	3,844	190,333	68,430	4,189	199,625	72,425	4,434	206,438	76,043	4,655	213,673
2043	65,646	3,710	194,043	71,576	4,046	203,671	75,848	4,288	210,726	79,685	4,505	218,178
2044	68,017	3,550	197,593	74,197	3,873	207,544	78,715	4,109	214,835	82,732	4,319	222,497
2045	69,305	3,340	200,933	75,690	3,648	211,192	80,410	3,876	218,711	84,571	4,077	226,575
2046	70,648	3,144	204,078	77,243	3,438	214,630	82,174	3,658	222,369	86,485	3,850	230,425
2047	72,021	2,960	207,037	78,833	3,240	217,871	83,984	3,452	225,822	88,450	3,636	234,061
2048	73,434	2,787	209,824	80,471	3,054	220,925	85,851	3,259	229,081	90,477	3,435	237,496
2049	74,887	2,624	212,449	82,156	2,880	223,805	87,775	3,077	232,157	92,568	3,245	240,741
2050	76,377	2,472	214,921	83,886	2,715	226,520	89,753	2,905	235,062	94,719	3,066	243,807
2051	77,918	2,329	217,249	85,674	2,561	229,080	91,801	2,744	237,806	96,945	2,898	246,705
2052	79,510	2,194	219,443	87,522	2,416	231,496	93,918	2,592	240,399	99,248	2,740	249,444
2053	81,178	2,069	221,512	89,454	2,280	233,776	96,132	2,450	242,849	101,653	2,591	252,035
2054	82,894	1,951	223,463	91,443	2,152	235,928	98,414	2,316	245,165	104,134	2,451	254,486
2055	84,652	1,840	225,302	93,483	2,032	237,959	100,759	2,190	247,355	106,685	2,319	256,805
2056	86,490	1,736	227,038	95,612	1,919	239,878	103,206	2,071	249,426	109,346	2,195	258,999
2057	88,358	1,637	228,675	97,780	1,812	241,690	105,706	1,959	251,385	112,067	2,077	261,076
2058	90,235	1,544	230,219	99,967	1,711	243,401	108,238	1,852	253,238	114,828	1,965	263,041
2059	92,225	1,457	231,677	102,278	1,616	245,017	110,909	1,753	254,990	117,736	1,861	264,902
2060	94,296	1,376	233,052	104,680	1,527	246,544	113,686	1,659	256,648	120,758	1,762	266,663

Plan Without Nuclear - CC
Total Annual Costs(Millions)

Fuel Cost Forecast	Medium Gas Cost												Low Gas Cost		
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV			Env I		
Year	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	5,037	5,037	5,037	5,027	5,027	5,027	5,025	5,025	5,025	5,025	5,025	5,025	3,718	3,718	3,718
2008	5,957	5,500	10,537	5,946	5,490	10,517	5,944	5,488	10,513	5,944	5,488	10,513	4,394	4,058	7,775
2009	6,158	5,250	15,787	6,160	5,251	15,769	6,159	5,251	15,764	6,159	5,251	15,764	4,518	3,852	11,627
2010	6,572	5,174	20,960	6,184	4,868	20,637	6,840	5,384	21,148	7,036	5,539	21,303	4,869	3,833	15,460
2011	6,517	4,737	25,697	6,253	4,545	25,181	6,847	4,977	26,125	7,059	5,131	26,434	4,837	3,516	18,976
2012	6,514	4,371	30,068	6,378	4,279	29,460	6,923	4,645	30,770	7,162	4,805	31,239	4,945	3,318	22,294
2013	6,810	4,219	34,286	6,763	4,190	33,650	7,162	4,437	35,207	7,410	4,591	35,830	5,172	3,204	25,497
2014	7,334	4,195	38,481	7,352	4,205	37,856	7,777	4,449	39,655	8,062	4,611	40,441	5,556	3,178	28,675
2015	8,198	4,329	42,810	8,270	4,367	42,223	8,665	4,576	44,231	8,984	4,744	45,186	6,238	3,294	31,969
2016	9,103	4,438	47,248	9,281	4,525	46,747	9,660	4,709	48,941	10,009	4,880	50,066	6,938	3,382	35,351
2017	9,588	4,316	51,564	9,924	4,467	51,214	10,247	4,613	53,553	10,634	4,787	54,852	7,323	3,296	38,646
2018	10,447	4,341	55,905	10,870	4,517	55,731	11,136	4,628	58,181	11,565	4,806	59,658	8,057	3,347	41,993
2019	11,324	4,345	60,249	11,898	4,565	60,296	12,137	4,657	62,838	12,616	4,841	64,499	8,733	3,349	45,343
2020	12,092	4,283	64,532	12,907	4,572	64,868	13,125	4,649	67,487	13,680	4,846	69,345	9,304	3,295	48,637
2021	12,926	4,227	68,760	13,931	4,556	69,425	14,120	4,618	72,105	14,733	4,819	74,164	9,939	3,250	51,887
2022	13,858	4,184	72,944	15,022	4,536	73,961	15,223	4,597	76,702	15,927	4,810	78,974	10,672	3,221	55,108
2023	14,777	4,119	77,063	16,139	4,499	78,461	16,316	4,549	81,251	17,084	4,763	83,737	11,387	3,173	58,281
2024	15,820	4,071	81,135	17,438	4,489	82,949	17,669	4,548	85,799	18,539	4,772	88,509	12,190	3,136	61,417
2025	17,045	4,050	85,184	18,845	4,478	87,427	19,062	4,530	90,329	19,994	4,751	93,261	13,134	3,119	64,536
2026	18,272	4,008	89,192	20,267	4,446	91,873	20,613	4,522	94,851	21,639	4,748	98,008	14,074	3,085	67,621
2027	19,674	3,984	93,176	21,903	4,436	96,309	22,415	4,540	99,391	23,571	4,774	102,783	15,171	3,070	70,692
2028	20,950	3,917	97,093	23,389	4,374	100,683	24,242	4,533	103,925	25,573	4,783	107,566	16,147	3,017	73,709
2029	22,175	3,828	100,920	24,744	4,272	104,955	25,902	4,472	108,397	27,374	4,727	112,292	17,095	2,949	76,658
2030	23,659	3,770	104,690	26,338	4,198	109,153	27,875	4,444	112,840	29,501	4,703	116,996	18,254	2,907	79,564
2031	25,201	3,708	108,398	28,044	4,127	113,280	29,717	4,374	117,214	31,455	4,630	121,626	19,438	2,858	82,422
2032	27,166	3,690	112,088	30,217	4,106	117,386	32,051	4,355	121,570	33,929	4,611	126,237	20,945	2,843	85,266
2033	29,932	3,754	115,842	33,280	4,175	121,560	35,337	4,433	126,003	37,413	4,694	130,931	23,050	2,888	88,154
2034	32,061	3,712	119,554	35,629	4,126	125,686	37,861	4,385	130,388	40,085	4,643	135,575	24,693	2,857	91,011
2035	34,082	3,643	123,197	37,864	4,049	129,735	40,275	4,307	134,695	42,647	4,561	140,136	26,251	2,804	93,815
2036	37,021	3,654	126,851	41,139	4,061	133,797	43,810	4,326	139,021	46,403	4,582	144,718	28,453	2,806	96,620
2037	39,396	3,590	130,441	43,772	3,990	137,786	46,657	4,253	143,274	49,419	4,506	149,224	30,269	2,756	99,376
2038	41,416	3,484	133,925	46,033	3,874	141,660	49,125	4,135	147,409	52,051	4,382	153,606	31,819	2,675	102,051
2039	43,689	3,394	137,319	48,568	3,774	145,434	51,883	4,032	151,442	54,978	4,273	157,879	33,544	2,603	104,654
2040	46,339	3,324	140,643	51,532	3,697	149,131	55,104	3,954	155,396	58,401	4,191	162,070	35,536	2,546	107,200
2041	47,618	3,154	143,796	52,992	3,511	152,642	56,742	3,760	159,155	60,152	3,986	166,057	36,454	2,412	109,613
2042	48,690	2,978	146,774	54,247	3,319	155,961	58,181	3,560	162,715	61,721	3,777	169,834	37,143	2,270	111,882
2043	50,682	2,863	149,637	56,544	3,195	159,155	60,759	3,433	166,149	64,522	3,646	173,480	38,448	2,170	114,052
2044	52,359	2,731	152,368	58,467	3,051	162,206	62,928	3,284	169,432	66,880	3,490	176,971	39,558	2,062	116,114
2045	53,256	2,565	154,933	59,566	2,870	165,076	64,227	3,095	172,527	68,339	3,294	180,264	40,134	1,932	118,045
2046	54,198	2,411	157,344	60,716	2,701	167,777	65,586	2,918	175,446	69,865	3,109	183,373	40,748	1,811	119,857
2047	55,159	2,266	159,610	61,892	2,543	170,320	66,980	2,752	178,198	71,433	2,936	186,309	41,373	1,698	121,555
2048	56,150	2,130	161,740	63,105	2,394	172,714	68,421	2,596	180,795	73,055	2,772	189,081	42,019	1,593	123,148
2049	57,172	2,003	163,742	64,356	2,255	174,969	69,908	2,450	183,244	74,730	2,619	191,700	42,687	1,494	124,642
2050	58,219	1,883	165,626	65,640	2,124	177,093	71,439	2,312	185,556	76,457	2,474	194,175	43,371	1,402	126,044
2051	59,306	1,772	167,397	66,971	2,001	179,094	73,028	2,182	187,738	78,250	2,339	196,513	44,087	1,316	127,361
2052	60,432	1,667	169,065	68,350	1,886	180,980	74,675	2,061	189,799	80,109	2,211	198,724	44,833	1,236	128,597
2053	61,623	1,570	170,635	69,802	1,779	182,759	76,406	1,947	191,746	82,062	2,091	200,815	45,633	1,162	129,759
2054	62,850	1,479	172,113	71,299	1,678	184,436	78,194	1,840	193,586	84,080	1,979	202,794	46,460	1,093	130,852
2055	64,107	1,393	173,506	72,834	1,583	186,019	80,032	1,739	195,325	86,159	1,872	204,666	47,308	1,027	131,879
2056	65,432	1,313	174,819	74,446	1,494	187,513	81,960	1,645	196,970	88,338	1,773	206,439	48,212	967	132,846
2057	66,773	1,237	176,056	76,084	1,410	188,922	83,928	1,555	198,525	90,566	1,678	208,117	49,122	910	133,756
2058	68,109	1,165	177,221	77,728	1,330	190,252	85,914	1,470	199,995	92,825	1,588	209,706	50,018	856	134,611
2059	69,547	1,099	178,320	79,482	1,256	191,508	88,025	1,391	201,386	95,220	1,505	211,210	51,002	806	135,417
2060	71,051	1,037	179,356	81,313	1,186	192,694	90,229	1,316	202,702	97,720	1,426	212,635	52,043	759	136,175

Plan Without Nuclear - IGCC
Total Annual Costs(Millions)

Fuel Cost Forecast	*High Gas Cost*											
Environmental Compliance Cost Forecast	*Env I*			*Env II*			*Env III*			*Env IV*		
Year	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*	*Total Annual Costs (Nominal)*	*NPV Total Annual Costs*	*NPV Cumulative Total Costs*
2007	6,785	6,785	6,785	6,777	6,777	6,777	6,775	6,775	6,775	6,775	6,775	6,775
2008	8,056	7,438	14,223	8,046	7,429	14,206	8,044	7,427	14,202	8,044	7,427	14,202
2009	8,326	7,098	21,322	8,324	7,097	21,303	8,322	7,095	21,297	8,322	7,095	21,297
2010	8,680	6,833	28,155	8,293	6,528	27,831	8,948	7,044	28,341	9,145	7,199	28,496
2011	8,507	6,184	34,338	8,243	5,992	33,823	8,842	6,427	34,768	9,057	6,583	35,079
2012	8,396	5,633	39,972	8,259	5,541	39,364	8,808	5,910	40,678	9,052	6,074	41,153
2013	8,784	5,442	45,414	8,739	5,414	44,778	9,143	5,664	46,343	9,390	5,820	46,973
2014	9,508	5,439	50,853	9,528	5,450	50,228	9,961	5,698	52,041	10,249	5,863	52,836
2015	10,559	5,577	56,429	10,633	5,615	55,844	11,032	5,827	57,867	11,356	5,997	58,833
2016	11,892	5,799	62,228	12,071	5,886	61,730	12,454	6,073	63,940	12,806	6,244	65,077
2017	12,476	5,616	67,844	12,815	5,769	67,499	13,140	5,915	69,855	13,529	6,091	71,168
2018	14,012	5,821	73,665	14,462	6,008	73,507	14,742	6,125	75,980	15,196	6,313	77,482
2019	15,448	5,924	79,589	16,078	6,165	79,672	16,337	6,265	82,245	16,860	6,466	83,948
2020	16,854	5,964	85,553	17,778	6,292	85,964	18,024	6,379	88,624	18,660	6,605	90,552
2021	18,209	5,948	91,501	19,374	6,330	92,294	19,598	6,403	95,027	20,312	6,636	97,189
2022	19,212	5,794	97,296	20,547	6,198	98,492	20,786	6,270	101,297	21,607	6,518	103,707
2023	20,251	5,639	102,935	21,793	6,070	104,561	22,009	6,130	107,427	22,901	6,379	110,086
2024	21,475	5,521	108,456	23,331	6,000	110,561	23,596	6,068	113,495	24,614	6,330	116,417
2025	22,931	5,443	113,899	24,990	5,933	116,494	25,247	5,994	119,489	26,334	6,253	122,670
2026	24,343	5,335	119,234	26,627	5,837	122,331	27,010	5,921	125,410	28,205	6,184	128,853
2027	25,953	5,252	124,486	28,502	5,769	128,100	29,066	5,883	131,293	30,410	6,156	135,009
2028	27,472	5,133	129,619	30,254	5,654	133,754	31,210	5,833	137,126	32,758	6,123	141,132
2029	28,869	4,980	134,599	31,794	5,486	139,240	33,093	5,711	142,837	34,797	6,005	147,138
2030	30,574	4,870	139,468	33,613	5,355	144,595	35,344	5,632	148,469	37,226	5,932	153,070
2031	32,434	4,770	144,238	35,650	5,244	149,839	37,528	5,521	153,990	39,534	5,817	158,887
2032	34,793	4,725	148,963	38,233	5,193	155,032	40,286	5,473	159,463	42,442	5,766	164,653
2033	38,311	4,803	153,766	42,063	5,275	160,307	44,347	5,562	165,025	46,708	5,859	170,512
2034	40,871	4,731	158,497	44,867	5,195	165,502	47,346	5,483	170,507	49,872	5,776	176,288
2035	43,189	4,617	163,114	47,413	5,069	170,571	50,091	5,356	175,864	52,774	5,644	181,932
2036	46,895	4,628	167,742	51,470	5,081	175,652	54,426	5,374	181,238	57,347	5,663	187,595
2037	49,783	4,537	172,279	54,633	4,980	180,632	57,825	5,272	186,509	60,931	5,556	193,151
2038	52,194	4,392	176,671	57,293	4,822	185,455	60,720	5,111	191,621	63,998	5,388	198,538
2039	54,983	4,272	180,943	60,355	4,690	190,145	64,027	4,977	198,597	67,491	5,246	203,785
2040	58,269	4,180	185,123	63,974	4,591	194,736	67,933	4,875	201,473	71,617	5,141	208,925
2041	59,839	3,964	189,087	65,743	4,356	199,092	69,904	4,633	206,105	73,722	4,886	213,812
2042	61,233	3,746	192,833	67,334	4,120	203,212	71,704	4,388	210,493	75,663	4,631	218,443
2043	63,805	3,605	198,438	70,235	3,969	207,181	74,900	4,233	214,727	79,090	4,471	222,913
2044	65,929	3,440	199,878	72,630	3,791	210,972	77,560	4,048	218,775	81,947	4,278	227,191
2045	66,977	3,228	203,106	73,898	3,562	214,533	79,047	3,810	222,585	83,590	4,030	231,221
2046	68,146	3,033	206,138	75,294	3,351	217,885	80,672	3,591	226,177	85,376	3,801	235,021
2047	69,462	2,855	208,993	76,843	3,158	221,043	82,459	3,390	229,566	87,331	3,590	238,612
2048	70,816	2,687	211,680	78,439	2,977	224,020	84,302	3,200	232,766	89,348	3,392	242,003
2049	72,209	2,530	214,211	80,081	2,807	226,827	86,203	3,022	235,788	91,426	3,205	245,208
2050	73,637	2,383	216,594	81,767	2,646	229,474	88,158	2,854	238,641	93,569	3,029	248,237
2051	75,114	2,245	218,838	83,510	2,496	231,969	90,181	2,696	241,337	95,785	2,863	251,100
2052	76,641	2,115	220,953	85,311	2,355	234,324	92,275	2,547	243,884	98,078	2,707	253,807
2053	78,242	1,994	222,947	87,197	2,222	236,546	94,464	2,408	246,291	100,473	2,561	256,368
2054	79,890	1,880	224,827	89,138	2,098	238,644	96,722	2,276	248,568	102,945	2,423	258,791
2055	81,579	1,773	226,600	91,128	1,980	240,624	99,042	2,153	250,720	105,487	2,293	261,084
2056	83,345	1,672	228,272	93,206	1,870	242,495	101,464	2,036	252,756	108,138	2,170	263,254
2057	85,138	1,578	229,850	95,322	1,766	244,261	103,937	1,926	254,683	110,849	2,054	265,309
2058	86,916	1,487	231,337	97,433	1,667	245,929	106,421	1,821	256,504	113,579	1,944	267,252
2059	88,839	1,404	232,741	99,699	1,575	247,504	109,075	1,724	258,227	116,487	1,841	269,093
2060	90,848	1,326	234,173	102,062	1,489	249,099	111,842	1,632	259,966	119,516	1,744	270,943

Note: For all cases, NPV Cumulative Total Costs Value in year 2060 includes a Coal Inventory Working Capital Carrying Costs of $106.738 millions in NPV $2007.

Plan Without Nuclear - IGCC
Total Annual Costs(Millions)

Sim Deposition
Docket No. 070650
Late Filed Exhibit # 3
Page 8 of 8

Fuel Cost Forecast	Medium Gas Cost												Low Gas Cost		
Environmental Compliance Cost Forecast	Env I			Env II			Env III			Env IV			Env I		
Year	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs	Total Annual Costs (Nominal)	NPV Total Annual Costs	NPV Cumulative Total Costs
2007	5,037	5,037	5,037	5,027	5,027	5,027	5,025	5,025	5,025	5,025	5,025	5,025	3,718	3,718	3,718
2008	5,957	5,500	10,537	5,946	5,490	10,517	5,944	5,488	10,513	5,944	5,488	10,513	4,394	4,058	7,775
2009	6,158	5,250	15,787	6,160	5,251	15,769	6,159	5,251	15,764	6,159	5,251	15,764	4,518	3,852	11,627
2010	6,572	5,174	20,960	6,184	4,868	20,637	6,840	5,384	21,148	7,036	5,539	21,303	4,869	3,833	15,460
2011	6,517	4,737	25,697	6,253	4,545	25,181	6,847	4,977	26,125	7,059	5,131	26,434	4,837	3,516	18,976
2012	6,514	4,371	30,068	6,378	4,279	29,460	6,923	4,645	30,770	7,162	4,805	31,239	4,945	3,318	22,294
2013	6,810	4,219	34,286	6,763	4,190	33,650	7,162	4,437	35,207	7,410	4,591	35,830	5,172	3,204	25,497
2014	7,334	4,195	38,481	7,352	4,205	37,856	7,777	4,449	39,655	8,082	4,611	40,441	5,556	3,178	28,675
2015	8,198	4,329	42,810	8,270	4,367	42,223	8,665	4,576	44,231	8,984	4,744	45,186	6,238	3,294	31,969
2016	9,103	4,438	47,248	9,281	4,525	46,747	9,660	4,709	48,941	10,009	4,880	50,066	6,938	3,382	35,351
2017	9,588	4,316	51,564	9,924	4,467	51,214	10,247	4,613	53,553	10,634	4,787	54,852	7,323	3,296	38,646
2018	11,018	4,576	56,139	11,460	4,760	55,974	11,740	4,876	58,429	12,190	5,063	59,916	8,681	3,604	42,250
2019	12,232	4,689	60,828	12,854	4,928	60,902	13,113	5,027	63,456	13,631	5,226	65,142	9,755	3,737	45,987
2020	13,510	4,779	65,607	14,431	5,105	66,007	14,677	5,193	68,649	15,305	5,415	70,556	10,933	3,865	49,852
2021	14,652	4,784	70,390	15,810	5,163	71,170	16,028	5,234	73,883	16,741	5,467	76,024	11,942	3,896	53,749
2022	15,473	4,664	75,054	16,801	5,065	76,235	17,037	5,137	79,019	17,848	5,382	81,406	12,580	3,789	57,538
2023	16,277	4,530	79,584	17,826	4,962	81,197	18,033	5,020	84,039	18,919	5,267	86,673	13,197	3,670	61,208
2024	17,250	4,432	84,016	19,097	4,908	86,106	19,362	4,977	89,016	20,366	5,236	91,909	13,940	3,579	64,787
2025	18,390	4,362	88,379	20,440	4,850	90,956	20,693	4,911	93,927	21,767	5,166	97,075	14,806	3,510	68,297
2026	19,492	4,269	92,648	21,764	4,768	95,724	22,149	4,853	98,780	23,332	5,113	102,188	15,642	3,423	71,720
2027	20,768	4,200	96,847	23,302	4,714	100,438	23,869	4,829	103,608	25,196	5,098	107,286	16,633	3,361	75,081
2028	21,936	4,096	100,943	24,696	4,613	105,051	25,648	4,791	108,399	27,175	5,077	112,363	17,518	3,268	78,349
2029	23,035	3,971	104,914	25,934	4,473	109,523	27,226	4,696	113,095	28,909	4,987	117,350	18,355	3,161	81,510
2030	24,385	3,881	108,795	27,398	4,362	113,886	29,117	4,637	117,732	30,971	4,933	122,283	19,405	3,086	84,596
2031	25,818	3,794	112,590	29,009	4,265	118,151	30,875	4,540	122,273	32,851	4,831	127,115	20,499	3,010	87,606
2032	27,653	3,752	116,342	31,067	4,217	122,368	33,105	4,495	126,767	35,230	4,784	131,899	21,895	2,968	90,574
2033	30,407	3,809	120,151	34,125	4,277	126,645	36,396	4,562	131,330	38,721	4,855	136,753	24,019	3,006	93,581
2034	32,391	3,747	123,898	36,352	4,207	130,852	38,816	4,493	135,822	41,302	4,781	141,535	25,532	2,951	96,531
2035	34,173	3,650	127,548	38,362	4,099	134,951	41,020	4,384	140,206	43,863	4,667	146,202	26,871	2,867	99,399
2036	36,996	3,649	131,197	41,534	4,098	139,048	44,465	4,388	144,594	47,344	4,673	150,875	28,975	2,855	102,253
2037	39,236	3,573	134,770	44,048	4,013	143,061	47,207	4,301	148,896	50,266	4,581	155,456	30,682	2,791	105,045
2038	41,113	3,457	138,227	46,182	3,885	146,946	49,560	4,170	153,065	52,787	4,442	159,898	32,117	2,698	107,742
2039	43,258	3,358	141,585	48,602	3,775	150,720	52,219	4,057	157,122	55,630	4,322	164,220	33,735	2,616	110,359
2040	45,778	3,282	144,867	51,454	3,690	154,410	55,348	3,970	161,092	58,977	4,231	168,451	35,629	2,552	112,910
2041	46,939	3,107	147,974	52,810	3,497	157,907	56,898	3,769	164,861	60,654	4,018	172,469	36,454	2,411	115,321
2042	47,896	2,928	150,902	53,968	3,300	161,208	58,257	3,563	168,424	62,153	3,802	176,272	37,055	2,263	117,584
2043	49,643	2,803	153,705	56,039	3,165	164,373	60,625	3,425	171,849	64,755	3,659	179,931	38,137	2,151	119,735
2044	51,111	2,665	156,370	57,773	3,014	167,387	62,625	3,267	175,116	66,956	3,494	183,424	39,067	2,036	121,771
2045	51,789	2,494	158,864	58,668	2,826	170,213	63,737	3,071	178,187	68,231	3,288	186,713	39,444	1,898	123,669
2046	52,578	2,339	161,203	59,683	2,655	172,868	64,976	2,891	181,079	69,641	3,090	189,812	39,925	1,775	125,444
2047	53,504	2,198	163,401	60,841	2,500	175,368	66,369	2,727	183,806	71,211	2,927	192,738	40,534	1,664	127,107
2048	54,459	2,066	165,466	62,036	2,354	177,722	67,807	2,573	186,379	72,833	2,764	195,502	41,164	1,560	128,668
2049	55,443	1,942	167,408	63,267	2,217	179,939	69,293	2,428	188,807	74,510	2,611	198,114	41,816	1,464	130,132
2050	56,452	1,826	169,235	64,532	2,088	182,026	70,823	2,292	191,099	76,237	2,467	200,581	42,484	1,373	131,505
2051	57,499	1,718	170,952	65,843	1,967	183,994	72,410	2,164	193,263	78,030	2,332	202,913	43,182	1,289	132,794
2052	58,585	1,616	172,568	67,202	1,854	185,848	74,057	2,044	195,306	79,889	2,205	205,118	43,910	1,211	134,005
2053	59,735	1,522	174,090	68,633	1,749	187,597	75,787	1,931	197,238	81,841	2,086	207,203	44,693	1,138	135,143
2054	60,921	1,433	175,523	70,110	1,650	189,246	77,575	1,825	199,063	83,858	1,973	209,177	45,502	1,070	136,213
2055	62,135	1,350	176,873	71,623	1,556	190,803	79,414	1,726	200,789	85,935	1,867	211,044	46,330	1,008	137,219
2056	63,415	1,272	178,146	73,213	1,469	192,272	81,342	1,632	202,421	88,109	1,768	212,812	47,215	947	138,166
2057	64,710	1,199	179,344	74,828	1,386	193,658	83,309	1,544	203,965	90,333	1,674	214,486	48,105	891	139,057
2058	65,977	1,129	180,473	76,425	1,308	194,966	85,273	1,459	205,424	92,563	1,584	216,070	48,957	837	139,895
2059	67,376	1,064	181,538	78,165	1,235	196,201	87,395	1,381	206,805	94,960	1,501	217,571	49,930	789	140,683
2060	68,848	1,004	182,648	79,989	1,167	197,474	89,616	1,308	208,218	97,468	1,422	219,099	50,965	743	141,533

Note: For all cases, NPV Cumulative Total Costs Value in year 2060 includes a Coal Inventory Working Capital Carrying Costs of $106.738 millions in NPV $2007.

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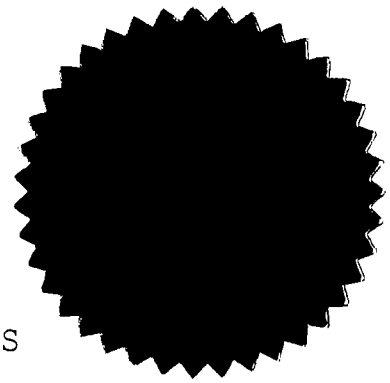
Deposition Transcript of Steven D. Scroggs including Late Filed Exhibits Nos. 1, 2, and 3 and Deposition Exhibit No. 4 (including errata sheet)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI

In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.
_____/



TELEPHONE DEPOSITION OF:	STEVEN D. SCROGGS
TAKEN AT INSTANCE OF:	The FPSC Staff
DATE:	January 18, 2008
TIME:	Commenced at 10:04 a.m. Concluded at 1:49 p.m.
LOCATION:	2540 Shumard Oak Boulevard Tallahassee, Florida
REPORTED BY:	LORI DEZELL Registered Professional Reporter

ACCURATE STENOTYPE REPORTERS, INC.
2094 REMINGTON GREEN LANE
TALLAHASSEE, FLORIDA 32308
(850)878-2221

APPEARANCES:

REPRESENTING FLORIDA POWER & LIGHT COMPANY:

JOHN BUTLER, ESQUIRE (BY TELEPHONE)
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Juno Beach, Florida 33408

REPRESENTING THE CITIZENS OF THE STATE OF FLORIDA:

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REPRESENTING JEA:

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REPRESENTING ORLANDO UTILITIES COMMISSION:

ROY C. YOUNG, ESQUIRE (BY TELEPHONE)
225 South Adams Street, Suite 200
Tallahassee, Florida 32301

Hearing Exhibit 000562

REPRESENTING JAN AND BOB KRASOWSKI:

MR. BOB KRASOWSKI (BY TELEPHONE)
1086 Michigan Avenue
Naples, Florida 34103-3857

REPRESENTING THE FPSC STAFF:

JENNIFER BRUBAKER, ESQUIRE (BY TELEPHONE)
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

ALSO PRESENT:

SHEVIE BROWN
ROBERT GRAVES
BILL McNULTY
CHARLENE POBLETE
JENNY WU

Hearing Exhibit 000563

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1	(Late-filed) January 2008 Nuclear News article titled "Renaissance Now?"	29
2	(Late-filed) Documentation from Westinghouse supporting responses to Interrogatories 88 and 89	37
3	"Summary of Water Issues" by Steven D. Scroggs	71
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CERTIFICATE OF OATH
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STIPULATIONS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

MR. BUTLER: We have here Steve Scroggs, the witness; myself, John Butler; Sebrina Spradley; and Jessica Cano of FPL. And we also have Jenna DeValerio, a Notary Public who is prepared to swear in Mr. Scroggs.

MS. BRUBAKER: If you'd go ahead, please.

MR. BUTLER: I'm sorry?

MS. BRUBAKER: If you'd go ahead and have Mr. Scroggs sworn in, please.

MR. BUTLER: Okay. And then either now or after she finishes, if you would, please, give us the fax number where we should send the certificate.

MS. BRUBAKER: Certainly. I'll go ahead and give it to you now.

MR. BUTLER: Okay.

MS. BRUBAKER: 850-413 -- and doggone it, the

number just -- 6250.

MR. BUTLER: Okay. Very good. All right.

Well, then, Jenna, go ahead and swear in the witness, please.

Thereupon,

STEVEN D. SCROGGS

was called as a witness, having been first duly sworn by Jenna DeValerio, a Notary in the State of Florida, was examined and testified as follows:

MR. BUTLER: Okay.

MS. BRUBAKER: Okay. We're good to get started?

MR. BUTLER: Can we identify who else is on the call?

MS. BRUBAKER: Oh, I'm sorry. Certainly. Again, this is Jennifer Brubaker for staff.

MR. GRAVES: Robert Graves, Public Service Commission staff.

MR. BROWN: Shevie Brown, PSC staff.

MS. BROWNLESS: Suzanne Brownless representing JEA.

MR. McNULTY: Bill McNulty, PSC staff.

MS. WU: Jenny Wu, PSC staff.

MS. POBLETE: Charlene Poblete, PSC staff.

MR. BECK: This is Charlie Beck. I'm here

also.

MS. KAUFMAN: Vicki Kaufman.

MR. KRASOWSKI: Bob Krasowski.

MR. BRYANT: This is Fred Bryant, if you didn't catch it before.

MR. KRASOWSKI: Excuse me. I might as well make the point that I'm Bob Krasowski, intervenor in this case. Thank you.

MR. BUTLER: Okay.

MS. BRUBAKER: Very good. Any other preliminary matters before we get started?

MR. BUTLER: The only preliminary matter I would note is that we had trouble hearing some of the people speaking just now. I don't think it's too big a deal in terms of getting everybody identified, but, please, everyone, speak up, because we would not have been able to hear all of a question or comment that would have been raised at the prior volume level.

MS. BRUBAKER: Certainly. And I think the problem is one of proximity. Jenny Wu and Charlene Poblete were sitting a bit behind the table from the microphone. They're with the Commission staff.

MR. BUTLER: Okay.

MS. BRUBAKER: Okay. We'll go ahead and get started. Go on the record, please.

DIRECT EXAMINATION

BY MS. BRUBAKER:

Q Good morning, Mr. Scroggs. My name is Jennifer Brubaker. As I mentioned earlier, I'm the Commission attorney who will be conducting your deposition this morning on behalf of the Commission staff.

If you have any questions at any point during the deposition, if you need to take a break, need to confer with your attorney, please just speak up and let me know. Also, for the benefit of both the witness and the court reporter, we're happy to accommodate breaks as needed, so don't be shy to speak up.

Mr. Scroggs, would you please state your name and business address for the record?

A Good morning. Steven Scroggs. My business address is 700 Universe Boulevard, Juno Beach, Florida.

Q And you're employed by who, Mr. Scroggs?

A Florida Power & Light Company.

Q And what's your position with FPL?

A Senior director of project development.

Q Okay. And, Mr. Scroggs, you prefiled direct testimony and exhibits in this proceeding; is that

correct?

A That's correct.

Q Okay. At this time do you have any changes, additions, deletions, modifications to that testimony or the exhibits?

A I do have some minor errata to the direct testimony.

Q Okay. Could you identify that for me, please?

A Sure. On page No. 46, line 8 of my direct.

Q Yes.

A The sentence that says: "Fixed operations and maintenance costs." All right?

Q Uh-huh.

A Insert after "operations and maintenance costs" the term "Capital Replacement costs or fuel surcharges." So the sentence would read: "Those costs were explicitly considered as costs that are accrued for or extended during facility operation or are therefore included as fixed operations and maintenance costs, Capital Replacement costs or fuel surcharges in the system-based cost comparisons by FPL witness Sim."

MR. BUTLER: Are any of the words to be capitalized in what you just added and described?

THE WITNESS: The term "Capital Replacement" should be capitalized.

Q And, Mr. --

A Following.

Q Sorry. Please go ahead.

A On that same page, following that paragraph or that sentence that was just modified, I would add a new paragraph as follows: "Specifically, decommissioning costs are included as Fixed Operations and Maintenance charges, Dry Cast Storage costs are included within the Capital Replacement charges and handling of spent fuel as a surcharge in the fuel cost forecast."

MR. BUTLER: Same question to you about whether any of the terms there need to be capitalized?

A The term "Fixed Operations and Maintenance" should be capitalized, "Dry Cast Storage" should be capitalized, and "Capital Replacement" should be capitalized.

The other errata is a very minor one. I'll have to get back to that. I've lost the place for that.

Q What accounts, Mr. Scroggs, what accounts for the changes you've described to me on page 46?

A Trying to be more explicit about the cost categories that cover the various (inaudible) charges.

THE COURT REPORTER: Various what charges?

Q I'm sorry. Could you repeat that last part of

your sentence?

A Just trying to be more specific about the source of costs for each of the various categories of spent fuel handling costs.

Q Okay. And if I could perhaps ask your attorney to make sure to forward to all parties those changes, and also the -- what you've I think stated was a small -- fairly small change to -- you're unable to identify right at this moment?

A It's like a grammatical issue.

Q Okay. Very good.

A The other -- the other item I thought I would bring to the attention of the group is on page 19 there's a Q and A that asks about the status of the application in Miami-Dade county for land use approval. And there is obviously, since the time that this has been filed, a significant change in that we have received approval from the Board of County Commissioners in Miami-Dade County for those applied approvals.

Q All right. And that accounts for everything you wish to point out in your testimony and exhibits at this time?

A Yes, ma'am.

Q Okay. I have asked that your attorneys make available to you a number of documents that I'll be

referring to in the course of your deposition. There's a number of interrogatory responses, for example. Do you have those documents in front of you?

A I do.

Q Okay. If I could just start off with a quick question regarding FPL's response to Staff Interrogatory No. 18. Do you have that document in front of you?

A I do.

Q Did you either prepare this response or have you had a chance to review it; are you familiar with it?

A I'm familiar with it.

Q Okay. If I could direct your attention, please, to the row that is captioned as variable O&M dollars per megawatt hours.

A Uh-huh.

Q And looking at the columns, Turkey Point Unit 6, case B, and then there at the far side of the columns IGCC and gas CC.

A Okay.

Q Okay. So comparing those columns and rows, we have for Turkey Point Unit 6 a variable O&M of zero and then for the IGCC we have 4.7, and for the gas combined cycle we have a .8; is that correct?

A Correct.

Q Okay. Looking at these numbers and comparing them, can you explain to me why the variable O&M for Turkey Point Unit 6 is listed as zero?

A In the standard process for accounting for developed plant cost, the nuclear costs are generally characterized completely as fixed O&M costs or capital replacement costs, and are not looked at on a variable basis as you would look at certain consumable costs that are common with IGCC or combined cycle technology.

Q Okay. And the same answer would apply for the column Turkey Point Unit 7; is that correct?

A That's correct.

Q Okay. Thank you.

Mr. Scroggs, in your testimony you discuss long-lead procurement items. Can you give me a better understanding of what those are, what the definition of a long-lead procurement item is in the context of your testimony in these proceedings?

A Long-lead procurement item would be an item that would need to be, because of its specific nature and/or its position in the manufacturing construction cycle, it would require procurement in advance so that that procurement would allow for the component to be fabricated, finished, delivered in time so that it can be sequenced into the construction process at an optimal

Hearing Exhibit 000573

point.

Some of these items are very large vessels that are actually in the center of the reactor island and the buildings are constructed around them after they're set in place. So they're required early in the process and they have specific manufacturing requirements that identify the need to procure the event.

Q Now, is there a difference between these long-lead procurement items and other items in terms of the timing of payments?

A As they require advance commitment, there's a commercial arrangement that's associated with that advance commitment that would require similar advance payments.

Q Okay. And would you agree that if there's a key difference between long-lead procurement items and other items, is the necessity for making advance payments?

A Well, I would say, you know, that there is -- there's a specific -- as it pertains to this specific project, we can identify several very specific pieces that require advance payment and long-lead procurement. As we proceed through the design process, there will continue to be identified through the logistic and

scheduling process items that need to be procured in advance. So, you know, it's not -- not a -- it's a common practice in construction that you have to procure certain specialty equipment in advance of actually needing them on the job site so that they can be manufactured and then delivered to the job site for proper sequencing in the construction process.

Q For an item to be classified as a long-lead procurement item, how many months or years or what have you in advance of installation must payments be due?

A There's no strict definition to how we would classify anything under a specific term. The means that we've used to identify a set of forging that are necessary for the plant construction has been critical long-lead components.

Q And what are the long-lead procurement expenses associated with these types of items, in terms of what types of expenses and what amount?

A I believe, in response to Interrogatory No. 89, staff's sixth set, I provided a table that summarizes the annual expected payment costs associated with each of the identified critical long-lead components. Costs are characterized by the process by which these components are produced. Initial payment is a forging reservation fee on actually buying anything

other than the right to manufacturing capability within a specific manufacturer's facility for a specific period of time and a specific set of components.

Q And then --

A Later on -- I'm sorry. Go ahead.

Q No, my apologies. Please continue.

A Later on, in the years 2010 and beyond, you see a stream of payments associated with essentially the costs as they are occurred by the manufacturer to purchase the material, to actually move the material into the foundry, start the forging processes, deliver the material to site, so that, you know, essentially the characteristics of these payments are a pay as you go for the production and delivery of the equipment.

Q Now, you've used the term forging. Can you give me kind of a layman's understanding of what a forging is? In other words, when you pay for forging, what do you get?

A A forging is a -- a forging is a specific metallurgical technique that is used to produce a specific size, shape component for a specific function out of a single piece of metal. In other words, you're buying a big block of metal and you're either machining or stamping or some other metallurgical forming process to form that block of metal into the appropriate size

and shape component.

The reason we do this is because it's a much stronger process to forge out of a single piece of metal than to have multiple welds that might present a weakness at some point in the life of that component.

Q Now, you referenced Staff Interrogatory No. 89, and I believe you mentioned the forging reservation fee. Referenced in 2008, that's shown to be 16 million; is that correct?

A That's correct.

Q And is the forging reservation fee the long-lead item which FPL expects to occur -- the only long-lead item FPL expects to incur in 2008 for Turkey Point 6 and 7?

A Not necessarily. That is a specific fee that we know will likely be required prior to the conclusion of the nuclear power plant cost recovery process of 2008. And as such, we wanted to identify that and communicate that.

Q And the forging reservation fee, is it correct that that's the advance payment necessary for preserving the manufacturing space for constructing all the forgings for Turkey Point Units 6 and 7?

A All the special forging of a certain size. There will be a number of smaller forgings that can be

Hearing Exhibit 000577

accomplished at a larger number of manufacturing facilities. These are of a specific size and shape that at present there is only one manufacturer in the world that is capable of producing these. That would be Japan Steel Works.

Q Okay. Can I refer you, please, to Staff Interrogatory No. 88 -- or rather FPL's response to Interrogatory No. 88.

A Yes.

Q And are you familiar with this response, or did you help prepare it?

A I prepared it.

Q Okay. Now, a portion of this response states that the long-lead procurement process requires FPL to initiate a series of payments ultimately resulting in the permanent specified components. That's kind of what we've been talking about, correct?

A Correct.

Q Okay. And how is the purchase of these components different than how FPL purchases the components from its nonnuclear plants that it's constructed in the past?

A In practice, there's really no difference in the manner of paying an advance payment, a series of advance payments to a vendor for equipment that needs to

Hearing Exhibit 000578

be delivered for a power plant. In the specific instance of this project, the lead time for these items, the construction schedule for nuclear identify a much longer time period between initiating the payments and receiving the finished product, just because of the specific nature of the components in question.

Q Is -- is that lag time peculiar to nuclear components or has FPL made advance payments for reserving manufacturing space or equipment for its combined cycle units or other types of plants?

MR. BUTLER: Jennifer?

MS. BRUBAKER: Yes?

MR. BUTLER: I don't understand your question. The first part of it was is that lag time special, but then the last part of it was really just, have we made advance payments. And are you asking whether the length of time is unique to the nuclear or is the overall concept of making advance payments unique to nuclear?

MS. BRUBAKER: I take your point, John. I'll be happy to break it into two questions.

BY MS. BRUBAKER:

Q The first question would be, is the lag time between making those payments and actually receiving the equipment, is that unique to nuclear?

A Specific number of years in this case happens to be specific to nuclear. The fact that there's a lag time is more a function of market availability, and there have been market situations in the past where FPL has made advance procurements or reservations on combustion turbines, steam generators to assure that we had access to those needed components to satisfy our requirements for power plant construction.

Q And with regard to the payments you've just described, could you describe which plants, which equipment, about when those payments were made, that sort of thing?

A I don't have any specific information available. I probably was not a -- or I was not an employee of FPL at that time. But -- and the period of time I'm specifically referring to is in the late '80s, early '90s, there was an -- industry focus shifted to natural gas-fired generation. There was a significant increase in the amount of capacity required in the nation, and there was quite a competition for combustion turbine and steam generator equipment to build combined cycle units, which were the preferred design of that period.

And I know that many companies, companies that I had worked for, had engaged either Westinghouse or

Hearing Exhibit 000580

General Electric in procurement deals that secured certain manufacturing space for combustion turbines so that their needs could be met in the long term.

Q In terms of a lag time between making advance payments and actually receiving the -- the element, would you say that the lag time would be comparative between nuclear plants and then coal or, you know, steam turbine, what have you, or was it longer for nuclear?

A It would be a fact -- it would be a function of the market's ability to supply the demand and the market availability of that manufacturing capability. It's kind of a hypothetical I would say, you know. These types of components have a specific manufacturing requirement. That manufacturing requirement is limited, and therefore in order to make sure that if you have a schedule to -- that requires a component by X date, you won't, you know, be prudent in taking action to secure that manufacturing capability to meet that schedule.

Q Okay. Thank you.

Again, directing your attention, please, to FPL's response to Interrogatory No. 88, if I could just have you read for the record that last sentence in that response.

A "At this time, the above critical items are the only long-lead procurement items which would require

a commitment in advance of completing the 2008 NPPCR rule process."

Q And do I understand correctly that this sentence appears to indicate that all the items in table 88-1 of that response require a commitment in advance of the 2008 nuclear power cost recovery process; is that correct?

A Well, let me restate it in a manner that I would be comfortable with and you can tell me if I've addressed your question.

Q Okay.

A Forging reservation is a reservation fee that's required to secure the manufacturing capability for each of these components, and that would be required prior to the completion of the NPPCR process in 2008. That reservation fee is not a purchase order or portion of the purchase of those physical items.

Q If I could direct your attention to FPL's response to Interrogatory No. 89, please.

MR. BUTLER: Sorry. Jennifer?

MS. BRUBAKER: Yes?

MR. BUTLER: In spite of the lengthy pause, Mr. Scroggs wasn't finished with his answer. I mean --

MS. BRUBAKER: I'm terribly sorry. Please

continue.

MR. BUTLER: Oh, no problem.

THE WITNESS: I just wanted to identify, the reservation fee we think is likely needed in 2008, that gives us an acute position. The purchase orders and the commitment associated with those purchase orders for the actual components wouldn't occur until the 2010 time period.

BY MS. BRUBAKER:

Q And just so I'm not stepping on your toes, that does complete your response?

A Yes.

Q Okay. The joys of telephonic depositions.

Referring next, please, to FPL's response to Interrogatory No. 89.

A Okay.

Q I'm looking at Table 89-1, and looking in the column 2010, the cumulative total shown there is $92 million. And can you just break down for me -- do I understand correctly 16 million of that goes to the forging reservation fee?

A Correct.

Q And what comprises the rest of that amount shown there? What do those amounts represent?

A As you can see in that table, under the column

identified as 2010, there's a component-by-component allocation of the 76 million annual estimate for 2010. The $6 million assigned to each reactor pressure vessel for Unit 1 and Unit 2, 16 million for the steam generator vessels for Unit 1, 16 million for the steam generator vessels for Unit 2, 16 million for forging associated with the coolant pumps for Unit 1, and 16 million associated with the forging for the coolant pumps for Unit 2.

MR. BUTLER: Jennifer?

MS. BRUBAKER: Yes?

MR. BUTLER: Let me interject here just for clarity of the record. Mr. Scroggs, when you're using the term Unit 1 and Unit 2 there, how does that relate to the terminology we use at Turkey Point Units 6 and 7?

A Unit 1 would be Turkey Point 6; Unit 2 would be Turkey Point 7.

MR. BUTLER: Thank you.

BY MS. BRUBAKER:

Q Mr. Scroggs, do you agree that in order to -- in order for FPL to meet the in-service dates of 2018 and 2020 for Turkey Point Units 6 and 7, that it will need to make a long-lead payment to reserve manufacturing space for these forgings that we've been

discussing?

A Best information we have available to date, it will be necessary.

Q Okay. At what point -- when did FPL become aware of the fact that it would need to make that kind of long-lead payment?

A I'm looking up one of my responses. I think I answered this. Staff's Eighth Set of Interrogatories, Interrogatory No. 112.

Q Yes.

A I generally answered this question. Our involvement in looking at new nuclear construction has been for quite some time as a member of the new start consortium and as an operator and interested party in the industry. And again, through our other engineering and construction activities, we know that market conditions from time to time may require advance payment and advance procurement activities to ensure that you have the necessary equipment to meet the schedule.

So the concept is not new, it's not unique to nuclear. In the specific case of Turkey Point 6 and 7, because we have not finalized a design selection and we have not entered into detailed negotiation with vendors on payment schedules, we did not have a precise or estimate of the amount and quantity and timing of these

long-lead payments until really late December, early January of this year.

Q Now, you reference the vendor, you identified them as a Japanese Steel Works, correct?

A Well, maybe I should clarify. The vendors -- the prime vendors we are working with are General Electric and Westinghouse. Those are the two designs we're considering. The prime vendor then turns to international suppliers for specific components and manufacturing capabilities. Westinghouse or General Electric would rely on Japan Steel Works to provide the heavy forgings necessary for the construction of either design.

Q I see. To your knowledge, is there any potential vendor or vendors other than Japan Steel Works for the forgings you've referenced?

A At this point in time there's no identified vendor with the same capability.

Q And is it correct that FPL is competing with other utilities or projects to essentially get in the queue for forgings from Japan Steel Works?

A That would be an accurate description.

Q Can you identify for me which utilities or projects?

A In general, heavy forging -- ultraheavy

Hearing Exhibit 000586

forgings of this size are not unique to just nuclear power generation. They're also used in oil and gas exploration, refineries, and other heavy industries. So it's not just FPL's Turkey Point 6 and 7 project competing with other nuclear projects. There's an entire international market that competes for this heavy forging capability.

That said, we're restricted to a host of nuclear projects. There's quite a few nuclear projects announced and underway in China, India, and other nations around the world. Specifically to the United States there are about 18 utilities that plan to submit COLAs, combined operating license applications, to the NRC within the same time frame, roughly within a year plus or minus of FPL's targeted submittal date.

So within the U.S., there's 18 projects. Some of those are single unit projects, some of those are multiple unit projects. What I do know of current actions by those projects is that there have been five entities who have made long-lead procurement payments.

Q What's the source of your knowledge regarding those projects and their relations with Japan Steel Works? Is that something that's publicly available, what projects are pending before Japan Steel Works?

A Well, the information -- certainly the terms

and all are very confidential. We don't have access to that. My specific information comes from a recent article in a magazine called Nuclear News. This is a publication of the American Nuclear Society that follows industry trends. This article identifies five specific -- it goes through a discussion of different projects in the United States, of these 18 projects that are pending, in terms of turning in applications and discusses the status as to whatever this journalist determined is the procurement status.

MS. BRUBAKER: Mr. Scroggs, and I guess also Mr. Butler, I'd be interested in obtaining a copy of that article as a late-filed exhibit. Any objections?

MR. BUTLER: No, we can provide it.

MS. BRUBAKER: Okay.

MS. BRUBAKER: And I'm afraid, Mr. Scroggs, I didn't quite get the title of the journal or the article down. Would you repeat it for me, please?

THE WITNESS: The magazine is called Nuclear News.

MR. BUTLER: Article title?

THE WITNESS: And the article titled, "Renaissance Now?"

MS. BRUBAKER: For the purposes of the

late-filed exhibit, I'll just call it Nuclear News article, "Renaissance Now?"

THE WITNESS: The January 2008 edition.

MS. BRUBAKER: And if we could add that to the title too, just so we're specific.

(Late-Filed Exhibit No. 1 was identified.)

BY MS. BRUBAKER:

Q Thank you, Mr. Scroggs. Is it correct that FPL is currently in negotiations with Japan Steel Works regarding the Turkey Point Units 6 and 7 projects?

A More accurately I would characterize it as FPL is in negotiation with the prime vendors, General Electric and Westinghouse, who on our behalf would be negotiating directly with Japan Steel Works.

Q Thank you for the clarification. Could you describe for me the status of those negotiations between those vendors and Japan Steel Works?

A I can only say that those vendors have identified that they have an ongoing relationship with Japan Steel Works for multiple projects that are in the planning stages and have open communications with Japan Steel Works regarding their manufacturing capability and the ability to secure that for our specific project.

Q And I think you've touched on this earlier, so just for the sake of making sure I'm clear, is it

correct that FPL must make its initial payment to Japan Steel Works in 2008 to secure the 2018, 2020 in-service dates?

A That's the best information we have right now.

Q And can you tell me when in 2008 that payment would be -- need to be made?

A Our current plan is that it would be in the June time frame.

Q Okay. And what's the basis -- what are the facts or circumstances that support that June 2008 is the time at which the payment would need to be made?

A We have targeted that time period as the time period where we would complete our final design selection. Once we would complete our final design selection, and pending an affirmative need determination, we would proceed with the necessary long-lead procurement steps to secure the earliest practical point of start which would require a reservation fee to the chosen vendor to secure those manufacturing slots.

Q Now, you referenced finalizing your design selection. Is it correct there are basically two design selections for Turkey Point Units 6 and 7 that are currently under consideration?

A Yes. We have narrowed the candidate list to

Hearing Exhibit 000590

two specific designs.

Q Could you just identify for the record briefly what those are?

A First design would be Westinghouse's AP 1000 model. That is an 1100-megawatt net capability pressurized water reactor. The second would be General Electric's ESBWR, which is Economic Simplified Boiling Water Reactor, capacity of approximately 1520 megawatts net, and it's a boiling water reactor design.

Q Okay. Now, you reference in your testimony, do you not, a number of steps that would lead to the design selection, and I believe you said that would be expected to be completed by about June 2008?

A That's correct.

Q Okay. Would you agree that the -- let me strike that. Let me start that again.

In your opinion, can FPL reserve -- make reserve payments on its forgings before the design selection is done, is completed?

A FPL can make a reservation fee in advance of completion of final design selection, but it would -- that reservation fee is through a specific vendor for a specific set of components. We don't have -- in my understanding, we don't have the capability of reserving a new spot without having it attached to a specific

design and a specific set of components.

Q Okay. So in other words, design selection would have to be finalized before advance payments could be made?

A Not a necessary step, but we feel it's a prudent step.

Q I -- I think I may have misunderstood your earlier answer then. Is it possible to make advance payments if you have not finalized your design selection?

A It is possible. They will accept money. But our -- in concept, it would be for a specific design. So, you know, if we chose -- if we made advance payments for a Westinghouse design but we chose in the final determination to go with the General Electric design, that payment wouldn't be valid for a General Electric design.

Q And in that case, would that delay the construction of those items, your place in the queue and so forth?

A Again, it's a market situation. Our best estimate is there are 18 projects in the U.S. alone that are potential -- and five of those -- five of which have made reservation fees, so there would be 13 of which in our situation that haven't. If -- you know, if

everybody ran to the bank and made their reservation fees right now, they could lock it up and preclude FPL from having capability for some time. If FPL gets in first, then we've secured our position. If we made a payment to Westinghouse and we chose to go with GE, we'd probably double the expected advance payment associated with those long-lead procurement items.

Q How would it double?

A You have to make one with each vendor.

Q Would those payments be refundable if you -- for instance, if you made one for each vendor, and you selected one vendor over the other, would the vendor with whom you are not going for your final selection, would that amount be refundable to FPL?

A Again, none of the terms of these agreements have been negotiated, but I would consider that a highly unlikely scenario.

Q Okay. So when you used the word prudent earlier, it would be prudent to select which design FPL will go with before making the advance payment? Is that what you're talking about, prudent in terms of cost, or prudent in terms of your place in the queue?

A Both. It's prudent -- it would be prudent for us to make a final design selection and then make one advance reservation fee payment for that selected

bidder. I do not foresee a problem coming to that conclusion by June of 2008.

Q Okay. Now, does FPL have any quotes or letters or documentation from Japan Steel Works which indicates that payment expenditures are needed beginning in June 2008 in order to maintain the employment schedule of 2018, 2020, or is --

A Again --

Q I'm sorry. Go ahead.

A Our discussions have been with the prime vendors, General Electric and Westinghouse. We have not had direct discussions with Japan Steel Works. They are a supplier to General Electric or Westinghouse. So, you know, we're not jumping over our prime vendor to talk directly with Japan Steel Works. We don't have the special knowledge and the relationships with Japan Steel Works to negotiate this type of thing directly, you know.

So our information has been provided to us by and through discussions with General Electric and Westinghouse, the contents of which has been communicated through my responses to Interrogatory 88 and 89 specifically.

Q Okay. With regard, for instance, to response to Interrogatory No. 89, you mentioned the forging

period for purchase orders for each of the specific components, as well as when those components would be installed.

In the case of Interrogatory 89, the same list of equipment, and then an estimated expenditure schedule for those components.

MS. BRUBAKER: Okay. Let me take just a minute off the record, please.

(Off the record.)

MS. BRUBAKER: Thank you, appreciate it. We're back on the record.

BY MS. BRUBAKER:

Q The information you've described for me, the information that basically is summarized in Interrogatories No. 88 and 89 as you've described, is that information based on documentation or is that information based on verbal discussions you've had?

A Based on documentation provided by Westinghouse.

Q Okay. Would it be possible as a -- and certainly to the extent it's confidential we'll need to discuss that, but would it be possible to have that documentation as a late-filed exhibit?

A Yes.

MR. BUTLER: It is, and let me go off the

record a moment to see whether we need to assert any confidentiality on that.

MS. BRUBAKER: Certainly. We'll go off the record.

(Off the record.)

MR. BUTLER: Documentation from Westinghouse supporting responses to Interrogatories 88 and 89?

MS. BRUBAKER: Yes. That would be Late-Filed Exhibit 2. And just for clarity of the record, I've asked that that information be provided. To the extent that it is under a claim of confidentiality, I've asked Mr. Butler to confer with me so we can just make sure it needs to be submitted or not.

MR. BUTLER: Okay.

MS. BRUBAKER: Okay.

(Late-Filed Exhibit No. 2 was marked for identification.)

BY MS. BRUBAKER:

Q All right. Mr. Scroggs, if I can please refer you to your testimony at page 29.

MR. BUTLER: I'm sorry, which page?

MS. BRUBAKER: Page 29.

MR. BUTLER: Okay.

Q And specifically I'm looking at the sentence

that begins on line 14 and ends on line 17. If you'd just take a moment to look at that, I'll go ahead and read it into the record if that's okay.

"Obtaining a commitment for manufacturing capability of ultraheavy forging for the reactor pressure vessels and other necessary items that would support the earliest practical deployment schedule is a long-lead procurement item FPL will pursue immediately."

Mr. Scroggs, in the context of that sentence, what do you mean by "immediately"?

A We're in negotiations with the vendors now, so that by the time we reach a final selection, we'll be in a position to understand the commercial terms and payment schedules surrounding being able to execute a manufacturing reservation.

Q Now, you're familiar, Mr. Scroggs, are you not, with the DEP site certification that would be needed for the approval of Turkey Point Units 6 and 7?

A Yes, I am.

Q Okay. Would FPL make a commitment -- sorry. Let me strike that. Let me go back.

Again, looking to your testimony, page 29, you talk about obtaining a commitment for manufacturing capability of ultraheavy forgings. Would FPL make that commitment prior to the completion of the DEP site

certification process, or is there necessarily any relevant tie between those two?

A We intend to file a site certification application concurrent with the combined operating license, in that same time frame, so that would put it, you know, towards the end of 2008, beginning of 2009. We certainly are aware of advice we're receiving from the vendors as to our manufacturing reservations should definitely be in advance of that, the June time frame. So the answer to your question would be yes.

Q All right. Still on page 29 of your testimony, if I could refer you, please, to lines 20 through 22. Actually the sentence there starts on line 19, but what I'm interested in is the phrase there on line 20: "However, these reservations may retain value for FPL and others and be potentially tradeable in the event that the project does not move forward."

Could you explain to me what's meant there?

A What we're doing is we're buying an option for manufacturing space in a certain time period to support a certain specific schedule. If FPL were to proceed and determine that either we would not proceed forward with the project or that we would proceed forward on a different schedule that did not fit those reservation fees, there would potentially be other buyers that would

Hearing Exhibit 000599

want to have -- make use of that manufacturing space that we had reserved, so that there would be an opportunity to sell that option to someone else to support their projects.

Q What information or documents do you rely on in support that these reservations would be tradeable? Is there a market or a clearinghouse, or -- or would that be by contract with these parties? Can you explain for me?

A In general terms, this is a fairly standard business practice. There is a valuable commodity to enter into option arrangements to secure the use of that commodity for a specific owner and that terms would be included in that that would allow that to potentially be assignable to someone else under specific terms.

Q Now, would GE or FPL make the trade, or GE or Westinghouse, just depending on who the vendor is?

A Well, you mean would either GE or a Westinghouse vendor make the trade or FPL would make the trade?

Q That's correct. Thanks for the clarification.

A The payment would give FPL rights to that option. Whether the negotiations would likely involve Westinghouse or GE, let's say they had another customer who is needing that queue space, or they had a series of

manufacturing projects that they could juggle around and utilize that queue space, Westinghouse may be the purchaser of the option back from FPL.

But, you know, in terms of the right to that option, that would be a right that FPL would have, and any assignment of that right and compensation for the assignment of that right would come through FPL.

Q Okay. Now, Mr. Scroggs, are you familiar generally with the nuclear cost recovery process that's contemplated under 25 -- excuse me, Rule 25-6.0423, Florida Administrative Code?

A Familiar with it? Yes.

Q Okay. And to your knowledge that's the rule under which FPL will seek recovery for Turkey Point Units 6 and 7 should the need be granted?

A Yes.

Q Okay. And under that process, when would you expect a determination to be made by the Commission regarding FPL's petition to recovery costs under that rule?

A My understanding is that the filing would culminate in a hearing sometime in the September or October time frame of 2008.

Q Okay. Hypothetically, if the Commission were to defer making a decision on the need for FPL to make

Hearing Exhibit 000601

the reservation commitments to defer that determination to the cost recovery proceeding rather than the need determination, in your opinion would FPL still pursue making those commitments with Japan Steel Works?

A I can't speak for the final business decision of FPL's executives, but I would recommend that they would.

Q Okay. And why is that?

A Because of my understanding of the market competition for these reservations and the critical need to have these components secured to support the earliest practical deployment schedule.

Q So it would not be a recommendation under that circumstance to delay making the advance payments?

A Again, from a project schedule risk position, I think it's very appropriate that those reservations be made.

MS. BRUBAKER: If I could just have a moment, please.

MR. BUTLER: Jennifer?

MS. BRUBAKER: Yes.

MR. BUTLER: I'd like to take a break before too long. Do you want -- since you're taking a moment here, do you want to go ahead and --

MS. BRUBAKER: Yes. I'm kind of crossing

through questions. Let's go ahead and do that. What's your preference, five, ten?

MR. BUTLER: I think five minutes is fine.

MS. BRUBAKER: All right. Thank you. We'll come back in five minutes.

MR. BUTLER: Okay. Very good.

(Break taken.)

MS. BRUBAKER: Okay. Thank you. I think we'll go back on the record if everyone is ready.

MR. BUTLER: We are.

MS. BRUBAKER: Thank you.

BY MS. BRUBAKER:

Q Mr. Scroggs, if I could please refer you to page 30 of your testimony.

A Okay.

Q And looking at lines 2 through 3, there's a sentence that reads: "Current estimates indicate that long-lead expenditures for ultraheavy forgings could be on the order of $100 million."

Is that correct?

A Correct.

Q Okay. I think you've touched on this earlier, so if you'll just indulge me. I'm trying to reconcile that with some numbers you mentioned earlier. You mentioned the $16 million that would be the 2008

expense, correct?

A Correct.

Q Okay. And what accounts for the rest of that estimate?

A Specifically, that was an estimate that we had at the time that we filed, and we have been somewhat pleasantly surprised to find out that it's not as dramatic as we might have thought.

Q If I could have you refer, please, to FPL's response to Interrogatory No. 89. And I'm looking at the column 2010, at a cumulative total of $92 million. Would you reconcile that number to the $100 million estimate discussed in your testimony?

A The two were independently developed and there is no commonality between the two. The -- our estimate provided by early discussions with GE and Westinghouse was that we might be looking at 50 million a year over both 2008 and 2009, in a series of payments that would total up to about $100 million. Now we have -- now we have more specific information as to how those payments might come about.

Q And can you briefly describe for me what that more specific information is?

A As detailed in my response to Interrogatory 89.

Q Okay. If I could refer you, please, to the FPL response to Staff Interrogatory No. 85.

A Okay.

Q And specifically page 5 of 29.

A Okay.

Q I'm looking at row 8, long-lead procurement advance payments, and then the columns C and D, projected 2008, project 2009 respectively, and each column for that row lists $50 million, correct?

A That's correct.

Q Okay. And I'm trying to understand that breakdown in relation to your testimony. Is that just the estimated breakdown of the $100 million that's discussed in your testimony?

A Correct.

Q Okay. And is that information -- has that information been updated or are those amounts still best estimates?

MR. BUTLER: Jennifer, are you noting note 2 on this page?

MS. BRUBAKER: Okay. I've seen note 2 says budgeted values. Is that what you're referring?

MR. BUTLER: Yeah, and it goes on to point out that there is, you know, discussions with vendors that identify approximately 16 million long-lead

procurement items. Now, I can tell you that note was added there, as sort of getting to the point that you were just raising, sort of the difference between the initial budgets and then this latest information that shows up in the Interrogatories 88 and 89.

BY MS. BRUBAKER:

Q Well, Mr. Scroggs, is it correct that that $100 million that's referenced there, does that include the reservation fee?

A $100 million was a high-level estimate over two years of reservation fees and/or advance payments that might be necessary to procure the identified components. At the present time, we've received a more specific estimate that I used in developing my response to Interrogatory 89 that identified a much smaller amount in 2008 and no amount necessary in 2009.

That said, I've also identified that that critical long-lead component listing may not be entirely inclusive. There may be, as we move along in negotiations, in the planning process identify certain things that because of market conditions or the number of suppliers available would be prudent for us to procure early.

The goal obviously is to have those identified

Hearing Exhibit 000606

in time for our May 1st cost recovery filing so that those -- those items can be identified and vetted through that cost recovery rule process.

MS. BRUBAKER: Let me take just a moment if I could.

(Off the record.)

BY MS. BRUBAKER:

Q Mr. Scroggs, if I could have you next, please, turn to page 34 of your testimony, and I'm looking at lines 3 through 8.

A Okay.

Q And I apologize, I had a little note to myself to ask you a question before I moved to that section. I'm doing my best to confuse you, I know.

Just real briefly, the $16 million reservation fee that we discussed earlier, can you tell me if that amount is identified or accounted for anywhere in Appendix H of the need study? Again, I apologize for switching gears on you very quickly for a second there.

A The development of Appendix H was obviously well in advance of us receiving the more detailed information that I've used to characterize the reservation. So, again, Appendix H was developed in advance of and without the knowledge of more specific estimates that I've provided.

Hearing Exhibit 000607

Q In your opinion, would it be appropriate to include that $16 million reservation fee in Appendix H at this point?

A I would -- you know, my understanding is that this Appendix H was based on the budgets that we had put together for the project, and as we discussed, the budget included $50 million in each 2008 and 2009 for the project, so at the present, you know, anything that's developed off that budget is probably a little higher than our expectation.

Q So at this point the actual amounts would be lower then? Than what's budgeted?

A Based on our current budget and our current estimate, our estimate is a lower amount of expenditures on past payments and long-lead procurements than we currently have budgeted.

Q Okay. Thank you. Now, if I could direct you back, please, to page 34 of your testimony, lines 3 through 8.

MR. BUTLER: Excuse me. I need to speak to him a second.

MS. BRUBAKER: Certainly.

(Off the record.)

MS. BRUBAKER: This is Jennifer. Just for clarification, are you still speaking off record or

are we ready to begin?

MR. BUTLER: We were still speaking off the record. What Mr. Scroggs is pointing out -- I think it's a point we ought to note -- is that -- remember that Appendix H is set up as an example, an illustrative example that has, you'll note in the upper left-hand corner, a little box, overnight costs in 2007 dollars per KW, and it's one dollar. We would love to be able to build it for that but are not expecting that we'll be able to.

So what's on Appendix H really isn't showing anything close to the sort of information that would get down to details like what's in the advance -- advance payments expectations.

MS. BRUBAKER: Well, I guess my question then is going to be, what is the document we should look at to get the best, most correct, current, available information?

MR. BUTLER: I would think the interrogatory responses --

MS. BRUBAKER: Okay.

MR. BUTLER: -- that we have been discussing. And, you know, as you had noted in the -- Interrogatory 85 has the budgeted amounts and, you know, they are, as we sit here today, based on the

information currently available, it looks like they have turned out to be conservative in the sense that they have more budgeted in there for the long-lead procurement than what, you know, what the best current information says we're expecting to have to incur in the 2008 time frame.

MS. BRUBAKER: Okay.

THE WITNESS: You know, just to expand on that, if you look at my exhibit, SDS-9 talks about expenditures by phase of the project. It talks about, for example -- well, let me know when you get there.

MS. BRUBAKER: We're there. Thank you.

THE WITNESS: If you look at the top categories, the exploratory phase and licensing phase, under the licensing phase category for the 2 x 1100 megawatt case A, there's a line that says "preconstruction costs," and it identifies them out of $155 million. Right?

That $150 million would be, if it includes two 50-million-dollar long-lead payments that are in our budget, our current expectation is that it will be significantly below that so that this number, 155 million in the licensing phase for case A, could be reasonably expected to be much less.

Hearing Exhibit 000610

MR. BUTLER: Is that all?

MS. BRUBAKER: I believe so. Thank you.

BY MS. BRUBAKER:

Q All right. Mr. Scroggs, page 34 of your testimony.

A Yes, ma'am.

Q And you discuss here that the Turkey Point Units 6 and 7 project will be subject to pervasive risk management, correct?

A Risk management will be pervasive through the project, yes.

Q Okay. And reviews will be conducted through regulatory oversight, internal management, risk control processes and what have you, correct?

A Correct.

Q What are the risk control processes you reference here that FPL will exercise to manage the risk --

MS. BRUBAKER: Yes? I'm sorry, did somebody speak up?

MR. BUTLER: Nobody did here. It sounds like we're getting a little bit of cross-talk from your end.

MS. BRUBAKER: Okay.

A I understand your question.

Q Okay.

A FPL has several different risk management processes, primarily the corporately managed process of a risk committee. Risk committee is an appointed panel of senior management from different parts of the company that are independently routinely reviewing the plans, status, and expenditures associated with any major capital project.

So in that sense, you essentially established an independent panel that objectively reviews the execution of its capital project and provides feedback to the project management team as to essentially a score card of how you're doing, things that you need to be looking at, making sure that there's an independent set of experts advising the project team on things they should be doing to manage risks associated with the project.

That's a -- that's a formal high-level risk committee. Within the engineering construction division business unit, there is a process by which the project management team develops a dashboard of indicators for the project. These indicators are related to economic schedule, licensing and other milestones, and those quantitative and qualitative measures are tracked to ensure that the project is proceeding on pace and on

schedule.

Q Now, these indicators you referenced, what's -- what are they based on? Are they based on an internal set of metrics, are they based on some industry-wide standards?

A I think this process, the process that FPL employs in capital project construction, is a fairly accepted project management tool and that, you know, it's something that you would find in any large capital project process, construction process throughout the United States and the western world.

So they're specific to the plans, scheduled budgets for the particular project and allow a high-level oversight and tracking of how the project is doing on multiple fronts. So there's many -- many indicators developed for each project based on specific issues with the project.

Q If I could, Mr. Scroggs, I'd like to refer you to a document I believe I asked your attorney to make available to you. It will probably have on the top of it, "Florida Power & Light Company response to FPSC Staff Data Request Set 1, Nuclear Power Plant Cost Recovery."

Do you have that document?

A Just a -- I'm looking at a -- yeah, the title

Hearing Exhibit 000613

is, "Florida Power & Light Company Response to FPSC Staff Data Request Set 1, Nuclear Power Plant Cost Recovery"?

Q Yes. And are you familiar with this document? Have you seen it before?

A Yes, I am.

Q Okay. And can you just tell me briefly what it was produced in response to?

A I believe following the cost recovery rulemaking, there were a number of interactions with PSC staff discussing framework issues associated with the filing requirements that would be specific to the rule.

Q Could I direct you, please, to section C of that response, and for purposes of the record, section C asks the question: "What steps does the utility plan to take to ensure that the costs incurred are prudent."

And could I have you read, please, the last sentence in that -- in FPL's response to section C?

A "Following award of agreements FPL would use industry standard project management processing to monitor costs against scope to ensure FPL receives what it contracted for and scope changes are properly evaluated for their merit."

Q And the project management processes that's described in this document, are those the same types

that you've talked about in order to manage the risks of the project?

A Yes.

Q Okay. I've also asked that your attorney provide to you a document, "Progress Energy Florida, FPSC Staff Data Request Set 1, Nuclear Cost Recovery." Do you have that before you?

A I do.

Q Have you ever seen this document before? Are you familiar with it?

A Yes, I am.

Q Okay. And to the best of your knowledge, is this a similar response that was -- is this a response prepared by Progress Energy Florida similar to the one that FPL provided in response to the rule development?

A I believe this responds to the same questions, yes, ma'am.

Q Okay. If I could please refer you to section C of that document. And I'm going to read just a few sentences very quickly for the record.

"PEF," P-E-F, Progress Energy Florida, "will utilize existing processes and controls throughout the phases of the project to ensure that decisions made and costs incurred are prudent. The nuclear construction organization's existing project management processes and

procedures are based on the guidelines established by the Project Management Body of Knowledge, American National Standard (ANSI/PMI, 99-001-2000). These processes have been effectively used to support the prudent implementation of other large scale projects at our nuclear plants."

Mr. Scroggs, the guidelines that are referenced there, Project Management Body of Knowledge, American National Standard, are you familiar with those guidelines?

A No, I'm not.

Q Okay.

A I'm familiar with their existence. I'm not familiar with the specific content of those standards.

Q Okay. To your knowledge, would those guidelines be used by FPL in managing the risks and costs of its project?

A FPL has extensive experience in construction cost management and process control. I don't know specifically if this is the standard that FPL's processes refer to, I would be surprised if it wasn't, but I would assume this standard or something equivalent has been the basis for our process management.

Q Turning my attention back again, please, to FPL's response to the staff data request, section C.

The first sentence, and I'll just summarize for the record -- or I'll just read it for clarity's sake.

"In cases where bidding is possible for scopes of work and/or materials, FPL would select suppliers with consideration given to the lowest cost of supply, recognizing that lowest cost of supply is not the sole criterion in the selection process. In cases where bidding is not possible, FPL would ensure through negotiations and benchmarking for similar scopes of supply that the agreement contracts reflect market costs."

To the best of your knowledge, that information is correct and applicable to the risk management for Turkey Point Units 6 and 7?

A That's correct.

Q Okay. We'll move on then. Mr. Scroggs, could I refer you, please, to your exhibit, prefiled Exhibit SDS-6.

A Okay.

Q And that's a document captioned, "Overnight cost estimate range." What does this exhibit capture? What does it show?

A The intent of this exhibit is to identify by major line item the costs and range of costs that comprise the total project cost.

Q Now, is it appropriate to use the overnight cost estimate range shown on this exhibit to determine the cost range to build Turkey Point Units 6 and 7?

A This is an estimate of the range that is the best information we have available today, yes.

Q Okay. Does this range, does this estimate in your opinion show -- sorry. Let me backtrack that question.

Are there any elements of total costs that are not included in the overnight costs shown on Exhibit SDS-6?

A Yes, there are two important elements of total costs that are not included in an overnight cost estimate. Those are the impact of cost escalation that occurs during the construction period. Overnight costs recognize or assume that you can purchase 100 percent of the equipment and materials and labor necessary for the project at one point in time.

In reality, those purchases will be spread out over a period of time for the design and construction of the project, and the prices in effect at that time will dictate what is actually paid. And we use the term escalation to represent what those costs might escalate to at the time at which they're purchase.

The second important cost that's not included

is cost of interest during construction.

Q And why were those elements not included in the overnight cost estimate range?

A The overnight cost estimate range is a tool that is used in generation planning to allow comparison of equivalent costs, and it takes a longer time to build a nuclear plant than it does a combined cycle plant, so you want to be able to compare them on a more equivalent basis. So the overnight cost range is a tool by which you can compare cost-effectiveness of one technology to another.

Q Okay. Now, in your opinion, does Exhibit SDS-6 provide the best estimate of the cost range to build Turkey Point 6 and 7?

MR. BUTLER: Best estimate for what purpose?

MS. BRUBAKER: Just in terms of -- I guess I don't understand your question.

MR. BUTLER: Well, I mean, Mr. Scroggs described the -- sort of the limitations on it, and that is something that's used to compare cost-effectiveness of one technology to another, and, you know, is that the purpose, when you say it's the best estimate available it's for that purpose or for evaluating revenue requirements over a period of time or, you know, what purpose are you

referring to?

MS. BRUBAKER: If you would, let me just take moment to confer, please. Off the record.

(Off the record.)

BY MS. BRUBAKER:

Q Okay. Thanks. We're back on the record.

Does SDS-6 provide the best estimate in terms of determining the revenue requirement?

A SDS-6 would be incomplete to determine the revenue requirements because it doesn't include an estimate of escalation for interest that would be costs that would be -- that would affect the revenue requirements.

Q Okay. So in terms of looking at the revenue requirements, what would be the best analysis that's been provided by FPL in this proceeding? What should we look at?

A Well, in my exhibits, SDS-8 provides the project total cost estimate range, including an estimate of escalation and interest during construction. I believe that's the information that was used by witness Sim in developing the economic comparison.

Q Mr. Scroggs, could I have you turn to SDS-7.

A Yes.

Q And what do the two pages of this exhibit,

Hearing Exhibit 000620

what do they demonstrate; what are they meant to show?

A This is an illustration of the relative economics of the cost estimate range that FPL has provided for new nuclear, and the results of the system analysis that resource planning conducted for combined cycle, natural gas facility, and integrated gasification combined cycle facility under various fuel and emission market scenarios.

Q Is it fair to categorize nuclear as being a capital intensive project?

A That is correct.

Q Okay. And if you were to compare nuclear to combined cycle or an IGCC plant, is nuclear more capital-intensive, at least initially?

A Nuclear is -- has a higher initial capital cost and much lower operational costs.

Q Okay. And essentially, when you're looking at the cumulative cost of building and operating a plant, you look at the cost of -- I'm sorry.

MS. BRUBAKER: Would you read back his answer for me just real briefly?

(Requested portion read by reporter.)

Q Mr. Scroggs, when you look at the cumulative cost for a plant, you have to consider both the capital and the operational costs, correct?

A Correct.

Q Okay. And in terms of looking at the cumulative cost of building and operating a plant with nuclear, at some point -- initially it has a higher cost, and at some point does the cumulative cost of building nuclear cost less than plans with, say, combined cycle or an IGCC?

MR. BUTLER: Jennifer, I'm going to observe that that's really in Dr. Sim's area of testimony. To the extent that Mr. Scroggs can address it, I'm certainly going to allow him to do so. But when you get into the sort of looking at the cumulative present value of revenue requirements of the different scenarios, that's what the Sim testimony covers.

A I mean, I can answer your question in general. What SDS-7 shows is, for a combined cycle plant under different scenarios, what would be the breakeven overnight capital costs of a nuclear plant and be economically equivalent. Okay?

So therefore if you have a nuclear plant that is characterized in cost by high initial capital outlay followed by low and stable operational costs, versus a combined cycle facility that has low initial capital outlay and increasing and volatile operational costs out

in time, there would logically be a point at which the overall costs or cumulative costs for nuclear would become equivalent with the cost experienced with a combined cycle facility and from that point forward the costs for nuclear would be less than a similar combined cycle facility.

Q Based on the information that's contained in your Exhibit SDS-7, when would that breakeven point be?

A SDS-7 does not address the crossover point for this. This is a tool that we developed to show all the costs associated with nuclear versus all the costs associated with combined cycle, and bring them back to this one 2007 overnight cost tool that we used to compare them, and show that -- let's take a specific case.

For the case identified as Medium 3, that would be a medium fuel price forecast in the third level emissions price forecast. You have a number that's identified as $5,327 per KW. So that -- what that says is, for a nuclear plant to be economically equivalent with the life cycle cost of a combined cycle plant of the same size, you could spend up to 5,237 -- or $5,327 per KW on the capital cost of the nuclear plant and have it be economically equivalent.

Q So the breakeven that's discussed in your

testimony and exhibits is really more of a financial nature rather than a breakeven in terms of time?

A It's a -- yes, it's a present value representation, form of representation of the overall life cycle cost difference.

Q Okay. Thank you. If I could refer you next, please, Mr. Scroggs, to FPL's response to Interrogatory No. 34.

A Okay.

Q And are you familiar with this response, or did you author it?

A I'm familiar with it. I authored portions of it.

Q Okay. Just a few quick questions for the sake of clarification. In your response -- in this response rather, it states that the preparation phase costs are estimated to range from 163 million to 523 million, correct?

A Correct.

Q Okay. And it also mentions that of the 523 million, 473 million is composed of in-site selection and preconstruction costs, and 50 million in construction costs, correct?

A Correct.

Q And again, just for clarification, does the

Hearing Exhibit 000624

preparation phase cost of 523 million include long-lead items?

A Yes.

Q I'm sorry. We didn't quite get that on the phone.

A Yes.

Q Thank you. Could you provide the estimated cost of those long-lead items?

A The -- this interrogatory was prepared based on the budget for the project as we have discussed, which identified 50 million in 2008 and 50 million in 2009. So it would be using an estimate that is higher than our current expectation based off the estimate that we've provided in response to Interrogatory No. 89.

Q Okay. So again, 89 is the most current, best information available in the docket that's been filed?

A Yes. It's the most current and best information available on those specific critical long-lead components. Recognize that there are and will be additional long-lead items. At this point we don't see very significant amount of those expenditures in 2008 and 2009.

But, you know, again, until we prepare our filing for cost recovery and go through the negotiations necessary to get to that filing, I won't -- we won't be

able to determine specifically what additional long-lead items might be identified in that filing.

Q Okay. Thank you. In your testimony, Mr. Scroggs, you reference a study that was conducted by the Tennessee Valley Authority. Do you recall that discussion?

A Yes.

Q Okay. And I've asked that your attorney have available to you the -- I'm not really sure how to caption this, the Tennessee Valley Authority study. It's TVA ABWR. Do you have that study before you?

A I do.

Q And for clarity, that should have a date of August 2005 on the cover page.

A I have it.

Q Could I ask you, please, to turn to page 1-6 of that study?

A Okay.

Q In looking at the last sentence on that page, it indicates, does it not, that the study was based on twin units with a one-year lag of commercial operation, correct?

A Correct.

Q Okay. Now, am I correct your exhibits appear to project a two-year lag between construction and

Hearing Exhibit 000626

commercial operation of Turkey Point Units 6 and 7; is that correct?

A Correct.

Q Okay. And why did you model a two-year lag versus a one-year lag?

A Current information from both vendors that we are talking with, General Electric and Westinghouse, indicate anywhere between a 12- to 24-month period is optimal for the logistical considerations and planning considerations around construction. I chose to proceed with a plan for a 24-month lag period.

Q Now, given that the study is modeled on a one-year lag time and FPL's filing is based on a two-year lag time, how was this difference captured in FPL's modifications to the TVA study?

A Well, what FPL used the TVA study for was primarily refining the cost estimate, power island specific scope of supply. So in SDS Exhibit 6, the costs included under power plant island and supporting construction would be those items intended or based on the TVA study.

Site-specific items unique to Turkey Point, owners' costs that are outside of the power plant island supporting construction cost range were developed independently using FPL's knowledge and experience of

Hearing Exhibit 000627

construction in Florida.

MS. BRUBAKER: I'm sorry, did somebody speak?

MR. BUTLER: Nobody here.

MS. BRUBAKER: Okay. Thank you. We're just getting a weird ghost on our phone, I think.

MR. BUTLER: We are too. We heard the same thing. How you doing? Good.

Didn't come from here.

BY MS. BRUBAKER:

Q I'm sorry. Mr. Scroggs, did you complete your answer?

A (No response.)

Q Mr. Scroggs, did that complete your answer?

A Yes, it did.

Q Thank you. Appreciate it.

If I could refer you next to page 4.2-33 of the TVA study.

A Give me that reference again to make sure I'm looking at the right page.

Q Certainly. It's 4.2-33.

A Okay.

Q And you'll see a table there, a construction lag cost evaluation result. Are we literally on the same page?

A We are.

Q Okay. And do you see the first sentence underneath the table which reads, "It is concluded that the one-year lag construction schedule is more cost-effective than the two-year lag construction schedule"?

A I see that.

Q And FPL, for Turkey Point Units 6 and 7, it has a two-year lag construction schedule; is that correct?

A Correct.

Q Okay. Now, in light of the statement here on the TVA study, do you agree that a one-year lag construction schedule is more cost-effective than a two-year lag construction schedule?

A No, I don't. To be able to make such a statement, I think it would only apply to one specific project in one specific area being conducted by one team of design and architect, construction. That is the conclusion that the TVA study came to.

In our discussions with Westinghouse and General Electric, and recognizing the potential for differences between the TVA's Bellefonte site and FPL's Turkey Point site, we felt that it was more reasonable to assume a two-year construction lag period, and to the extent that as the planning for the project proceeds,

Hearing Exhibit 000629

and refinements could be made to that, those refinements would be made as appropriate with the best information at the time.

Q Thank you. Mr. Scroggs, are you generally familiar with the fact that a service hearing was held last week in Miami in this docket in which the Commission took public comment on FPL's need petition?

A I am.

Q Okay. And there were a number of comments at the service hearing regarding water issues associated with the Turkey Point 6 and 7 project. Are you -- were you present for those discussions; are you generally familiar with them?

A I was present.

Q Okay. And at the time FPL indicated that it would address -- provide some additional information regarding those water issues. Has FPL done so?

A FPL has.

Q And what documentation has been provided?

A Report titled "Summary of Water Issues." That was conveyed to staff, I believe, yesterday morning.

Q Okay. And you either personally prepared or reviewed that document, correct?

A Correct.

Q Okay.

MS. BRUBAKER: Mr. Butler, your preference. I could either offer it -- ask that it be filed as a late-filed exhibit, or do you want to introduce it as an exhibit here? What's your preference?

MR. BUTLER: Well, if you have any questions you'd like to ask Mr. Scroggs about it, you know, we had provided it to you so you would be able to do so. We could make it an exhibit to the deposition at this point. Otherwise, if you don't, then we can certainly just do it as a late-filed exhibit.

MS. BRUBAKER: I think we'll go ahead and have it identified if that's all right then. Late-Filed Exhibit No. 3, I believe it would be.

MR. BUTLER: It's actually going to just be Exhibit 3, I think.

MS. BRUBAKER: Oh, you're right. You're right. Thank you. Thank you, John. "Summary of Water Issues" by Steven D. Scroggs.

(Exhibit No. 3 was marked for identification.)

BY MS. BRUBAKER:

Q And I assume, Mr. Scroggs, you do have a copy of that paper in front of you and available to you?

A Yes, I do.

Q Okay. In general terms, can you explain the

water requirements for the Turkey Point site for the proposed units? Specifically what I'm thinking of is the uses of water at the site, the volumes that are required for each use, and the water sources for each use. And I'll be happy to break that down if you need me to.

A Well, let me take a stab at it.

Q Okay.

A Three primary sources of water consumption at the site. The first would be potable water requirements through just sanitary health requirements for the employees at the site. Those would be purchased through Miami-Dade water and sewer, managed as any other potable water source. Very minor. Maybe something on the order of 20,000-gallons-per-day consumption.

The second water source would be water source that we described as processed water. Processed water is water that would be refined and highly treated so that it could be utilized in the steam generation cycle of the power plant. The requirements for that generally provided by the city as potable water as the base input, and then we would use additional equipment and clarifiers and filters and ion beds to -- to clean it up to the standards that we would need. The amounts of use for that are estimated at 200,000 gallons per day.

Hearing Exhibit 000632

The third and largest consumptive use or need for water is that used for processed cooling. Processed cooling water for these 1100-megawatt units that we're considering are on the order of, you know, we've bracketed it between 30 to 45 million gallons per day per unit, so a range between 60 and 90 million gallons per day for the two-unit project.

Coolant water is water that would be used in this particular design in a cooling tower. Cooling tower provides water flow over the processed water used in the plant to remove the heat. The heat is largely removed through the evaporation of the cooling water, similar to the technology that FPL employs in many of its plants, including the most current, the Turkey Point 5.

Q Mr. Scroggs, could I refer you, please, to your Exhibit SDS-2, and specifically 9 of 174. I'll give you a minute to pull that.

A Okay.

Q Now, Exhibit SDS-2 is a site collection study report, correct, where you compare and evaluate the various pros and cons of different sites for the Turkey Point -- or for the two nuclear units?

A That's correct.

Q Okay. And each potential site was assigned a

rating of 1 to 5, with 1 being less suitable, 5 being most suitable, for each of the screening criteria, correct?

A Correct.

Q And there are also weight factors given to the relative importance of these criteria, 1 being least important, 10 being most important, correct?

A Yes.

Q Okay. Now, I note on page 9 of 174 of your exhibit that cooling water supply was listed as a criterion that was given a weight factor of 9.5.

A Correct.

Q And am I correct, this criterion is weighted more heavily than the others that are listed there?

A That's correct.

Q And why is that?

A Cooling water supply is a necessary component of steam-based power generation.

Q Now, turning the page to pages 10 and 11 of your exhibit, there are four categories of metrics listed there, correct, flow, flexibility, risk, and regulatory challenge?

A You said 10 and 11, and I'm trying to make sure I'm looking at the right place.

Q Oh, I'm sorry. It's Exhibit SDS-2, page 10 of

174 and page 11 of 174. Sorry for the confusion.

A I was getting myself crossed up on the lettering -- the numbering for the actual document, not the exhibit number. I'm sorry. I'm on the same page.

Q My apologies.

And you see the flow, flexibility, risk, regulatory challenge and whatnot that I referenced there, the metrics?

A Sure.

Q Okay. And turning you next, please, to pages 35 through 37 of 174.

A Yep.

Q And this shows those metrics for cooling water supply, correct?

A It does.

Q Okay. On page 37 of 174, I'm looking at the column, Turkey Point. For cooling water supply in terms of flow, that was given a 5. That's the highest weight available, correct?

A The highest score, or rating.

Q Score?

A Yes.

Q Okay. What does that mean? I note there's -- in estimated flow there's a word "unlimited." What does that mean exactly?

A Specifically talking about an ocean intake. The -- if an ocean intake was selected and approved, then there would essentially be no limit to the amount of flow that could be utilized for cooling water.

Q Okay. And why is there no limit?

A Ocean's thick. The body of water that you're drawing from and your ability or your impact to that body of water would be negligible.

Q Now, again, on page 37 of 174, for the criteria of risk, the rating given to Turkey Point was a 4 rather than a 5, correct?

A Correct.

Q Can you explain why Turkey Point did not receive a rating of 5?

A Let me give you a little background. This is a rating that's done by a group of experts in the area of which I was just one person involved. So, you know, this represents an aggregate consensus rating by many people with many different backgrounds. Specifically, I would say the reason that it did not receive a 5, a 5 might imply that there is little or no risk in obtaining the approvals for the water sources identified.

So recognize that that's not a statement that should be made, I just rate at 4, realizing that the number of alternative water sources available at

Hearing Exhibit 000636

Turkey Point lead us to believe that there's a high likelihood of being able to identify a suitable water supply from one of several potential sources.

Q Now, would you agree that it's important to have a backup source of cooling water to the primary source for the Turkey Point site?

A As a practical matter of operations, it's advisable and desirable to have a backup source, as we have designed into the West County 1 and 2 process that uses a combination of Floridan aquifer and surface water as a potential alternate source.

With respect to the safety of the reactor and the design, I point out that the paths of design that we are considering, both in the General Electric and Westinghouse designs, are independent of the cooling water used for process operation. In other words, they aren't dependent on cooling water supply or the backup of a complete water supply. They're independent and apart from that.

Q If I could have you refer, please, to your paper, "Summary of Water Issues."

A Okay.

Q And if I could have you turn to the second page, please.

A Yes.

Q The last paragraph on that page, there's a sentence, "Currently there are five sources under active consideration as described in Table 1, below."

What sources are referred to there?

A In Table 1, you see I've identified five sources and locations. Reclaimed water provided by the Miami-Dade County water treatment system; ground water from the lower Floridan aquifer; ground water from the boulder zone, which is below and geographically separated from the Floridan aquifer; marine water taken from the surface through a remnant canal intake system that's being considered, and marine source that would be taken subsurface through a system identified as a rainy well system.

Q Now, each of the sources that are listed there in Table 1, there will be permits or approvals necessary to secure that water, correct?

A That's correct.

Q Okay. And can you briefly describe which entities those approvals would need to be secured from?

A The approvals will be a part of two licensing processes, one which is the state site certification process, and the other would be the NRC combined licensing process. The specific entities involved will be dependent on the sources selected.

Hearing Exhibit 000638

Ground water and reclaimed water would -- in the state is largely -- is the purview and jurisdiction of the water management district, who is responsible -- the responsible entity for those approvals.

If the marine source was identified, then the approval of the Army Corps of Engineers, U.S. Fish and Wildlife Service and other federal agencies would be involved.

Q Now, of the sources that are listed here, do you have any opinion at this time as to which source or sources would be more likely to be approved for the proposed units?

A That would be difficult for me to speculate without detailed engineering and investigation activity that we are undertaking now to characterize these sources, which would be more acceptable. There is a strong desire on our part to fully investigate reclaimed water as the source. We think that helps to solve a number of problems for Miami-Dade County. It represents a good environmental stewardship approach that FPL is in the forefront of all of our activities.

So if there -- you know, be it a preference or a desire, we would like to see reclaimed water. But again, the full investigation and characterization would have to be complete for me to speculate on the

regulator's approval of the source.

Q Do you have any idea at what point that investigation will be completed?

A The characterization of the water supply is necessary for both the state and federal license applications. Our current schedule is targeted to provide those applications to their respective entities in spring of 2009.

Q Now, if I could direct you back, please, to your Exhibit SDS-2. Again, page 37 of 174.

A Okay.

Q And for the criteria "regulatory challenge" to cooling water supply, the rating given to Turkey Point was a 4 rather than a 5. And again, could you just explain for me in your understanding why it was given a rating of 4 versus 5?

A Again, because there are difference -- multiple alternatives identified, each of which we feel is -- has precedent and would be reasonable and within the guidelines that the water management district and other entities use to make these rulings.

MS. BRUBAKER: Okay. I'm -- looks like I've got another maybe ten or 15 minutes of questioning. Shall we just soldier on?

MR. BUTLER: Yeah. Why don't we do that and

then we'll see what we need to do regarding breaks at the end of that.

MS. BRUBAKER: Okay. Very good.

MR. BUTLER: Is that okay with you?

MS. BRUBAKER: Sounds good.

BY MS. BRUBAKER:

Q Mr. Scroggs, if I could turn you back, please, to your "Summary of Water Issues" paper, specifically page 5.

MR. BUTLER: By the way, something you're doing points out a glitch with this that we will correct, which is providing a version that has page numbers on it. I'll provide that to the court reporter. Sorry about that.

MS. BRUBAKER: No, that's fine. Thank you.

MS. BROWNLESS: John, if you could provide that to the rest of the parties, that would be lovely too.

MR. BUTLER: We will.

MS. BRUBAKER: And I apologize for that. I should have distributed it last night, but did not get to it.

MS. BROWNLESS: That's cool.

BY MS. BRUBAKER:

Q Okay. So page 5, and there at the very bottom

of the page, you're referencing your Exhibit SDS-6, correct?

A Correct.

Q And you indicate that your exhibit includes capital costs for water supply in the amount of 250 to $350 million, correct?

A Correct.

Q And this cost estimate was incorporated in the evaluation of Turkey Point Units 6 and 7 as a generation alternative; is that correct?

A Correct.

Q Okay. Is it correct that the estimated capital cost associated with reclaimed water supply for the proposed units is estimated by FPL to be within a reasonable range of the estimated cost of 250 and $350 million?

A Yes, correct.

Q Okay. And that includes the wastewater system, infrastructure and delivery system to the plant; is that also correct?

A That is not correct.

Q Okay. Can you tell me why those amounts are not included in that number?

A One, we were looking at -- we looked at different water sources have different cost

characteristics, much as nuclear and combined cycle technologies have different cost characteristics. Some are more capital-intensive up front, others have -- with lower operating costs. Others are lower in terms of capital-intensive nature up front with higher operating costs.

Reclaimed water, we would look to purchase finished reclaimed water from Miami-Dade County, so we would enter into a water supply agreement that would pay for finished quality of water that could be used in cooling. That finished quality of water, as our initial discussions with the water and sewer department indicate, would be high-level disinfected water which would be very -- you know, a good moderate quality and require no or little treatment on site so it would have no long-term operating costs to FPL. Low operating costs.

MS. BRUBAKER: Let me take just a moment if I may, please.

(Off the record.)

THE WITNESS: If you would allow me to expand on that, maybe I can answer some more questions.

BY MS. BRUBAKER:

Q Certainly. Please do.

A So, as I described, there's capital costs up

front and operating costs for any water source that we would include. The source that we envisioned when we developed the cost estimate was a source that was similar to that which we have experience with, well-based ground water brought to the surface via a series and combination of supply wells treated to be usable and then used in a cooling tower, and there's a small waste stream that would be deep well injected. It's similar to the experience at Turkey Point 5 and with West County 1 and 2.

That gives us, as I identified, on the order of 250 to $300 million of that cost estimate is represented for those costs. That would be from supply through treatment through the cooling towers and the deep well injection system. So, stem to stern. So that was used as the basis.

Now, what that does is when we look at these other water sources that have different cost structures, that is a good approximation, but it may not be used in that same way. It may not be used as capital cost of 250 to 300 million up front with a series of operational treatment costs that happened during operations. It may be very low up front costs or lower up front costs and that pool of money that would have -- you know, in our estimate is identified as capital up front would be

equivalently spread out over time and be a resource or a pool of money that could be used to compensate for potentially increased operational costs.

Specifically talking about reclaimed water, there would be in our mind, our understanding of most of these agreements and water supply agreement with the water and sewer department for Miami-Dade County, for which they would provide a certain flow to the project at some rate, and that rate would be paid over the operational period of the project. That rate would be a financial commitment through this long-term water supply agreement that the county could use as a funding source to amortize or to fund the necessary infrastructure to provide that water supply.

And, you know, our estimate is not specific to every water source that we're considering, but we feel it is sufficient and comprehensive for whatever costs any of these sources would present to us.

Q Now, in terms of the capital costs associated with the reclaim system, have those been summarized or provided in any of the filings in this docket to this point?

A No, they have not because they have not been developed.

Q Okay. Looking at page 3 of your "Summary Of

Water Issues" paper.

A Yes.

Q You reference reclaim systems used at Palo Verde Nuclear Generating Station, and I believe also energy sites in Rhode Island and Texas, correct?

A Correct.

Q Do you know, in your opinion, would these be reasonable proxies in terms of capital costs for whatever reclaim system might be used in this proceeding? In other words, would the capital costs be comparable in your opinion to the costs that might be used in this proceeding, for Turkey Point Units 6 and 7?

A The costs would be generally indicative of the types of costs. However, I'm not familiar specifically with the specific design features. Palo Verde, for example, uses a large reservoir that the finished water is delivered to and that that reservoir is used as the source for the plant.

So, you know, in that the reclaim design for FPL's potential use of reclaim for Miami-Dade has not been completed, it would be difficult to say that one is truly representative of the other.

Q I'd refer you, please, to page 6 of the paper.

A Okay.

Q And you indicate there at the top of the paper

that "operational costs are included within the fixed operation and maintenance cost estimate utilized in the comparative economic analysis."

Next sentence reads: "This estimate is consistent with FPL's design for the West County Energy Center 1 and 2 project."

Is that correct?

A That's correct.

Q Okay.

A And when I said -- that last sentence talks about "this estimate is consistent," that speaks to the entire paragraph of 250- to 300-million-dollar capital costs and the fixed O&M cost.

Q Okay. So just so I'm clear, what is the fixed operation and maintenance cost estimate for water supply used in FPL's comparative economic analysis of the nuclear generation alternative?

A FPL provided an estimate of 120-dollar-per-kilowatt year for all fixed O&M costs associated with 1100-megawatt unit design. I believe that was in response to Interrogatory No. 18. Is that the one we discussed earlier? That total figure is inclusive of costs associated with water and would be representative of a fairly small amount of fixed O&M costs that would be needed for water and water

treatment.

Q Now, with the five different sources -- water sources that are discussed in your paper on page 3, I believe you made a reference as to the relative quality of those water sources; is that correct?

A That's correct.

Q And could you just describe briefly for me what you mean by "quality" in that context?

A Quality refers to the chemical constituency of the water, particularly in the mineral content and other content, you know, how dirty, how saline-latent, how many other constituents are in the water, because that affects the treatment and design -- actually, the treatment that you have to impart on the water in order for it to be usable, and it also affects the thermal efficiency of that water source in removing heat.

A lower quality water source would require more treatment and be less efficient than a higher quality source. And by efficiency, I mean in order to remove the same amount of heat, you would have to have more lower quality water than higher quality water.

Q When you state that the operation estimates -- operation costs estimated for this project are consistent with West County 1 and 2, would that still be the case if you used a lower quality of water?

A In fact, West County 1 and 2 uses Floridan aquifer water that does have a fair amount of saline content in it, chloride content, and there's a fairly good portion of the cost of the system at West County 1 and 2 is for treatment of that water before it's able to be used in the plant.

Q Just so I'm clear, would you say that the costs are comparable on a per gallon of water basis or is there some difference that might take place depending on the quality of the water used?

A That's a compound question.

Q I'll --

A I didn't understand it.

Q Let me see if I can rephrase.

MS. BRUBAKER: Just one moment, please.

Q We'll move on. Just a few more questions, Mr. Scroggs, if you would, please. I'm going to ask you just a few questions that were basically punted to you, I think, in the course of prior depositions this week. To the extent you can address them, I'd please ask that you do so, and if you can't, please just let me know who would be the more appropriate person to ask those questions.

Mr. Kosky's deposition took place earlier this week. In his direct testimony -- do you have his

testimony before you, before I get too far ahead of myself?

A I do not have a copy of his testimony with me. I'm sure we can get one.

MR. BUTLER: We have one for him.

MS. BRUBAKER: Can I trouble you to pull that, please?

MR. BUTLER: Sure. No problem. What page?

Q Looking particularly at his page 8 of his testimony, lines 6 through 12 once you're there.

A Okay. I'm looking at it.

Q Okay. And Mr. Kosky identifies there four types of major requirements for the environmental parameter for Turkey Point Units 6 and 7, correct?

A Correct.

Q Okay. Has to your knowledge FPL assessed the equipment and costs associated with complying with each of those requirements?

A The equipment and costs will be a part of the design engineering that is occurring as the applications are being developed and the detailed site-specific designs are being completed.

Now, we have, you know, some working estimates that, you know, I can talk through, but I don't have the benefit of a detailed formal design process.

Q Okay. Well, to the extent you're able, could you address or identify the equipment and costs of complying with each of these major environmental requirements?

A Minimizing impacts to the wetlands and providing compensatory wetland mitigation is a cost that would be determined through the environmental assessments associated with the plant and the plant's impact. The state of Florida has a uniform methodology for -- uniform mitigation assessment methodology, it's UMAM, that is used to score wetlands that are impacted and provide through that score a representative cost or a mitigation value.

So that's a pretty prescribed process. FPL would develop that through its application process, agencies and interested parties would have a chance to review that and provide their opinions as to the accuracy of that scoring, and that would be done in the review process for the site certification application.

In developing the cost estimate, we obviously identified not by line item but by contingency the amounts of costs that might be associated with wetland mitigation.

Permitting adverse impacts to fish and wildlife is a similar process of delineation of critical

habitat, and direct impact to threatened or endangered species has a similar rigorous evaluation process, similar to wetlands mitigation. There would be a scoring process and a suggestion of what mitigation, if any, is required to address impacts to threatened or endangered species or threatened and endangered species habitat, likewise and included in our cost estimate of the contingency.

The use of lowest quality water and minimizing impacts to surface and ground waters is specifically considered, and as I've described, our estimate is based on our experience in using Floridan aquifer water and dealing with the quality issues presented by that water. So, you know, it's specifically addressed in our estimate.

Installing control technologies to minimize air emissions is a cost that is associated with every power generation project, but it would be particularly minor in costs associated with nuclear. It would be a portion of the design of the cooling tower system. Again, not a regulated emission, but certainly in order to address concerns of any visible emissions from the facility through the cooling tower system. Obviously that is explicitly considered in our cost estimate.

Q Now -- and I'm sorry, did that complete your

answer?

A Yes, it did.

Q Okay. Do I understand correctly that currently you are in an evaluation and scoring process with regard to these, or do you have actual estimates at this point?

A We are in the process of the -- developing the applications. The content of those applications will be a detailed scoring and estimate based on -- and it's kind of an iterative process. The design specifics affect the impact, and then you calculate the impact as the design has not been specifically enumerated yet. There's some, you know, work necessary on the design to determine then what goes into the other portions of the equation.

Q So the cost estimates, these line item contingencies you're talking about, are they currently reflect in your filing?

A They're reflected in SDS-6 and the title, "Allowance for Cost Risk," those three categories.

Q Just so I'm clear, could you identify which line? Is it just "Allowance for Cost Risk," or are these amounts also reflected in other items?

A Well, again, we didn't break out only water-specific costs in this cost estimate. So, you

know, there are some line items that are specifically in this scope, such as cooling towers. There are other items that a portion of which will be associated with water, such as site work, additional required scope in the upper area.

For each of the three major categories of costs, power plant island, owner's cost, and additional project related costs, there is a line item identified as "Allowance for Cost Risk."

Q And does this include other types of risk besides those specifically identified with those environmental issues?

A Yes, it does.

Q And can you tell me what those are?

A Cost variation associated with material requirements or additional costs that might result to the project as a result of delays or project schedule change.

Q And anywhere in your exhibits or in FPL's filings, do you have those costs more specifically broken out?

A We do not.

Q Okay. That's fine. We'll move on.

Just a few more questions. Are you generally familiar with the generation alternative cost analyses

that appear in witness Sim's direct testimony?

A I'm generally familiar with it, yes.

Q Do you know whether the cost of complying with environmental requirements are included in Dr. Sim's generation cost alternative cost analyses?

A Yes, they are.

MS. BRUBAKER: And I thank you. That's all I have.

MR. BUTLER: Do any of the other parties have questions they want to ask of Mr. Scroggs?

MR. BECK: John, this is Charlie. I will have none.

MR. BUTLER: Okay. Thank you, Charlie.

MS. KAUFMAN: This is Vicki. I have a few.

MR. BUTLER: How much do you think you have? I'm trying to get an assessment.

MS. KAUFMAN: Yeah, I understand. Not much. Ten minutes maybe.

MR. BUTLER: Anyone else?

MR. YOUNG: This is Roy. Assuming Vicki doesn't ask what I would want to ask, I'd want to ask one or two questions.

MR. BRYANT: Hey, John, this is Fred, and I'm in the same situation.

MR. BUTLER: Okay.

Hearing Exhibit 000655

MR. KRASOWSKI: And this is Bob Krasowski. I have two questions as well.

MS. BROWNLESS: And, John, I will be in the same spot as all the other intervenors.

MR. BUTLER: I'm sorry, is that Suzanne?

MS. BROWNLESS: Yes, sir.

MR. BUTLER: Okay. Well, why don't we do this then. Let's take a short break, and then if you all are being more accurate than we lawyers usually are with our time estimates, I'm thinking that we can probably conclude this by 1:00 or thereabouts. If it turns out that's not true, then I think what we're going to end up wanting to do is to take a lunch break at some point.

But let's take a short break and then just hopefully see if we can move through pretty quickly and just get a complete -- get it wrapped up.

MS. KAUFMAN: Yeah, that would be my preference.

MR. BUTLER: Okay.

MS. BRUBAKER: John, five minutes?

MR. BUTLER: So we'll come back at 20 till. Okay. Very good. Thanks.

(Break taken.)

CROSS-EXAMINATION

Hearing Exhibit 000656

BY MS. KAUFMAN:

Q Good afternoon, Mr. Scroggs. I'm Vicki Kaufman and I'm appearing on behalf of Seminole Electric. And I just -- I just have a few questions for you. And the first one has to do with your testimony at page 64, beginning at line 20. Just let me know when you're ready.

A I'm there.

Q Okay. And on that page and going on over to page 65, you talk about the fact that Florida Power & Light has had discussions with other Florida utilities regarding co-ownership participation in the project, correct?

A That's correct.

Q Do you discuss anywhere else in your testimony other than these couple sentences your discussions with other utilities?

A No other location in my testimony, but I do have a response to Staff's Fifth Set of Interrogatories, Interrogatory No. 75, that speaks to the same subject.

Q Right. And we're going to talk about that in a moment. But in your testimony, your -- this is the only place where you talk about the potential co-ownership issue, correct?

A Correct.

Q Okay. Now, in that passage that we're looking at, you say you discussed this co-ownership issue with other utilities who expressed an interest, correct?

A That's correct.

Q And you have discussed it with Orlando Utilities Commission -- not you; we'll get to that in a moment. FPL has discussed it with Orlando Utilities Commission and the Florida Municipal Power Agency; is that correct?

A Correct.

Q Has FPL to your knowledge discussed co-ownership with any other utility?

A No.

Q Okay. Now, the discussions -- you were not a participant in the discussions, were you?

A Yes, I was.

Q Oh, you were. You participated in the discussions with Orlando Utility Commission?

A I did.

Q And with FMPA?

A I did.

Q Okay. Let's take those one at a time. As to OUC, who else was present on behalf of Florida Power & Light?

A No one else.

Hearing Exhibit 000658

Q Just you and an OUC representative?
A There were several OUC representatives.
Q Okay. But you were the only FPL representative?
A Correct.
Q And is the same the case with the FMPA discussions?
A Is not correct.
Q Okay. Who else was present on behalf of FPL?
A Mike Leighton, chief development officer for Florida Power & Light, and David Hicks, senior project director for project development.
Q Okay. And as to the FMPA discussions, was there one discussion or more than one?
A Multiple discussions.
Q How many; do you know?
A Approximately four meetings.
Q Were these face-to-face meetings?
A Yes, they were.
Q Okay. And how about with OUC, how many discussions?
A Two face-to-face meetings, a couple of phone calls.
Q Okay. And why is it that you engaged in these discussions with FMPA and with OUC?

A They specifically expressed an interest, asked us to discuss it with them, so we did.

Q Did you think that engaging in those discussions was important or relevant to the project we're discussing in this case?

A We have ownership relationships with those utilities in our St. Lucie 2 project, so we have an ongoing relationship with those utilities and felt that it would be responsive to their request to bring them up-to-date on our project plans.

Q Did you think it was important to do that in the context of this proceeding?

MR. BUTLER: Sorry, in the context of this proceeding?

Q Of the determination of need proceeding?

MR. BUTLER: Are you asking him a legal conclusion?

MS. KAUFMAN: No, I'm asking his opinion as the only witness that discusses this issue. I'm not asking for a legal conclusion.

A I felt it was important to talk to our current partners about potential future partnership.

Q And why was it important to talk about potential future partnership with OUC and FMPA?

A Their expression of interest.

Q So because they expressed interest, you thought it was important to talk to them; is that -- did I understand that correctly?

A Yes. It's important -- it was important to talk to them and it was important to understand -- for them to understand where the project stood.

Q Mr. Scroggs, I had asked Mr. Butler to have two documents available for you at your deposition today.

MS. KAUFMAN: Mr. Butler, do you have those two documents available for Mr. Scroggs?

MR. BUTLER: Yes, we do. You're talking about the two letters, right?

MS. KAUFMAN: Yes.

BY MS. KAUFMAN:

Q Mr. Scroggs, do you have in front of you an October 26, 2007 letter from Seminole, and then your response?

A Yes, I have them.

Q Okay. I apologize for not being up-to-date on where we are with the numbering, but I'd like to have these marked as an exhibit. It can be a composite exhibit.

MR. BUTLER: I think it would be 4.

MS. KAUFMAN: Okay. If it's all right with

everyone, let's just call it Seminole correspondence.

MR. BUTLER: Fine.

(Exhibit No. 4 was marked for identification.)

BY MS. KAUFMAN:

Q Okay. Mr. Scroggs, taking a look at the first letter, I assume that you're familiar with Mr. Woodbury's letter of October 26, correct?

A I am.

Q Okay. And as I understand it, Mr. Litchfield referred the letter to you to respond, correct?

A That's correct.

Q Okay. Do you know whether anyone else at Florida Power & Light was made aware of Mr. Woodbury's correspondence?

A You would have to direct that question to Mr. Litchfield.

Q Okay. So you don't -- you don't know one way or the other?

A I do not have specific knowledge of who knew about the letter. I was directed by Mr. Litchfield to respond.

Q Did anybody give you any direction in regard to your response, or did you draft it on your own?

MR. BUTLER: I'm sorry, could you repeat your

question?

Q Yes. Mr. Scroggs, did anybody give you any direction regarding how to respond to Mr. Woodbury, or did you draft that letter on your own?

A I drafted the letter and I shared it with Mr. Litchfield, if he felt it was appropriate.

Q Did Mr. Litchfield direct you to make any changes to your draft?

A Not that I recall.

Q Okay. Now, Mr. Woodbury, would you agree with me, in this letter expresses interest in participation in the project?

A Yes.

Q And you responded to Mr. Woodbury on November 8, correct? That's the second letter in this series; is that right?

A Correct.

Q And even though Mr. Woodbury expressed interest in talking to Florida Power & Light, would you agree that Florida Power & Light declined to talk to him about the project?

A I think in the context of my response, we essentially covered the same territory that I covered in person with the Florida Municipal Power Agency and Orlando Utilities Commission; so I thought that, you

know, in responding to Mr. Woodbury, I was providing him the same -- similar level of information that was essentially conveyed to the other utilities.

Q Well, would you agree that Mr. Woodbury in his October 26 correspondence to which you responded was interested in discussing co-ownership with you, and you responded that you -- you -- I don't want to put words in your mouth, the letter will speak for itself, but that at this point in time, you were not interested, or FPL was not interested in discussing that with Seminole?

A I wouldn't characterize it as a lack of interest. I think we're fairly explicit in our response that it would be premature to have any substantive conversation about this. And it's similar to what we communicated to FMPA and OUC.

The project status at this time doesn't contain a level of specificity that would support a decision-making process or inputs into the discussion of an ownership agreement. So at this point in time, it's just not ripe for discussion.

Q I understand. You would agree with me though that as of the date you wrote this letter, you were not willing to have any substantive discussions with Seminole about the project?

MR. BUTLER: I object to the form of the

question. You can answer it though.

Q You can answer it.

A I wouldn't characterize it as unwilling or disinterested.

Q How --

A We indicated --

Q You did not talk to Seminole in --

MR. BUTLER: Ms. Kaufman, he was still answering.

Q I'm sorry. I didn't mean to interrupt you. Go ahead.

A I was just saying that I think the characterization is not accurate and that the letter speaks for itself as to the status of our ability to engage in any substantive dialogue at this time, and, you know, it doesn't say that we're not willing. We certainly are willing, but it's just not -- we don't feel that it's productive at this time and would serve the purposes of either party beyond sharing the status of the project and our -- and our reasons for not joining in more detailed discussions based on not having more details to discuss.

Q Just so we're clear and then I'll move on, Mr. Scroggs, as a result of the correspondence between you and Mr. Woodbury, Florida Power & Light did not then

and has not up to this time today engaged in any substantive discussions with Seminole Electric, correct? About co-ownership?

A I can only speak to my involvement. I have not. I felt my letter communicated the situation fairly and appropriately.

Q Are you aware if anyone else at Florida Power & Light has engaged in such discussions with Seminole?

A I am not aware of any other discussions.

Q Take a look at that interrogatory that you referred to, which is Interrogatory No. 75, and let me know when you have that in front of you.

A I have it.

Q Okay. And I particularly want to refer your attention to Part D of the interrogatory.

MR. BUTLER: B as in bravo?

Q D as in dog.

MR. BUTLER: Okay.

Q Sorry. And this is a staff interrogatory, and the question in Part D like dog asked you to identify or discuss other alternatives to ownership participation FPL has considered that might reduce FPL's cost of building and operating Turkey Point 6 and 7. And just to quote in part, you -- FPL's response, it says: "At this point FPL has not identified alternatives to joint

ownership participation that would be appropriate for spreading the cost of building and operating Turkey Point 6 and 7 with other entities."

Does FPL recognize the alternative of joint ownership as one way to spread the cost of building and operating the unit?

A I think, as my response continues, and say, of course, any alternative, including joint ownership participation that's spread the cost of the project to others is likely also to reduce FPL's share of the benefits. So FPL would have to consider carefully whether any particular form of cost spreading would be in the ultimate best interest of FPL and its customers.

Q Would you agree with me that certainly co-ownership could result in spreading the cost of owning and operating the plant?

A Could result in that, yes.

Q To your knowledge, Mr. Scroggs, has anybody at FPL done any sort of analysis as to whether and how co-ownership would affect the cost of owning and operating the plant for FPL's retail ratepayers?

A To my knowledge, nobody has engaged in that analysis.

Q Has anybody engaged in any analysis to your knowledge at FPL in regard to how, let's say, building

Hearing Exhibit 000667

three units and engaging in co-ownership might result in perhaps a benefit for the retail ratepayers?

MR. BUTLER: I'm going to object to this question. I don't see how it connects to the issues that have been identified in the prehearing conference for resolution in this docket.

MS. KAUFMAN: Mr. Butler, I think it goes to the cost-effectiveness of the project.

MR. BUTLER: No, it doesn't. It goes to the cost-effectiveness of some hypothetical alternative to the project.

MS. KAUFMAN: Right. It goes to whether this is the most cost-effective alternative.

MR. BUTLER: Which I don't think is one of the standards that one uses in determining the need for a nuclear power plant under the relevant statute. But I will let him answer that question to the extent he can, but this is really getting off base.

BY MS. KAUFMAN:

Q Do you need me to repeat it, Mr. Scroggs?

A If you would, please.

Q Okay. I will try. I believe I asked you whether you or anybody at Florida Power & Light as an alternative to the proposed project considered the option of perhaps building three nuclear units and

Hearing Exhibit 000668

engaging in a co-ownership arrangement with interested utilities?

A In looking at the project alternatives, we did look at multiple number of units of different sizes, and we came to the conclusion that a two-unit site offered the most economies of scale, the most efficient use, and that a third unit wouldn't necessarily offer the same economies of scale of a combined operating license valid for up to two units. So a third unit would actually have been the part of a second license application, duplicating a lot of efforts and exposing the project to certain issues.

So optimally, two-unit projects, and in our discussions with vendors, their business models are set up to provide optimal economics around two units, so that's generally the driver for arriving at a two-unit project.

Q When was this analysis of more than two units performed?

A Early stages of the development project -- process.

Q And did that analysis factor in the co-ownership of the unit?

A Co-ownership of the unit would be a separate issue. It was not considered as a part of whether a

Hearing Exhibit 000669

third unit would be cost-effective versus a two-unit project.

Q All right. Just so I'm clear, let me just be sure I understood what you just said, you did consider more than two units but in doing that analysis, the issue or factor of co-ownership was not considered; is that correct?

A That's correct. Our responsibility is to plan for the needs of our customers, and in doing our project development and generation planning, we look at the needs of our customers and what's best for our customers.

Q Do you also consider what would be the most cost-effective for your customers?

A Yes, which is the driver for the analysis I just described.

MS. KAUFMAN: Thank you, Mr. Scroggs. That's all I have.

MR. BUTLER: Does anyone other than Mr. Krasowski have any further questions on this ownership issue?

MS. BROWNLESS: I have a few questions. Fred, do you want to go ahead?

MR. BRYANT: No, you go ahead, Suzanne -- this is Fred Bryant -- and I'll follow up.

MS. BROWNLESS: Thank you.

CROSS-EXAMINATION

BY MS. BROWNLESS:

Q Mr. Scroggs, I'm Suzanne Brownless here appearing on behalf of JEA, and I'd just like to follow up on some of the items raised by Ms. Kaufman.

Has anyone other than OUC, FMPA, and Seminole Electric requested any meetings regarding co-ownership?

A No.

Q I'm sorry. I can't hear you.

A No.

Q Okay. Do you have any other utilities who currently own portions of your existing generating facilities?

A You mean other than OUC or FMPA?

Q Yes, sir.

A Is that directed to the nuclear facilities or any facility?

Q Any generating facility, sir.

A I'm aware that there are co-ownership arrangements with St. Johns River. I think there are other entities that are a part of the St. Lucie 2 co-ownership that are generally represented by FMPA.

Q Okay.

A But the specifics of which I do not know or do

not have at hand.

Q The St. Johns River Power Park co-ownership agreement is with JEA, is it not?

A I believe so.

Q Okay. Doesn't Florida Power & Light also own part of Scherer Unit 4 with JEA?

A I believe that's correct.

Q Okay. Have you initiated any conversations with JEA as a current co-owner on other projects regarding co-ownership of Turkey Units 6 and 7?

A No.

Q Generally speaking -- I'm sorry, do you --

A I just want to make sure you heard my response.

Q Yes, sir. Thank you.

Generally speaking, do the existing co-ownership agreements that JEA has with FP&L require JEA to contribute to both capital costs and operating costs, both fixed and variable?

A I don't know the cost sharing structure of those arrangements.

Q Okay. Assume for purposes of this question that is, in fact, correct, would that -- would such a co-ownership agreement with those general terms and conditions reduce the revenue requirements necessary to

support this plant for FP&L's customers?

MR. BUTLER: I'm going to object to the question, Suzanne. I mean, what you're doing is posing hypotheticals regarding agreements that Mr. Scroggs clearly doesn't have any information on. We're not presenting him as an expert on co-ownership agreements, and I think that the notion of hypothetical questions to a witness who is reporting here on simply the facts of the joint ownership discussions that have occurred is beyond the proper scope of examination.

MS. BROWNLESS: Well, your objection is noted, but the question remains.

BY MS. BROWNLESS:

Q So please answer it, Mr. Scroggs.

A Can you restate the question, please?

Q Sure. If you have a co-ownership agreement in which the co-owner contributes to the capital cost of the unit and to the variable and fixed O&M costs of the unit, does that result in a lower revenue requirement for FP&L associated with those units?

A The effect in overall lowering, if that would be the case, is completely dependent on the percentage of involvement, the terms of the involvement, the aggregate financing costs that would result, so it would

Hearing Exhibit 000673

be very difficult to predict any reduction in revenue requirements. It would, however, be easy to predict that it would be a reduction in benefits to FPL customers.

Q And why would it be a reduction in benefits?

A The benefits to the FPL customers that have been identified through our economic analysis would be diluted amongst a larger pool of owners. Therefore, the magnitude of benefits would be reduced.

Q Would it reduce FP&L's cost per kilowatt hour projected for this project?

A I'm not able to make a judgment on that.

Q What type of data would you need to make such a judgment?

A I have to have a negotiated and agreed-upon set of terms and an understanding of the impact of those terms to the operational costs, the financing for the project, and the risk structures going forward for the project.

Q Okay. So as a general hypothesis, co-ownership in which capital costs are reduced and fixed and variable O&M costs are reduced do not result in a benefit to FP&L?

A You're presupposing that the result of such a co-ownership would be a reduction. I don't know that.

Hearing Exhibit 000674

Q Well, assume it is, Mr. Scroggs. I can't believe FP&L would negotiate a co-ownership agreement in which capital costs and variable O&M costs associated with co-ownership were not borne by the utility receiving the benefit of the electricity.

MR. BUTLER: I would object to the comments as argumentative. I'm going to object again to the line of these questions as unconnected to any issue that has been allowed in the proceeding. I further object that you are working hard to make something out of a hypothetical that isn't defined, that Mr. Scroggs is not familiar with, and that is not in an area he's been identified as an expert.

MS. BROWNLESS: Well, Mr. Scroggs --

MR. BUTLER: I'll allow him to answer an additional question. Beyond that, you know, I think we've really been pretty tolerant here. You haven't noticed the deposition, and I think this is getting a bit over the top.

MS. BROWNLESS: We'll quit. Thank you, Mr. Scroggs.

THE WITNESS: Thank you.

MR. BRYANT: Suzanne, are you through?

MS. BROWNLESS: Yes, sir. That's it for me, Fred.

MR. BRYANT: Oh, okay. I'm sorry. Is it appropriate for me to go next?

CROSS-EXAMINATION

BY MR. BRYANT:

Q Mr. Scroggs, this is Fred Bryant. I'm general counsel for the Florida Municipal Power Agency. How are you today?

A Fine, sir.

Q Hopefully I'll be very brief. I suspect, if you're as hungry as I am, we will get through this pretty quickly.

Sir, you had previously testified that you were present in discussions with certain people from the Florida Municipal Power Agency as to possible joint ownership in these two units. Would you identify the best you can who those individuals were?

A Rick Casey was the principal representative for FMPA, and he was joined by another gentleman whose name escapes me right now.

Q And it was those two and only two with the discussions that you held with FMPA people?

A Yes, sir.

Q Approximately what time frame; can you remember?

A I believe early in '07 we met with Mr. Casey

and his colleague, and then had maybe two or three more meetings over the course of 2007, culminating in roughly the August time frame.

Q Were all of those meetings in your office, sir, or in Florida Power & Light's facilities?

A Some -- I think maybe one or two were in Florida Power & Light facilities and one or two were in FMPA facilities in Orlando.

Q To the best of your ability, can you summarize what those discussions -- you know, the gist of those discussions?

A Specifically, I described the status of the project, a general schedule for moving forward with the project, and some of the challenges we saw in being able to have any substantive discussions on joint ownership at this point in time because of the really early formative nature of the project and that we didn't have the necessary information, cost-specific schedules, commitment schedules, structure of how these contract agreements with vendors and equipment providers would be structured, the things -- the elements that would be necessary for us to have a reasonable conversation with a potential joint owner.

Q Would you characterize those discussions as amicable?

Hearing Exhibit 000677

A Yes, I would.

Q To the best of your recollection, when was the last discussion that you have had with people from FMPA?

MR. BUTLER: I'll object as asked and answered, but I will let him remind you of the answer. Go ahead.

A Actually, the last meeting we had I believe was in the July-August time frame of 2007. I did have a phone conversation with Mr. Casey prior to our need filing, indicating that we would be identifying that we had discussions with certain utilities in my direct testimony.

Q Yes. And I'm sorry. That was really what I was referring to when I said discussions. Sir, are you aware of discussions other than yourself of FPL officials with FMPA officials?

A On the topic of joint ownership of Turkey Point 6 and 7, I am not. No, sir, I am not.

Q Did you make, in preparation for your answer or for the statement in the petition of need attributed to you and the testimony you filed in the petition for need in this case and the answer to the interrogatories that you answered in relation to this issue, did you make any inquiry as to whether or not there were discussions by others with -- officials from FMPA?

A I did not. As the project director for the project, I kind of assumed I would be aware of any substantive conversation on this subject.

Q Therefore, you're not aware of an exchange of e-mails between Mr. Olivera and Mr. Fontes, who is CEO of FMPA, and of course Armando Olivera is the CEO of FPL; is that correct?

A That's correct, I'm not aware of that.

Q Have you reviewed or been furnished copies subsequent to your answers, or subsequent to your testimony and answers to interrogatories of a series of e-mails between Mr. Olivera and Mr. Fontes?

A Not to my recollection.

Q If --

MR. BRYANT: John, I don't know if you have a copy of those e-mails with you today. They're short. I'm just going read it to him. I'm not going to ask that they be introduced at this point in time.

MR. BUTLER: Why don't you just do that. I think that will be quicker and shorter.

Q Okay. It's very short, and if everyone will bear with me, and I'm going to read it and trust everyone will trust me as to the accuracy of what I read.

October 27, 2006, 9:43 a.m. Is an e-mail from Mr. Olivera to Mr. Fontes, copies to Michael Leighton.

Is that how you would pronounce that name, sir?

A Leighton.

Q Leighton? All right. Copy to Michael Leighton. Subject: Nuclear. And this is from Mr. Olivera. "We would like to have some very preliminary discussions with your folks about our thoughts on new nuclear and any possible ownership interest by FMPA. If you are still interested, would you like me to know who is the right contact in your organization? Thanks."

The next e-mail from Mr. Fontes to Mr. Olivera, copied to Michael Leighton and Rick Casey, who you've previously identified as employed by FMPA, dated 10/30/2006. Subject: Nuclear. "Armando, very good to hear from you. Yes, we would be interested in beginning discussions on such a joint project development opportunity. Generation rediversification is an important strategic goal of our integrated resource plan. Moreover, the St. Lucie plant has performed well and FPL has done a good job of managing that nuclear facility. Please contact Rick Casey at 321," et cetera, and that's a phone number. "What time

frame are you considering for these discussions?"

I'll stop there to ask you a question about this e-mail. And would you suspect that this October 30th, 2006 e-mail where Mr. Fontes responds to Mr. Olivera and suggests that Mr. Olivera contact Rick Casey, that your contact with Rick Casey was a result of this e-mail? Did you initiate that contact with Rick Casey?

A Yes, I --

MR. BUTLER: Mr. Bryant, you made a couple of references to -- it sounds like you're saying 2006. Are you saying that these e-mails are from 2006?

MR. BRYANT: Yes. Well, John, I can't testify they're from 2006. The copy of the e-mail, which is dated in the e-mail, it says 10/30/2006, yes.

MR. BUTLER: Okay.

A Yeah, I think that the direction -- Michael Leighton is my boss, and I was directed to contact Rick Casey and talk about discussions.

Q Yeah. Wasn't a trick question. We're just trying to sort of trace down the chain of events and tie in the time frames we've been talking about.

A No, I thought -- I misunderstood that you were describing e-mails from 2007. So if the e-mails are from 2006, they make sense that those are the e-mails

that initiated our conversation.

MR. BUTLER: My apologies, Fred. Somehow something you said, and it may have been just me misunderstanding it, I thought you initially were talking something from 2007, and then it switched over to 2006. Just want to be sure what year you were talking about.

MR. BRYANT: Okay, good. Thanks, John.

BY MR. BRYANT:

Q And then the last one that I'm going to read to you is October 30th, 2006 from Armando to Roger Fontes, saying: "We'd like to initiate the discussions now so you know our thinking and the options we are looking at. Also helpful to understand your thinking and what you are looking for, because ultimately that could also affect our decision (size, location, et cetera). We have not made a final decision to build a plant. I want to make sure that we preserve the option as the next generation to be built after the Glades coal project. Mike is in a position to explain to you our concerns, i.e., permitting and ultimate nuclear spent fuel disposal, et cetera."

I'm assuming Mike here means Mike Leighton again. Would that be a fair assumption? I'm not asking you to testify to that, but would that be a fair

assumption?

A It would be logical.

Q Yes, sir. Sir, would you characterize these exchange of e-mails as discussions between Mr. Olivera and Mr. Fontes?

A Seems like they were exchanges that initiated a more detailed discussion.

Q Certainly. And in the broad realm we find ourselves in e-mail and the methodology we now use for communication, it would not offend you if I characterized these exchange of e-mails as discussions then?

A I think that would be a fair characterization.

Q And you had previously, in response to my questions, indicated that you were unaware of this set of e-mails in these discussions; is that correct?

A Yeah. I don't know what precipitates my boss telling me to go do something. I just go do it.

Q Yes, I understand. And thus would you agree that the statement in your -- in the need petition attributed to you as to summary of discussions and the testimony that you prefiled in this need proceeding as to discussion is not necessarily complete absent referring to these discussions? Is that a fair statement?

A I think they're a complete and fair characterization of the discussions held.

Q And had you known then what you know now, would you have included these discussions in summary form or any other form as a part of your statement of discussions and answers to interrogatories?

A No.

Q Let me make sure I understand the answer to that question. You would not have included these discussions in your summary of discussions in your testimony that you prefiled?

A Not specific and separate recalled out. I think all discussions are included in the way I've characterized the exchanges that we've had.

Q Would you characterize then you have a different understanding of summary of discussions than others might have? I'm not just -- I'm not coloring that statement, just that you felt like your summary was complete?

A I feel my summary of discussions is complete. From your description, there was an initiating set of exchanged e-mails that precipitated these discussions that I was involved in.

Q Are you aware of any in-person discussions between Mr. Fontes and Mr. Olivera?

Hearing Exhibit 000684

A I am not.

Q Are you aware of a letter dated December 14, 2007, from Mr. Olivera to Mr. Fontes, Mr. Ken Ksionek at OUC, Mr. Barry Moline at FMEA, Florida Municipal Electric Association, and Mr. Tim Woodbury at Seminole Electric Cooperative?

A I do recall a letter that was sent out to multiple parties on the topic of joint ownership from Armando Olivera, yes. I do not have a copy of that in front of me.

Q Yes, sir. And your counsel --

MR. BRYANT: John, do you have a copy of that letter with you?

MR. BUTLER: I don't off the -- we may be able to find a copy.

Q Let me just quickly read it. Gentlemen -- and it's styled, Re: Turkey Point Units 6 and 7 Need Determination Proceedings, Florida Public Service Commission. "In view of the recent petitions to intervene in FPL's need determination docket" --

MR. BUTLER: I'll tell you what, Fred, if you want to ask questions about that, since it's somewhat more involved than the e-mails were, let's just take a break, we'll go get Mr. Scroggs a copy of the letter.

MR. BRYANT: Yeah. Will it take very long for you to do that? If it's going to be any inconvenience, just let me know, John.

MR. BUTLER: No. It'll just take a couple of minutes. I think I've got a place where I can get to it quickly. All right.

MR. BRYANT: Do you want me to continue, John, while you're getting a copy, or did John go out of the room?

THE WITNESS: John's left the room. He'll be back shortly and we'll let you know when he's back.

MR. BRYANT: Okay. I won't burden you with me continuing until he gets back.

THE WITNESS: Appreciate it. Thank you.

(Off the record.)

BY MR. BRYANT:

Q Sir, do you think it would be fair to characterize this letter as continuance of the discussions that we've been talking about?

A Certainly seems like it.

Q So next week -- week after, when we go to hearing in Tallahassee and you're asked to testify about discussions between FPL and other electric utilities -- particularly Florida Municipal Power Agency -- and give a summary of those discussions, would you envision that

your prefiled testimony would be modified to make it up-to-date by including this exchange of e-mails and this latest letter that you just looked at as part of the discussions that FPL has had with other utilities?

MR. BUTLER: I think that's for his lawyers to decide, Mr. Bryant. If you want to ask him about it in examination, I'm sure you'll have a chance to do so.

Q Do you still believe, Mr. Scroggs, that your summary is complete as filed in your prefiled testimony, as you have testified to here today?

A I believe my summary satisfies the requirements for the need petition.

Q Is that a legal conclusion or a factual conclusion on your part as the one who has prepared this summary?

A Factual conclusion on my part. I'm not a legal expert.

Q All right. Good. Bear with me just for a moment.

You have previously testified that FMPA is a co-owner of the St. Lucie project, is that -- your St. Lucie 2 nuclear project; is that correct?

A My understanding, yes.

Q And you previously were answering some

questions, I believe, from Ms. Brownless about whether or not you considered potential joint ownership as possibly being beneficial to FPL. Do you remember that exchange of questions and answers?

A I recall the exchange.

Q Are you aware that in the St. Lucie 2 ownership between Florida Municipal Power Agency and FMPA there is a reliability and expectation change agreement; it's called a reliability exchange agreement?

A I'm aware of other ancillary agreements surrounding joint ownership, in general.

Q Are you -- do you believe it's a fair characterization on my part to describe the reliability exchange agreement as an agreement between Florida Power & Light and FMPA, where FMPA receives 50 percent of its ownership entitlement out of St. Lucie 2 and the other 50 percent of its ownership entitlement out of St. Lucie 2 out of the St. Lucie 1 nuclear plant?

MR. BUTLER: I'm going to object to the question. If you -- Mr. Scroggs has already indicated he's only generally familiar with these agreements. If you have questions of that level of detail, you certainly need to show him the document.

MR. BRYANT: Well, I'm seeing if he's aware of

Hearing Exhibit 000688

it, John.

MR. BUTLER: He already indicated that he is only generally aware of the agreement surrounding the St. Lucie 2 participation. And if you have questions for him about it, you ought to have made arrangements to provide a document to him.

MR. BRYANT: Bear with me, John. Let him answer, and if he's unaware of it, then we'll go from there.

A I'm not aware of the details.

Q Okay. Would you agree that it would be -- that based upon the -- let me start over.

Would you believe that it would be a good agreement with FPL to have an agreement where, in a co-ownership, joint ownership situation, where the two co-owners, FPL and FMPA, have entered into some type of agreement where half of the ownership capacity of the co-owner FMPA comes out of one unit and half out of the other unit of FPL, and vice versa with FPL?

MR. BUTLER: I'm going to object.

Q A reliability exchange agreement for purposes of enhancing reliability?

MR. BUTLER: I'm going to object on similar grounds to my objection to Ms. Brownless's question. A hypothetical posed to a witness that

we're not supporting here as an expert on the subject of co-ownership arrangements. I think it is way beyond the scope of the issues in the case, and I think, as was the case in Ms. Brownless's question, the answer would have to depend on details of the agreement that obviously aren't before Mr. Scroggs.

MR. BRYANT: I'll move on, John. We're both getting hungry. Bear with me for a moment.

That's all I have, John.

THE WITNESS: Thank you.

MR. BRYANT: Thank you, Mr. Scroggs.

THE WITNESS: Yes, sir.

MR. YOUNG: This is Roy Young. I guess I'm left.

CROSS-EXAMINATION

BY MR. YOUNG:

Q Mr. Scroggs, I only have two questions. Who did -- if you remember. You said you had two face-to-face meetings with the OUC folks. I should know who that is but I don't. Can you remember who they were?

A Principal individual I spoke with was Claston Sunanon.

Q Okay.

A There were other -- there were two others, but I don't recall their names.

Q Okay. Do you anticipate continuing those types of conversations with OUC beyond the need hearing and through construction?

A Do I -- I do anticipate that.

Q You do?

MR. YOUNG: Thank you very much. That's all I have.

MR. BUTLER: Anyone else?

MR. KRASOWSKI: Are you ready for me? I'm Bob Krasowski.

MR. BUTLER: I think we're ready.

CROSS-EXAMINATION

BY MR. KRASOWSKI:

Q Hello, Mr. Scroggs.

A Hello.

Q Hello. I just have a couple of questions on two different areas. One, to help me understand the situation as it exists, you've just been talking about -- I'd like to ask you why you didn't provide a summary of your discussions, your -- what was identified as in your petition as preliminary discussions, why didn't you provide a summary of those discussions as you're doing now and avoid this whole situation?

MR. BUTLER: I'm going to object to that question as completely irrelevant.

MR. KRASOWSKI: Okay. Well, I understand your objection. The question still stands. Should I rephrase it? Maybe I'll rephrase it.

MR. BUTLER: Try to rephrase it and see if we've got something he can answer.

BY MR. KRASOWSKI:

Q Okay. In front of me I'm looking at the requirements of your petition under 403.519, and the requirements are fairly general in terms of all you need to do is inform on whether there were any discussions with any electric utilities regarding ownership of a portion of the nuclear integrated gasification combined cycle power plant by such electric utilities.

And I think you accommodated that, but apparently in the rule it makes a further requirement of the summary. So why is it you didn't provide a summary?

MR. BUTLER: Object to the question as lacking foundation on -- there is a summary.

Q There is a summary. And by that, are you referring to section 9 in your petition that deals with the issue of discussing co-ownership?

MR. BUTLER: Paragraph 63, if I remember correctly.

Q Let me look real quick. Okay? Yes, that's right, paragraph 63. So is that what you're referring to as far as you're satisfying what you believe to be the requirement of the rule and law?

MR. BUTLER: That's right.

MR. KRASOWSKI: Okay. Thank you.

MR. BUTLER: What you're doing clearly is an exchange of legal observations here, not questions for Mr. Scroggs.

MR. KRASOWSKI: Didn't Mr. Scroggs develop that portion of the petition?

MR. BUTLER: You can ask that question to him.

A No.

BY MR. KRASOWSKI:

Q Okay. Oh, and could you tell me who did, Mr. Scroggs, so I can ask them the question?

A It would be someone in FPL's legal department.

Q Okay. Okay. Thank you. I have another question I'd like to ask you. Early on in the discussion you were talking to Mrs. -- to Ms. Brubaker, you -- she referred to page 19 of your testimony, and -- okay. And you mentioned -- you made the comment about the -- the permit requirements and Miami being approved, that you had received the permit requirement -- I'm looking -- do you know what I'm talking about?

A Identify your --

Q It's Miami-Dade County unusual use permit, and there was a meeting on December 20th. You attended. I was there as well. And you spoke. Now, you were saying on page 19 that an update on your -- on your -- on your petition here, you were updating that and saying you had obtained that permit, but -- okay? So that's what I'm talking about. So in regards to your previous comments, I'm asking if there was -- if those -- if that permit is still contingent on resolving the water issues.

A To be specific, we filed an application for public hearing for unusual use variances to the Miami-Dade County code. On December 20th, the Board of County Commissioners voted approval of those unusual use variances contingent upon 22 conditions of approval. Within those conditions of approval are specific directions, actions that must be undertaken by FPL during the investigatory process to fully explore water resources and ensure that our selection does not adversely impact Miami-Dade County citizens or the environment.

Q Thank you. Have you addressed all of those specific water issues yet?

A No.

Q Okay. Now, there's a gentleman, John Renfrow,

who I believe represents the water utilities component in Miami-Dade County who spoke on the 20th, and he mentioned certain restrictions as far as what might or might not be available to this project. He kind of narrowed it down to the wastewater alone, but I don't remember hearing anything about the general ocean water use. But will you be ready to discuss his comments on -- at the hearing when you appear?

MR. BUTLER: I'm going to object to the predicate for the question as involving a whole lot of information not in the record. But the sort of upshot of the question, Mr. Scroggs, you may answer.

A I could -- in response to your question, sir, John Renfrow is the director of the water and sewer department in Miami-Dade County. In the December 20th hearing he spoke to, I believe, Commissioner Sorensen's line of questioning regarding the consumptive use permit in Miami-Dade County and how that identified that, as a condition of their new consumptive use permit, that they would investigate the use of reclaimed water for the purposes of cooling water at Turkey Point. And he affirmed that that was in their consumptive use permit as a condition and that they would be pursuing that.

Q Thank you. Did Mr. Renfrow also at that time

identify that any aquifer use would not be permissible?

A Well, more specifically I would say that as a condition of approval, we have identified that the Biscayne aquifer would not be utilized for cooling water. So as a specific condition of approval, Biscayne aquifer has been taken off the table as an alternative.

Q And then I believe there were two other restrictions. Do you want to comment on those, or can I save the question for the hearing when I will have this -- the document, the transcript in front of me?

MR. BUTLER: How you choose to ask your questions is up to you.

MR. KRASOWSKI: Okay. Well, I guess what I'm looking for is that if -- I would like to ask Mr. Scroggs if he will be familiar with all of the material at the time of the hearing so I can ask the question and get an answer.

MR. BUTLER: We can't commit that he's going to be familiar with all the material. Who knows what that entails. If you want to ask him a question here, ask him. If you have materials you'd like to raise with him at the hearing, you know, you'll have your opportunity to do that.

MR. KRASOWSKI: Okay. Well, just to clarify. The materials I'm referring to would be the

Hearing Exhibit 000696

transcript of that meeting that Mr. Scroggs participated in and Mr. Renfrow made those comments at.

MR. BUTLER: It's not the purpose of a deposition to get commitments as to what people's homework assignments are going to be. If you have a question, ask him now. If you have a question at the hearing, you're welcome to ask him then.

MR. KRASOWSKI: Okay. Well --

MR. BUTLER: You could have facilitated this by doing what the other parties have done, which is to provide the documents in advance if you had questions you wanted to ask him about specifics.

MR. KRASOWSKI: Okay. And does that hold true for this upcoming hearing? If I send the documents, specific documents, there's a better chance that he'll be prepared to address my questions?

MR. BUTLER: It depends on the documents and the volume of documents.

MR. KRASOWSKI: Okay. Well, for now --

MR. BUTLER: He's prepared to answer the questions now. You know, it's up to you whether you want to ask him. Sounds like the real problem is that you don't have the material.

Hearing Exhibit 000697

MR. KRASOWSKI: That I what?

MR. BUTLER: It sounds like the real problem is that you don't have the material. He is prepared with a pretty vivid memory of the hearing to talk about it if you want to.

MR. KRASOWSKI: Yeah. Well, in the interest of being effective and efficient with all of our time, I would want to have the materials in front of me. And as I said earlier, I don't have the transcript that specifically identified what Mr. Renfrow said, and -- but I will be getting it and I'll have it at the hearing.

MR. BUTLER: That's up to you. That's up to you. Speaking of effectiveness and efficiency, do you have any other questions?

MR. KRASOWSKI: As I was saying, no, I don't have any other questions at this time. Thank you for your answers and thank you for the opportunity to ask the questions.

THE WITNESS: Thank you, sir.

MR. BUTLER: I believe that's the end of the direct examination of Mr. Scroggs. Anyone else? I have one brief redirect that I would like to ask Mr. Scroggs.

CROSS-EXAMINATION

Hearing Exhibit 000698

BY MR. BUTLER:

Q Mr. Scroggs, you were asked by Ms. Brubaker some questions about what had been identified as Exhibit 3, your summary of water issues. And I'd like to ask you whether you have considered a range or a -- you know, determined a range of costs that you think would reasonably bracket FPL's expectations of the ultimate cost of providing necessary water resource for Turkey Point Units 6 and 7?

A Yes, I have. Again, specifically within our cost estimate range, I feel there's 250 to $300 million worth of capital included that would be earmarked for capital costs of water or would represent, if they're not required as capital costs, a pool of money that could pay for longer term operating costs.

In specific to the sources that we're looking at, we don't have detailed cost estimates. We don't have an engineered design and engineered constructive drawings to estimate from. But we have experience in the field and feel that, on the outside, most of these sources would represent somewhere on the order of 250 to $300 million.

In the world of the reclaimed sources, it could be slightly higher, but those higher costs would come from potential infrastructure projects undertaken

by Miami-Dade in order to supply water through a water supply agreement, and that that water supply agreement would include operational costs for units of water that would help fund those projects. So we feel that our cost estimates are adequate, and while not comprehensive, with the alternatives that we've identified, we feel that those are all well within that range.

MR. BUTLER: That's all the questions that I have.

Okay. Are we at a conclusion?

MS. BRUBAKER: I believe we're at a conclusion. Thank you, everyone.

MR. BUTLER: Thank you. And we will -- we don't waive reading and signing.

(Deposition concluded.)

* * *

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, LORI DEZELL, Registered Professional Reporter, certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1 through 140 are a true and correct record of the aforesaid 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 21st day of January, 2008.

LORI DEZELL, RPR, CCR
Notary Public
2894-A Remington Green Lane
Tallahassee, Florida 32308
1-800-934-9090
850-878-2221

Hearing Exhibit 000701

ERRATA SHEET

I have read the transcript of my deposition, pages 1 through 141, and hereby subscribe to same, including any corrections and/or amendments listed below.

1-25-08
DATE

Steven D Scroggs
STEVEN D. SCROGGS

(FPL's Petition to determine need for Turkey Point Nuclear Unite 6 & 7)

Page	Line	Correction or Amendment	Reason for Change
9	18	Change "extended" to "expended"	Correction
10	8	Change "Cast" to "Cask"	Correction
10	9	Add "is included" after "fuel"	Correction
10	15	Change "Cast" to "Cask"	Correction
14	7	Add "prior to" after "procure"	Correction
15	25	Change "anything" to "nothing"	Correction
16	9	Change "occurred" to "incurred"	Correction
20	6	Add "turbine" after "steam"	Correction
20	21	Add "turbine" after "steam"	Correction
21	17	Change "won't" to "would"	Correction
23	5	Change "acute" to "adequate"	Correction
25	13	Change "new start" to "Nustart"	Correction
35	12	Remove "." after generators	Correction
35	12	Lower case "i" in word "incase"	Correction
35	13	Add "." after "reactors"	Correction
35	13	Change "you" to "You"	Correction
48	15	Change "past" to "advance"	Correction
50	18	Change "them out" to "the amount"	Correction
50	20	Change "$150" to "$155"	Correction
52	9	Change "established" to "establish"	Correction
54	20	Change "processing" to "processes"	Correction
58	24	Change "purchase" to "purchased"	Correction
69	18	Change "design" to "designer"	Correction
69	18	Remove "and" after "designer" (formerly design	Correction
69	18	add comma after "designer" (formerly design)	Correction
69	18	Change "construction" to Constructor"	Correction
73	20	Change "collection" to "selection"	Correction
76	6	Change "thick" to "big"	Correction
77	13	Change "paths of" to "passive"	Correction
78	13	Change "rainy" to "Rainey"	Correction
88	11	Change "saline-latent" to "saline-laden"	Correction
109	8	Add "." after "scale"	Correction
109	8	Change "a" to "A" after "scale"	Correction
109	8	Add "is" after "license"	Correction
125	17	Change "styled" to "titled"	Correction
139	18	Change "constructive" to "construction"	Correction

CERTIFICATE OF OATH

STATE OF FLORIDA

COUNTY OF P.ALM BEACH

I, the undersigned authority, certify that **Steven D. Scroggs** personally appeared before me at **700 Universe Boulevard, Juno Beach, Florida** and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Juno Beach, County of Palm Beach, State of Florida, this 17th day of January, 2008.

Notary Public State of Florida
Jennifer M Payne
My Commission D 0439096
Expires 06/09/200 3

Notary Public
State of Florida

Personally known ___X___ OR produced identification _____.

Type of identification produced_____.

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January 21, 2008

JOHN BUTLER, ESQUIRE
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: FPL's Petition to determine need for Turkey Point Nuclear Units 6 and 7

Dear Mr. Butler:

Enclosed please find your copy of the deposition of STEVEN D. SCROGGS taken on 1/18/08, in the above-styled case.

As the witness did not waive reading and signing, I am also attaching the errata sheet as the last page of the transcript and request that your office make the necessary arrangements with the witness to read your copy of the deposition, noting any corrections on the errata sheet, then dating and signing the errata sheet.

Please forward the original signed and dated errata sheet to Jennifer Brubaker. If the errata sheet or a request for an extension is not received within 45 days, counsel may assume that the signature has been waived.

Thank you for your cooperation in this matter.

Sincerely yours,

Lori Dezell, RPR, CCR

Enclosures (Errata Sheet and transcript.)

cc: Jennifer Brubaker, Esquire

Renaissance now?

BY E. MICHAEL BLAKE

Progress on the first license applications, funding availability for loan guarantees, and a presidential election are among the factors that could influence whether orders for new reactors are actually placed in the United States during 2008.

IS THIS THE year? Will even one organization finally stop issuing denials and make a firm commitment during 2008 to buy and build a new power reactor? Or will everyone just continue with license applications and state-level permitting until after a new administration takes over in Washington?

The year 2008 promises to be the most active for the nuclear community—electricity providers and regulators alike—at least since the mid-1970s (and perhaps ever, with the added prospect of a license application for a high-level waste repository at Yucca Mountain, in Nevada). There are almost certain to be at least 10 combined construction and operating license (COL) applications in the Nuclear Regulatory Commission's hands by the end of the year, for four different reactor technologies. At this writing (December 2007), the most immediate concern raised by this prospect is the stasis in funding for the NRC, which since October 1 has been operating with the same budget it had in fiscal year 2007, despite the need to hire dozens more staffers to process and review the applications. The NRC has sought a steep increase in funding for FY 2008, and the longer the continuing resolution remains in place, the later the agency will obtain the resources it needs.

Experience suggests that the budget issue will be resolved eventually. NRC funding is generally not controversial, especially because, by statute, nearly all of it is recovered from licensees through user fees. And so, although there may be some delays, it seems likely that the NRC will ultimately be able to handle the applications.

If the NRC budget can be cleared up early in the year, it is possible to look ahead to the rest of the year, and the other potential factors. This look ahead at 2008 begins with a rundown of where things stand as the year begins.

What to build

Thus far, every new project for baseload nuclear generation is based on a reactor design that has already been certified by the NRC, is under review for certification, or is to be submitted for certification, perhaps by the time this magazine is printed. Under 10 CFR Part 52—the regulations governing the licensing process for new reactors—certification resolves all of a reactor's nuclear safety issues, so these issues (ideally) would not be subject to review or challenge during the licensing of specific projects.

The various reactor designs anticipated for use in the United States and their status are as follows:

■ The only candidate reactor design for which the certification process appears to have been completed is the Advanced Boiling Water Reactor (ABWR), originated by General Electric. It has been built in the real world by GE's licensees in Japan, Hitachi and Toshiba. It is the only candidate with which there is operating experience, as well as a growing body of knowledge on the modular construction techniques intended to reduce the time required for a plant to be built. ABWRs in the United States are expected to be rated at 1350 MWe each.

■ Westinghouse's AP1000, a pressurized water reactor that would be rated at 1100 MWe or slightly higher, was certified in January 2006, but the vendor has since submitted amendments to the design. So far, the NRC has viewed these amendments as needing only staff-level review, rather than a completely new certification process. The reviews of these amendments are not expected to cause any delays with license applications that employ the AP1000.

■ GE applied in August 2005 for the certification of its Economic Simplified Boiling Water Reactor (ESBWR) design, which when built would be rated at 1400–1500 MWe. The application cites safety features of both the ABWR and GE's Simplified Boiling Water Reactor, which has also been certified, and much of the review effort has involved the NRC's informing GE that more detail is needed of the ESBWR design, with less presumption of similarity to other designs. The NRC has finished about half of the chapters in the safety evaluation report (SER) with open items. It is believed that with the approval conveyed through the SER, the licensing of specific plants can begin, and the remainder of the design certification process can be done in parallel. (See story on page 20 for more details.)

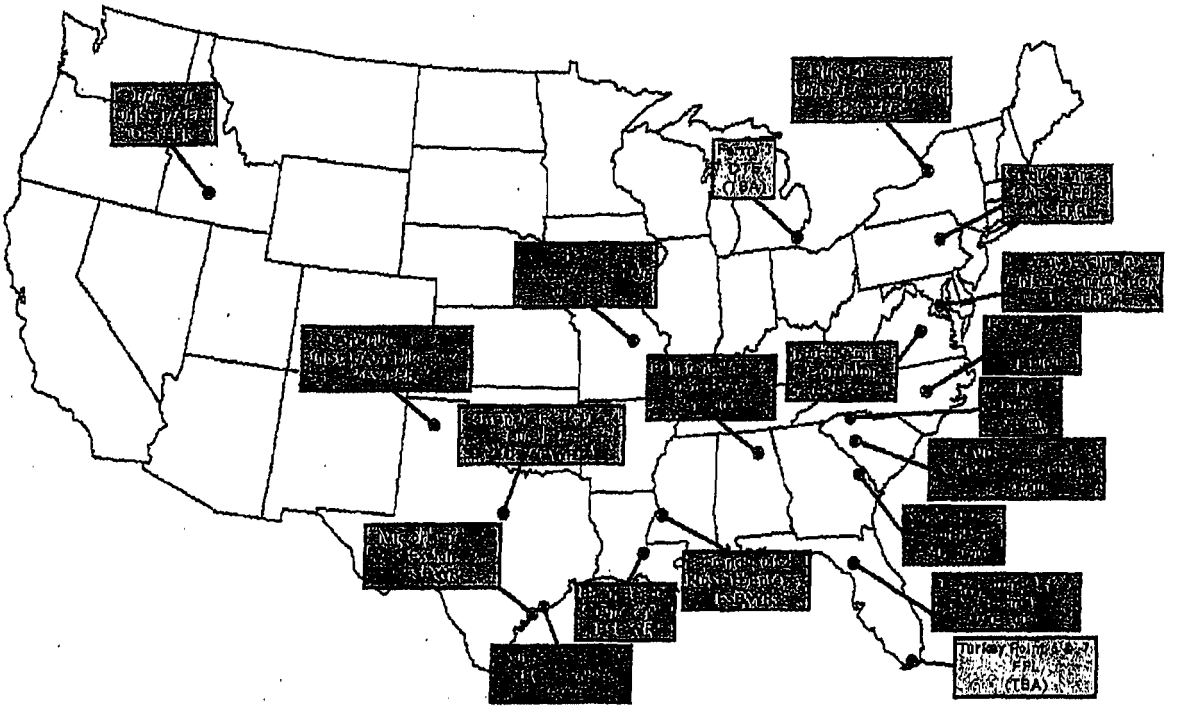
It should be remembered, however, that the 10CFR52 licensing process has not been used before now, and despite detailed preparation and extensive guidance documents for use by both applicants and regulators, expectations may not always match reality. As is noted below, early-stage work

...and Duke makes five

Writing news for a monthly publication often entails the pursuit of moving targets. This article has already gone through a number of updates because of important developments in late November and early December, but eventually one has to give the layout and production people a decent chance to remain on schedule, and so the following item is not included in the text:

Duke Energy submitted its application for a combined construction and operating license for the Lee plant in South Carolina to the Nuclear Regulatory Commission on December 13. This is the fifth COL application to date. More general information on the project is included in this article, and more details on the application are provided in a news item in the Late News section of this issue. Because this issue will not reach readers until January, it should be borne in mind that other data presented as status reports might have become outdated.—*E.M.B.*

Hearing Exhibit 000705



THE MAYBE MAP: Shown above are the projects for which the Nuclear Regulatory Commission has announced that it has been notified of intent to apply for licenses, with the boxes colored to indicate the chosen reactor model (blue = AP1000, green = U.S. EPR, orange = US-APWR, purple = ABWR, red = ESBWR, yellow = no decision yet). As of this writing, there is still not a single project that has reached the point of a firm commitment to build—which, in this era, is considered to be a signed contract for engineering, procurement, and construction (EPC). As the term suggests, an EPC would bring together equipment vendors and architect-engineers, and for some of the projects shown above there already exist partnerships assembled among the potential suppliers. Several of the potential buyers routinely speak these days in terms of *when* they will build, and not *if*, but until EPCs are signed, *NN* will consider all information about new power reactors in the United States to be speculative. Not included on the map are expressions of interest by American Electric Power Company, Arizona Public Service Company, the Fresno Nuclear Energy Group, MidAmerican Energy Holdings, Pacific Gas & Electric Company, and Public Service Electric and Gas Company—or rumors concerning others.

on the first few COL applications has already led to some disagreements on whether the submissions are sufficient.

Reactor safety experience dating back to the Three Mile Island-2 accident in 1979 has persuaded the main players in the U.S. nuclear industry that new reactor designs should depend less on engineered safety features and more on "passive" processes, such as natural circulation, to ensure ultimate safe shutdown, even in the event of a catastrophic accident. This philosophy is reflected in the AP1000 and the ESBWR, which are seen as "American" designs, even though Westinghouse is now owned by Toshiba of Japan, and GE has linked up with Japan's Hitachi for ESBWR work.

■ For the most part, the non-U.S. reactor vendors have headed in the opposite direction. Areva's U.S. EPR, a PWR that would be rated at about 1600 MWe, takes engineered safety features even further than earlier designs had, with four separate trains of reactor shutdown capability. (The original European Pressurized water Reactor design is used in a reactor under construction in Finland and in another soon to be built in France; the U.S. version has been modified somewhat.) After over two years of pre-application reviews of topical reports submitted to the NRC in the hope of resolving some specific issues in advance, Areva applied to the NRC for certification of the U.S. EPR design on December 11. Because the first full COL application for an EPR is to be submitted in the first quarter of 2008, there will be even more work to be done in parallel on design certification and licensing than there is with the ESBWR.

■ The last key player in reactor design (at least this year) is Mitsubishi Heavy Industries (MHI), with its US-APWR. A PWR rated as high as 1700 MWe (although the version for the U.S. market would probably generate about 1600 MWe), it also depends mainly on engineered safety features, but not to the extent of the U.S. EPR. It is the latest entry in the field, although MHI has tried to catch up by spending less than a year and a half in pre-application, aiming to apply for design certification at about the same time as Areva.

Who might build

The first phase of the industry's exploration of 10CFR52 ended in November, when the last of three early site permit (ESP) applications submitted in 2003 was approved by the NRC. Dominion's ESP for North Anna, in Virginia, like the one granted earlier in the year to Entergy for Grand Gulf, in Mississippi, will be used directly in a license application. With the environmental issues addressed in an ESP now resolved for up to 20 years, the COL reviews for North Anna and Grand Gulf can focus on plant construction and operation. The third ESP, for Exelon's Clinton, in Illinois, will remain unused for the time being. Exelon has no plans to seek a COL for Clinton, and current Illinois law would impede the construction of new reactors in the state.

The only ESP application now under review is from Southern Nuclear Operating Company, submitted in August 2006 for its Vogtle site in Georgia, in preparation for the submission of a COL application early this year (see below). Southern is also seeking a limited work authorization in connec-

tion with the ESP proceeding in order to allow some work to be done on the site before the COL can be issued. The only other prospects for ESPs are two sites in the Carolinas for which Duke Energy has expressed interest but has not announced a schedule for submission, and an application proposed for mid-2010 from an entity that has asked not to be identified.

COLs submitted

■ The first submission related to a COL was a partial application on July 13 (with two later supplements) for Calvert Cliffs -3, a U.S. EPR at the site near Lusby, Md., where Constellation Energy operates two PWRs. A partial submission dealing mainly with environmental issues is permitted under 10CFR52. The NRC, however, informed UniStar Nuclear on August 23 that the agency had suspended its review of whether the application was acceptable for docketing, because even the supplements did not provide enough information. UniStar responded on October 30 with a plan to provide the needed information, and with some of the information itself. The plan stated that the remaining information was to be provided by December 14.

Among the many differences between the earlier generation of nuclear power and what may be the new one is that there may no longer be a single event that can be seen as a "reactor order." UniStar was the first to take the step of arranging for the large forgings necessary for fabrication into the major components of a new power reactor (and whenever this takes place, it is almost always referred to as "procuring," not "ordering"). UniStar is a joint venture of an electricity provider (Constellation Energy) and a reactor vendor (Areva), but to date neither UniStar nor either partner has announced a commitment to ordering.

Outlook for 2008: When the partial application was submitted, UniStar told the NRC that the submission of the rest of the application, including the plant's safety analysis report, was planned for no later than March 15, 2008. At this writing, there had been no statement to the effect that this would change. Calvert Cliffs-3 is intended to be the reference COL application (R-COL) for the U.S. EPR, under the NRC-encouraged approach for design-centered licensing. In November, UniStar sought state-level permitting in Maryland for the project, and approval at this level may have to take place before there is a firm decision to build the reactor.

■ The first submission of a full COL application was by STP Nuclear Operating Company (STPNOC) and the owner of its largest share, NRG Energy, on September 24 for South Texas-3 and -4, twin ABWRs at the site near Palacios, Tex., where two PWRs are now in operation. NRG, a merchant electricity provider that bought the assets of Texas Genco in 2006, exists in an entirely different environment from that of the state-regulated, service area–based utilities that operate nearly all of the existing power reactors in the United States. With no rate base through which to charge customers for investments such as new generation, NRG often pre-sells a proposed plant's electricity to buyers (known as "off-takers"), and it took this approach with South Texas-3 and -4. Once enough off-takers are lined up, NRG uses their commitments to arrange financing for the project.

On November 29, NRG/STPNOC earned the distinction of having the first docketed COL application. Even as it accepted the application, however, the NRC said that it needed more information in order to work out a schedule for its reviews. More details are provided on page 15.

Outlook for 2008: NRG appears to be closer than anyone else to making a genuine commitment to ordering the nuclear steam supply systems and major components for new reactors. Company representatives have stated that they expect to place the order this year, perhaps as early as January. While the initial U.S. marketing of the ABWR was done by GE, in August NRG signed a project services agreement with Toshiba (which, along with Hitachi, has made hardware for the ABWRs now in service), giving that company the inside track to getting the engineering, procurement, and construction contract that now counts as a formal commitment to the construction of a reactor.

■ The 10CFR52 licensing process was to have been tried out initially by one of the recipients of cost-sharing support under the Department of Energy's Nuclear Power 2010 program, but after the licensing demonstration project was launched in 2004, interest in new nuclear power spread, and COL plans began popping up everywhere, without cost-sharing. One of the NP2010 partners—the NuStart consortium, made up of utilities and reactor vendors—on October 30 became the third COL applicant, for Bellefonte-1 and -2, two AP1000s for a TVA Nuclear site near Scottsboro, Ala., where two earlier PWRs had been started but never finished.

Bellefonte is the R-COL for the AP1000, the design for which there are currently the most expected subsequent COL (S-COL) applications (see below). Because of the cost-sharing aspect of NP2010, there is some uncertainty about how the federal budget (not just the time spent under the continuing resolution, but the eventual appropriation amount for FY 2008) might affect what can be done. Pursuit of the COL application might be set, but NP2010 contributions to design certification and first-of-a-kind engineering have yet to be clarified.

Outlook for 2008: Because so many S-COLs might depend on it, the NRC's acceptance review of the Bellefonte application (still ongoing) could determine whether as many as six applications stay close to their original schedules or are delayed. Beyond that, dramatic announcements this year seem unlikely. TVA just brought Browns Ferry-1 back on line in 2007 and has committed to finishing Watts Bar-2. TVA has stated that it might need more capacity in the 2015–2020 time frame but will have to spend more time studying demand growth and the effectiveness of conservation measures before deciding whether to order two new reactors.

■ The other NP2010 partner is Dominion, whose early and continued involvement (going back to the ESP application) has often been paired with corporate skepticism about the value of the process. By mid-2007, however, Dominion was permitting its employees to refer to its still-uncommitted effort as North Anna-3, which would be an ESBWR built at the site of two PWRs operating near Louisa, Va. Dominion has also procured large forgings. On November 27, Dominion became the fourth COL applicant, with what became the R-COL for the ESBWR (see page 13, this issue).

North Anna-3 has undergone two major changes since it was initially envisioned. The first reactor choice was AECL Technologies' ACR-700, a heavy-water reactor that would use slightly enriched uranium. Dominion, however, later switched to the ESBWR. Then, when there were environmental challenges by citizen organizations on the adequacy of cooling water from the lake that Dominion had earlier created for the first two units, Dominion decided to add cooling towers for any new nuclear capacity at the site. The latter decision forced some reviews to be redone, delaying the issuance of the ESP.

Outlook for 2008: Once the NRC accepts the application, the main point of interest will be the extent to which the level of approval in the ESBWR certification indeed allows the license reviews to be carried out meaningfully. As for whether an order would be placed, Dominion has said that for the reactor to go on line in 2015, a commitment to build would have to be made by sometime in 2009, so there may be no action on that front this year.

COL submissions scheduled

This summary continues in what has been, approximately, the order of scheduled submissions of COL applications.

■ Duke Energy was the first organization to announce (early in 2005) a licensing effort outside of NP2010, and it has designated the site of its canceled Cherokee plant near Gaffney, S.C., the William States Lee III Nuclear Station, in honor of the company's late president and nuclear pioneer. We will henceforth refer to the two AP1000s as Lee-1 and -2. Previously

Hearing Exhibit 000707

Scroggs Deposition
Dkt #070650
Late Filed Exhibit #1

The Westinghouse AP1000™ is ready for global use.

China will build four AP1000s, beginning in 2009.
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targeted for an October 2007 COL submission, Lee's application had not been handed in by early December.

Outlook for 2008: Lee is likely to be one of the first S-COLs for the AP1000. If the Bellefonte acceptance review requires changes or extra information, the same might have to be provided in the S-COLs when they are submitted. Duke officials have said that they are in negotiations with Westinghouse on contract terms, and while there have been no clear indications on when the order or the engineering, procurement, and construction contract might be placed, Duke has been a serious player all along and clearly would prefer to build reactors for new generation.

■ By current standards, SCANA—the parent company of South Carolina Electric and Gas Company—is a small fry among nuclear licensees, with a modest service area and a single power reactor in operation. In partnership with South Carolina's main public power agency—Santee Cooper, which takes its name from a hydroelectric dam—SCANA has nonetheless pursued prospects for Summer-2 and -3, twin AP1000s for its reactor site near Parr, S.C., so eagerly that it appeared for a while that its COL application might be ready before any of the others for AP1000s. If the new reactors are built, the site might one day be able to boast involvement in more generations of power reactors than any other: Parr was also the site of the Carolinas-Virginia Tube Reactor, a 17-MWe heavy-water reactor that operated during the mid-1960s.

Outlook for 2008: Like Lee, this appears to be an early S-COL for the AP1000. SCANA has generally had little to say about when or if it would place an order, neither dropping hints nor issuing denials, and so it is unclear whether anything will take place this year.

■ NuStart has a BWR project to go with its PWR project at Bellefonte: Grand Gulf -2, a single ESBWR for Entergy's site at Port Gibson, Miss. Although Grand Gulf received its ESP before North Anna did, the latter became the R-COL for the ESBWR. During 2007, Entergy announced a slight delay in the COL submission, to January 2008. Entergy has procured forgings for one ESBWR but has not stated whether they are for Grand Gulf-2 or its own non-NuStart project at River Bend (see below).

Outlook for 2008: The acceptance review for North Anna-3 could influence the submission date for Grand Gulf-2, perhaps leading to a further delay. Entergy has been in negotiations with GE-Hitachi over issues such as setting a fixed price. For years, Entergy has been eager to revive nuclear power, and a firm order for Grand Gulf-2 might be placed this year, before one for North Anna-3.

■ Progress Energy has proposed the largest nuclear capacity addition of any announced applicant: four AP1000s, with a total capacity of about 4500 MWe. The first COL application would be for Harris-2 and -3, at the company's site near New Hill, N.C. Despite the planned January submission, however, Progress last year announced a delay in the project of about two years, along with the cancellation of its coal-fired projects in the Carolinas and the adoption of demand-side management.

Outlook for 2008: Progress has thus far stayed with its submission date despite the project delay. If the NRC's budget flatline continues, there might be discussion on whether this S-COL needs to be reviewed on the original schedule. The delay suggests that reactor orders this year are unlikely.

■ Southern has scheduled its COL application submission for Vogtle-3 and -4, twin AP1000s at its site near Waynesboro, Ga., for March. While the company has been clear about its general preference for new nuclear, the Georgia Public Service Commission threw Southern a curve in 2007, approving the request for new capacity but requiring that Southern open it up to any provider and fuel type.

Outlook for 2008: The state ruling has put Southern in the position of telling Westinghouse that if the new reactors' pricing cannot compete favorably with whatever options might be made available, the project must end. It seems unlikely that any other provider could suddenly emerge and make more than 2200 MWe of new capacity available by 2015, so conditions seem to favor the project's going ahead. Still, the prospects of a reactor order this year, which otherwise seemed likely, are currently uncertain.

■ Separately from NuStart, Entergy has decided to seek a license for River Bend-2, an ESBWR for the site near St. Francisville, La. The application is scheduled for submission in May.

Outlook for 2008: Entergy's procurement of one set of forgings, with no formal assignment to one project or the other, keeps the company's options open in case one of the projects has to be deferred or canceled. With Grand Gulf-2 in the lead, there does not appear to be the sort of urgency with River Bend-2 that would lead to a reactor order this year.

■ Progress Energy operates in two regions, each with its own set of conditions. The retrenchment noted above applies specifically to the Carolinas. In northern Florida, demand-side management and similar initiatives are already considered to have gone about as far as they can. Thus, Levy County-1 and -2 remain on schedule to be available for service around 2016. While this site is only a few miles from the company's Crystal River plant and shares the same water source, this is the first project set at what counts as a completely greenfield location. The sites mentioned above have all been previously approved for nuclear plant construction.

The state ruling has put Southern in the position of telling Westinghouse that if the new reactors' pricing cannot compete favorably with whatever options might be made available, the project must end.

Outlook for 2008: The greenfield site may make this proceeding a relatively long one, even with the benefit of an S-COL that has some issues resolved at the R-COL stage. Progress clearly wants to use more nuclear power, but there may not be a need to get a deal done for reactor hardware this year.

■ In April 2007, AmerenUE became the first major electricity provider other than Constellation Energy to plan a license application with UniStar Nuclear (of which Constellation is an owner). Callaway-2 would be a U.S. EPR at the site of AmerenUE's operating reactor near Fulton, Mo. As things stand now, Callaway-2 would be the first S-COL for the U.S. EPR. The application is planned for the third quarter of the year.

Outlook for 2008: AmerenUE has also procured forgings, and so the project appears to be fairly serious. The UniStar model, however, is unique, with UniStar not only licensing and building reactors but also operating them, with outside parties such as AmerenUE considered investors rather than owners, essentially providing the site and marketing the electricity. It seems fair to predict that deciding and agreeing on the roles of the parties will take some time, and that an order during 2008 is not likely.

■ The company now known as Luminant, after the private-equity takeover of TXU engineered last year by Kohlberg Kravis

Roberts, has scaled down its original plans for as much as 6000 MWe of new nuclear capacity at as many as three sites in Texas, to **Comanche Peak-3 and -4** at the company's existing reactor site near Glen Rose. Luminant has chosen MHI's US-APWR for both reactors, the only applicant thus far to do so. The submission is scheduled for December.

Outlook for 2008: Like the U.S. EPR, the US-APWR will be in the early stages of the design certification process when the COL application is submitted. The applicant's new owner has thus far agreed with the previous owner on the general idea of building new reactors, but ordering seems unlikely this year, or any time until the certification and licensing are seen to be making headway.

■ UniStar has envisioned that U.S. EPRs would be built in fleets, with the reactors in each fleet standardized all the way down to operator training. As part of establishing the first fleet, Constellation offered up not just Calvert Cliffs-3 but also **Nine Mile Point -3**, at the company's site near Scriba, N.Y. Submission is planned for the third quarter, probably after Callaway-2.

Outlook for 2008: With forgings already procured, progressing to an order is possible this year. More interesting developments may arise in later years. If license renewal at Indian Point, in downstate New York, is blocked or delayed, the state may need more power fairly quickly.

■ The second outside company to take serious interest in the U.S. EPR is PPL Energy, which in June 2007 announced plans to apply for a COL for **Susquehanna-3**, at the site of the company's BWRs near Berwick, Pa. The submission is scheduled for the third quarter of 2008.

Outlook for 2008: Unlike AmerenUE, PPL has not announced the procurement of forgings, and so it seems reasonable to predict that there will not be an order placed here until some time after the order is placed for Callaway-3.

■ Exelon Generation, unable to build new reactors in Illinois and declaring an unwillingness to build them anywhere until the high-level waste disposal situation is resolved, nonetheless announced in September 2006 that it will apply for a license for new nuclear capacity in Texas. In November 2007, Exelon decided that the reactor model would be the ESBWR, and in December the company procured forgings through GE-Hitachi for two reactors (see page 17). The site would be greenfield, about 20 miles south of Victoria. Submission is scheduled for September 2008.

Outlook for 2008: Exelon has not appeared to be as eager to build reactors as some of the other players, but the forgings deal shows continued progress. A reactor order this year still seems unlikely.

■ DTE Energy announced last February that it will apply for a COL for new capacity at its existing reactor site, Fermi, near Newport, Mich. At this writing, the reactor type had not been announced. Submission is expected sometime late this year.

Outlook for 2008: DTE representatives have been quoted as being very much in favor of new reactors, but the project appears to be too new to advance to the point of an order this year. The reactor type should be announced sometime before submission.

■ If NRG and UniStar differ from the established model for nuclear licensees, at least they involve substantial organizations with experience in large-scale electricity production. This cannot be said of Amarillo Power, which despite the name has no assets in electricity production or distribution and is a venture of a real estate developer and former nuclear-project welder. **Amarillo-1 and -2** would both be U.S. EPRs, built at an as-yet-unannounced greenfield site near Amarillo, Tex. The submission is planned for the fourth quarter of this year.

Outlook for 2008: Because this project would come under UniStar, it might ultimately be viable, because UniStar would provide all of the expertise, but there would still have to be an enormous investment. Two U.S. EPRs at full power would produce more than three times as much electricity as is consumed by the entire Texas Panhandle. Of the eight new reactors currently planned in Texas, these two appear to be the least likely to be built.

■ Also outside the conventional electricity industry is Alternate Energy Holdings, Inc., a Virginia-based partnership that has proposed to build a U.S. EPR as part of an energy park near **Bruneau, Idaho**. AEHI principals have some background in nuclear power and finance and have stated that they have financing available. A COL application is to be submitted in January 2009.

Outlook for 2008: No applicant has indicated that a reactor order would be placed before a COL application is submitted, and AEHI will not submit its application until 2009.

■ At the end of the line is FPL Group, whose Florida Power and Light Company unit intends to apply sometime in 2009 for COLs for **Turkey Point-6 and -7**, at the site near Florida City where two PWRs are now in service. The reactor choice has not been announced, but the company has informed state regulators that there would indeed be two reactors and has requested a certificate of need for the new capacity.

Outlook for 2008: The reactor choice will probably be announced, although an order seems unlikely. The late filing does not indicate a lack of interest. FPL expects to need the power starting around 2020 and sees no need to start sooner.

Further expressions of interest

The above covers every action, ongoing or expected, that has been reported by the NRC. Beyond that, there have been some expressions of interest that have not reached the point of licensing projects.

Arizona Public Service Company stated in 2006 that it is considering more reactors for its Palo Verde site. Pacific Gas and Electric Company has aired the possibility of building new reactors outside California, beyond the reach of the state law that would impede their construction. The California law may be challenged in a ballot initiative by the Fresno Nuclear Energy Group, a business organization that has proposed building a U.S. EPR. PSEG Nuclear has floated the possibility of a new reactor at Hope Creek/Salem, in New Jersey. A subsidiary of MidAmerican Energy Holdings is performing tests on land in Idaho to determine whether it is suitable as a reactor site. Ameriosn Electric Power Company officials have expressed interest in a possible COL application. Public officials in Utah and Kansas have encouraged reactor development in their states. Potential developments such as these will probably stay in the background this year, although a ballot initiative against the California law would draw a great deal of attention.

In the wider world

Different companies have different reasons for choosing to become license applicants—or, to put it another way, the reasons are about the same for everyone, but they have varying influence on each applicant. The incentives in the Energy Policy Act of 2005 (EPAct) are sometimes given as the main cause for the current level of interest, but Duke and Southern started their projects before the law was passed, and at that time the energy bill's prospects looked no better than they had been the previous two years, when the bill was voted down. Some applicants, such as NRG and AmerenUE, have mentioned the EPAct incentives as having spurred their decisions to apply for licenses. Other factors include availability of financing, state regulatory climate, and projected demand growth. All applicants, however, appear to have a genuine willingness to try nuclear again, at least under the current approach of trying out some of the licensing process before committing to the purchase of a new plant.

While loan guarantees were made possible by EPAct, the amount of money to be made available—as Treasury backing, although this is treated like an appropriation—was debated in Congress all last year, and until an amount for a fiscal year is approved, the DOE has limited ability to approve guarantees. Some applicants may want to see that the guarantees will definitely be available before progressing much further.

Continued

Hearing Exhibit 000710

The extent to which licensing under 10CFR52 would actually be less cumbersome than it was under 10CFR50 has yet to be determined, and it may be that other potential reactor customers will watch and wait until a few applicants get all the way through to operation—at least seven years from now—before deciding whether the process is worthwhile. The NRC, the Nuclear Energy Institute, and the various design-centered working groups have held frequent meetings in an effort to learn what will actually be needed to get through the process, especially the innovation of ITAAC (inspections, tests, analyses, and acceptance criteria), which is the key to getting from the end of construction to approval for operation. The licensees carry out ITAACs, and the NRC determines whether they satisfy the conditions of the license. All parties are now working on more detailed guidance.

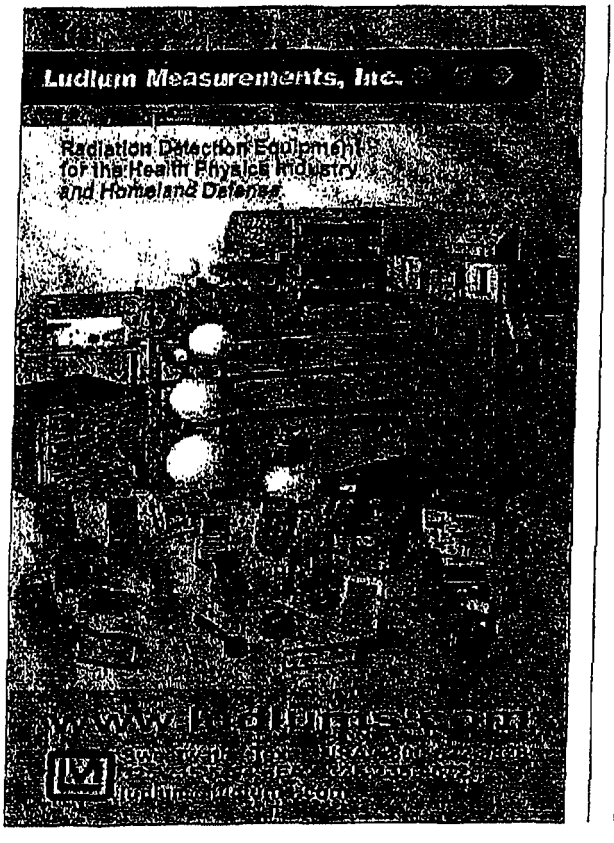
Thus far, citizen organizations opposed to nuclear power have not made discernable headway in 10CFR52 proceedings. Nuclear opponents, however, have responded to the interest in new reactors by reviving the debate through the news media and Internet sites. The focus may be less on individual COL applications than on The Issue That Won't Go Away: spent fuel/high-level waste/Yucca Mountain. The DOE plans to apply to the NRC in 2008 for a license to build and operate a final repository at the Nevada site. While a licensed repository is not strictly necessary for new reactors, the increased attention to the issue may affect public opinion—and the perceptions of the investment community—on nuclear power in general, including new reactor construction.

Finally, there is an event later this year that may affect every aspect of this supposed renaissance: the presidential election. Even if this were to have little practical effect on license applications or plant ordering, the perception of the outcome might be enough to delay some decision-making until after the first week of November. In essence, the general belief is that another Republican president would either accept or encourage new reactors, while a Democrat would oppose them, and so orders that might otherwise be placed early in the year could instead be held back and committed only if a Republican wins.

Judging from the candidates' own Web sites and public statements and, frankly, ignoring the candidates who have shown no signs yet of having a chance to be nominated, a new era of nuclear construction does not appear to depend much on the next occupant of the White House. The Republicans are indeed in favor of more nuclear power as part of their energy policies, but the major Democrats (except John Edwards, something of a long shot) have made a point of including new nuclear, at least as something to be "on the table." New reactor designs, climate change, and the recent performance of existing reactors provide the contenders with the justification—if they feel they need it—for accepting nuclear without appearing to abandon the party's stances on environment and nuclear safety.

The loss of Republican influence need not prevent new reactor ordering. The Democrats took over both houses of Congress in 2006, and the push for new licenses has continued unabated. Decades of high-level waste debate and stagnation have not stopped existing reactors from operating (with older spent fuel going to dry storage), and so the issue may not interfere with the licensing and building of new reactors. (Low-level waste might turn out to be a bigger problem, with the expected closure of the disposal site in Barnwell, S.C., to all but three states.)

And so it begins—what may be the pivotal year in Generation III+. Is now the time to recruit and train new craft workers, upgrade existing U.S. manufacturing facilities to N-stamp level, maybe even encourage someone to develop an alternative to the effective monopoly of Japan Steel Works on heavy forgings? We may get the message very soon, perhaps from South Texas. NN



FPL AP1000 COD July 2018 and July 2020

Note: The following information was provided by Westinghouse on January 4, 2007

Item	Estimate Price (M$)	Reservation Year	PO Year	Delivery Year	Expenditure Schedule (percent of price per year)										
					2008-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Forging Slots	8-12	2008			100										
RV 1	48	2008	2010	2015	*	10	20	25	24	6	10		5		
RV 2	48	2008	2010	2017	*	10			20	25	24	6	10		5
Prz 1	8	2011	2012	2015			5	20	25	25	25				
Prz 2	8	2011	2012	2017			5	20			25	25	25		
SG 1	124	2008	2010	2015	*	10	15	25	22	13	10		5		
SG 2	124	2008	2010	2017	*	10	15			25	22	13	10		5
CMT 1	11	2011	2012	2015			5	35	10	30	20				
CMT 2	11	2011	2012	2017			5	35			10	30	20		
RCP 1	90	2008	2010	2015		15	25	15	15	15	10		5		
RCP 2	90	2008	2010	2017		15	10	15	15	15	10	10	5		5

Notes : 1. Estimated Prices November 2007 $
2. * Forging slots reservation fee applies to SG and RV for two AP1000 Units
3. Assumes 72 month plant schedule (18 Site/48 Const./6 Test)
4. Other LLM will result from full study and will impact 2010 and beyond analysis (Ex: Contmt. Vessel, Modules, Accum, RCS Piping)
5. Note numbers in "Item" column refer to 1st or 2nd plant and not quantities of individual components
6. Columns "Reservation Year", "PO Year", & "Delivery Year" are tentative subject to construction review

Item	Estimate Price (M$)	Reservation Year	PO Year	Delivery Year	Expenditure Schedule ($2007, MM)											
					2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Forging Slots	8-12	2008			12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RV 1	48	2008	2010	2015	0.0	0.0	4.8	9.6	12.0	11.5	2.9	4.8	0.0	2.4	0.0	0.0
RV 2	48	2008	2010	2017	0.0	0.0	4.8	0.0	0.0	9.6	12.0	11.5	2.9	4.8	0.0	2.4
Prz 1	8	2011	2012	2015	0.0	0.0	0.0	0.4	1.6	2.0	2.0	2.0	0.0	0.0	0.0	0.0
Prz 2	8	2011	2012	2017	0.0	0.0	0.0	0.4	1.6	0.0	0.0	2.0	2.0	2.0	0.0	0.0
SG 1	124	2008	2010	2015	0.0	0.0	12.4	18.6	31.0	27.3	16.1	12.4	0.0	6.2	0.0	0.0
SG 2	124	2008	2010	2017	0.0	0.0	12.4	18.6	0.0	0.0	31.0	27.3	16.1	12.4	0.0	6.2
CMT 1	11	2011	2012	2015	0.0	0.0	0.0	0.6	3.9	1.1	3.3	2.2	0.0	0.0	0.0	0.0
CMT 2	11	2011	2012	2017	0.0	0.0	0.0	0.6	3.9	0.0	0.0	1.1	3.3	2.2	0.0	0.0
RCP 1	90	2008	2010	2015	0.0	0.0	13.5	22.5	13.5	13.5	13.5	9.0	0.0	4.5	0.0	0.0
RCP 2	90	2008	2010	2017	0.0	0.0	13.5	9.0	13.5	13.5	13.5	9.0	9.0	4.5	0.0	4.5

Scroggs Deposition
Dkt #070650
Late Filed Exhibit #2

Summary of Long Lead

Rounded (2007$) from Westinghouse Info

Item Description	Estimated Expenditure Schedule (2007$, MM)												Component Total (2007$, MM)
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Forging Reservation Fee	15	0	0	0	0	0	0	0	0	0	0	0	15
Reactor Pressure Vessel (Unit 1)	0	0	5	10	15	15	5	5	0	5	0	0	60
Reactor Pressure Vessel (Unit 2)	0	0	5	0	0	10	15	15	5	5	0	5	60
Pressurizer Vessel (Unit 1)	0	0	0	2	2	2	2	2	0	0	0	0	10
Pressurizer Vessel (Unit 2)	0	0	0	2	2	0	0	2	2	2	0	0	10
Steam Generator Vessels (Unit 1)	0	0	15	20	35	30	20	15	0	10	0	0	145
Steam Generator Vessels (Unit 2)	0	0	15	20	0	0	35	30	20	15	0	10	145
Containment (Unit 1)	0	0	0	1	5	1	5	3	0	0	0	0	15
Containment (Unit 2)	0	0	0	1	5	0	0	1	5	3	0	0	15
Reactor Coolant Pumps (Unit 1)	0	0	15	25	15	15	15	10	0	5	0	0	100
Reactor Coolant Pumps (Unit 2)	0	0	15	10	15	15	15	10	10	5	0	5	100
Annual Total	15	0	70	91	94	88	112	93	42	50	0	20	
Cumulative Total	15	15	85	176	270	358	470	563	605	655	655	675	

Escalation factor @ 2.5% annually 1.025 1.051 1.077 1.104 1.131 1.16 1.189 1.218 1.249 1.28 1.312 1.345

Escalated - precise

Item Description	Estimated Expenditure Schedule (Year Spent $, MM)												Component Total (Year Spent $, MM)
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Forging Reservation Fee	15.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15
Reactor Pressure Vessel (Unit 1)	0.0	0.0	5.4	11.0	17.0	17.4	5.9	6.1	0.0	6.4	0.0	0.0	69
Reactor Pressure Vessel (Unit 2)	0.0	0.0	5.4	0.0	0.0	11.6	17.8	18.3	6.2	6.4	0.0	6.7	72
Pressurizer Vessel (Unit 1)	0.0	0.0	0.0	2.2	2.3	2.3	2.4	2.4	0.0	0.0	0.0	0.0	12
Pressurizer Vessel (Unit 2)	0.0	0.0	0.0	2.2	2.3	0.0	0.0	2.4	2.5	2.6	0.0	0.0	12
Steam Generator Vessels (Unit 1)	0.0	0.0	16.2	22.1	39.6	34.8	23.8	18.3	0.0	12.8	0.0	0.0	167
Steam Generator Vessels (Unit 2)	0.0	0.0	16.2	22.1	0.0	0.0	41.6	36.6	25.0	19.2	0.0	13.4	174
Containment (Unit 1)	0.0	0.0	0.0	1.1	5.7	1.2	5.9	3.7	0.0	0.0	0.0	0.0	18
Containment (Unit 2)	0.0	0.0	0.0	1.1	5.7	0.0	0.0	1.2	6.2	3.8	0.0	0.0	18
Reactor Coolant Pumps (Unit 1)	0.0	0.0	16.2	27.6	17.0	17.4	17.8	12.2	0.0	6.4	0.0	0.0	115
Reactor Coolant Pumps (Unit 2)	0.0	0.0	16.2	11.0	17.0	17.4	17.8	12.2	12.5	6.4	0.0	6.7	117
Annual Total	15	0	75	100	106	102	133	113	52	64	0	27	
Cumulative Total	15	15	91	191	298	400	533	646	699	763	763	789	

Escalated & Rounded

Item Description	Estimated Expenditure Schedule (Year Spent $, MM)												Component Total ($MM)
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Forging Reservation Fee	16	0	0	0	0	0	0	0	0	0	0	0	16
Reactor Pressure Vessel (Unit 1)	0	0	6	11	17	18	6	6	0	7	0	0	71
Reactor Pressure Vessel (Unit 2)	0	0	6	0	0	12	18	18	6	7	0	7	74
Pressurizer Vessel (Unit 1)	0	0	0	2	2	2	2	2	0	0	0	0	10
Pressurizer Vessel (Unit 2)	0	0	0	2	2	0	0	2	2	3	0	0	11
Steam Generator Vessels (Unit 1)	0	0	16	22	40	35	24	20	0	13	0	0	170
Steam Generator Vessels (Unit 2)	0	0	16	22	0	0	42	37	25	20	0	14	176
Containment (Unit 1)	0	0	0	1	6	1	6	4	0	0	0	0	18
Containment (Unit 2)	0	0	0	1	6	0	0	1	6	4	0	0	18
Reactor Coolant Pumps (Unit 1)	0	0	16	28	17	18	18	12	0	7	0	0	116
Reactor Coolant Pumps (Unit 2)	0	0	16	11	17	18	18	12	13	7	0	7	119
Annual Total	16	0	76	100	107	104	134	114	52	68	0	28	
Cumulative Total	16	16	92	192	299	403	537	651	703	771	771	799	

Notes: The above charts are based on the data provided on the sheet entitled "FPL AP1000 COD July 2018 and July 2020"

Summary of Water Issues
Steven D. Scroggs

Scroggs Deposition
Dkt # 070650
Exhibit # 3

Abstract - FPL has conducted preliminary screening to determine availability and feasibility of alternative water resources capable of providing cooling water to the proposed Turkey Point 6 & 7 project. As a result, a set of alternatives has been developed that will be fully investigated for technical, environmental and economic compatibility with the objectives of the project and affected regulatory agencies. FPL's cost estimate range already includes costs for water supply and the conclusions of the economic comparison to combined cycle natural gas or IGCC alternatives are very robust. This white paper will describe the results of the preliminary screening conducted to date, the process by which the water source selection will be made and the robustness of the cost-effectiveness of the project.

Background

Steam based power plants (including nuclear technology) by their nature require more cooling water than plants using combined cycle technology; however design features minimize the volume of water required and allow the use of lower quality water sources that are not required for drinking water.

The thermal cycle used in any steam based electrical generation requires water for cooling during operation, process use (steam to drive the turbines), and cooling for reactor safety considerations. Operational cooling water is by far the largest need, representing the majority of water use on site. Passive nuclear designs, such as those being considered for Turkey Point 6 & 7, maintain the safety of the reactor by cooling mechanisms that do not require continuous supply. This means that the safety of the reactor is independent of the operational cooling water supply.

The amount of cooling water required will depend on the technology in use and the quality of the source. For example, combined cycle natural gas plants produce over 60 percent of the plant capacity in combustion turbines that do not require water cooling, so they require less water per MW of total capacity than technologies more dependent on steam cycles. Pulverized coal, biomass-based generation, and nuclear technologies require cooling water for 100 percent of the power. The application of cooling towers at Turkey Point 6 & 7 will allow for more efficient use of cooling water than once-through cooling, as is currently used by many existing steam based plants in Florida.

The quality of the source of cooling water significantly influences the design of the water systems at the plant and the total quantity required. Given the necessity to preserve high quality sources for drinking water, agricultural and environmental uses, contemporary power plants are commonly designed to use low quality water as alternative sources for cooling water. All other things equal, a high quality source will require less treatment, produce a smaller blowdown stream and reduce the overall amount of water needed than a lower quality source. Figure 1 provides a general diagram of the cooling water system.

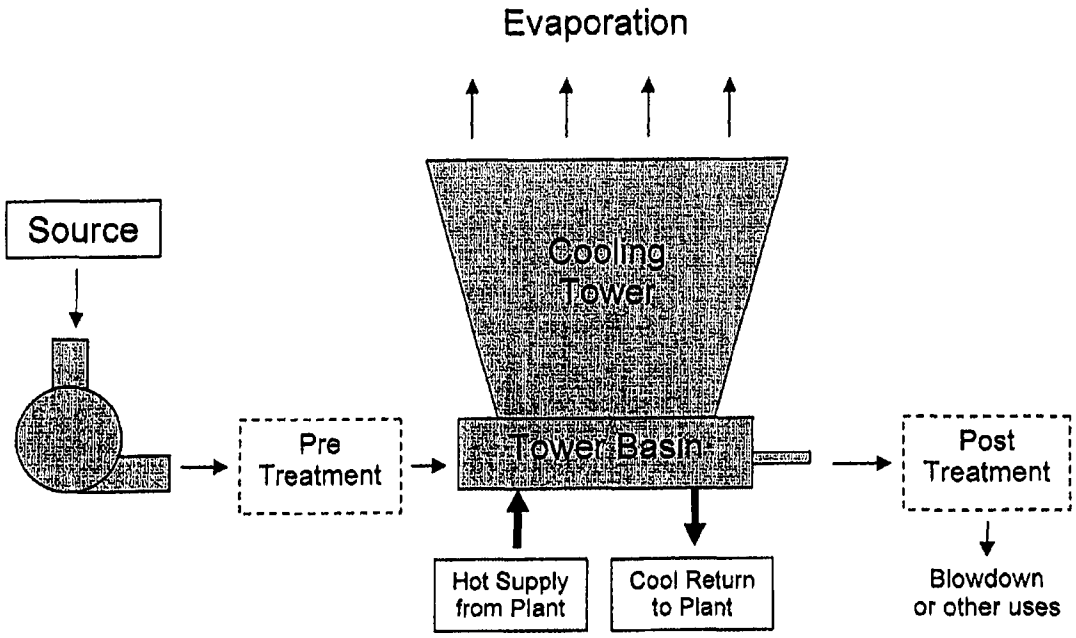


Figure 1. General diagram of cooling water process for steam-electric generation.

The cooling needs for the Turkey Point 6 & 7 project will not be precisely estimated until a source is selected, pre and post treatment processes engineered and cooling tower designs completed. FPL has estimated that a 2,200 MW project design will require approximately 86 million gallons per day (MGD). This value could range from 60 to 90 MGD depending on all the variables described above. Similarly, the cost estimate for the selected cooling water design will not be precisely estimated until these steps are complete.

When considering the range of available alternative sources one must also consider the current regulatory environment. Revisions to federal regulations that have occurred since many existing plants were licensed have essentially eliminated the option of once-through cooling designs at new power plants.

Supply Alternatives

Multiple viable alternatives are available and will be fully investigated to determine which source or sources meet technical, environmental and economic objectives.

In support of state regulatory approvals before the Florida Department of Environmental Protection (FDEP), FPL is required to investigate all alternative water sources before arriving at its selection. Currently there are five sources under active consideration as described in Table 1, below. Detailed investigation and analysis will yield the source or combination of sources that best meets the technical, environmental and economic requirements of the project and regulatory agencies.

Table 1. Water Source Alternative Characteristics

Source	Location of Source	Method of Delivery	Estimated Quantity [1]	Expected Quality [2]
Reclaimed Water	Miami-Dade Water Treatment System	9 – 32 mile pipeline from treatment facility.	up to 100 MGD	Moderate
Groundwater	Lower Floridan Aquifer (2400 + ft deep)	Well field near site	up to 100 MGD	Low (saline)
Groundwater	Boulder Zone (2800 + ft deep)	Well field near site	unlimited	Low (saline)
Marine - surface	Remnant Canal Intake	3 mile pipeline from remnant canal	unlimited	Low (saline)
Marine - subsurface	Card Sound/Atlantic	Rainey Well field below sea floor and pipeline delivery	unlimited	Low (saline)

1) Quantity available from each source will be determined by technical and environmental review.
2) Quality will determine pre and post-treatment needs and cooling tower design features.

Reclaimed Water: Miami-Dade County is currently permitted to dispose of over 300 MGD of treated waste water through deep well injection and ocean outfall. The potential for this source to be redirected to provide cooling water to the Turkey Point 6 & 7 project would support objectives of many stakeholders seeking more constructive use of this resource. The concept would be to use the existing waste water system infrastructure to deliver waste water to a treatment facility that would produce reclaimed water that meets the regulatory requirements (Chapter 62-610 F.A.C, Part III) for use in a cooling tower and for land application (e.g., golf course irrigation). The treated waste water would then be delivered to the plant site. This type of arrangement is currently in use at the Palo Verde Nuclear Generating Station in Arizona and is in use at FPL Energy sites in Rhode Island and Texas. The relative higher quality of the water would allow for process blowdown water (a by-product of the cooling process) to be minimized and potentially treated for continued use in wetland re-hydration projects in the region.

Lower Floridan: FPL has successfully designed recent projects using water from the upper Floridan aquifer for operational cooling. In South Florida, the water in this aquifer ranges from brackish in the upper Floridan to near seawater in the lower Floridan. The lower Floridan is characterized by high salinity and total dissolved solids making it undesirable as a source for domestic, agricultural or environmental uses without extensive treatment. The South Florida Water Management District Governing Board policy and recent state legislation encourages the development and use of "alternative water sources," such as the Floridan aquifer. The capacity of the lower Floridan is considerable, but less is known regarding the impacts of drawing water from this source. Well fields would need to be developed in the region of the site to withdraw the

necessary water. Process blowdown streams would be managed based on the resulting quality and treatment options.

Boulder Zone: The boulder zone is the deepest part of the Floridan aquifer and is separated from other portions of the aquifer by a significant geological barrier or "confining layer." This source has the characteristics of sea water and is generally at a stable temperature between 65 and 75 ° F. The capacity of the boulder zone is essentially unlimited, but less is known regarding the impacts of drawing large amounts of water from this source. Waste water is injected by Miami-Dade into the boulder zone, so the impact from existing injection sites will need to be analyzed. Well fields would need to be developed in the region of the site to withdraw the necessary water. Waste streams would be managed based on quality and treatment options.

Remnant Canal Intake: At the southern end of the existing closed loop cooling canals at Turkey Point is a 20 foot deep, 200 yard wide and one mile long canal that connects with Card Sound. This canal was originally intended as a discharge for the Turkey Point 3 & 4 project, but was abandoned in favor of the current canal design. Conceptually, a low velocity, one-way intake structure could be designed wholly within this canal that would not produce significant adverse impacts to fish and wildlife and provide the necessary amounts of cooling water. Engineering and biological studies will be required to determine whether or not this concept can be achieved. The capacity of this source would be unlimited.

Rainey Well System: This type of system uses high technology directional drilling processes to establish a network of long perforated pipes below the ocean floor that would unobtrusively, and at extremely low velocities withdraw the required cooling water for the facility through the ocean floor. Engineering and biological studies will be required to determine whether or not this concept can be achieved. The capacity of this source would be unlimited.

Combination of Sources. It is entirely possible that the best water supply design may rely on more than one source. This would potentially accommodate the use of a source that is desirable, but may be subject to limited availability. For example, the use of reclaimed water could provide many benefits, however due to maintenance or other operational issues water from the Miami-Dade water treatment system may not always be available in sufficient quality or quantity. Instead of disqualifying reclaimed water as a source, identification of an alternate source of cooling water would allow maximum use of reclaimed water and ensure that operational needs of the power plant would be met. This concept is used in FPL's West County Energy Center (WCEC) design which uses a combination of upper Floridan aquifer and excess surface water when available.

Process for Selection

The process to develop, review and approve the water source selection is comprehensive. FPL is appropriately involving agencies and stakeholders early.

As a power plant developer and operator in Florida and the United States, FPL has significant experience in the design, licensing and operation of a wide range of water supply systems. The needs and opportunities associated with the Turkey Point 6 & 7 project were identified early in the process. As a proactive step, FPL formed a working group of representatives from local, state and federal government agencies. These agencies, directly or indirectly, are a party to the FDEP and Nuclear Regulatory Commission (NRC) environmental license review process that will follow the design stage occurring over the next year. Feedback from these agencies has influenced project direction to date and will continue to help guide the project through the design phase. In this manner, FPL seeks to increase the likelihood that the selected water supply will be found suitable by these organizations during the review process. The final project water supply selection will be presented in detail in the FDEP Site Certification Application and the NRC Combined License Application targeted for March 2009.

The selection process involves three specific reviews: technical, environmental, and economic. The technical review involves multiple engineering organizations working with FPL to integrate the operational cooling water requirements of the power plant with potential sources of supply. In this evaluation, each alternative is reviewed to determine the technical requirements placed on delivery infrastructure, treatment systems and cooling towers based on the quality and location of each source. At this stage the specific capital and operational costs associated with a particular source(s) can be estimated.

An environmental review is conducted in tandem with the technical review to determine the environmental considerations, mitigation opportunities and opportunities to benefit planned restoration projects offered by each alternative. This review will also consider the management of blowdown streams, the mitigation alternatives and associated infrastructure required by each source.

The economic review builds on the results of the proceeding analysis and determines which alternative or combination of alternatives meets the operational requirements of the project and presents an environmental and economic benefit package that supports the objectives of regional projects and addresses the needs and concerns of the stakeholders. Input from stakeholders will be solicited throughout the design process through the Compatibility Working Group and other communications avenues.

Once FPL selects the water source(s) for the project, the applications for federal and state license approvals will be submitted and reviewed for regulatory compliance. During this process conditions of approval will be developed that may modify the water resource plan and the mitigation plan for the project.

Cost Implications

FPL has included an appropriate allocation for water supply in its cost estimate range based on FPL's significant experience in this area.

FPL's cost estimate range, represented in Exhibit SDS-6, includes capital costs for water supply. These costs, included in a number of specific line items in the exhibit, represent approximately $250 to $300 million of capital costs. Most of these costs are within the Owners Cost category. Operational costs are included within the Fixed Operation and Maintenance cost estimate utilized in the comparative economic analysis. This estimate is consistent with FPL's design for the West County Energy Center 1 & 2 project.

The estimated cost for each of the alternatives will be developed as the more detailed analysis is conducted. Based on the information available today, the costs of all alternatives under consideration are within a reasonable range of the estimate included in FPL's cost estimate range. The work necessary to develop these costs and make the selection will be conducted in 2008, allowing this information to be developed early in the process prior to significant preconstruction expenditures. It is important to note that higher quality alternatives, such as reclaimed water, may have higher upfront capital costs but will require less treatment and therefore will offer lower operational costs. Generally, lower quality alternatives involve lower capital costs but require higher operational costs. The tradeoffs created by these cost structures will be analyzed as a part of the selection process.

Specifically, reclaimed water may require improvements to the existing waste water system and additional delivery infrastructure (pipeline) to bring the treated water from the treatment location to the site. However, the relatively higher quality of the water would reduce the treatment and operational costs at the power plant site. However, there may be additional costs associated with system improvements and pipelines for delivery. The costs of any infrastructure improvements necessary to provide this supply would likely be allocated based on the benefits provided. For instance, increased use of reclaimed water and the costs to facilitate increased use is incumbent on Miami-Dade County regardless of the end user. FPL's involvement, to provide a substantial beneficial end use for reclaimed water, can help defray these costs for Miami-Dade citizens. FPL would be a paying customer to help fund these projects. The costs of this additional delivery infrastructure will be estimated as a part of the analysis of this source and reflected as operating costs.

Economic and System Benefits

There is a significant margin above the current cost estimate range that could be tapped to support unique water supply projects while maintaining the cost-effectiveness of Turkey Point 6 & 7.

FPL's cost estimate for new nuclear is estimated to range from approximately $3,100/kW to just over $4,500/kW (2007, overnight costs). As shown in Exhibit SDS-7, page 1 of 2, this range is below the breakeven capital cost for eight of nine scenarios when compared to combined cycle natural gas plants.

If one were to hypothesize an additional $2 billion of capital costs for a 2,200 MW project at the mid-range estimate (Case A, $3,596/kW), Turkey Point 6 & 7 would still be

equal to or more cost-effective than a similar sized natural gas project in eight of nine scenarios. An additional $3 billion over the mid range case, or $1 billion over the high range case could be added and still preserve the cost advantage of nuclear in seven of the nine scenarios. Thus, the cost of even very large capital-intensive water supply systems could be accommodated without changing the overall economics of the new nuclear project. Of course, this comparison is limited to the specific economic benefits of nuclear, whereas the qualitative benefits of fuel diversity, energy independence and reduced greenhouse gas emission provided by nuclear generation must also be considered in the decision process. Even under circumstances of equivalent economics these important qualitative benefits would still support the choice of new nuclear.

Summary

FPL has conducted adequate due diligence to determine that a sufficient number of water resource options exist to proceed with the project and is involving stakeholders in the design phase to increase the likelihood of regulatory approval. The cost estimate range includes an appropriate estimate for the capital cost associated with water supply. A significant margin exists before a combined cycle natural gas alternative would be economically on par with Turkey Point 6 & 7. Even if such a situation were presented, the important qualitative benefits offered by Turkey Point 6 & 7 far outweigh the increased uncertainty presented by increased exposure to fuel price volatility, supply disruption and increased greenhouse gas emissions.

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

DELIVERED VIA FEDERAL EXPRESS

October 26, 2007

Mr. R. Wade Litchfield
Vice President
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420

Re: FPSC Docket No. 070650-EI

Dear Mr. Litchfield:

I have read with interest Florida Power & Light Company's petition for a need determination regarding Turkey Point nuclear units 6 and 7 filed with the Florida Public Service Commission on October 16, 2007 in the above-referenced proceeding. At paragraph 63 of the filing, FPL states that it has held preliminary discussions with several Florida utilities regarding the potential for ownership participation by them and will continue to explore partnership opportunities with Florida utilities.

Seminole was not one of those Florida utilities that was contacted by FPL, so I am taking this opportunity to note for the record our interest in an ownership share of Turkey Point units 6 and 7 in the amount of 400 MW (with half attributable to each unit). Seminole would be pleased to discuss this matter with you at your earliest convenience.

Please contact me or Mr. Mike Opalinski, Seminole's Senior V.P. of Strategic Services, with any questions regarding this letter or our request. Thank you in advance for your consideration of this matter.

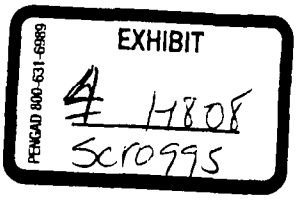
Very truly yours,

Timothy S. Woodbury
Executive Vice President
and General Manager

cc: Ann Cole (FPSC)
Mal Green (SECI)
Mike Opalinski (SECI)
Armando Olivera (FPL)

16313 North Dale Mabry Highway P.O. Box 272000 Tampa, Florida 33688-2000
Telephone 813 963 0994 Fax 813 264 7906 www.seminole-electric.com

EXHIBIT 1



Florida Power & Light Company, 700 Universe Blvd, June Beach, FL 33408

FPL

November 8, 2007

Timothy S. Woodbury
Executive Vice President
and General Manager
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33688-2000

Re: Docket No. 070650-EI

In re: Florida Power & Light Company's Petition to Determine Need for Turkey Point Units 6 and 7 Nuclear-Fueled Electrical Power

Dear Mr Woodbury:

Mr Litchfield has referred your letter dated October 26, 2007 to me for a response. As you know, Florida Power & Light Company ("FPL") has initiated a process that is intended to culminate in the construction of two new nuclear units at Turkey Point Although we have discussed the possibility of third-party ownership interest in some portion of one or both units or their output, I am sure you understand that our focus at this time must remain on obtaining the requisite regulatory approvals and moving forward with the significant siting and preconstruction activities.

We appreciate your willingness to discuss Seminole Electric's interest in exploring the possibility of some form of partnership or ownership participation However, we feel that such discussions would be premature until we are much further down the road on this project This will allow the necessary time to resolve many of the regulatory issues facing the project and further clarify commercial parameters and project schedules

Sincerely,

Steven D Scroggs
Senior Director, Project Development
Florida Power & Light Company

EXHIBIT 2

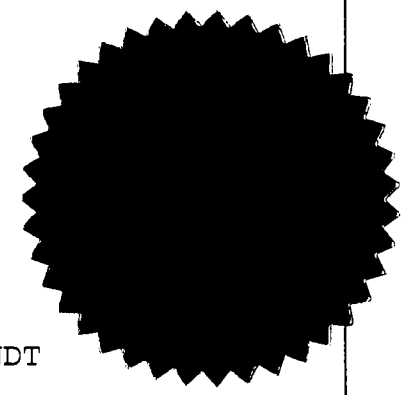
16

Deposition Transcript of C. Dennis Brandt including Late-Filed Deposition Exhibit Nos. 1-3 (including errata sheet)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI

In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.
_____/



TELEPHONE DEPOSITION OF: C. DENNIS BRANDT

TAKEN AT THE INSTANCE OF: The FPSC Staff

DATE: January 18, 2008

TIME: Commenced at 2:05 p.m.
Concluded at 2:56 p.m.

LOCATION: 2540 Shumard Oak Boulevard
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR
Notary Public, State
of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
2894 REMINGTON GREEN LANE
TALLAHASSEE, FLORIDA 32308
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APPEARANCES:

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REPRESENTING THE FPSC STAFF:

KATHERINE E. FLEMING, ESQUIRE
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

ALSO PRESENT:

LEO HERRERA
CRAIG HEWITT
SHEVIE BROWN

Hearing Exhibit 000725

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Hearing Exhibit 000726

STIPULATIONS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

MR. HUNTOON: This is Steve Huntoon for Florida Power & Light Company. With me today is C. Dennis Brandt and Leo Herrera and Debra Dominguez, and we're here pursuant to the notice of telephonic deposition provided by the staff. Deborah Dominguez is our notary who can administer the oath, if you would like, at this point.

MS. FLEMING: Yes, please. Go ahead.

(Witness sworn.)

MR. HUNTOON: So the witness has been sworn, and Debra will be faxing the certificate of oath to the number that you gave us.

Katherine, as we did in the prior deposition, can we reserve as to all objections except with regard to privilege and form?

MS. FLEMING: Yes.

MR. HUNTOON: Thank you. The witness is

Hearing Exhibit 000727

prepared to respond to questions.

MS. FLEMING: Okay. Thank you.

Thereupon,

C. DENNIS BRANDT

the witness herein, having been first duly sworn by Debra Ann Dominguez, a notary public in the State of Florida, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. FLEMING:

Q. Good afternoon, Mr. Brandt. How are you?

A. Fine, thank you. How are you today?

Q. Good. I'm Katherine Fleming here on behalf of the Commission. I appreciate you taking your time to meet with us this afternoon.

If at any point during the deposition you need a break, please let me know, or if you need any clarification on any of my questions or don't understand my questions, please let me know, and we'll try to work through it together.

A. Thank you very much.

Q. Before we get started, I just want to make sure that you have a copy of your prefiled testimony and exhibits with you.

A. Yes, I do.

Q. Okay. Do you have anything else with you

Hearing Exhibit 000728

today?

A. No, ma'am.

Q. Okay. Great. Let's go ahead and get started. If you could, please state your name and business address for the record.

A. My name is C. Dennis Brandt. My business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. You're employed by FPL; is that correct?

A. That is correct.

Q. And what is your position with FPL?

A. I'm the Director of Product Management and Operations.

Q. And what do your responsibilities include in that position?

A. I'm responsible for the life cycle management of FPL's products and services, and that includes overseeing the implementation, development, and tracking of the various DSM programs offered to our residential and business customers.

Q. And you filed prefiled testimony in this docket consisting of 30 pages; is that correct?

A. Yes, ma'am.

Q. And do you have any corrections to your testimony at this time?

Hearing Exhibit 000729

A. I have an update to my testimony.

Q. Okay.

A. On pages 3 and 7 of my prefiled testimony, I discussed the effectiveness of FPL's DSM efforts based on the U.S. Department of Energy data. That information was based on year 2005 information. In November of 2007, the DOE published updated information, and based on the revised information, FPL still remains ranked number one in cumulative conservation achievement, and we moved up from fourth in the U.S. to third in the U.S. in load management.

So the resulting changes to my testimony are on page 3, line 14, you would change four to three, and on line 15, change 2005 to 2006. Also, on page 7, line 18, change 2005 to 2006, and on line 20, change four to three. Those are the only changes to my prefiled testimony.

Q. And do you also intend to make these changes either by an errata sheet or at the hearing?

A. It's my understanding I'll make those changes at the hearing.

Q. Okay. Thank you. Let me have you turn to page 11 of your testimony, please.

A. Okay. I'm there.

Q. On lines 7 through 8, you state that FPL

Hearing Exhibit 000730

currently has Commission-approved goals for the years 2005 through 2014; is that correct?

A. Yes, that is correct.

Q. And you also state that in 2006, FPL was successful in meeting all those goals; is that correct?

A. Yes, ma'am.

Q. Has FPL exceeded its Commission-approved DSM goals over the past few years?

A. Looking at both the combined residential and commercial, we have exceeded our goals in the winter peak, we've exceeded them in the summer peak, and we've been slightly behind in the gigawatt-hour reduction.

Q. If you're able to do so --

A. I'm sorry. Excuse me. Let me correct that. We've exceeded all three. I'm sorry. We've exceeded the winter peak, we've exceeded the summer peak, and we've exceed the gigawatt-hour reduction.

Q. Okay. Now, if you're able to do so, can you estimate the megawatt and the megawatt-hours above FPL's goals for the years 2007 through 2009?

A. For our goals?

Q. Yes.

A. 2007 through 2009, for summer peak, the megawatt reduction -- let me just do a little calculation here.

Approximately 224 megawatts.

Q. 224 megawatts?

A. Yes.

Q. And what about megawatt-hours?

A. Megawatt-hours. The megawatt-hours is -- hold on. About 285 gigawatt-hours.

Q. Okay. Thank you. Has FPL included this level of performance into the forecasted load requirements of its system?

A. Yes, we have.

Q. Okay. Now, is this enough to mitigate the need for Turkey Point 6 and 7?

A. No, it is not.

Q. Let me have you turn specifically to pages 11 and 12 of your testimony, where you're discussing how the DSM goals are developed. And it's my understanding from your testimony that all measures are screened utilizing the RIM test and then later screened utilizing the Participant test to determine cost-effectiveness; is that correct?

A. We basically go through a two-step process. For us to offer a program, it is screened to ensure that it passes both the RIM test and also the Participant test.

Q. Now, doesn't FPL provide the Commission with

the results from the RIM, Participant, and the Total Resource Cost test with every conservation program approval request?

A. Yes, it does.

Q. Okay. Now, what's the reasoning for only using the RIM test and the Participant test to determine cost-effectiveness and excluding the Total Resource Cost test?

A. It's FPL's position that the RIM test and the Participant test are the two tests that are most appropriate for evaluating demand-side management, for several reasons, the first being that from the RIM test perspective, our objective is to seek demand-side management programs that have the least impact on our customers' rates as compared to other alternatives that might be built.

So the benefit of the RIM test is, number one, it minimizes rate impacts, and it also creates no losers. And by no losers, I mean that customers benefit whether they participate in the program or not. For those customers that do participate in the program, they obviously get savings by reduced energy usage from being in the program, and all other customers who do not participate in the program still receive the benefits of the lowest possible rates.

Hearing Exhibit 000733

The Participant test is really a test that says does it make economic sense for a customer to even participate in the program. So if a program passes the RIM test and failed the Participant test, you probably wouldn't get very many people participating in it. So it's really an indication of how the market might accept that program, so obviously, those two tests are critical.

FPL does not rely on the TRC test because we have some concerns about the way the test actually calculates costs. For instance, a simple example is that the incentives that are paid to a program participant under the TRC test are not even considered in the costs, in determining the cost-benefits of the program. Theoretically, I could pay for the full cost of any measure to a customer who participates, and that would not be considered or impact cost-effectiveness under TRC. It would, however, impact the total costs of the program, and those costs must be recovered from our customers through, for instance, the ECCR clause. And so, you know, it's not a true apples comparison of costs and benefits.

And lastly, there's no assurance that a program that passes TRC would not result in rates going up for our customers. In fact, a program that passes

TRC may very well cause rates to go up as compared to the alternative that it's being compared to.

Q. Okay. Thank you for that explanation. If FPL were to adopt the TRC test as a screening tool, would FPL be able to offer additional conservation programs to its customers?

A. There potentially could be other programs that could be offered. However, once again, we would be concerned about the ramifications of offering those types of programs.

Q. And one of those ramifications would be possibly a rate increase to the customers?

A. Yes, ma'am, both the rate increase and the total cost of the programs that must be recovered.

Q. Now, do you know of any programs that would pass the TRC screening test that are not already part of FPL's program offerings?

A. I'm sure there are programs that would pass TRC that fail RIM, and that being the case, they would not be part of our current program offerings.

Q. Could you give me an example of a program that would fail RIM but pass the TRC test?

A. Although I haven't done the analysis on a specific measure, I would suspect something like an exit sign. A high-efficiency exit sign would probably pass

TRC, and I know that fails RIM.

Q. Okay. Thank you. And you stated earlier that FPL also uses the Participant test as a screening tool?

A. That is correct.

Q. Does FPL still use a two-year payback criteria for the Participant test as a screening tool?

A. Yes, we do.

Q. Can you explain to me exactly how this two-year payback works?

A. Sure. When we're looking at the part of the analysis of, for instance, determining the RIM cost-effectiveness, we determine the maximum incentive that we can pay to a participant and still have the program pass RIM. We then compare that maximum incentive to the customer's incremental cost of implementing the measure and the bill savings realized from participating in the program, and we calculate their payback based on that maximum incentive.

If that maximum incentive reduces the payback to the customer to less than two years, then we would limit the incentive that we pay to the incentive that would in fact result in a two-year payback. In many cases, the incentive from the RIM analysis isn't sufficient to get it to a two-year payback for a customer, in which case we would not adjust the

Hearing Exhibit 000736

incentive downward.

Q. Can you give me an example of a program that did not pass this screening test?

A. Well, I'm not sure I would call what we're talking about a screening test. I think it's more of a constraint that we impose on the maximum incentive. We never want to have an incentive that would result in shorter than a two-year payback.

Q. Okay. Well, can you give me an example of a program that you considered that didn't pass the two-year payback in that instance?

A. Well, are you asking a program that we reduced the incentive because it had a shorter than two-year payback?

Q. Yes. Thank you.

A. I honestly can't think of one right here right now.

Q. Okay. That's fine. At this point, I would like to you turn to page 12 of your testimony. And I'm looking specifically at lines 17 through 22, where you discuss the DSM goals-setting process.

A. I have it in front of me.

Q. It's my understanding that goals are required to be reassessed every five years; is that correct?

A. That is my understanding.

Hearing Exhibit 000737

Q. And FPL's current goals cover the time period 2005 through 2014, with 2009 being the fifth year; is that correct?

A. That is correct.

Q. Does that mean that the Commission will reset DSM goals by 2010 for FPL?

A. If my understanding of the process is accurate, the next goals-setting process will set goals for the time period 2010 through 2019. And I would assume, based on the timing to get that done, that new goals will actually probably be approved sometime in 2009.

Q. Okay. So then FPL would be filing a petition then in 2009; is that correct?

A. That's correct.

Q. Has FPL begun to take any steps to identify additional DSM measures that could be incorporated into the goals-setting process?

A. We have just basically as of now started laying out schedules and information requirements that we would want to gather in preparation for starting this whole effort.

Q. Okay. Thank you. Now I would like to turn to the topic of renewables. You discuss renewables in your testimony starting on page 21, and you address or you

Hearing Exhibit 000738

discuss programs that FPL has engaged in in support of renewables. Some of these programs are no longer in existence, and some are still in existence; is that correct?

A. That is correct.

Q. Can you just briefly walk through the programs that FPL has engaged in in support of renewables, please?

A. I'll be happy to.

Q. Thank you.

A. The first one that I would like to talk about is the Conservation Water Heating Program, which was implemented back in 1982. That program was offered for several years, and during that time, we had 48,000 customers who participated in it. That program was discontinued when it was found not to be cost-effective and pass the RIM test.

In the mid-1980s, FPL had a Passive Home Program which was really focused on trying to disseminate information about passive solar design. During the existence of that program, it won a United States Department of Energy award for innovation. That program was basically phased out when many of the things it was focusing on were made part of the changes in the Florida Model Energy Building Code. So in a sense, many

Hearing Exhibit 000739

of the things we were pushing in this program became code requirements, and there was no need for us to continue that program.

In early 1991, we did an early program that looked at the feasibility of using photovoltaics to power swimming pool pumps. That program had mixed results, in that back in 1991, the cost of photovoltaics was even higher than they are today. And there were implementation issues on the customer side, such as finding adequate sunlight or unshaded areas to power the PVs, and also some issues about customer acceptance.

The next program I would like to talk about is one of the initial programs that FPL offered trying to promote photovoltaics. In 1998, we basically had a program that worked with customers to get contributions to contribute to building solar facilities, photovoltaics. During the life of that R&D project, our customers contributed $89,000 for the development of photovoltaics, and FPL used that money to install a photovoltaic site at its Martin Plant.

In 2002, FPL launched the Photovoltaic Research, Development and Education Project. The objectives were to increase the public awareness of roof tile PV technology, to understand how they operate, how resilient are, what their impacts are on our load shave,

Hearing Exhibit 000740

and similar data. We also had an effort to work with building officials to make them aware of this technology so that when homeowners approached them, you know, there wouldn't be an impediment to getting these things installed. That project was completed in 2003 and was very successful. We had several workshops with code officials to bring this new technology to their awareness.

The last program I'll talk about is FPL's Sunshine Energy program, and that program started as a pilot, which was called the Green Power Pricing Research Project, in November of 2004. And the objective was to allow in the pilot residential customers to sign up to voluntarily purchase renewable resources and also work on developing solar facilities. In that program, customers contributed 9.75 per month for 100 kilowatt-hours of renewable energy attributes.

That program, the pilot of that was completed, and in September of 2006, we filed a petition with the Commission to convert that program to a permanent program and also to extend that to business customers. That program was approved on December 1st, 2006. That program currently has around 37,000 participants in it. And based on the most latest data from the National Renewable Energy Lab, that was number three in the

Hearing Exhibit 000741

country in renewable energy sales through these types of programs.

In addition to that Florida Sunshine Energy program, there was a commitment to build solar. FPL has completed the development of Rothenbach Park, which is a 250-kW PV facility that's on and operating, and that's in Sarasota. It's the largest PV facility in Florida. And there have been numerous other smaller PV projects implemented through the program.

Q. Okay. Thank you for that summary. So is it my understanding then as far as all the renewable projects that FPL has had, Sunshine Energy is the one that's still current?

A. Yes, ma'am, that is correct.

Q. Okay. Well, let's talk about that Sunshine Energy program then, since that's the one that's still in effect. You stated that the Sunshine Energy program allows customers to voluntarily sign up and pay for energy produced by renewable sources; is that correct?

A. That is correct.

Q. Does FPL receive any benefits from the Sunshine Energy program?

A. Could you clarify for me what you mean by benefits?

Q. I guess I'm just trying to understand this.

Hearing Exhibit 000742

Customers are signing up voluntarily, so customers get a benefit of contributing to conservation measures. What does FPL get as a benefit for having customers sign up for this program?

A. The main benefit for FPL is to help create a renewable energy market in Florida. I think by programs like this, you know, it creates a mechanism by which renewable projects that wouldn't otherwise potentially be cost-effective or be able to be financed and built would not happen. So the Sunshine Energy program creates a pull on the market to generate new renewable facilities.

Q. And those new renewable facilities, are they built in Florida?

A. Some of them are or could be. I mean, the way the program is set up is, although we allow renewable energy credits from outside of Florida in the program, over time, we will move to have more and more of these renewable energy credits come from Florida sources. We need to create a demand for the renewable energy credits through our program that will encourage the development of renewable facilities in Florida.

Q. Okay. Thank you. And you also stated that the voluntary participants pay 9.75 per month for a 1,000 kilowatt-hour block of renewable energy

attributes; is that correct?

A. Yes. Renewable energy credits or attributes, yes, that is correct.

Q. Does that 1,000 kilowatt-hours of renewable energy credits defer any capacity on FPL's system?

A. No, it does not.

Q. And in your testimony, you state that FPL entered into a contract with a supplier for the purchase of these energy credits; is that correct?

A. We've actually entered into a contract with two different suppliers.

Q. Okay. Is there a reason why you have two different suppliers?

A. When we initially launched the program, we had one supplier that provided the tradeable renewable energy credits for residential customers, and that supplier provided more than just renewable energy credits. They also provided marketing and sales support for the program. When we launched the business program, we elected to go with a supplier just to provide the tradeable renewable energy credits.

Q. Okay. Thank you. In your testimony, you also say that in addition, for every 10,000 participants, FPL has agreed to have built 1,000 kilowatts of photovoltaic capacity in Florida; is that correct?

A. I believe we are committed to build 150 kW of photovoltaic or solar facilities for every 10,000 participants.

Q. And of those 10,000 participants, are you just counting the residential, or are you including residential and commercial?

A. Actually, the solar commitment only applies to residential customers.

Q. Okay. Now, this commitment that FPL has made, is it -- actually, let me backtrack a little bit. So FPL will build 150 kW of solar, is that correct, for every 10,000 customers on this program?

A. Yes. FPL will have 150 kW of solar facilities built for every 10,000 customers.

Q. Now, is there a time frame that these 150 kW of solar have to be built?

A. Our goal is to have the 150 kW built within one year of hitting that milestone.

Q. Okay. Turning to page 24 of your testimony, you talk a little bit about the program, and you state that by year-end of 2006, there were 28,742 customers; is that correct?

A. Yes, that is correct.

Q. And you stated that this program started in 2004; is that correct?

Hearing Exhibit 000745

A. The pilot of the program began in 2004, yes, that's correct.

Q. If you know, how many customers were enrolled in the program at the end of 2004?

A. I do not have that information with me.

Q. Okay. And I'm assuming the same response will stand for how many customers were enrolled at the end of 2005?

A. Unfortunately, yes, that's correct. I don't have that with me.

Q. Okay. Would you happen to know how many customers were enrolled in this program at the end of 2007?

A. Approximately 37,000.

Q. Okay. At this time, since you don't have this information with you, I would like to ask for a late-filed exhibit to show the total number of customers enrolled at the end of 2004, 2005, 2006, and 2007.

A. That's fine.

MR. HUNTOON: We can do that.

MS. FLEMING: Okay. Thank you.

(Late-filed Deposition Exhibit Number 1 was identified.)

BY MS. FLEMING:

Q. Going back to the 2006 numbers, because that's

Hearing Exhibit 000746

what you have in your testimony, you had 28,742 customers enrolled by the end of 2006. How many kW of PV were on-line by the end of 2006?

A. At the end of 2006, I'm not positive, but it was a very small number.

Q. Okay. And in your testimony, though, it states for every 10,000 customers, you would put on 150 kW of PV?

A. That's correct.

Q. So it would be maybe a little less than 300, is that correct, if my math is correct? I'm not a mathematician.

A. For 27,000 or --

Q. For the number of customers enrolled at the end of 2006.

A. 28,700. It would actually be close to -- I guess it all depends, based on how many customers I had at the end of 2005, because we try to get it done within a year.

Q. Okay. What I would request is a late-filed exhibit that shows the kW of PV that was on-line at the end of each year I guess from 2005 through 2007, since that way there's a comparison, somewhat of a time line, so we can see how many customers were on-line, how much PV was up in Florida, and so on and so forth. Does that

make sense?

A. Yes, it does.

Q. And that would be Late-filed Exhibit 2. And I'm trying to think of a name for it. Would it be appropriate to say PV capacity --

A. It would be okay to call it solar capacity.

Q. Okay. Solar capacity from 2005 through 2007?

A. That's fine.

(Late-filed Deposition Exhibit Number 2 was identified.)

BY MS. FLEMING:

Q. Now, would there be any solar capacity on-line in 2004?

A. No, there wasn't.

Q. Okay. So we'll keep it 2005 through 2007.

So as far as you know, though, has FPL remained current with this program in terms of putting in 150 kW of solar per 10,000 customers?

A. We were not current during 2005 and 2006. I'm fairly confident of that. I think it was primarily driven by issues of some site selection that we went through. We actually picked the site to do a project very similar to Rothenbach Park that just prior to construction -- it was actually a museum in Miami, and prior to construction, we were made aware that the

museum was going to move, so that didn't seem to be a very prudent decision to follow through on. And then the other major barrier in those early years was a fairly active hurricane season two years in a row that caused postponement of the construction and site selection of additional projects.

Q. So when FPL was -- I mean, wouldn't that result in some sort of deficiency in the program or a default in the program?

A. I do not believe so.

Q. Why is that?

A. Because I don't believe there's actually a time bound in the project on getting those built. We make our best efforts to try to get them built within one year.

Q. Okay. Thank you. Continuing on that same page, on lines 5 and 6, you state that the program purchased 1,894 gigawatt-hours of TRECs as of year-end 2006; is that correct?

A. Excuse me. Can you redirect me to the proper page?

Q. Oh, I'm sorry. It was page 24, lines 5 to 6.

A. I'm there. Thank you.

Q. Where it stated that the program purchased 1,894 gigawatt-hours of TRECs.

A. I see that, yes.

Q. Can you walk me through, I guess in layman's terms, what exactly is a TREC?

A. Sure. I'll be happy to. If you think about what makes these projects work, typically a renewable project has a cost per kWh or per kW that would be higher than traditional facilities that a utility might build. So a project developer that would like to build a renewable energy facility would typically have difficulty trying to secure financing for that project, because if you look at the traditional sources of revenue for that project, it would be selling the energy or the capacity to a utility, and the utility obviously is going to base that on their avoided cost or their incremental cost or some component similar to that. So in order -- because these projects actually are good for the environment, they create another revenue stream that people who are interested in encouraging the development of renewables are willing to fund.

So that's what these TRECs are. Basically, it's a separate revenue stream that really is focused on the environmental attributes of a renewable project. So a renewable developer can basically line up two revenue streams, one from a utility that it's going to sell the kilowatt-hour energy output to, and then this other

Hearing Exhibit 000750

revenue stream, which is the tradeable renewable energy attributes, and that would make the project financeable or a going project, you know, that you could actually build.

Q. Now, when you purchase these TRECs, when you purchase them, are they in Florida, or are they out of Florida?

A. Sunshine Energy buys TRECs both in Florida and out of Florida.

Q. For those that are purchased out of Florida, is there any benefit to the Florida consumers with those purchases?

A. I would say the benefit for the Florida consumers directly is that we've created a market for TRECs, and to the extent that without a pull or a customer demand for TRECs, then this whole TREC financial revenue stream that I talked about wouldn't exist. So as was the objective for Sunshine Energy, we have purchased TRECs from out of state. However, over time, our goal has been to purchase more and more of the TRECs in Florida. So we're using out-of-state TRECs right now in this program to meet customer demand, hoping that the demand will encourage enough new renewable development in Florida that we can move away from out-of-state TRECs.

Q. You just stated that with the Sunshine Energy, you're trying to purchase more and more in Florida, but you still currently purchase some out of state. If you can, what is the percentage of TRECs purchased in state versus out of state?

A. I don't have that with me.

Q. Is that something that you would be able to provide as a late-filed?

A. Absolutely.

Q. Okay. Let me get that as Late-filed 3.

A. That's fine.

Q. And if you can, help me with a title for this.

A. How about "TRECs Purchased for Sunshine Energy In State and Out of State"?

MS. FLEMING: Okay. That works for me. Thank you so much.

(Late-filed Deposition Exhibit Number 3 was identified.)

BY MS. FLEMING:

Q. Back to the 1,894 gigawatts. What is the real significance of purchasing that many gigawatts of TRECs?

A. The significance of purchasing that amount of TRECs shows how effective the program might be in encouraging customers to support renewable facilities and renewable projects.

Hearing Exhibit 000752

Q. Now, with the purchase of this, was actual energy delivered to Florida from the purchase of these TRECs?

A. No, not necessarily. Remember, the objective here is to create a market, a funding mechanism for the development of renewable energy. So the revenue stream created by purchasing the TRECs, that revenue stream is what will encourage the development of new renewable energy facilities in Florida and other places.

Q. So what type of results has FPL achieved with the Sunshine Energy program? I notice that you've mentioned that it's the third largest renewable energy program in the country, but what are the results that FPL has achieved with the Sunshine Energy program?

A. We have one of the largest number of program participants in the country. We have developed a pool of facilities that we'll provide you in a late-filed exhibit. I think we've increased our customers' awareness of the whole renewable energy market and brought the issue of environmental aspects to their information. We also, as I said, built the largest solar facility in Florida as a result of this program.

Q. Okay. Thank you. And you talk in your testimony also about the projects that have been developed with the Sunshine Energy program beginning on

Hearing Exhibit 000753

the page 25.

A. Yes, ma'am.

Q. If we can, I would like to talk about -- if you would, discuss each of those programs briefly, please.

A. The SunSmart Schools project is basically a project that we worked with to put PV facilities at four schools in our service territory. And along with those installations of those PV panels at the schools, there's also an education curriculum that was part of the installation where students could not only have the PV panels at their school, but also teach them the science and math around how PV panels work and what they might mean.

The second project is the Miami Science Museum, which is a small solar array. That's a museum in Miami that caters to families and children, and there's a display there that includes a 2-kW solar array that the Sunshine Energy program built there.

There's also a residential subdivision in Naples where we worked with the developer to put 54 kW of solar panels on homes.

And lastly is the construction of the 250-kW site in Sarasota at Rothenbach Park. That project is up and running, although it says in my testimony that it

Hearing Exhibit 000754

was to be completed in 2007, by October. But that is up and running.

What's interesting about that project is, that project was actually developed on a closed landfill. So not only do you have a closed landfill that you don't think about, you know, what are you going to do with it, it has also been, we've found, kind of a great environmental story for Sarasota County to take that landfill and turn it into something that improves the environment like the PV system that's there.

Q. Okay. And I would like to ask a couple of questions about each of those programs that you've discussed. Starting with the SunSmart Schools, you stated that this program is covering, I guess, four schools in your service area; is that correct?

A. That is correct.

Q. Is FPL looking at installing this or implementing this at other schools in the service area?

A. Yes, we are.

Q. Do you happen to know how many other schools?

A. I don't have that number with me.

Q. Okay. As far as the Miami Science Museum, you said it's a small project. It's only 2 kW of solar?

A. That is correct.

Q. Is there any possibility of expanding that

solar there at the Miami Science Museum?

A. Our plans right now are not necessarily to expand at that particular museum, but we are looking at and our plans do include trying to find additional public parks, museums, schools. You know, those types of public places is where we really want to focus going forward for the installation of these systems.

Q. So on a going-forward basis, FPL wants to look at public places to install these solar panels; is that correct?

A. That is correct.

Q. So FPL is considering then other projects for the Sunshine Energy program?

A. Oh, absolutely.

Q. At this point, do you happen to know what is the kW of the solar capacity that FPL is expecting to achieve with these new projects?

A. I don't know specifically. We're still trying to identify sites. But obviously, our goal is to continue to meet the commitment that we have for 150 kW for every 10,000 participants.

Q. Those projects that you're talking about on a going-forward basis, do you have the timing of any of those projects? Are any that are near finalization, I guess the finalizing stages?

A. We are working on one with the Florida Energy Office to try to get those done, and we're hoping to get those done, I think, within the next several months.

Q. Do you happen to know how much kW of solar that would include with that project?

A. I don't know that.

Q. Okay. And you stated that the project with the Florida Energy Office, you intend to get it started within the next several months. Is there --

A. That's actually out there right now. We're soliciting participants. We also have another project where we're working with a grocery chain to try to promote Sunshine Energy through a couple of their stores.

Q. Do you know the timing of that one, when that may be implemented?

A. That's supposed to be done, I would say, within the next four or five months.

Q. Okay. Turning back to the other projects you had identified, you identified 54 kW on homes in the Naples area; is that correct?

A. Yes, that is correct.

Q. The subdivision, The Quarry, how was that subdivision selected?

A. We basically worked with the developer of the

Hearing Exhibit 000757

subdivision, and he was interested in trying to promote renewables as part of his subdivision.

Q. And what benefits did the developer get from promoting the subdivision as a green --

A. I would assume he was trying to differentiate himself from all the other developments that are going on in that area.

Q. Do you know how well this program is doing there in that subdivision?

A. Well, this program is done in that subdivision. We've elected not to do any more there.

Q. Okay. So who benefits from this program? Is it just the residents in that subdivision?

A. Absolutely not. I think all the participants in the program benefit.

Q. Well, can you explain to me how that works? If you put solar panels on someone's home in a subdivision, how does that work with their utility bill, and how does that help the general body of customers for FPL?

A. Okay. Let's talk about the customers that had the PV panels put on their roof. First of all, because the PV panels put down energy, their electric bill with FPL would be less. That's pretty straightforward.

All customers in the program benefit, because

once again, it creates significant awareness about the technology. It helps drive the technology to be more cost-competitive. It lowers the barriers to get these types of things installed. So it makes this whole area of renewables much, much more market-ready, which is -- if you think about the battle we're facing, we're trying to make it cost-competitive and pervasive. And by doing these types of things, you create awareness, you create market pull, and hopefully you stimulate the market to get more and more of these things done.

Q. Okay. Thank you very much. Well, with all these -- I think the other one you mentioned was the Rothenbach Park; is that correct?

A. That is correct.

Q. And it was developed at a closed landfill?

A. That is correct.

Q. And you stated that it is currently operating; is that correct?

A. Yes, that is correct.

Q. And is FPL looking at other large projects such as the one of this size?

A. I'm not sure we would do another one of that size. I think we're looking more at, as I said, public places. Rothenbach Park was unique. You know, there was a strong interest by a county. There was a good

Hearing Exhibit 000759

site. Although it was a closed landfill, it was a large area. To put it in perspective, Rothenbach Park is about half the size of a football field. And, you know, there was a willingness to do all that. If we ran across something like that, we would obviously consider it. We haven't run across another opportunity like that thus far.

Q. Now, you stated that FPL on a going-forward basis will be having this program, I guess, in public places. Has FPL considered possibly offering this program to all its customers?

A. We do offer the Sunshine Energy program to all of our customers.

Q. I'm sorry. I guess I didn't phrase that correctly. Do you offer -- has FPL considered offering the option to all its customers of putting rooftop solar on their homes? I guess that's a better way to --

A. That is actually part of what the FPL effort is that I described. We're working through the Florida Energy Office to work together to try to identify those situations.

Q. All right. Now, is the Sunshine Energy program taken into account in FPL's DSM goals?

A. No, it is not.

Q. Are any energy or capacity savings from the

Hearing Exhibit 000760

Sunshine Energy program included in FPL's load forecast?

A. I do not believe so.

Q. Okay. Does the Sunshine Energy program or will the Sunshine Energy program affect FPL's need for Turkey Point 6 and 7?

A. Absolutely not.

MS. FLEMING: Okay. Let me check my questions and see if I have any other follow-up.

Mr. Brandt, I think that's all we have.

THE WITNESS: Okay. Thank you.

MS. FLEMING: And let me check. Is there anyone else on the phone that called in during the questioning that has questions?

MR. BECK: Katherine, this is Charlie Beck. I have no questions.

MS. FLEMING: Okay. Thank you. Anyone else? Mr. Huntoon?

MR. HUNTOON: No, we don't have anything further.

MS. FLEMING: All right. So I think we are done here, and now we're off the record.

(Deposition concluded at 2:56 p.m.)

Hearing Exhibit 000761

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that a review of the transcript was requested; that my shorthand notes were thereafter translated under my supervision; and that the foregoing pages numbered 1 through 38 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 20th day of January, 2008.

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

Hearing Exhibit 000762

CERTIFICATE OF OATH

STATE OF FLORIDA

COUNTY OF MIAMI-DADE

I, the undersigned authority, certify that C. Dennis Brandt personally appeared before me at 9250 West Flagler Street, Miami, Florida 33174, and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Miami, County of Miami-Dade, State of Florida, this 18th day of January, 2008.

Debra Ann Dominguez

Notary Public

State of FLORIDA

Personally known to me OR produced identification —.

Type of identification produced —.

Debra Ann Dominguez
Commission # DD312184
Expires: April 20, 2008
Bonded thru 1-800-350-5161

ASR ACCURATE STENOTYPE REPORTERS INCORPORATED
CERTIFIED COURT REPORTERS

January 21, 2008

John Butler, Esquire
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Need Determination for Turkey Point 6 and 7
Docket No. 070650-EI

Dear Mr. Butler:

Enclosed is your copy of the deposition of C. Dennis Brandt taken in the above matter on January 18, 2008.

Since reading and signing was not waived, we are enclosing an errata sheet and request that your office make arrangements with the witness to read the deposition and make any corrections on the errata sheet.

Please forward the original completed errata sheet to Jane Faurot at the Commission for attachment to the original transcript. You should also attach a copy to your transcript so that it will be complete.

Thank you for your cooperation in this matter. It was a pleasure working with you.

Sincerely,

Mary A. Neel

Mary A. Neel

/mn
cc: Jane Faurot
Enclosures

ERRATA SHEET

Under penalties of perjury, I declare that I have read the foregoing transcript of my deposition, pages 1 through 39, and that the facts stated therein are true, including any corrections and/or amendments listed below.

1/23/08
Date

C. Dennis Brandt
C. DENNIS BRANDT

Page	Line	Correction or Amendment	Reason for Change
13	1	Add 'it' after 'that'	Correction
17	25	Add 'they' after 'resilient'	Correction
17	25	Change 'shave' to 'shape'	Correction
18	16	Change '100' to '1000'	Correction
35	23	Change 'down' to 'out'	Correction

Deposition taken on 01/18/08, Docket No. 070650-EI

Brandt Deposition
Docket No. 070650-EI
Late Filed Exhibit # 1

Sunshine Energy Program
Year-end Participation

Year	Total Participants
2004	10,785
2005	23,059
2006	28,742
2007	37,181

Brandt Deposition
Docket No. 070650-EI
Late Filed Exhibit # 2

Sunshine Energy Program
Solar Capacity

Year	kW Capacity
2005	0
2006	0
2007	319

Brandt Deposition
Docket No. 070650-EI
Late Filed Exhibit # 3

Sunshine Energy Program
TRECs Purchased In State vs. Out of State

Year	In State TRECs	Out of State TRECs
2004	20,531	30,797
2005	106,885	117,709
2006	136,257	166,535
2007	97,017	276,730

Florida Power & Light Company

Biographical Information

Armando J. Olivera
President

Armando Olivera is president of Florida Power & Light Company (FPL), the principal subsidiary of FPL Group, Inc., and one of the largest investor-owned electric utilities in the nation. He was appointed president in June 2003.

Under Mr. Olivera's leadership, FPL has invested heavily in ensuring reliable service and meeting strong current and projected growth in demand for electric power in its vast service territory. FPL has one of the most efficient fossil power plant fleets in the nation and has taken a number of additional actions to mitigate high fuel costs. The company has implemented an industry-leading program to harden its electric system against hurricanes as well as ensure everyday reliability.

Mr. Olivera joined FPL in 1972 and has served in a variety of management positions in the areas of transmission and distribution operations, fuels management, and strategic planning and resource allocation. His prior position before becoming president was as senior vice president of Power Systems.

Mr. Olivera holds a Bachelor of Science degree in electrical engineering from Cornell University and a master of business administration degree from the University of Miami. He also is a graduate of the professional management development program of the Harvard Business School.

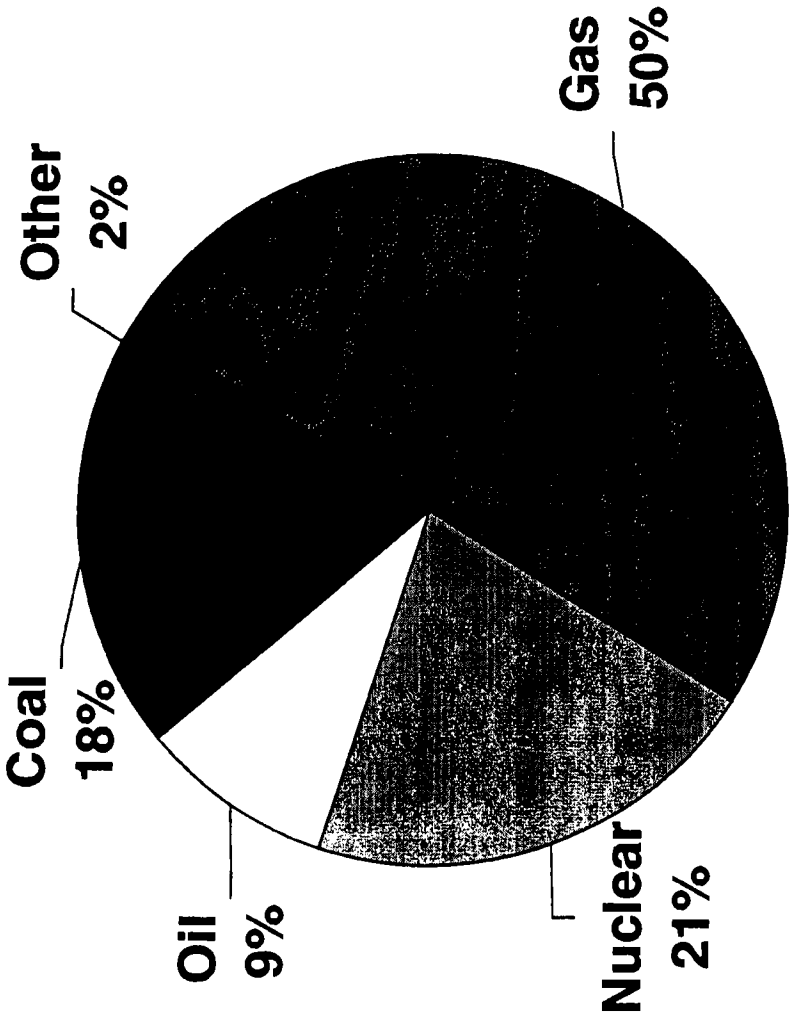
In 2007, Mr. Olivera was appointed by Florida Governor Charlie Crist to serve on the Florida Governor's Action Team on Energy and Climate Change, which is tasked with developing a comprehensive strategy that achieves targets for statewide greenhouse gas reductions.

He is the current president of the Southeastern Electric Exchange, immediate past Chairman of the Florida Reliability Coordinating Council (FRCC), and a member of the board of Enterprise Florida, as well as a member of Cornell University Engineering Council and Cornell University Council.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 16
COMPANY FL Power + Light (Direct)
WITNESS Armando J. Olivera (AJO-1)
DATE 01/30-02/01/08

Docket No. 07 _____ - EI
Actual Energy Mix 2006
Exhibit RS–1, Page 1 of 1

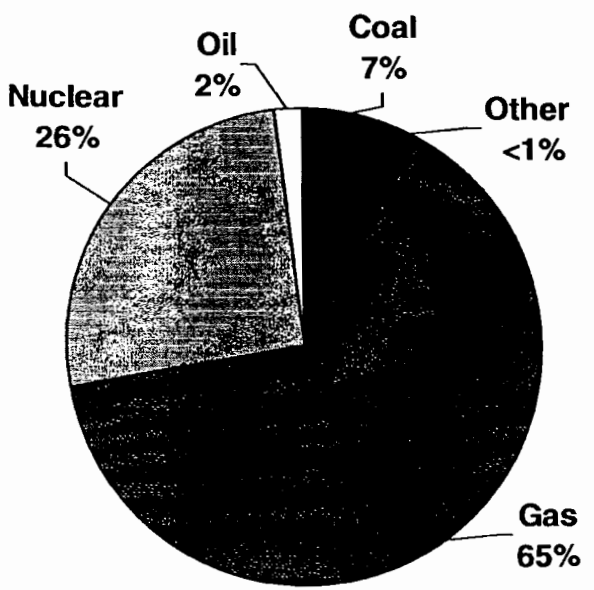
Actual Energy Mix 2006



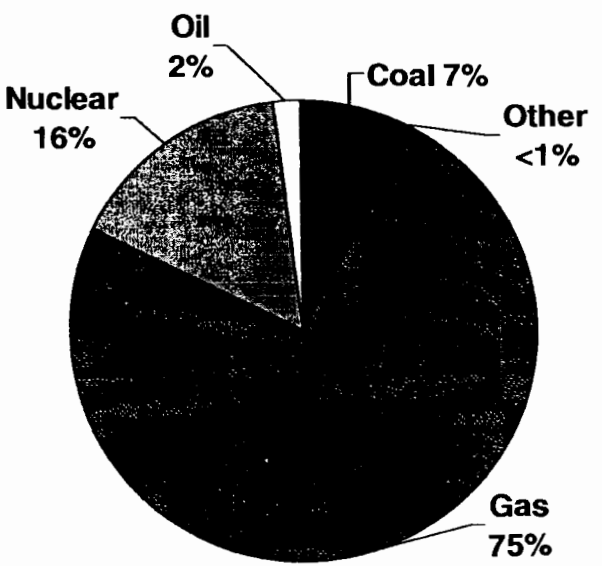
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 17
COMPANY FL Power + Light (Direct)
WITNESS Rene Silva (RS-1)
DATE 01/30 - 02/01/08

Projected Energy Mix
2021

With Turkey Point 6 & 7



With "All Gas" Additions



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 18
COMPANY FL Power + Light (Direct)
WITNESS Rene Silva (RS-2)
DATE 01/30-08/01/08

Docket No. 07 _____ - EI
Projected Energy Mix 2021
Exhibit RS-2, Page 1 of 1

FPL's Flexibility to Incorporate Increased DSM and Renewable Resources

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 19
COMPANY FL Power & Light (Direct)
WITNESS Rene Silva (RS-3)
DATE 01/30-02/01/08

Docket No. 07_____ - EI
Resource Need
Exhibit RS-3, Page 1 of 1

Turkey Point 6 & 7

Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios

Plan with Nuclear vs. Plan without Nuclear-CC

Breakeven Nuclear Capital Costs ($/kW in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
ENV I	6,157	4,543	3,206
ENV II	6,701	5,065	
ENV III	6,949	5,327	
ENV IV	7,281	5,680	

Plan with Nuclear vs. Plan without Nuclear-IGCC

Breakeven Nuclear Capital Costs ($/kW in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
ENV I	6,725	6,212	5,921
ENV II	7,996	7,487	
ENV III	8,630	8,123	
ENV IV	9,450	8,956	

NUCLEAR COMPARED TO CC

In 8 of 9 outcomes (bold) the breakeven cost is above the entire nuclear cost range, so almost every outcome is favorable to nuclear generation

In the one remaining outcome the breakeven cost is within the nuclear cost range, so here nuclear is competitive with gas generation; but if this scenario were to occur, it would result in the lowest cost to customers, whether adding nuclear or gas generation

NUCLEAR COMPARED TO IGCC

All 9 outcomes (bold) have a breakeven cost that is significantly above the nuclear cost range, so all outcomes are favorable to nuclear generation

Note: The nuclear cost range is estimated between $3,108/kW and $4,540/kW

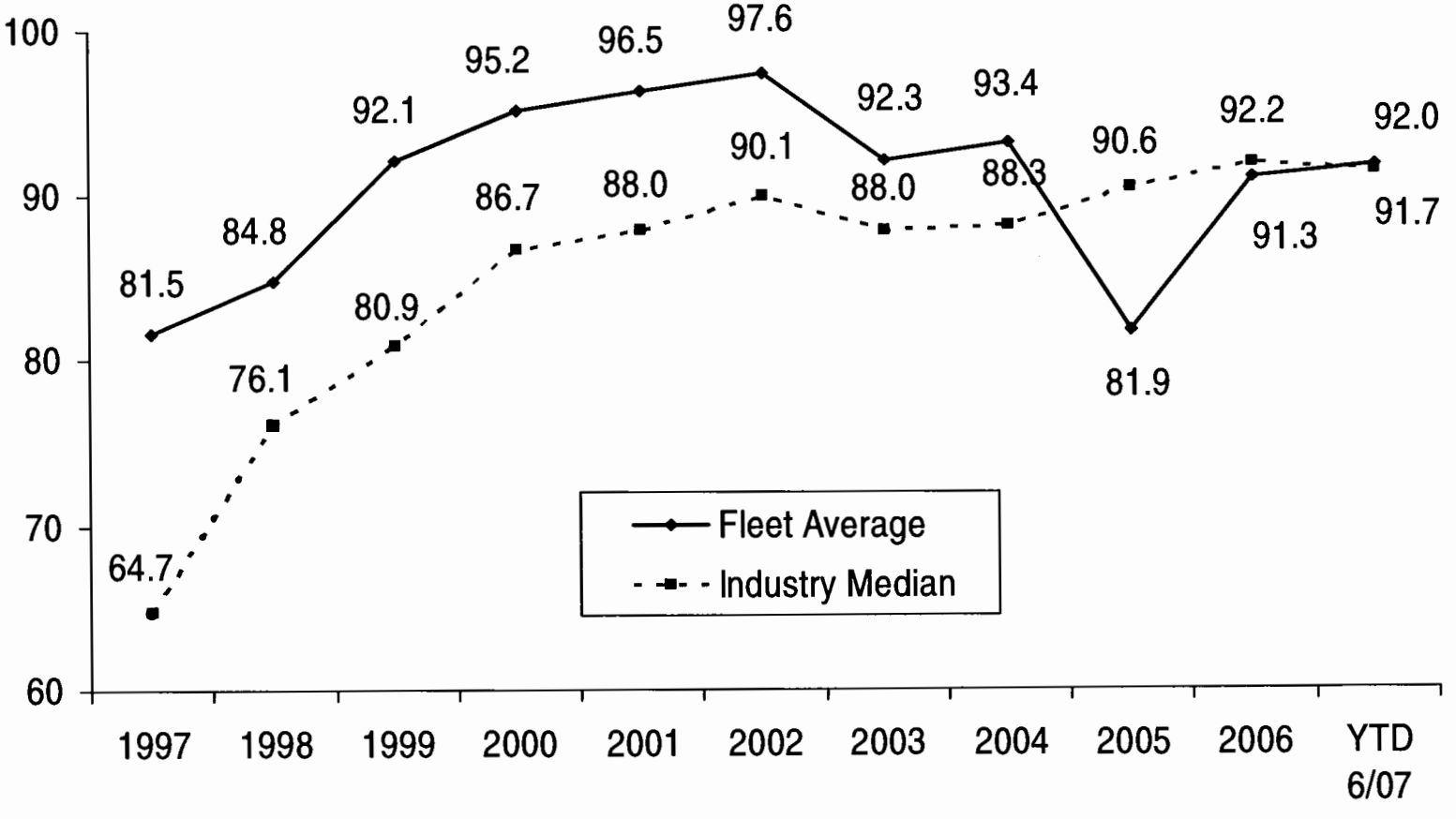
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 07065-EI EXHIBIT 20
COMPANY FL Power & Light (Direct)
WITNESS Rene Silva (RS-4)
DATE 01/30 - 02/01/08

Docket No 07_____-EI
Economic Analysis Results:
Breakeven Cost for Nuclear Capital Costs
Exhibit RS-4, Page 1 of 1

WANO Index – Fleet Performance

1997 – Year-to-Date 6/30/07

(Average of 4 sites)



Seabrook added to fleet in 2003; Duane Arnold added to fleet in 2006

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 21
COMPANY FL Power & Light (Direct)
WITNESS S. A. Stall (SAS-1)
DATE 01/30-02/01/08

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WANO Indices
Exhibit JAS-1, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 22
COMPANY FL Power & Light (Direct)
WITNESS J. A. Stall (JAS-2)
DATE 01/30-02/01/08

NRC Performance Indicators

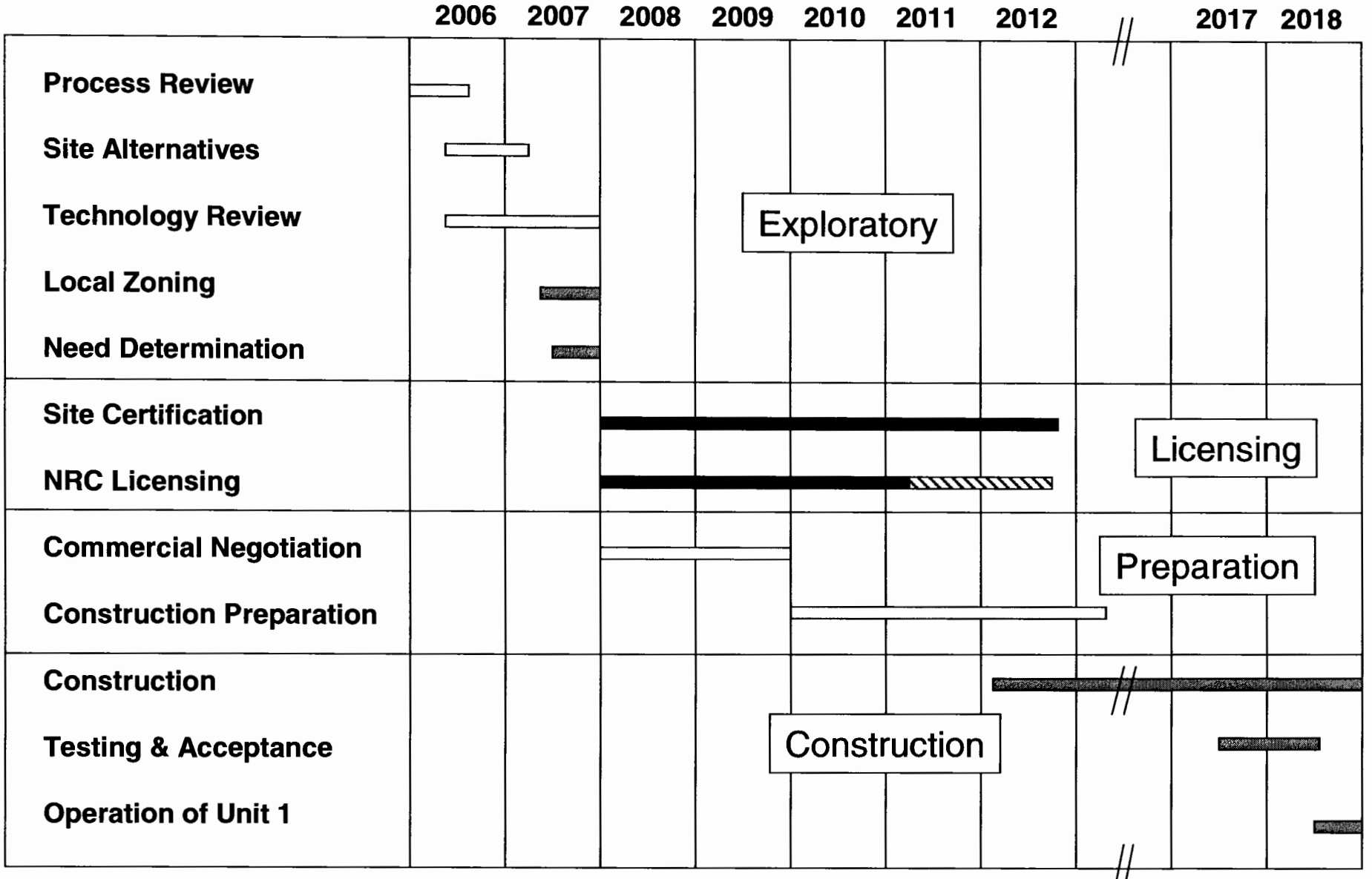
	Turkey Point Unit 3	Turkey Point Unit 4	St. Lucie Unit 1	St. Lucie Unit 2	Seabrook Station	Duane Arnold
Initiating Events Cornerstone						
Unplanned reactor scrams per 7000 critical hours (automatic and manual)	Green	Green	Green	Green	Green	Green
Unplanned reactor scrams with loss of normal heat removal	Green	Green	Green	Green	Green	Green
Unplanned Power Changes per 7000 critical hours	Green	Green	Green	Green	Green	Green
Mitigating Systems Cornerstone						
Mitigating System Performance	Green	Green	Green	Green	Green	Green
Safety System Functional Failures	Green	Green	Green	Green	Green	Green
Barriers Cornerstone						
RCS Activity	Green	Green	Green	Green	Green	Green
RCS Leakage	Green	Green	Green	Green	Green	Green
Emergency Preparedness Cornerstone						
Emergency Response Organization (ERO) drill/exercise performance	Green	Green	Green	Green	Green	Green
ERO Drill Participation	Green	Green	Green	Green	Green	Green
Alert and Notification System Performance	Green	Green	Green	Green	Green	Green
Occupational Radiation Safety Cornerstone						
Occupational Exposure Control Effectiveness	Green	Green	Green	Green	Green	Green
Public Radiation Safety Cornerstone						
RETS/ODCM Radiological Effluent Occurrence	Green	Green	Green	Green	Green	Green
Physical Protection Cornerstone						
Protected Area Security Equipment Performance Index	Green	Green	Green	Green	Green	Green
Personnel Screening Program Performance	Green	Green	Green	Green	Green	Green
FFD/Personnel Reliability Program Performance	Green	Green	Green	Green	Green	Green

Acceptable Performance Licensee Response Band	Green	Acceptable Performance Increased Regulatory Response Band	White	Acceptable Performance Required Regulatory Response Band	Yellow	Unacceptable Performance Plants not normally permitted to operate within this band	

Docket No. 07____-EI
NRC Performance Indicators
Exhibit JAS-2, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 23
COMPANY FL Power & Light (Direct)
WITNESS Steven D. Scroggs (SDS-1)
DATE 01/30-02/01/08

Illustrative Deployment Process Timeline



Docket No. 07____-EI
Development Process Timeline
Exhibit SDS-1, Page 1 of 1

FLORIDA POWER & LIGHT COMPANY
PROJECT BLUEGRASS
NEW NUCLEAR POWER GENERATION

FINAL

SITE SELECTION STUDY REPORT

October 2006

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 24
COMPANY FL Power + Light (Direct)
WITNESS Steven D. Scroggs (SDS-2)
DATE 01/30-02/01/08

Florida Power & Light Company
Project Bluegrass
Nuclear Power Plant Site Selection Study Report

FINAL

October 2006

Acronyms and Abbreviations
1.0 Background and Introduction
2.0 Siting Process Overview
3.0 Potential Site Selection
4.0 Evaluation of Potential Sites and Identification of Candidate Sites
5.0 Evaluation of Candidate Sites and Identification of Alternative Sites
6.0 Selection of Proposed Site

Appendix A – Weight Factor Development
Appendix B – Technical Basis for Screening Criterion Ratings
Appendix C – Technical Basis for General Site Criterion Ratings

Acronyms and Abbreviations

%g	percent of gravity
AAA	American Automobile Association
AFB	Air Force Base
bgs	below ground surface
CFR	Code of Federal Regulations
cfs	cubic feet per second
CH	Critical Habitat
COL	Combined Operating License
COLA	Combined Operating License Application
E	Endangered
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
F	Fahrenheit
FDEP	Florida Department of Environmental Protection
FEMA	Federal Emergency Management Agency
FIRM	Flood Insurance Rate Maps
FPL	Florida Power & Light Company
ft	feet
ft^2	square feet
gpd	gallons per day
gpm	gallons per minute
in	inches

kV	kilovolts
MDWASD	Miami-Dade County Water and Sewer Department
mgd	million gallons per day
mi	miles
MSA	Metropolitan Statistical Area
MSL	Mean Sea Level
NAVD	North American Vertical Datum
NCDC	National Climate Data Center
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NP	Nuclear Plant
NRC	Nuclear Regulatory Commission
NRHP	National Register of Historic Places
NUREG	Nuclear Regulatory Commission Regulation
NWI	National Wetlands Inventory
NWR	National Wildlife Refuge
OFW	Outstanding Florida Waters
Okee	Okeechobee
PE	Probability of Exceedance
PGA	Peak Ground Acceleration
PPE	Plant, Property, and Equipment
psm	persons per square mile
ROI	Region of Interest
ROW	Right of Way
RR	Railroad
RTE	Rare, Threatened, and Endangered
S/A	Similar in Appearance
sq. mi.	square miles
T	Threatened
T&E	Threatened and Endangered
tbd	to be determined
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
WCA	Water Conservation Area
WMA	Wildlife Management Area
WWTP	Waste Water Treatment Plant
yr	year

1.0 Background and Introduction

Florida Power & Light Company (FPL) intends to prepare a Combined Operating License Application (COLA) for a new nuclear power plant. An early step in this process is selection of a site that will provide the geographic setting for the COLA. This *Siting Plan* provides a description of the bases, assumptions, and processes applied in selecting the FPL COL site.

The purpose of the new Nuclear Power Plant Project is to provide needed generating capacity to FPL's customers that will enhance the fuel diversity and fuel supply reliability of FPL's fleet, reduce emissions from the FPL system on a per-kilowatt basis, and help balance the generation and load in Southeast Florida.

The overall objective of the siting process was to identify a nuclear power plant site that 1) meets FPL's business objectives for the COL project, 2) satisfies applicable Nuclear Regulatory Commission (NRC) site suitability requirements, and 3) is compliant with National Environmental Policy Act (NEPA) requirements regarding the consideration of alternative sites.

Sites were evaluated based on a bounding set of site-related plant characteristics that define the nuclear plant physical site suitability requirements. This set of parameters is analogous to the Plant Parameter Envelope defined in NEI-01-04, "Industry Guideline for an Early Site Permit License Application – 10 CFR Part 52, Subpart A." Site requirements and plant interface parameters used in the siting evaluations were derived from "Florida Power & Light Company, Project Bluegrass New Nuclear Power Generation Project: Site Requirements Document to support Combined Construction and Operating License Application (COLA)", Revision B, July 24, 2006.

Processes for site selection also take into account that existing sites have special status with NRC regarding consideration of alternative sites. For example, guidance provided to NRC staff on their review of alternative site analyses (NUREG-1555, Section 9.3, III [8]) states, in part [emphasis added]:

> "*Recognize that there will be special cases in which the proposed site was not selected on the basis of a systematic site-selection process.* Examples include facilities proposed to be constructed on the site of an existing nuclear power facility previously found acceptable on the basis of a NEPA review and/or demonstrated to be environmentally satisfactory on the basis of operating experience..."

An overall description of the siting process is provided in Section 2.0; additional detail on component steps in the site selection process is provided in succeeding sections.

2.0 Siting Process Overview

Site selection was conducted in accordance with the overall process outlined in the EPRI *Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application* (Siting Guide), March 2002. This process, as adapted for the FPL site selection study, is depicted in Figure 2-1.

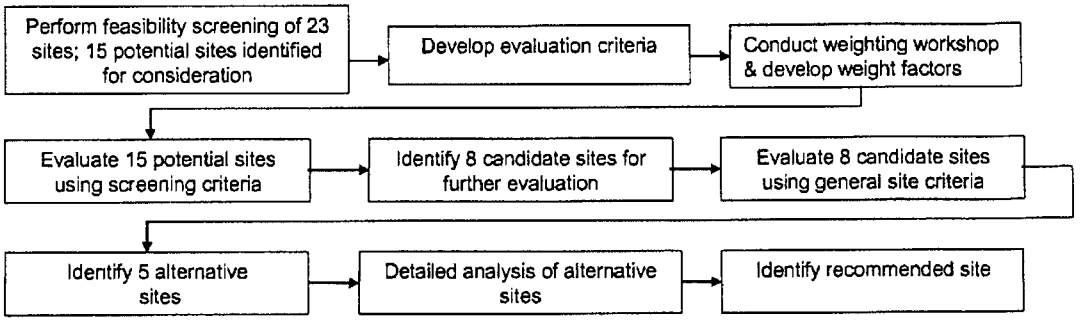


Figure 2-1 Site Selection Process Overview

A team composed of personnel from Enercon Services, Inc. and McCallum-Turner, Inc. was established to perform the analyses required under the site-selection process. The Enercon/McCallum-Turner team initiated data collection and analysis to support evaluation of the 15 identified potential sites. Screening-level criteria developed from the EPRI Existing Site Criteria (Table 4.2 of the EPRI *Siting Guide*) were developed and applied. Based on the results of evaluation of the 15 sites potential sites against the screening criteria, a down-select of eight candidate sites was made.

Using available data and criteria developed based on the EPRI general site criteria (Section 3.0 of the EPRI *Siting Guide*), detailed site-suitability evaluations of the candidate sites was conducted. Overall composite site-suitability ratings were developed for the eight candidate sites. Based on these ratings, five sites were identified as alternative sites. A recommended site for the new nuclear power plant was selected based on the composite ratings and other applicable considerations related to FPL business plans and objectives.

3.0 Potential Site Selection

The Region of Interest (ROI) for the FPL siting study was defined as areas within or immediately adjacent to the FPL service territory. Within that ROI, 23 sites were identified by FPL as locations that could be evaluated for the COL and, potentially, a new nuclear power plant. These sites, which included existing power plant sites and greenfield sites previously identified by FPL, represented the full suite of siting tradeoffs available within the ROI and therefore provided a basis for evaluation of a reasonable set of alternative locations.

FPL and Enercon/McCallum-Turner team personnel reviewed this set of sites in a joint meeting on August 1, 2006, to identify the final set of potential sites for this study. The following groups of sites were reviewed.

FPL Existing Sites

Twelve existing FPL power-generating sites were considered. Two of the sites are existing nuclear power generating plants.

- Canaveral
- Cutler
- Ft. Myers
- Lauderdale
- Manatee
- Martin
- Port Everglades
- Putnam
- Riviera
- Sanford
- St. Lucie (existing nuclear)
- Turkey Point (existing nuclear)

Additionally, three FPL-owned greenfield sites were considered:

- Andytown
- DeSoto
- West County

Finally, eight non-FPL-owned greenfield sites were considered; these sites were identified by the FPL corporate real estate department as being potentially available and feasible sites for new power generation projects:

- Charlotte
- Glades
- Hardee
- Hendry (2 locations)
- Highlands
- Okeechobee (2 locations)

Each of the sites was evaluated qualitatively with respect to the following considerations:

- Sufficient land currently exists for new nuclear power plant construction;
- Sufficient land can be obtained for new nuclear power plant construction;
- Adequate sources of water; and
- Transmission feasibility.

Using this process, the following 15 potential sites were identified for further consideration; these sites are depicted in Figure 3-1:

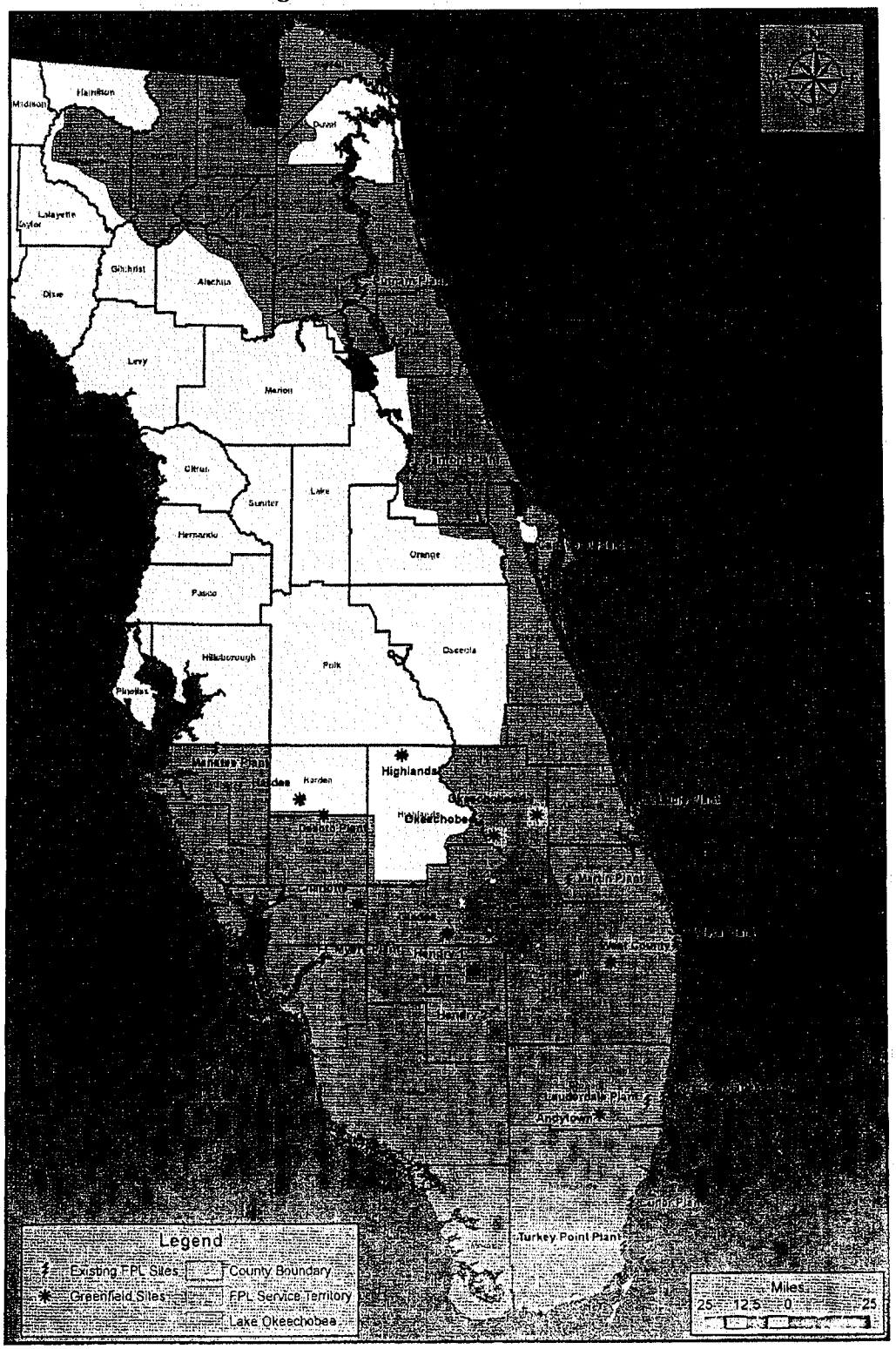
- Charlotte
- DeSoto

- Ft. Myers
- Glades
- Hardee
- Hendry (2 locations)
- Highlands
- Manatee
- Martin
- Okeechobee (2 locations)
- St. Lucie
- Turkey Point
- West County

Sites in the northern part of the ROI (Putnam, Sanford, Canaveral), as well as the Cutler site, were eliminated due to transmission feasibility; these sites are located far from the FPL load centers, and/or right-of-way acquisition would be difficult, and/or their transmission connections would have to be coordinated with other utilities. In addition, the Cutler, Sanford and Canaveral sites do not have adequate land area, and additional land could not feasibly be acquired.

The Andytown, Lauderdale, Port Everglades, and Riviera sites were eliminated from further consideration because these sites do not include enough land for a new nuclear power plant and additional land cannot be feasibly acquired in the time-frame required to support the FPL COLA schedule.

Figure 3-1 Potential Site Locations



4.0 Evaluation of Potential Sites and Identification of Candidate Sites

4.1 Potential Site Evaluation

The overall process for screening-level evaluation of potential sites was composed of the following elements; each element is described in the following paragraphs.

- Develop criterion ratings for each site;
- Develop weight factors reflecting the relative importance of each criterion; and
- Develop composite site-suitability ratings.

Criterion Ratings – Each potential site was assigned a rating of 1 to 5 (1 = least suitable, 5 = most suitable) for each of the screening criteria, using the rationale listed in Table 4-1. Information sources for these evaluations included publicly available data, data available from FPL files and personnel, and large-scale satellite photographs.

Weight Factors – Weight factors reflecting the relative importance of these criteria were developed by a multi-disciplinary committee in the areas of nuclear power plant site suitability that was convened at FPL offices on August 29, 2006; this committee was composed of subject matter experts in water use and availability, engineering, real estate, ecology, transmission, land use, health & safety, socioeconomics and public relations. The weight factors were derived using methodology consistent with the modified Delphi process specified in the Siting Guide (see Appendix A). Weight factors used (1 = least important, 10 = most important) are listed in the table below.

Criterion Number	Criterion	Weight Factor
P1	Cooling Water Supply	9.5
P2	Flooding	3.9
P3	Population	7.6
P4	Hazardous Land Uses	5.0
P5	Ecology	6.1
P6	Wetlands	6.4
P7	Railroad Access	5.6
P8	Transmission Access	8.5
P9	Land Acquisition	6.5

Composite Suitability Ratings – Ratings reflecting the overall suitability of each site were developed by multiplying criterion ratings by the criterion weight factors and summing over all criteria for each site.

Criteria presented in Table 4-1 were derived from the larger set of more detailed criteria listed in Chapter 3 of the EPRI *Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application* (Siting Guide), March 2002. They are intended to provide insights into the overall site suitability trade-offs between the potential sites and to take advantage of data available at this stage of the site selection process.

Table 4-1 Screening Evaluation Criteria

Criterion Number	Criterion	Measure of Suitability	
		Metric	Rating Rationale
P1	Water Supply	Composite ratings were based on an average of ratings for the following four aspects: **Flow –** Surface water: Low daily mean flow for the period of record as reported by USGS. Reclaimed water: WWTP flow reported by FDEP available for re-use on a county basis. Groundwater: Flow estimated based on FPL familiarity with Floridan aquifer, where feasible. Lake Okeechobee: Conservatively estimated to be at least the lower of the low daily mean flow reported for the C44 and C43 canals.	5 = No practical restriction 4 = Greater than 5 times the requirement 3 = 3-5 times the requirement 2 = Less than 3 times the requirement 1 = Insufficient flow *Note: A sensitivity analysis was performed regarding the rating rationale presented above. An alternate rating scale was developed that consisted of:* *1= Insufficient flow* *2=1 times the required flow* *3=1 to 3 times the required flow* *4=3 to 5 times the required flow* *5= No practical restriction.* *Applying this alternate rating rationale resulted in no substantial changes in the composite ratings [a flow sub-rating change at one of the sites (+1 at Charlotte) was calculated]. The original rationale presented above was used for the final criterion rating.*
		Flexibility – Number of alternate source(s) of water present and capable of providing substantial portion of required flow.	5 = Multiple sources each capable of full flow required 4 = Additional sources capable of providing substantial portion of flow 3 = One source capable of providing full flow 2 = Multiple sources each capable of providing substantial portion of flow with no single source providing full flow requirements 1 = Insufficient flow regardless of number of sources

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Criterion Number	Criterion	Measure of Suitability	
		Metric	Rating Rationale
		Risk – Associated with flow variability, longer pumping distances and/or other reliability aspects of water supply.	5= All aspects favorable 4= Some favorable aspects 3= Neutral 2= Some risk 1= Substantial risk
		Regulatory Challenge – Known areas with elevated competition for water resources, a high number of water users, difficult supply conditions or challenging compliance situation are ranked lower than those without such challenges, based on judgment.	5= All aspects favorable 4= Some favorable aspects 3= Neutral 2= Some challenges 1= Substantial challenges
P2	Flooding	Difference between mean site elevation and mean water elevation from USGS topographic maps, USGS gaging station measurements.	5 = Greater than 20 feet 4 = Between 20 feet and 10 feet 3 = Between 10 feet and 6 feet 2 = Between 6 feet and 3 feet (or near swamp lands) 1 = Less than 3 feet (or in swamp lands)

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Criterion Number	Criterion	Measure of Suitability	
		Metric	Rating Rationale
P3	Population	Composite ratings were based on an average of ratings based on the following two conditions: (1) Distance to nearest population center (high density); and (2) Population density of host county (based on 2000 census). In addition, a rating point was deducted or added if the site is or is not in a particularly densely populated area.	5 = No population centers within 20 miles 4 = Population centers between 20 and 15 miles 3 = Population centers between 15 and 10 miles 2 = Population centers between 10 and 5 miles 1= Population centers within 5 miles County Population Density Ratings: 5 = Less than 50 persons per square mile (psm) 4 = Between 250 psm and 50 psm 3 = Between 350 psm and 250 psm 2 = Between 500 psm and 350 psm 1 = Greater than 500 psm A point was added if no densely populated area is found within 40 miles of the site; a point deducted if a densely populated area is found within 15 miles of the site or if a large grouping of densely populated areas are located within 15-40 miles of the site.
P4	Hazardous Land Uses	Number of airports, pipelines, and other known hazardous industrial facilities (including Air Force Bases and Kennedy Space Center/Cape Canaveral), as determined from publicly available data.	5 = No major airport, city or county airport, military base, or rail within 10 miles [small air fields/landing strips are allowed if no more than 2 within 5 miles] 4 = No major airport (or Air Force Base) within 10 miles, no rail, pipeline small city or county airport within 5 miles [1-2 small air fields/landings strips are ok] 3 = Rail and small airports (multiple) < 5 miles 2 = Major airport or Air Force Base < 10 miles 1 = Major airport or Air Force Base < 10 miles, rail and multiple small airports < 5 miles, and existing plant location
P5	Ecology	Number of Federal Threatened, Endangered and Rare Species in County [aquatic and terrestrial]	5 = 0 species 4 = 1-10 species 3 = 11-20 species 2 = 21-30 species 1 = over 30 species
P6	Wetlands	Number of mapped wetland acres within a 5,000 acre nominal site area*, excluding riverine or marine areas.	5 = 0 acres 4 = Between 0 acres and 250 acres 3 = Between 250 acres and 500 acres 2 = Between 500 acres and 1,500 acres 1 = Greater than 1,500 acres

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Criterion Number	Criterion	Measure of Suitability	
		Metric	Rating Rationale
P7	Railroad Access	Estimated cost of constructing a rail spur to the site, based on distance in miles to the nearest in-service rail line.	Ratings computed by scaling costs from lowest (rating = 5) to highest (rating = 1). 1 = More than 15 miles 2 = Between 15 miles and 10 miles 3 = Between 10 miles and 5 miles 4 = Between 5 miles and 2 miles 5 = Fewer than 2 miles Note: Ratings may be adjusted if barge access is located in the immediate vicinity in lieu of railroad access.
P8	Transmission Access	Transmission access is evaluated in the preliminary screening in terms of distance to the load center in the greater Miami area (Palm Beach, Broward, and Miami-Dade Counties) and amount of new right-of-way that would have to be acquired.	Ratings computed by measuring distances to greater Miami Area Load Center and considering high-level evaluation of transmission issues. 1 = More than 200 miles 2 = Between 200 miles and 100 miles 3 = Between 100 miles and 70 miles 4 = Between 70 miles and 50 miles 5 = Fewer than 50 miles Ratings points adjusted based on amount of new right-of-way that must be acquired and the relative difficulty of acquisition. The plant switchyard is assumed to be the same for all sites.
P9	Land Acquisition	Estimated cost of acquiring land (nominally 3,000 acres**) at the site, based on the following cost/acre assumptions: – very remote areas - $8,000 - $12,000 [used $10,000] – farm areas - $15,000 - $20,000 per acre [used $17,500] – land near population centers - $30,000 - $40,000 per acre [used $35,000]	Ratings computed by scaling costs from lowest (rating = 5) to highest (rating = 1)

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Criterion Number	Criterion	Measure of Suitability	
		Metric	Rating Rationale
* In the screening phase wetlands criterion, a 5,000-acre general area was evaluated for each site to provide a general characterization of the presence of wetlands and to provide flexibility in the eventual plant layout. This general area size is consistent with the upper end of the Desired Owner Buffer Area identified in the FPL site requirements document. ** The low end of the Desired Owner Buffer Area (i.e., 3,000 acres) was used for the land acquisition criterion evaluation as the actual acreage that would be placed under FPL ownership.			

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4.2 Identification of Candidate Sites

Results of the screening evaluation are presented in Table 4-2 and Figure 4-1; the technical basis for the individual criterion ratings is detailed in Appendix B.

The screening evaluation process identified four sites that were clearly less suitable than the remaining eleven sites. As a result, the set of candidate sites was derived by taking the top eight ranked sites, but with the following optimizations:

Okeechobee 1 – Deferred in favor of Okeechobee 2, due to their close geographic proximity and the resulting expectation that no important siting trade-offs or opportunities would be eliminated. Okeechobee 1 is also farther from the proposed water source for these sites, leading to the expectation that it would encounter more cost and regulatory difficulties in water supply compared to Okeechobee 2.

Hendry 2 – Deferred in favor of the higher-rated Hendry 1, due to their close geographic proximity and the resulting expectation that no important siting trade-offs or opportunities would be eliminated. Hendry 2 is also farther from the proposed water source for these sites, leading to the expectation that it would encounter more cost and regulatory difficulties in water supply compared to Hendry 1.

Manatee – Deferred due to the expectation that the site is questionable with regard to the engineering and regulatory feasibility of developing a water supply and would encounter significant local resistance based on experience from previous FPL plant development activities in the site vicinity.

St. Lucie – Included based on the fact that it is an existing, operating nuclear power plant site. Inclusion of this site in the set of candidate sites allows detailed evaluation of the advantages of this existing site, including confidence in site characteristics, existing infrastructure, and public acceptance.

The eight candidate sites identified for further evaluation include:

- DeSoto
- Glades
- Hardee
- Hendry 1
- Martin
- Okeechobee 2
- St. Lucie
- Turkey Point

Table 4-2 Screening Criteria Site Ratings

	Cooling Water Supply	Flooding	Popula-tion	Hazard-ous Land Uses	Ecology	Wetlands	Railroad Access	Transmis-sion Access	Land Acquisi-tion	
	Weight Factor									
Potential Site Name	**9.5**	**3.9**	**7.6**	**5.0**	**6.1**	**6.4**	**5.6**	**8.5**	**6.5**	**Site Rating**
Charlotte	2	2	4	5	2	1	1	2	3	**142.9**
DeSoto	1	4	3	4	3	2	3	3	5	**173.8**
Ft. Myers	3	2	1	1	2	2	4	2	3	**132.8**
Glades	3	2	4	3	3	3	4	4	3	**195.1**
Hardee	1	4	4	3	3	2	5	2	3	**166.1**
Hendry 1	2	2	4	4	3	2	3	4	3	**178.6**
Hendry 2	2	1	5	5	3	1	2	4	3	**175.3**
Highlands	1	5	4	2	1	2	3	2	3	**141.6**
Manatee	3	5	2	3	3	3	4	1	5	**179.1**
Martin	3	2	3	3	2	4	5	5	5	**214.9**
Okeechobee 1	2	5	4	4	3	4	3	4	3	**203.1**
Okeechobee 2	3	3	3	3	3	2	4	4	3	**185.0**
St. Lucie	4	1	1	3	2	2	4	1	5	**152.9**
Turkey Point	4	1	1	2	1	2	4	5	5	**175.8**
West County	3	2	1	4	2	1	2	2	3	**130.2**

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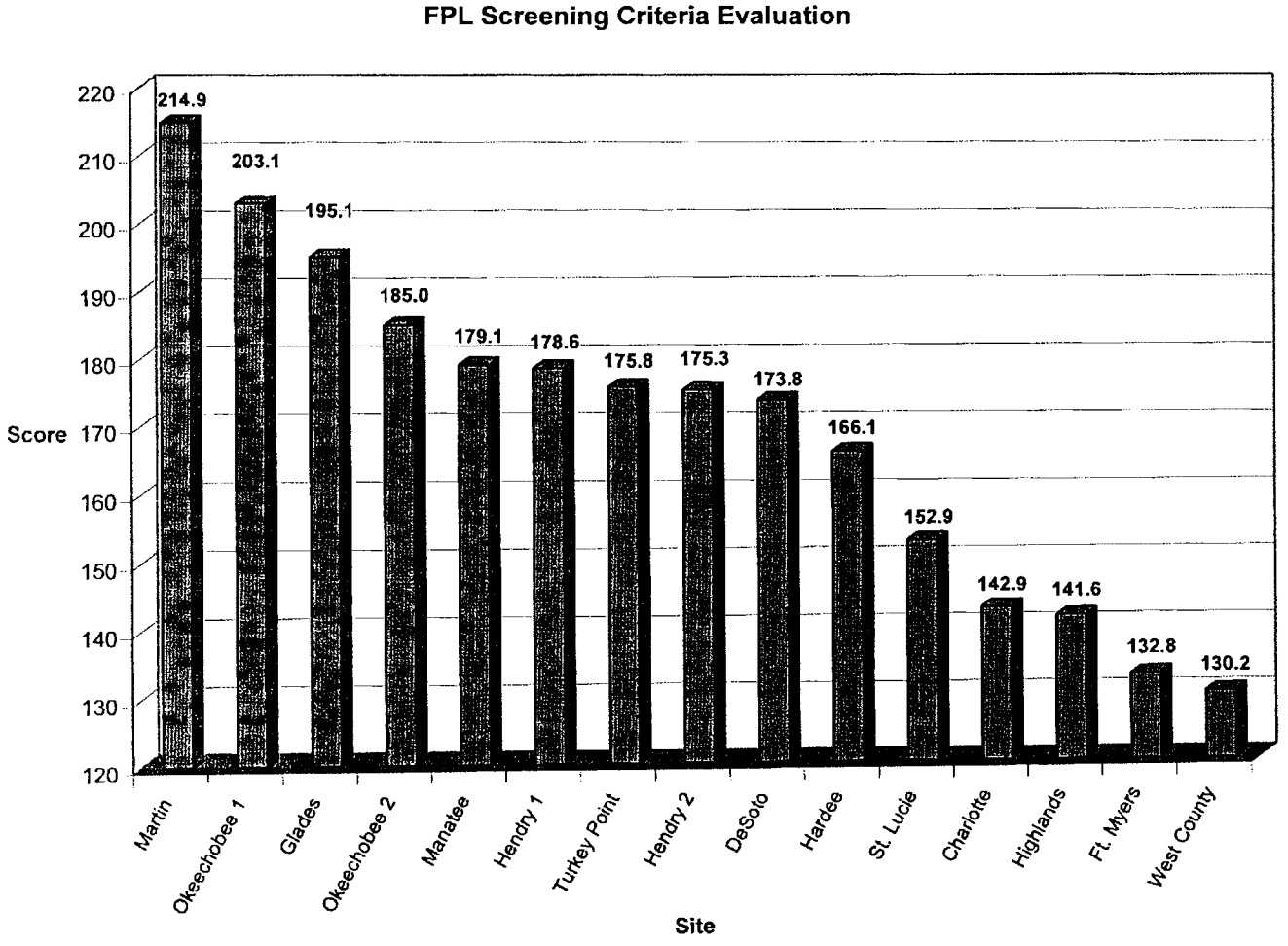
Figure 4-1 Screening Criteria Ratings



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5.0 Evaluation of Candidate Sites and Identification of Alternative Sites

The objective of this component of the site-selection process was to further evaluate the top eight ranked candidate sites and select a smaller set of alternative sites (an initial target for the number of alternative sites was four) for detailed evaluation and ultimate selection of the proposed site for the FPL COL. Section 5.1 outlines the process for evaluating candidate sites, while Section 5.2 describes process results and the selection of alternate sites.

5.1 Process for Evaluating Candidate Sites

General siting criteria used to evaluate the eight candidate sites were derived from those presented in Chapter 3.0 of the *Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application*, EPRI, Palo Alto, CA: 2002 (Siting Guide); criteria from the siting guide were tailored to reflect issues applicable to – and data available for – the FPL candidate sites. A list of the criteria appears in Table 5-1.

The overall process for applying the general site criteria was analogous to that described in Section 4.1 and was composed of the same three elements identified below. Results from applying the process are described in Section 5.2. Appendix C provides the detailed technical basis for the general site-criteria ratings.

Criterion Ratings – Each site was assigned a rating of 1 to 5 (1 = least suitable, 5 = most suitable) for each of the potential site evaluation criteria using the rationale described in Appendix C. Information sources for these evaluations included publicly available data, information available from FPL files and personnel, and USGS topographic maps.

Weight Factors – Weight factors reflecting the relative importance of these criteria were developed by a multi-disciplinary committee in the areas of nuclear power plant site suitability that was convened at FPL offices on August 29, 2006; this committee was composed of subject matter experts in water use and availability, engineering, real estate, ecology, transmission, land use, health & safety, socioeconomics and public relations. The weight factors were derived using methodology consistent with the modified Delphi process specified in the Siting Guide. Weight factors used (1 = least important, 10 = most important) are included in Table 5-2 below.

Composite Suitability Ratings – Ratings reflecting the overall suitability of each site were developed by multiplying criterion ratings by the criterion weight factors and summing all criteria for each site, as summarized in Table 5-2.

Table 5-1 Site Criteria

Siting Criteria
1.1 Health and Safety Criteria: Accident Cause-Related Criteria
1.1.1 Geology and Seismology
1.1.2.1 Cooling System Requirements: Cooling Water Supply
1.1.2.2 Cooling Water System: Ambient Temperature Requirements
1.1.3 Flooding
1.1.4 Nearby Hazardous Land Uses
1.1.5 Extreme Weather Conditions
1.2 Health and Safety Criteria: Accident Effects-Related
1.2.1 Population
1.2.2 Emergency Planning
1.2.3 Atmospheric Dispersion
1.3 Health and Safety Criteria: Operational Effects-Related
1.3.1 Surface Water – Radionuclide Pathway
1.3.2 Groundwater Radionuclide Pathway
1.3.3 Air Radionuclide Pathway
1.3.4 Air - Food Ingestion Pathway
1.3.5 Surface Water – Food Radionuclide Pathway
1.3.6 Transportation Safety
2.1 Environmental Criteria: Construction-Related Effects on Aquatic Ecology
2.1.1 Disruption of Important Species/Habitats
2.1.2 Bottom Sediment Disruption Effects
2.2 Environmental Criteria: Construction-Related Effects on Terrestrial
2.2.1 Disruption of Important Species/Habitats and Wetlands
2.2.2 Dewatering Effects on Adjacent Wetlands
2.3 Environmental Criteria: Operational-Related Effects on Aquatic Ecology
2.3.1 Thermal Discharge Effects

Siting Criteria
Environmental Criteria: Operational-Related Effects on Aquatic Ecology, cont'd.
2.3.2 Entrainment/Impingement Effects
2.3.3 Dredging/Disposal Effects
2.4 Environmental Criteria: Operational-Related Effects on Terrestrial Ecology
2.4.1 Drift Effects on Surrounding Areas
3 Socioeconomic Criteria
3.1 Socioeconomic – Construction Related Effects
3.2 Socioeconomics – Operation (deleted from evaluation, see Appendix C)
3.3 Environmental Justice
3.4 Land Use
4.1 Engineering and Cost-Related Criteria: Health and Safety Related Criteria
4.1.1 Water Supply
4.1.2 Pumping Distance
4.1.3 Flooding
4.1.4 Vibratory Ground Motion (deleted from evaluation, see Appendix C)
4.1.5 Civil Works
4.2 Engineering and Cost: Transportation or Transmission Related Criteria
4.2.1 Railroad Access
4.2.2 Highway Access
4.2.3 Barge Access
4.2.4 Transmission Access
4.3 Engineering and Cost-Related Criteria: Related to Socioeconomic & Land Use
4.3.1 Topography
4.3.2 Land Rights
4.3.3 Labor Rates

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5.2 Identification of Alternative Sites

Results of applying the evaluation process described in Section 5.1 to the eight candidate sites are summarized in Table 5-2 and Figure 5-1. Detailed discussions of the basis for site ratings for each of the criteria are provided in Appendix C.

The general criteria evaluation process identified three sites clearly less suitable than the remaining five sites. Based on these results, the following five alternative sites were identified for further, more detailed evaluation and consideration:

- Glades
- Martin
- Okeechobee 2
- St. Lucie
- Turkey Point

The DeSoto, Hardee, and Hendry 1 sites rated lower than the above sites in the general criteria evaluations, and were deferred from further analysis. Limited water availability was shown to be a factor in the general criteria evaluations for both the DeSoto and Hardee sites. The Hendry 1 site was observed to be similar to the Glades site, but was deferred from further consideration at this time due its lower composite rating.

Table 5-2 General Site Criteria Site Ratings

Criteria		Weight Factor	DeSoto		Glades		Hardee		Hendry 1		Martin		Okeechobee 2		St. Lucie		Turkey Point	
			Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score
1.1.1	Geology/Seismology	7.9	5	39.5	5	39.5	5	39.5	5	39.5	5	39.5	5	39.5	5	39.5	5	39.5
1.1.2	Cooling System Requirements	9.6	2	19.2	3	28.8	2	19.2	3	28.8	3.5	33.6	3.5	33.6	3.5	33.6	3.5	33.6
1.1.3	Flooding	3.9	5	19.5	1	3.9	5	19.5	2	7.8	3	11.7	3	11.7	1	3.9	1	3.9
1.1.4	Nearby Hazardous Land Uses	4.2	4	16.8	3	12.6	3	12.6	4	16.8	3	12.6	3	12.6	3	12.6	2	8.4
1.1.5	Extreme Weather Conditions	4.6	3	13.8	3	13.8	3	13.8	3	13.8	3	13.8	3	13.8	2	9.2	2	9.2
1.2	Accident Effect Related	8.1	4	32.4	4	32.4	4	32.4	4	32.4	3	24.3	4	32.4	3	24.3	3	24.3
1.3.1	Surface Water – Radionuclide Pathway	7.4	4	29.6	4	29.6	4	29.6	4	29.6	4	29.6	4	29.6	5	37	5	37
1.3.2	Groundwater Radionuclide Pathway	7.2	3	21.6	3	21.6	3	21.6	3	21.6	3	21.6	2	14.4	2	14.4	2	14.4
1.3.3	Air Radionuclide Pathway	7.4	4	29.6	4	29.6	4	29.6	4	29.6	4	29.6	4	29.6	5	37	5	37
1.3.4	Air – Food Ingestion Pathway	7.5	1	7.5	1	7.5	1	7.5	1	7.5	2	15	1	7.5	5	37.5	5	37.5
1.3.5	Surface Water – Food Radionuclide Pathway	7.4	1	7.4	2	14.8	1	7.4	1	7.4	1	7.4	2	14.8	5	37	5	37
1.3.6	Transportation Safety	5.4	3	16.2	3	16.2	3	16.2	3	16.2	3	16.2	3	16.2	3	16.2	3	16.2

Criteria		Weight Factor	DeSoto		Glades		Hardee		Hendry 1		Martin		Okeechobee 2		St. Lucie		Turkey Point	
			Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score
2.1.1	Disruption of Important Species/Habitats	**6.4**	4	25.6	4	25.6	5	32	4	25.6	4	25.6	4	25.6	3	19.2	3	19.2
2.1.2	Bottom Sediment Disruption Effects	**5.1**	3	15.3	3	15.3	3	15.3	3	15.3	3	15.3	3	15.3	4	20.4	4	20.4
2.2.1	Disruption of Important Species/Habitats and Wetlands	**6.5**	4	26	4.5	29.25	3.5	22.75	3.5	22.75	3.5	22.75	4	26	3	19.5	2.5	16.25
2.2.2	Dewatering Effects on Adjacent Wetlands	**5.6**	4	22.4	3	16.8	3	16.8	2	11.2	4	22.4	3	16.8	3	16.8	3	16.8
2.3.1	Thermal Discharge Effects	**6.1**	2	12.2	3	18.3	3	18.3	3	18.3	3	18.3	3	18.3	4	24.4	4	24.4
2.3.2	Entrainment/ Impingement Effects	**6.1**	4	24.4	4	24.4	4	24.4	4	24.4	3	18.3	4	24.4	3	18.3	3	18.3
2.3.3	Dredging/Disposal Effects	**4.9**	5	24.5	5	24.5	5	24.5	5	24.5	5	24.5	5	24.5	4	19.6	5	24.5
2.4.1	Drift Effects on Surrounding Areas	**5.9**	3	17.7	4	23.6	4	23.6	4	23.6	4	23.6	4	23.6	2	11.8	2	11.8
3.1.1	Socioeconomics – Construction-Related Effects	**5.2**	3	15.6	2	10.4	3	15.6	3	15.6	5	26	3	15.6	5	26	5	26
3.3.1	Environmental Justice	**4.3**	5	21.5	5	21.5	5	21.5	5	21.5	5	21.5	5	21.5	5	21.5	5	21.5
3.4.1	Land Use	**5.4**	3	16.2	3	16.2	3	16.2	3	16.2	3	16.2	3	16.2	3	16.2	4	21.6
4.1.1	Water Supply	**8.5**	1	8.5	4	34	1	8.5	3	25.5	4	34	4	34	5	42.5	5	42.5

Criteria		Weight Factor	DeSoto		Glades		Hardee		Hendry 1		Martin		Okeechobee 2		St. Lucie		Turkey Point	
			Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score	Rating	Score
4.1.2	Pumping Distance	5.6	2	11.2	4	22.4	2	11.2	3	16.8	4	22.4	4	22.4	5	28	5	28
4.1.3	Flooding	4.1	5	20.5	3	12.3	5	20.5	4	16.4	5	20.5	4	16.4	2	8.2	2	8.2
4.1.5	Civil Works	4.8	3	14.4	2	9.6	2	9.6	2	9.6	2.5	12	2	9.6	3	14.4	3	14.4
4.2.1	Railroad Access	6.7	3	20.1	4	26.8	5	33.5	3	20.1	5	33.5	4	26.8	4	26.8	4	26.8
4.2.2	Highway Access	6.6	5	33	5	33	5	33	4	26.4	5	33	5	33	5	33	5	33
4.2.3	Barge Access	6.7	1	6.7	3	20.1	4	26.8	3	20.1	4	26.8	3	20.1	4	26.8	5	33.5
4.2.4	Transmission Access	8.6	3	25.8	4	34.4	2	17.2	4	34.4	5	43	4	34.4	1	8.6	5	43
4.3.1	Topography	3.4	5	17	5	17	4	13.6	5	17	5	17	5	17	5	17	5	17
4.3.2	Land Rights	5.6	5	28	3	16.8	3	16.8	3	16.8	5	28	3	16.8	5	28	5	28
4.3.3	Labor Rates	5.4	5	27	5	27	3	16.2	5	27	3	16.2	4	21.6	3	16.2	2	10.8
	Composite Site Rating		**687**		**730**		**687**		**700**		**776**		**736**		**765**		**804**	

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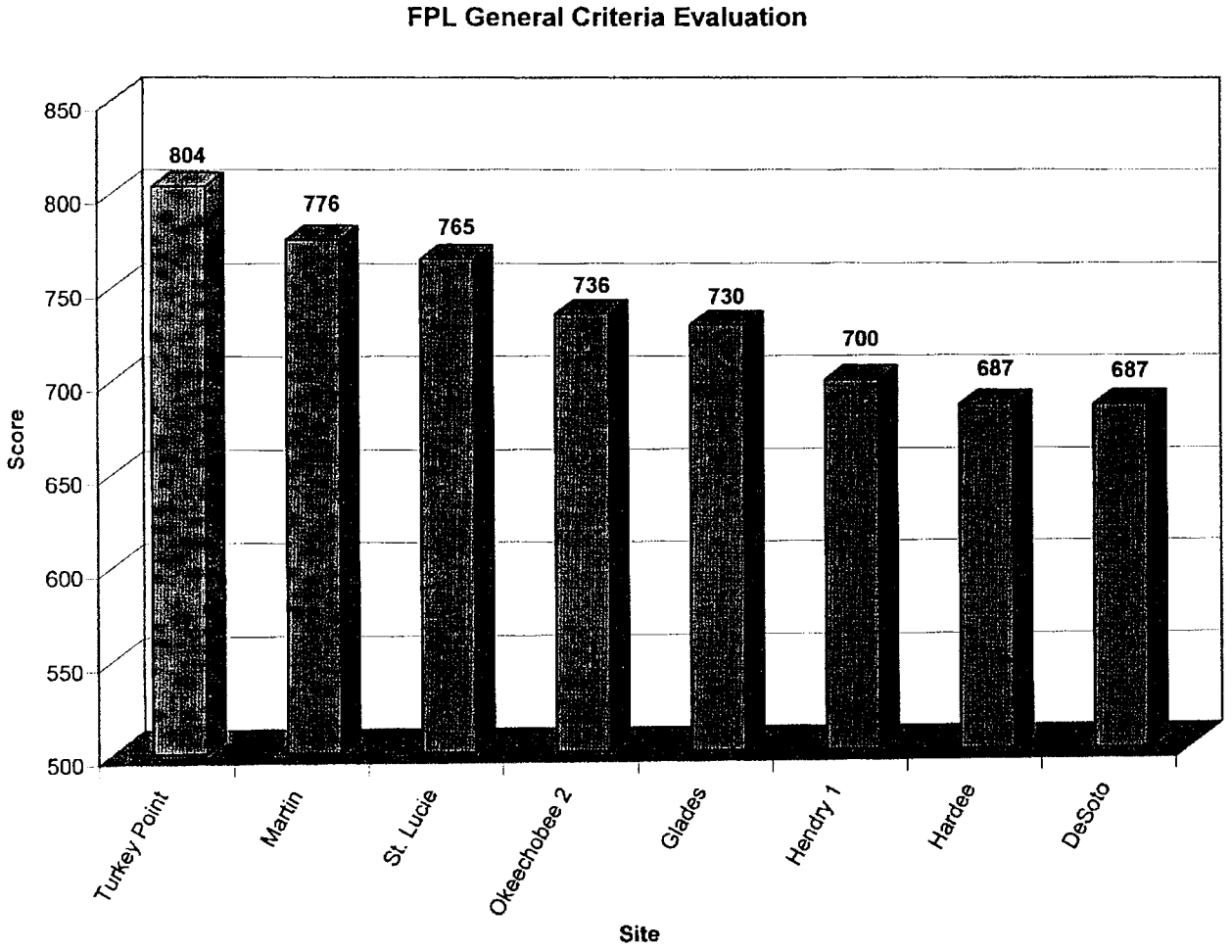
Figure 5-1 General Site Criteria Ratings



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6.0 Selection of Proposed Site

As discussed in Section 5.2, the Glades, Martin, Okeechobee 2, St. Lucie, and Turkey Point sites were selected as alternative sites for the FPL COL. Based on the comprehensive evaluations conducted to this point, all of these sites appear to be feasible locations for a new nuclear power plant.

To select a proposed site for the COL from this set of alternatives, additional considerations were evaluated to provide further insight on their relative suitability to support FPL's objectives for the COL and a future nuclear plant. Scope and results of these studies are described in Section 6.1. The rationale for selecting a proposed site from the alternatives considered is provided in Section 6.2.

6.1 Analysis of Alternative Sites

The objective of these additional considerations for the five alternative site studies was to provide further insight into site conditions and/or to provide further confidence on specific issues that were viewed as important to the COL site decision. Specific factors considered in this evaluation were as follows:

- Environmental impact – Existence of ecological or environmental permitting issues;
- Transmission – Availability of existing right-of-way and cost of upgrades;
- Land acquisition – Existing land ownership and expected difficulty of acquiring site (if applicable);
- Reliability (transmission) – Analysis of reliability from a power-transmission perspective;
- Reliability (generation) – Qualitative analysis of risk factors for reliable power production and supply;
- Public acceptance – Ability to obtain public acceptance to support siting activities;
- Political (local) – Governmental/organizational support at the local level;
- Political (state) – Governmental and regulatory support at the state and Federal level;
- Transmission takeaway – Feasibility of constructing the necessary upgrades to deliver power to the system;
- Schedule compatibility – Level of confidence that site will support commencement of COLA activities in January 2007; and
- Site layout feasibility – Ability of site to accommodate plant layout.

Evaluation of these factors was conducted by a multi-disciplinary team of FPL professionals with specific expertise, experience, and ongoing involvement in the areas being evaluated; for example, personnel involved in environmental permitting throughout the FPL service territory provided input on environmental matters, and public relations staff provided judgments on public acceptance and political factors.

Results of these evaluations were reported by assigning ratings for each alternative site that ranged from 1 to 3 (1 = more favorable, 3 = less favorable), based on experience and best professional judgment. Each of the ratings was discussed by personnel from FPL, Enercon

Services, and McCallum-Turner. The resulting ratings are summarized in Table 6-1; information on the basis for these ratings, along with results of the General Site Criteria evaluations (Section 5.0), are provided in the following paragraphs.

Environmental Impact

The St. Lucie site was rated least favorable because much of the land proposed for development contains red and black mangrove habitat and would incur significant environmental impact. Turkey Point was rated average with respect to environmental impact. Some of the land proposed for development at the Turkey Point site is designated as critical crocodile habitat. Some mitigation may be implemented because the entire cooling canal system is designated as critical habitat and the proposed area of development is small in relation to the whole canal system. The Glades, Martin, and Okeechobee 2 sites were rated as more favorable because environmental impacts can be mitigated more effectively than at the St. Lucie or Turkey Point sites.

Transmission

Transmission access was originally evaluated in terms of distance to the load center in the greater Miami area and the amount of new right-of-way that would have to be acquired; these factors are described in the screening criteria rating description in Section 4.0. Based on those evaluations the following ratings were applied to the alternative sites:

Glades – 2
Martin – 1
Okeechobee 2 – 2
St. Lucie – 3
Turkey Point – 1

Land Acquisition

The Turkey Point, St. Lucie, and Martin sites are all rated more favorable as these sites are FPL owned properties. The Glades site is rated average because while the property is not owned by FPL, options to purchase exist. The Okeechobee 2 site is rated less favorable because the property is not owned by FPL and purchasing options have not been developed.

Reliability (Transmission)

The Turkey Point and Martin sites are rated more favorable with respect to transmission reliability. Power generation from a new power plant at Turkey Point could be routed on a geographically diverse corridor, thereby minimizing reliability risks. Transmission from all other sites would be co-located with existing transmission lines with varying degrees of congestion and crossings. Transmission from the St. Lucie site is less favorable as co-location within one heavily used right-of-way would be required.

Reliability (Generation)

The Glades site is rated more favorable due to a lower hurricane frequency and resulting site evacuation and shut-down requirements. The Turkey Point site is rated less favorable due to the slightly higher frequency of hurricanes.

Public Acceptance

The Turkey Point site is rated more favorable because the existing nuclear plant's license renewal received strong local community support. The Glades site also is rated favorable due to demonstrated local government support. The Okeechobee 2 site is rated average because local political leaders have indicated they would support a nuclear power generation project. The Martin and St. Lucie sites do not appear to have a similarly strong supportive base and are rated less favorable.

Political Acceptance (Local)

The Glades and Okeechobee 2 sites are rated more favorable because no rezoning or comprehensive plan amendments would be required for a new nuclear power plant. The Turkey Point site was rated average because no comprehensive plan amendments would be necessary, but some level of rezoning or land use definition appears to be required. The Martin and St. Lucie sites are rated less favorable because both sites would require significant effort with local planning issues.

Political Acceptance (State/Federal)

With respect to regulatory requirements, there is no significant distinction between the alternative sites. The Florida State government has shown strong support for new nuclear power generation. The Martin site could present some resistance due to previously observed political perception surrounding water use issues and Lake Okeechobee water levels. As such, all sites have been rated more favorable, with the exception of the Martin site, which has been rated less favorable.

Transmission Takeaway Feasibility

The Turkey Point and St. Lucie sites are rated more favorable because neither site would require significant acquisition of new transmission right-of-way. The Glades site would require a significant acquisition of new right-of-way, but was rated average because a coal-fired power plant is proposed in the vicinity of the Glades location, and a nuclear plant at the site would benefit from earlier work to obtain some portion of the necessary right-of-way. The Martin site also was rated average because existing right-of-way could be utilized, although they are congested in areas. The Okeechobee 2 site is rated less favorable because significant amounts of right-of-way acquisition and new line construction would be required.

Schedule Compatibility

The ability to meet schedule requirements at a site closely parallels the land-acquisition evaluation above. The Turkey Point, St. Lucie, and Martin sites were rated more favorable because they are located on FPL-owned property. The Glades site was rated average as the property is not owned by FPL, but options to purchase exist. The Okeechobee 2 site was rated less favorable because the property is not owned by FPL and purchasing options have not been developed.

Site Layout

The Glades and Okeechobee 2 sites were rated more favorable. Both sites are greenfield sites and would allow the greatest flexibility in developing layouts for a new nuclear power plant. The Martin site was also rated more favorable because a considerable amount of FPL-owned property exists that would provide a similar amount of flexibility. Both existing nuclear power plant sites were rated lower than the greenfield sites because layout flexibility is reduced at each site due to the existing facilities. The Turkey Point site was rated average because there are several potential locations that can be developed. St. Lucie was rated less favorable because the restrictions to available land and surrounding natural features would significantly limit the ability to site new nuclear facilities.

Table 6-1 FPL Site Selection Study – Alternative Site Ratings*

	Technical Analysis Composite Rating/Score	Environ-mental Impact	Trans-mission	Land Acquisition	Reliability (Trans-mission)	Reliability (Generation)	Public Acceptance	Political (Local)	Political (State)	Transmission Takeaway Feasibility	Schedule Compati-bility	Site Layout
Glades	730 3	1	2	2	1	1	1	1	1	2	2	1
Martin	776 2	1	1	1	2	2	3	3	3	2	1	2
Okeechobee 2	736 3	1	2	3	2	2	2	1	1	3	3	1
St. Lucie	765 2	3	3	1	3	2	3	3	1	1	1	3
Turkey Point	804 1	2	1	1	1	2	1	2	1	1	1	2

* Note: A scale of 1 (more favorable) to 3 (less favorable) is used in this Table.

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6.2 Selection of Proposed Site

The results of the 11 additional site selection considerations (section 6.1), combined with the results of the general criteria evaluations (section 5.2), were used to identify a recommended site as described below.

Results of the evaluations as described in Section 6.1 confirm that all of the five alternative sites are viable locations for a nuclear power plant. However, these evaluations do serve to further distinguish among the five alternative sites and identify the most favorable site. The Turkey Point site rates more favorable in 8 of the 12 considerations, and does not rate less favorable in any. Each of the other alternative sites rates more favorable in fewer considerations and rates less favorable in at least one.

Based on these results, the overall ranking of the five alternative sites is as follows:

1. Turkey Point
2. Glades
3. Martin
4. Okeechobee 2
5. St. Lucie

Thus, taking into consideration the results of each evaluation conducted (including satisfying the overall business objectives for the FPL COL), the **Turkey Point** site was selected as the recommended site for Project Bluegrass.

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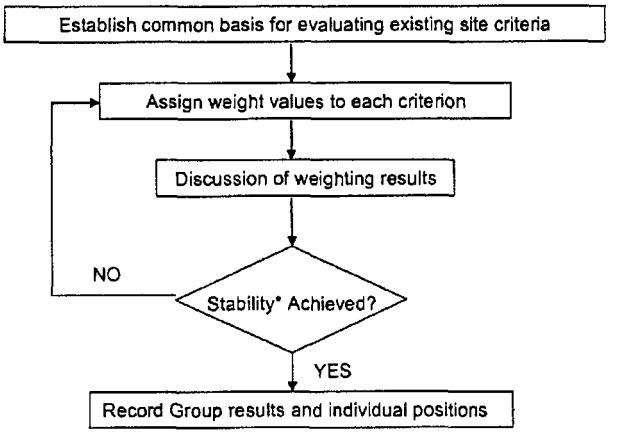
APPENDIX A
WEIGHT FACTOR DEVELOPMENT

Appendix A – Weight-Factor Development

For the potential and candidate site evaluation phases of the site selection process (Sections 4.0 and 5.0, respectively), weight factors were developed that reflect the relative importance of individual criteria in judging the overall suitability of nuclear power plant sites. As described below, weight factors were used in developing overall composite suitability ratings for sites under consideration.

Weight factors reflecting the relative importance of the screening criteria used to evaluate potential sites were developed consistent with the modified Delphi method suggested in the EPRI Siting Guide. The process used for weight-factor development is summarized in the diagram below.



Weight factors reflecting the relative importance of these criteria were developed by a multi-disciplinary committee in the areas of nuclear power plant site suitability that was convened at FPL offices on August 29, 2006; this committee was composed of subject matter experts in water use and availability, engineering, real estate, ecology, transmission, land use, health & safety, socioeconomics and public relations.

A brief description of the screening site criteria, data inputs, and rating methodologies was provided. Weights were assigned on a 1 to 10 scale, with 10 being most important and 1 being least. Individual weight scores were averaged to arrive at group composite criterion weighting factors.

After the first round of voting, a group discussion was held in which each committee member provided the rationale for his or her weight-factor assignments. Following this discussion, another polling of the group was conducted and committee members modified their weights, as they deemed appropriate, based on the discussions and arguments presented after the first round. A second discussion was held after the second round of voting. When polled, no members of the

committee indicated that they had been persuaded to change their weight assignments, and the Delphi session was terminated. The resulting weight factors are provided in Section 4.1.

The same process (described above) was applied to develop weight factors for the general site criteria. Again, after two rounds of voting, no members of the committee indicated that they had been persuaded to change their weight assignments, and the Delphi session was terminated. The resulting weight factors are provided in Table 5-2.

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APPENDIX B
TECHNICAL BASIS FOR SCREENING CRITERION RATINGS

Appendix B – Technical Basis for Screening Criterion Ratings

Descriptions of the methodology, rationale, and data used in evaluating potential sites are provided in Table 4-1. Results of the evaluations are provided in the following tables. All ratings are assigned on a scale of 1 to 5, with 5 representing a more suitable site from the perspective of each criterion and 1 representing a less suitable site.

Criterion P1 – Cooling Water Supply							
Site	Water Source[1]	Estimated Flow[1]	Rating[2]				
			Flow	Flexibility	Risk	Regulatory Challenge	Composite Rating
Charlotte	Combination – - Peace River - Reclaimed Water[4] (Charlotte Co) - Groundwater	 - 209 cfs - 11 cfs - tbd[5]	1	3	2	2	2
De Soto	Combination – - Peace River - Reclaimed Water[4] (DeSoto Co) - Groundwater	 - 62 cfs - 1 cfs - tbd[5]	1	1	2	2	1
Ft. Myers	- Caloosahatchee River - Orange River - Ocean (18 miles) - Reclaimed Water[4] (Lee Co.)	- 404 cfs - tbd[5] - Unlimited - 60 cfs	5	4	3	2	3
Glades	- Groundwater - C43 (2.5 miles) - Lake Okeechobee (5 miles) - Reclaimed Water[4] (Glades Co)	- 155 cfs[7] - 482 cfs - 360+ cfs - 0 cfs	3	5	2	2	3
Hardee	Combination – - Peace River - Groundwater - Reclaimed Water[4] (Hardee Co)	 - 62 cfs - tbd[5] - 1 cfs	1	1	1	2	1

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Criterion P1 – Cooling Water Supply							
Site	Water Source[1]	Estimated Flow[1]	Rating[2]				
			Flow	Flexibility	Risk	Regulatory Challenge	Composite Rating
Hendry 1	- Groundwater - Lake Okeechobee (11 miles) - Reclaimed Water[4] (Hendry Co)	- 155 cfs[7] - 360+ cfs - 3 cfs	3	3	2	2	2
Hendry 2	- Groundwater - Lake Okeechobee (24 miles) - Reclaimed Water[4] (Hendry Co)	- 155 cfs[7] - 360+ cfs - 3 cfs	3	3	2	2	2
Highlands	- Kissimmee River (10 miles) - Reclaimed Water[4] (Highlands Co)	- 105 cfs - 2 cfs	1	1	1	2	1
Manatee	- Tampa Bay (13 miles) - Reclaimed Water[4] (Manatee Co.)	- Unlimited - 45 cfs	5	3	3	2	3
Martin	- Lake Okeechobee - C-44 - Pond - Reclaimed Water[4] (Martin Co)	- 360+ cfs - 360 cfs - tbd[5] - 7 cfs	3	5	3	3	3
Okeechobee 1	- Groundwater - Lake Okeechobee (10 miles) - Reclaimed Water[4] (Ok Co)	- 155 cfs[7] - 360+ cfs - 1 cfs	3	3	2	2	2

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Criterion P1 – Cooling Water Supply							
Site	Water Source[1]	Estimated Flow[1]	Rating[2]				
			Flow	Flexibility	Risk	Regulatory Challenge	Composite Rating
Okeechobee 2	- Groundwater - Kissimmee River (2 miles) - Lake Okeechobee (8 miles) - Reclaimed Water[4] (Ok. Co)	- 155 cfs[7] - 475 cfs - 360+ cfs - 1 cfs	3	5	2	2	3
St. Lucie	- Ocean Intake - Reclaimed Water[4] (St. Lucie Co.)	- Unlimited - 17 cfs	5	3	4	4	4
Turkey Point	- Ocean Intake[3] (7 miles) - Reclaimed Water[4] (8 miles) - Groundwater - Canals (ltd)	- Unlimited - 142 cfs - tbd[5] - tbd[5]	5	4	4	4	4
West County	- Hydrostorage Pits - Groundwater - Lake Okeechobee (15 miles) - Ocean (24 miles) - Reclaimed Water[4] (Palm Beach Co)	- ~176 cfs[6] - tbd[5] - 360+ cfs - Unlimited - 130 cfs	5	5	2	1	3

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Criterion P1 – Cooling Water Supply							
Site	Water Source[1]	Estimated Flow[1]	Rating[2]				
			Flow	Flexibility	Risk	Regulatory Challenge	Composite Rating

Notes:

1. 178 cfs required. Water sources identified by water supply subcommittee.
2. See Table 4-1 for description.
3. Seven-mile pipeline to avoid Biscayne Bay.
4. All reclaimed water shown as total available for the county as reported by FDEP. Exception is for Turkey Point where flow for MDWASD South District WWTP is shown. This represents an indication of potential water for reuse and is not intended to determine feasibility.
5. Selected flows were not possible to quantify at this time. These values, if known, are not anticipated to significantly alter the ratings. At Ft. Myers, the Orange River flow is near zero per FPL. At Martin, source water for pond is the C-44 Canal.
6. Flow potentially available form L8 (low daily mean flow for last 10 years) used as representation of possible flow available from new hydrostorage pit.
7. Groundwater flow assumed to be 100 MGD based on FPL familiarity with aquifer. This withdrawal needs confirmed if any of these sites are carried forward.

Note: This evaluation has been performed in the absence of agency contact using publicly available flow data. Flow in the source water systems is complex and requires further investigation and contact with the respective water management district.

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Criterion P2 – Flooding		
Site	Rating	Comments and Discussion
Charlotte	2	Charlotte elevation = 57 feet. Fisheating Creek elevation = 29 feet, flood stage = 34 feet. Difference = 23 feet above flood stage. Site is located in/near swamp lands. Site is located at border of Zone A and Zone X. Site is at border of 100-year flood zone.
DeSoto	4	DeSoto elevation = 81 feet. Peace River current elevation (at Arcadia, FL) ~ 10 feet. River flood stage = 17 feet. Difference = 64 feet above flood stage. Site is located in Zone X (outside 500-year flood zone). Swamp areas exist in the vicinity of the proposed site. Site is not located in 100-year flood zone.
Ft. Myers	2	Ft. Myers elevation = 9 feet. Site is located in Zone AE with base flood elevations of 8 feet. Site is located in 100-year flood zone.
Glades	2*	Glades elevation = 15 feet. Caloosahatchee Canal (Okeechobee Waterway) and Lake Hicpochee elevation = 11 feet. Difference = 4 feet. Site is in Zone A (located in 100-year flood zone).
Hardee	4	Highlands elevation = 63 feet. Peace River current elevation (at Zolfo Springs, FL) ~ 39 feet. River flood stage = 46 feet. Difference = 17 feet above flood stage. Site is in Zone X (not located in 100-year flood zone).

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Criterion P2 – Flooding		
Site	Rating	Comments and Discussion
Hendry 1	2	Hendry 1 elevation = 19 feet. Lake Okeechobee elevation = 14 feet. Difference = 5 feet. Site is located near swamp areas. Site is located in Zone A3 (located in 100-year flood zone).
Hendry 2	1	Hendry 2 elevation = 14 feet. Site is located in swamp areas (east of canal and Levee 3). Site is in Zone A (located in 100-year flood zone). In the event of canal flooding, areas immediately northeast of the canal are primarily impacted as levees protect areas southwest of canals. Flexibility in locating the proposed site within the Hendry 2 parcel could result in improved flood conditions. Moving the site to the southwest of the canal and Levee 3 would increase elevation 2-3 feet, move the site out of swamp areas, and improve flood protection by utilizing Levee 3. The proposed site could be located in Zone C (not located in 100-year flood zone), and the site rating could be increased to a rating of 2 (or possibly 3).
Highlands	5	Highlands elevation = 74 feet. River stage data not available for Palmetto Creek or Arbuckle Creek. Topographic maps show approximate river elevation at 50 feet. Difference = 24 feet. Given site coordinates are located near swamp lands, but ample areas outside of swamp lands exist in the immediate vicinity of the proposed site. Site is located on border of Zone A (100-year flood zone) and Zone C (outside of 100-year flood zone). However, the exact proposed site location can be located in Zone C areas (not located in 100-year flood zone).

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Criterion P2 – Flooding		
Site	Rating	Comments and Discussion
Manatee	5	Manatee elevation = 46 feet Little Manatee River current elevation ~ 3 feet. River flood stage = 11 feet. Difference = 35 feet above flood stage. Site is located in Zone X (outside 500-year flood zone). Site is not located in 100-year flood zone. Flood Insurance Rate Map is old (circa 1971) and does not reflect current conditions. However, area flooding is not expected to differ significantly from prior surveys (i.e., reservoir is not expected to impact area flood potential).
Martin	2	Martin site elevation = 28 feet. Lake Okeechobee elevation = 14 feet. Difference = 14 feet. Site is located near swamp lands. Site is in Zone X (area of 500-year flood, area of 100-year flood with average depths of < 1 foot or with drainage area < 1 sq. mi., or area protected by levees from 100-year flood). Site is located east of boundary limit of flooding from Lake Okeechobee caused by breaching of Herbert Hoover Dike. Site is not located in 100-year flood zone.
Okeechobee 1	5	Okeechobee 1 elevation = 59 feet. Lake Okeechobee elevation = 14 feet. Difference = 45 feet. Swamp areas exist in the vicinity of the proposed site, but specific location could be moved to avoid these areas. Site is located in Zone C. Site is not located in 100-year flood zone.

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Criterion P2 – Flooding		
Site	Rating	Comments and Discussion
Okeechobee 2	3	Okeechobee 2 elevation = 28 feet. Kissimmee River ~ 20 feet. Difference = 8 feet. Swamp areas exist in the vicinity of the proposed site. Site is at border of Zone A and Zone C. Site is at border of 100-year flood zone.
St. Lucie	1	St. Lucie elevation = 0-5 feet. Atlantic Ocean elevation = 0 feet. Difference = 0-5 feet. Site is located in Zone AE with base flood elevations of 7-8 feet. Site is located in 100-year flood zone.
Turkey Point	1	Turkey Point elevation = 1-2 feet. Site is located in Zone AE with base flood elevations of 12 feet. Site is located in 100-year flood zone.
West County	2	West County elevation = 14 feet. Lake Okeechobee elevation = 14 feet. Difference = 0 feet. Site is located in/near swamp lands. Site is in Zone B (area between limit of 100-year flood and 500-year flood, area of 100-year flood with average depths of < 1 foot or with drainage area < 1 sq. mi., or area protected by levees from 100-year flood). In the event of canal flooding, areas immediately northeast of the canal are primarily impacted as levees protect areas southwest of canals. Flooding of West Palm Beach Canal could impact proposed site. Site is not located in 100-year flood zone.

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Criterion P2 – Flooding		
Site	Rating	Comments and Discussion
* Glades site is located within the 100-year floodplain, based on FEMA Flood Insurance Rate Maps and consistent with FPL information that the 1-in-100-year event is based on lake elevation at 21' NAVD. Screening level evaluation does not consider a dike breach of Lake Okeechobee, such site-specific factors is addressed in a subsequent phase of the evaluation. References: FEMA Digital Flood Insurance Rate Maps, http://www.msc.fema.gov Google Earth, http://earth.google.com; NOAA Stream and Flood Data, http://www.weather.gov/ahps/. USGS Topographic Maps (1 x 100,000 metric); U.S. Flood Hazard Areas, http://www.esri.com/hazards/makemap.html.		

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Criterion P3 – Population					
Site and County Population (2000 and 2005)	Rating				Comments and Discussion Population center data is for 2000
	County Density	Closest Pop Center	Average Rating*	Adjusted Rating**	
Charlotte (Charlotte) 141,627 (2000) 157,536 (2005) (11% growth rate 204.2 psm	4	5	4	4	No large population centers within 10 miles Population centers within 25 miles: Fort Myers Shores (5,733) – 16 miles SW La Belle (4,210) – 16.3 miles SE Ft. Myers (48,208) – 21 miles SW Arcadia (6,604) – 23 miles NW Port Charlotte (46,451) – 23 miles WNW
DeSoto (De Soto) 32,309 (2000) 35,406 (2005) (9.9% growth rate) 50.5 psm	5	2	3	3	Population centers within 10 miles: Arcadia (6,604) – 8.5 miles SW Population Centers within 20 miles: Zollo Springs (no pop data) - 12.1 miles N Wauchula (4,368) – 15.4 miles N Sebring (3667)/Lake Placid area(1668) – 20 miles ENE Port Charlotte (46,451) – 30 miles SW
Ft. Myers (Lee County) 440,888 (2000) 544,758 (2005) (23.6% growth rate); 548.6 psm	1	1	1	1	Population Centers within 5 miles: Tice (4,538) - 1.6 miles W Ft. Myers Shores (5,733) - 1.6 miles E Population Centers within 10 miles: Fort Myers (48,208) - 6.4 miles SW [North Ft. Myers]- Lehigh Acres (33,430) - 8 miles SE Cape Coral (102,286) - 11.2 miles SW

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Criterion P3 – Population					
Site and County Population (2000 and 2005)	Rating				Comments and Discussion Population center data is for 2000
	County Density	Closest Pop Center	Average Rating*	Adjusted Rating**	
Glades (Glades) 10,576 (2000) 11,252 (2005) (6.4% growth rate) 13.7 psm	5	1	3	4	Population centers within 5 miles: Moore Haven (1,635) – 2 miles E Population centers within 20 miles: Clewiston (6460) – 12 miles ESE Belle Glade (14, 906) – 12 miles E La Belle (4,210) – 18.4 miles W Population Centers within 50 miles Okeechobee (5.376) – 35 miles NE Fort Myers (western fringe, Lehigh Acres, 33,430) – 45 miles W
Hardee (Hardee Co) 26,938 (2000) 28,286 (2005) (5.0% growth rate) 42.3 psm	5	3	4	4	Population centers within 20 miles: Zollo Springs (no pop data) – 12 miles NE Wauchula (4,368) – 13.5 miles NE Arcadia (6,604) – 14 miles SE Population Centers within 30 miles: Sarasota (52,715) – 35 miles W Port Charlotte (46,461) – 26 miles SW
Hendry 1 (Hendry) 36,210 (2000) 39,561 (2005) (9.3% growth rate) 31.4 psm	5	2	3	4	Population centers within 10 miles Clewiston (6460) – 7.3 miles Population Centers within 25 miles: Belle Glade (14,906) 19.9 miles E La Belle (4,210) – 25 miles W

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Criterion P3 – Population					
Site and County Population (2000 and 2005)	Rating				Comments and Discussion Population center data is for 2000
	County Density	Closest Pop Center	Average Rating*	Adjusted Rating**	
Hendry 2 (Hendry) 36,210 (2000) 39,561 (2005) (9.3% growth rate) 31.4 psm	5	5	5	5	Population centers within 30 miles: Clewiston (6460) – 28 miles NW Belle Glade (14,906) – 28 miles NE Immokalee (13,763) – 27.6 miles W Population Centers within 50 miles Boca Raton/Atlantic coast (western fringe) 42 miles to Coral Springs
Highlands (Highlands) 87,366 (2000) 95,496 (2005) (9.3% growth rate) 85 psm	4	2	3	4	Population centers within 10 miles: Avon Park, (8,542), 4.6 miles W Sebring, (9667), 7 miles SW Population Centers within 20 miles Lake Wales (10,194), 20.7 miles NW Closest densely populated area: Vero Beach/ (17,705 – city; 20,362 – Vero beach South, CDP)/coastal development – 50 miles
Manatee (Manatee; site close to Hillsborough county border) 264,002 (2000) 306,779 (2005) (16.2% growth rate) 356.3 psm	3	2	2	2	Population centers within 10 miles: Parrish (no pop data) – 4.8 miles W Wimauma (4,246) – 7.2 miles N Ruskin (8,321) – 8 miles NW Population Centers within 20 miles Palmetto (12,571) – 13 miles SW Bradenton (49,504) – 14 miles SW Sarasota (52.715) – 19 miles SW St. Petersburg (248,232) – 20 miles NW Tampa (303,447) – 22 miles NW

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Criterion P3 – Population					
Site and County Population (2000 and 2005)	Rating				Comments and Discussion Population center data is for 2000
	County Density	Closest Pop Center	Average Rating*	Adjusted Rating**	
Martin (Martin) 126,731(2000) 139,728 (2005) (10.3% growth rate) 228.1 psm	4	2	3	3	Population centers within 10 miles: Indiantown (5,588) 7 miles SE Population Center within 25 miles: Port St. Lucie (88,769) – 20 miles E Stuart (14,633) – 25 miles NE Okeechobee (5,376) - 20 miles NW Site is 40 miles NW of West Palm Beach and 25 miles from Atlantic Coast development
Okeechobee 1 (Okeechobee) 35,910 (2000) 39,836 (2005) (10.9% growth rate) 46.4 psm	5	2	3	4	Population centers within 10 miles: Cypress Quarters (1,150) – 8 miles to SW Okeechobee (5,376) – 9 miles to SW Population Centers within 25 miles: Port St. Lucie (88,769) - 19 miles E (although western edge of development is at around 17 miles) Ft. Pierce (37,516) – 22 miles NE
Okeechobee 2 (Okeechobee) 35,910 (2000) 39,836 (2005) (10.9% growth rate) 46.4 psm	5	2	3	3	Population centers within 10 miles: Okeechobee (5,376) – 8 miles Population Centers within 20 miles: Lake Placid outskirts (1668) – 19.2 miles W Closest densely populated areas: Port St. Lucie (western edge) (88,769) – 30 miles E

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Criterion P3 – Population					
Site and County Population (2000 and 2005)	Rating				Comments and Discussion Population center data is for 2000
	County Density	Closest Pop Center	Average Rating*	Adjusted Rating**	
St. Lucie (St Lucie County) 192,695 (2000) 241,305 (2005) (25.2% growth rate) 336.3 psm	3	1	2	1	Population center within 5 miles: Port St. Lucie (88,769) – 4.5 miles W Population Centers within 10 miles: Ft Pierce (37,516) – 7 miles NW Stuart (14,633) – 8 miles S
Turkey Point (Miami Dade County) 2,253,362 (2000) 2,376,014 (2005) (5.4% growth rate) 1,157.9 (persons per square mile, psm)	1	2	1	1	No population centers within 5 miles Population Centers within 10 miles: Leisure City (22,152)- 7.2 miles N Homestead (31,909)– 9 miles NW Florida City (7,843) – 8 miles W Key Largo (11,806)– 10 miles S Major population center within 50 miles Miami (450,403 for Miami and Miami Beach)– 20-25 miles N, although S. Miami development within 10 miles N (9.6 miles Goulds and Cutler Ridge)
West County (Palm Beach Co) 1,131,184 (2000) 1,268,548 (2005) (12.1% growth rate) 573 psm	1	1	1	1	Population centers within 5 miles: Wellington (38,216) – 4 miles E Population Centers within 20 miles Belle Glade (14,506) – 17 miles W West Palm Beach (82,103) – 18 miles E (but 3-5 miles to residential/development); and coastal development extends below West Palm down to Miami.

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Criterion P3 – Population					
Site and County Population (2000 and 2005)	Rating				Comments and Discussion
	County Density	Closest Pop Center	Average Rating*	Adjusted Rating**	Population center data is for 2000
* Average of ratings based on host county population density and rating based on distance to nearest population center (identified using screening map and USGS 100,000 scale topographic map). ** Point added if no densely populated area is found within 40 miles of the site; point deducted if a densely populated area is found within 15 miles of the site or if a large grouping of densely populated areas are located within 15-40 miles of the site. References: US Census Bureau (2000 Census data); Enercon Screening Map; USGS 100,000 scale topographic maps; AAA Florida State Map.					

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Criterion P4 – Hazardous Land Uses		
Site	Rating	Comments and Discussion
Charlotte	5	Airports: Closest major airport is Regional Southwest Airport in Ft. Myers, 28.4 miles away; Charlotte County airport is 24 miles W and Arcadia airport is 24 miles NW; Smaller airports located 3.2, 7.4, 8.7, 12.9, 15.8, 16.3 and 18.1 miles away Rail: Closest is 18 miles E
DeSoto	4	Airports: No major airports; smaller airports at Arcadia (9.6 miles SW) and Sebring (24.8 miles to NW) Other small airport/landing strips at 2.5, 7.4, 8.2, 8.4, 12.7, 13.5, and 15.4 miles Rail: 7.1 miles W
Ft. Myers	1	Airport: Regional Southwest (Ft. Myers) – 10 miles S Other smaller airports: 2.1 miles, 4.8 miles (Lehigh Acres SE); 9.6 miles (Page Field SW), 9 and 10 miles Rail: 2.4 miles SW Natural gas pipeline service to site 1.5 miles from I-75 Existing power plant on site with natural gas pipeline service to site
Glades	3	Airports: Clewiston is 12.4 miles SE of site; other smaller airports at 2 and 3 miles from site (landing strips) Rail: 3.1 miles NE; 11 miles W
Hardee	3	Airports: No major airports; airport at Arcadia (9 miles) and smaller airstrips located 9.5 and 12.5 miles away Rail: Located 0.4 miles W [more like 4 miles from my site location]
Hendry 1	4	Airports: Clewiston Airport (7.3 miles); smaller airports at 4.5, 9.8, 10.5, 10.9, 16.6 miles Rail: 8.7 miles NE
Hendry 2	5	Airports: Small airports nearby at 2.2, 4.4 and 6.7 miles Rail: 12.8 miles N

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Criterion P4 – Hazardous Land Uses		
Site	Rating	Comments and Discussion
Highlands	2	Airports: Sebring Regional Airport 10.3 miles SE; MacDill AFB auxiliary/Avon Park AFB 3.7 miles NE; [also appears to be abandoned airfield on Avon Park Bombing Range, just NE of AFB airfield]; Avon Park Municipal 8 miles W; another smaller landing strip (for ranch) also further to the west. The Avon Park Airport fixed base operator is Avon Park Jet Center. The maximum runway length for the Avon Park Airport is 5,364 feet. Rail: 5.75 miles SE [railroad freight service provided by CSX includes side-track service to several industrial areas. Passenger service is provided by Amtrak which has scheduled arrivals and departures from Sebring.] Pipeline: None identified within 5 miles. Military Installations: Avon Park AFB/Avon Park Bombing Range – 4 miles NE
Manatee	3	Major Airports: 30 miles St Pete airport (NW); 18 miles MacDill AFB (NW); 27 miles Tampa airport (N); 18 miles Sarasota Bradenton airport (SW) Rail: 2.6 miles N Existing power plant with natural gas pipeline service to site
Martin	3	Airports: No major airports; Stuart Airport 25 miles E; smaller airports at 2.5, 6.4, 6.8, and 11 miles away Rail: 1.5 miles NE and 2.8 miles W Existing power plant with natural gas pipeline service to site
Okeechobee 1	4	Airports: Okeechobee County airport 9.6 miles SW; Sebring Airport over 25 miles NW; smaller airports located 3.5, 6.4, 6.6, 10, 12 and 13 miles away. Rail: 8.3 miles SW and 13.1 miles SE No pipelines identified
Okeechobee 2	3	Airports: Okeechobee County airport 7.3 miles E; smaller airports located 1.3, 4.3, 8.1 and 10 miles away Avon Bombing Range – 27 miles NW Rail: 2.2 miles NW

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Criterion P4 – Hazardous Land Uses		
Site	Rating	Comments and Discussion
St. Lucie	3	Airports: Major airport 12.4 miles NW (St. Lucie County International); smaller airport (Witham field in Stuart) 10.4 miles SW Pipeline: Did not see on topographic maps, but other reports show line extending down Atlantic Coast Rail located 2.1 miles W Site located on navigable waterway Existing nuclear plant
Turkey Point	2	Airport/Military Base: Homestead AFB—5.2 miles NW [unclear what operations occur at base now – has been some realigning and proposals to use air base as commercial airport; assume fully operational as AFB for now] Other Airports: Homestead general aviation airport – 14+ miles NW Rail: 10 miles W Site located on navigable waterway US Naval Reservation with heliport and radio facility, located 7 miles SW Pipelines: did not see any major pipeline routes marked on topographic maps, but natural gas pipeline service to site Existing power plants [2 nuclear units, 2 conventional boiler fossil units plus building new combined cycle unit]
West County	4	Airports: West Palm Beach airport 18.3 miles E; other smaller airports 12.7 and 13.4 miles away Rail: 13.6 miles NE; 14.1 miles NW Pipeline: 13.5 miles W Property is adjacent to existing Corbett Substation and soon to be used for new greenfield combined cycle natural gas power plant; surrounding land use is predominantly sugar cane and limestone mining (site previously used for mining operations). [Site could qualify as 5 based on criteria but the fact that a new power plant is going in and mining occurs in area drops its rating to a 4.]
References: Google Earth, http://earth.google.com. USGS Topographic Maps (1 x 100,000 metric).		

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Criterion P5 – Ecology/Federal RTE Species (by County)		
Site	Rating	Comments and Discussion
Charlotte	2	20 T&E species: 3 mammals, 9 birds (although documentation for 2 is very old), 7 fish and 1 plant
DeSoto	3	13 T&E species: 3 mammals (including manatee), 8 birds, 2 reptiles
Ft. Myers (Lee County)	2	20 T&E species: 3 mammals, 8 birds, 6 reptiles, 2 fish, 1 plant
Glades	3	16 T&E species: 3 mammals, 9 birds, 2 reptiles, 2 plants
Hardee County	3	12 T&E species: 2 mammals, 6 birds, 2 reptiles, 2 plants
Hendry 1	3	14 T&E species: 3 mammals, 9 birds, 2 reptiles
Hendry 2	3	14 T&E species: 3 mammals, 9 birds, 2 reptiles [just north of Big Cypress National Preserve/WMA and just to west of Rotenberger and Holey Land WMAs]
Highlands	1	37 T&E species: 3 mammals, 9 birds (documentation for one is 40 years old), 4 reptiles, 1 invertebrate, and 20 plants. Area includes unique ecological habitat along Lake Wales Ridge and State Forest and Avon Park Air Force Range. This habitat includes numerous protected species (federal and state).
Manatee	3	14 T&E species: 1 mammal, 6 birds, 1 fish, 5 reptiles, 1 plant
Martin	2	28 T&E species: 4 mammals, 10 birds, 7 reptiles, 1 fish, 6 plants
Okeechobee 1	3	14 T&E species: 3 mammals, 9 birds, 2 reptiles
Okeechobee 2	3	14 T&E species: 3 mammals, 9 birds, 2 reptiles
St. Lucie	2	27 T&E species: 4 mammals, 10 birds, 7 reptiles, 2 fish, 4 plants [+72 state species]
Turkey Point	1	40-44 T&E species: 3 mammals, 12 birds (but 4 last documented in 1960s or earlier; 1 last documented in 1987-1991 and 2 are possible migrants – 1901 and 1958), 7 reptiles, 1 fish, 2 invertebrates, 19 plants (2 last documented over 50 years ago); site located between Biscayne National Park and Everglades National Park FPL maintains natural wildlife area; wetlands set aside as Everglades Mitigation Bank; entire site is crocodile habitat
West County (Palm Beach)	2	30 T&E species: 4 mammals, 10 birds, 7 reptiles, 1 fish, 1 invertebrate, 7 plants [in between Loxahatchee NWR and JW Corbett WMA]

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Criterion P5– Ecology/Federal RTE Species (by County)		
Site	Rating	Comments and Discussion
Note: All six species of sea turtles occurring in the U.S. are protected under the Endangered Species Act of 1973. NOAA Fisheries and the U.S. Fish and Wildlife Service (USFWS) share jurisdiction for sea turtles, with NOAA Fisheries having lead responsibility for the conservation and recovery of sea turtles in the marine environment and USFWS on turtles on nesting beaches. References: US Fish and Wildlife Service, South Florida Field Office [www.fws.gov/southflorida/CountyList – data provided by county; supposed to be current through September or December 2005. US Fish and Wildlife Service, Vero Beach/South Florida [www.fws.gov/verobeach/species_lists/countyfr.html] June 2000.		

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Criterion P6 – Wetlands		
Site	Wetland Acres (within 5,000-acre site area)	Rating
Charlotte	2,008	1
De Soto	632	2
Ft. Myers	802	2
Glades	489	3
Hardee	622	2
Hendry 1	843	2
Hendry 2	2,170*	1
Highlands	547*	2
Manatee	461*	3
Martin	210	4
Okeechobee 1	231	4
Okeechobee 2	961	2
St. Lucie	1,074	2
Turkey Point	1,476	2
West County	1,905	1

* Estimated from radius map.

Reference: From NWI Wetlands Mapper. Does not include estuarine and marine deepwater, riverine or freshwater pond acreage.

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Criterion P7 – Railroad Access		
Site	Rating	Comments and Discussion
Charlotte	1	Rail is ~ 18.1 miles E (operated by South Central Florida Express, CSX Transportation has trackage rights). Rail is ~ 22.7 miles W (operated by Seminole Gulf RR, CSX Transportation has trackage rights).
DeSoto	3	Rail is ~ 7.1 miles W (operated by CSX Transportation). A rail line between Arcadia, FL and Bowling Green, FL (~ 2.3 miles W of the proposed site) formerly operated by Seaboard System RR has since been abandoned.
Ft. Myers	4	Rail is ~ 2.4 miles SW (operated by Seminole Gulf RR, CSX Transportation has trackage rights). Connection to rail could be complicated by development in Tice, FL and location near the Caloosahatchee River.
Glades	4	Rail is ~ 3.1 miles NE (operated by South Central Florida Express, CSX Transportation has trackage rights).
Hardee	5	Rail is ~ 0.4 miles W (operated by CSX Transportation). A rail line between Arcadia, FL and Bowling Green, FL (~ 6.4 miles E of the proposed site) formerly operated by Seaboard System RR has since been abandoned.
Hendry 1	3	Rail is ~ 8.7 miles NE (operated by South Central Florida Express, CSX Transportation and Florida East Coast Railway have trackage rights).
Hendry 2	2	Rail is ~ 12.8 miles N (operated by South Central Florida Express, CSX Transportation and Florida East Coast Railway have trackage rights).
Highlands	3	Rail is ~ 7.1 miles W (operated by CSX Transportation).
Manatee	4	Rail is ~ 2.2 miles N (operated by CSX Transportation). This rail line formerly ran between Palmetto, FL and Durant, FL but now terminates in Willow, FL (~ 2.6 miles N of proposed site). A spur from this rail line accesses the existing Manatee plant.
Martin	5	Rail is ~ 1.5 miles NE (operated by CSX Transportation). Rail is ~ 2.8 miles W (operated by Florida East Coast Railway). However, lake/reservoir is located between the Martin site and this rail line.
Okeechobee 1	3	Rail is ~ 8.3 miles SW (operated by CSX Transportation). Rail is ~ 13.1 miles SE (operated by Florida East Coast Railway).

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Criterion P7 – Railroad Access		
Site	Rating	Comments and Discussion
Okeechobee 2	4	Rail is ~ 2.2 miles NE (operated by CSX Transportation).
St. Lucie	4	Rail is ~ 2.1 miles W (operated by Florida East Coast Railway). However, Intercoastal Waterway is located between the St. Lucie site and this rail line. Due to the coastal location of the St. Lucie site, barge access is accessible in the immediate vicinity for delivery of heavy/large items. However, since rail access is not immediately accessible, a rating of 5 was not assigned.
Turkey Point	4	Rail is ~ 10.3 miles W (operated by CSX Transportation). Homestead, FL marks the southernmost point of Florida served by rail. A rail line to Homestead, FL formerly operated by Florida East Coast Railway has since been abandoned. Due to the coastal location of the Turkey Point site, barge access is immediately accessible for delivery of heavy/large items. A barge channel has been constructed in Biscayne Bay providing direct access to the site. As barge access provides an alternative to rail access, the rating has been increased to 4 (however, since rail access is not immediately accessible, a rating of 5 was not assigned).
West County	2	Rail is ~ 13.6 miles NE (operated by CSX Transportation). Rail is ~ 14.1 miles NW (operated by Florida East Coast Railway).
References: North American Railroad Map, version 2.14, http://www.RailroadMap.com. USGS Topographic Maps (1 x 100,000 metric).		

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Criterion P8 – Transmission Access		
Transmission access is evaluated in the preliminary screening in terms of distance to the load center in the greater Miami area, and amount of new right of way (ROW) that needs to be acquired. The highest ranked sites already own the ROW, and the lowest ranked sites require significant ROW acquisition which will be difficult to obtain. In addition the plant switchyard is assumed the same for all sites.		
Site	Rating	Comments and Discussion
Charlotte	2	~ 100 miles to Miami Load Center. 140 miles of new 500 kV ROW acquisition, 1 autotransformer, 7- 500 kV line terminals.
DeSoto	3	~ 125 miles to Miami Load Center. 135 miles of new 500 kV ROW acquisition, 2 autotransformers, 8- 500 kV line terminals. ROW near Orange River substation will be difficult to obtain.
Ft. Myers	2	~ 100 miles to Miami Load Center. 95 miles of new 500 kV ROW acquisition, 2 autotransformers, 6- 500 kV line terminals. 8-230 kV terminals ROW near Ft Myers substation will be difficult to obtain.
Glades	4	~ 75 miles to Miami Load Center. 146 miles of new 500 kV of which approximately 60 miles of new ROW acquisition, 1 autotransformer, 6- 500 kV line terminals; rebuild 120 miles of 230 kV lines.
Hardee	2	~ 135 miles to Miami Load Center. 165 miles of new 500 kV ROW acquisition, 2 autotransformers, 6- 500 kV line terminals.
Hendry 1	4	~ 60 miles to Miami Load Center. 72 miles of new 500 kV of which approximately 40 miles of new ROW acquisition, 1 autotransformer, 6- 500 kV line terminals; rebuild 120 miles of 230 kV lines.
Hendry 2	4	~ 45 miles to Miami Load Center. 72 miles of new 500 kV of which approximately 40 miles of new ROW acquisition, 1 autotransformer, 6- 500 kV line terminals; rebuild 120 miles of 230 kV lines.
Highlands	2	~ 125 miles to Miami Load Center. 165 miles of new 500 kV ROW acquisition, 2 autotransformers, 6- 500 kV line terminals.
Manatee	1	~ 165 miles to Miami Load Center. 250 miles of new 500 kV ROW acquisition, 2 autotransformers, 8- 500 kV line terminals. ROW will be difficult to obtain.

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Criterion P8 – Transmission Access		
Transmission access is evaluated in the preliminary screening in terms of distance to the load center in the greater Miami area, and amount of new right of way (ROW) that needs to be acquired. The highest ranked sites already own the ROW, and the lowest-ranked sites require significant ROW acquisition which will be difficult to obtain. In addition the plant switchyard is assumed the same for all sites.		
Site	Rating	Comments and Discussion
Martin	5	~ 65 miles to Miami Load Center. 35 miles of new 500 kV in existing ROW, 6- 500 kV line terminals.
Okeechobee 1	4	~ 90 miles to Miami Load Center. 75 miles of new 500 kV of which approximately 20 miles of new ROW acquisition, 2 autotransformers, 8- 500 kV line terminals.
Okeechobee 2	4	~ 90 miles to Miami Load Center. 95 miles of new 500 kV of which approximately 40 miles of new ROW acquisition, 2 autotransformers, 8- 500 kV line terminals.
St. Lucie	1	~ 85 miles to Miami Load Center. 80 miles of new 500 kV ROW acquisition, 2 autotransformers, 8- 500 kV line terminals. ROW will be difficult to obtain.
Turkey Point	5	~ 50 miles to Miami Load Center. 64 miles of existing 500 kV, 1 autotransformer, 8-500 kV line terminals.
West County	2	~ 45 miles to Miami Load Center. 50 miles of new 500 kV ROW acquisition, 50 miles of new 230 kV will need to be rebuilt, 1 autotransformer, 6- 500 kV line terminals . ROW to the south will be difficult to obtain.
References: Google Earth, http://earth.google.com.		

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Criterion P9 – Land Acquisition		
Site	Rating	Comments and Discussion
Charlotte	3	FPL does not own – farmland/rural [$45 M] [there is less farming here than in other counties (50% farming: cattle watermelons; fish)] [Note: assumed 1,000 acres at $10,000 per acre and 2,000 acres at $17,500 per acre]
DeSoto	5	FPL owns sufficient land
Ft. Myers[2]	3	FPL owns some land but would have to buy more land; $35,000 per acre [near Ft. Myers] – [$52.5 M]
Glades	3	Does not own – mostly farmland/agriculture [$52.5 M] County is second largest sugarcane producer in the state
Hardee	3	Does not own – mostly farmland/agriculture [$52.5 M]; County is leading citrus and cattle producer in state
Hendry 1	3	Does not own – mostly farmland/agriculture [$52.5 M] County is largest producer of sugarcane in the state; crops; cattle and citrus around Lake Okeechobee
Hendry 2	3	Does not own – mostly farmland/agriculture [$52.5 M] County is largest producer of sugarcane in the state; crops; cattle and citrus around Lake Okeechobee
Highlands	3	Does not own – mostly farmland/agriculture [$52.5 M]; County is big in citrus/crop and livestock (milk and beef). Avon park area (near site) is one of heaviest citrus producing areas in state
Manatee	5	FPL owns sufficient land
Martin	5	FPL owns sufficient land
Okeechobee 1	3	Does not own – mostly farmland/agriculture [$52.5 M] [County big in cattle, dairy, citrus]
Okeechobee 2	3	Does not own – mostly farmland/agriculture [$52.5 M] [County big in cattle, dairy, citrus]
St. Lucie	5	FPL owns sufficient land
Turkey Point	5	FPL owns sufficient land

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Criterion P9 – Land Acquisition		
Site	Rating	Comments and Discussion
West County[2]	3	FPL owns but would have to buy more land; $35,000 per acre [near West Palm Beach] - $52.5 M

[1] Land requirements of 3,000 acres per site where FPL does not own.
[2] Need to purchase 1,500 acres more at Ft. Myers and West County where FPL holdings are not sufficient for new nuclear plant.

Note: Costs per acre are assumed to be $10,000 in rural areas; $17,500 for farmland; $35,000 for sites near urban/developed areas.

References: FPL real estate; county profile data.

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FLORIDA POWER & LIGHT COMPANY
PROJECT BLUEGRASS
NEW NUCLEAR POWER GENERATION

APPENDIX C
TECHNICAL BASIS FOR GENERAL SITE CRITERION RATINGS

Appendix C – Technical Basis for General Site Criterion Ratings

General siting criteria used in the FPL nuclear power plant siting study were derived from those presented in Chapter 3.0 of the *Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application*, EPRI, Palo Alto, CA: 2002 (Siting Guide).

The following information is provided in this appendix for each criterion:

- Objective – what aspect of site suitability is being measured;
- Evaluation approach – technical basis/methodology used to develop site ratings from available data;
- Discussion – data and information available for the eight sites under consideration; and
- Results – ratings results and rationale.

The following candidate nuclear plant (NP) sites were evaluated for the FPL Combined Operating License Application in Florida: DeSoto, Glades, Hardee, Hendry 1, Martin, Okeechobee 2, St. Lucie, and Turkey Point (Miami-Dade County).

Note that the sites were evaluated with respect to the following siting criteria during the initial screening phase: cooling water supply, flooding, population, hazardous land uses, ecology, wetlands, railroad access, transmission access, and land acquisition. The evaluation and results of this phase are presented in the screening criteria report. For several of these criteria (e.g., transmission access), the screening criteria evaluations are used in the general site criteria evaluations reported in this appendix. For these criteria, a brief summary and the final ratings are presented in this appendix for completeness. For other screening criteria (e.g., flooding, population and ecology), additional data were evaluated or additional detail are provided in this appendix, as appropriate, to provide a more comprehensive analysis of the full suite of EPRI siting general site criteria and sub-criteria.

Technical bases for site ratings developed for each of the general site criteria are provided in the following sections. Criterion/section numbering is designed to reflect section numbers in Chapter 3 of the EPRI Siting Guide where the criteria is discussed, e.g., Criterion C.1.1.1 – Geology/ Seismology appears in Section 3.1.1.1 of the Siting Guide.

C.1 HEALTH AND SAFETY CRITERIA

C.1.1 ACCIDENT CAUSE-RELATED

C.1.1.1 Geology/Seismology

Objective – The objective of this criterion is to rank the suitability of the eight candidate sites with respect to the geologic and seismic setting.

Evaluation approach – A numerical system of weights and ratings based upon suitability criteria were assigned to each geologic/seismic category, including vibratory ground motion, capable tectonic sources, surface faulting and deformation, geologic hazards, and soil stability (Sections C.1.1.1.1 through C.1.1.1.8) and used to compute (i.e., rate times weight) an index number for each category. (To enable the comparative evaluation of sites, the weights and rating schemes adopted herein are the same for all eight sites.) The index numbers for each site were summed to compute a GEOL Index (Tables C.1.1-1 through C.1.1-8). The range of GEOL indexes was then used to develop a rating system for candidate sites (Section C.1.1.1.6). The sites were rated on a scale of 1 to 5, based on the GEOL scale, with the most suitable sites receiving an overall rating of 5. Weights and the basis for deriving correlating site ratings from the GEOL scale are discussed with respect to each of the sub-criteria in the sections below. NOTE: Within the GOEL index sub-criteria an inverse rating basis is used, with lower numbers indicating most suitable and 5 the least suitable; for the composite GEOL index, higher numbers indicate more suitable sites.

C.1.1.1.1 Vibratory Ground Motion

Objective – The purpose of this sub-criterion is to rate sites according to the expected magnitude of ground motion that can be expected. As long as expected peak ground accelerations do not exceed that for the certified designs under consideration, there are no exclusionary or avoidance components to this sub-criterion.

Evaluation approach – Peak Ground Acceleration (PGA) is a measure of the maximum force experienced by a small mass located at the surface of the ground during an earthquake and is an index of hazard for some structures. The units for PGA are in percent of gravity (%g); i.e. an acceleration of 0.30g is expressed as 30%g. PGA provided herein, as for other sites, is for a probability of exceedance (PE) of 2% in 50 years (once in 2,500 years). PGA data for eight FPL Florida sites were obtained from the USGS National Seismic Hazards Mapping Project, 2002 (http://eqint.cr.usgs.gov/eq/html/lookup-2002-interp.html).

Discussion/Results – The locations evaluated for each of the eight candidate sites have PGA values as shown in the table below.

Probabilistic ground motion values in %g

Site	PGA (%g) with 2% PE in 50 years
DeSoto	3.58
Glades	3.57
Hardee	3.56
Hendry 1	3.52
Martin	3.33
Okeechobee 2	3.55
St. Lucie	3.00
Turkey Point	2.11

The following table shows the assigned weight and rating scheme for vibratory ground motion.

Weight	Range	Rating	Index Range
	PGA (%g)		
5	0 – 3	1	0 - 50
	3 – 6	2	
	6 – 9	3	
	9 – 12	4	
	12 – 15	5	
	15 – 18	6	
	18 – 21	7	
	21 – 24	8	
	24 – 27	9	
	27 – 30	10	

Based upon the information provided in Tables C.1.1-1 through C.1.1-8, each candidate site receives the following ratings based on the computed index numbers for vibratory ground motion.

Site	Rating	Index No.
DeSoto	2	10
Glades	2	10
Hardee	2	10
Hendry 1	2	10
Martin	2	10
Okeechobee 2	2	10
St. Lucie	1-2	5-10
Turkey Point	1	5

C.1.1.1.2 Capable Tectonic Structure or Source

Objective – No absolute exclusionary criteria have been identified. Capable tectonic structures are addressed as avoidance criteria; therefore, the objective of this sub-criterion is to identify the existence of capable or potentially capable tectonic structures within 200 miles of each site. Candidate sites that are farthest from capable or potentially capable tectonic structures are considered more suitable.

Evaluation Approach – A database compiled by USGS (Quaternary Fault and Fold Database, 2003; http://qfaults.cr.usgs.gov/) and Crone and Wheeler (2000) were utilized to identify capable and potentially capable tectonic sources within 200 miles of each of the eight candidate sites. It was assumed that capable and potential capable tectonic sources, which are Quaternary features that may generate strong ground motion, fall into two categories as defined by Crone and Wheeler (2000, p5):

> Class A features have good geologic evidence of tectonic origin and are potentially seismogenic; and
>
> Class B features have geologic evidence that supports the existence of a seismogenic fault or suggests Quaternary deformation, but the currently available geologic evidence for Quaternary tectonic activity is less compelling than for a Class A feature.

Discussion/Results – There are no Class A or B features within 200 miles of the candidate sites. The following table shows the assigned weight and the rating scheme for capable tectonic sources.

Weight	Range (miles)	Rating	Index Range
Class A	None within 200 mile radius	0	0 – 10
2	Between 100 and 200 miles	2	
	Between 50 and 100 miles	3	
	Between 25 and 50 miles	4	
	Within 25 miles	5	
Class B	None within 200 mile radius	0	0 – 5
1	Between 100 and 200 miles	2	
	Between 50 and 100 miles	3	
	Between 25 and 50 miles	4	
	Within 25 miles	5	

Based on the information provided in Tables C.1.1-1 through C.1.1-8, each candidate site receives the following ratings and computed index numbers.

Class A

Site	Rating	Index No.
DeSoto	0	0
Glades	0	0
Hardee	0	0
Hendry 1	0	0
Martin	0	0
Okeechobee 2	0	0
St. Lucie	0	0
Turkey Point	0	0

Class B

Site	Rating	Index No.
DeSoto	0	0
Glades	0	0
Hardee	0	0
Hendry 1	0	0
Martin	0	0
Okeechobee 2	0	0
St. Lucie	0	0
Turkey Point	0	0

Crone and Wheeler (2000) and the USGS Fault Database (2003) also identify Class C and D features. Class C features are defined by Crone and Wheeler (2000) as features where:

> Geologic evidence is insufficient to demonstrate (1) the existence of a tectonic fault, or (2) Quaternary slip or deformation associated with the feature.

No Class C features are known to occur within 200 miles of any of the eight candidate sites.

Class D features are defined by Crone and Wheeler (2000) as features where:

> Geologic evidence demonstrates that the feature is not a tectonic fault or feature; this category includes features such as demonstrated joints or joint zones, landslides, erosional or fluvial scarps, or landforms resembling fault scarps, but of demonstrable non-tectonic origin.

One Class D feature is known to occur within 200 miles of all eight candidate sites.

Class D Feature

The following Class D feature occurs within 200 miles of the eight candidate sites, and is considered non-capable.

> Grossman's Hammock Rock Reef. The Grossman's Hammock rock reef is located approximately 120 miles south of the DeSoto site; 98 miles south-southeast of the Glades site; 150 miles southeast of the Hardee site, 88 miles south-southeast of the Hendry 1 site; 110 miles south of the Martin site; 120 miles south of the Okeechobee 2 site, 130 miles south of the St. Lucie site, and 25 miles west of the Turkey Point site. Following a tentative inference of Quaternary displacement at Grossman's Hammock, investigation by drilling and ground penetrating radar showed no evidence of Quaternary faulting. (USGS Fault Database, 2003; Crone and Wheeler, 2000).

C.1.1.1.3 Surface Faulting and Deformation

Objective – Develop site ratings for site suitability relative to surface faulting and deformation in the site vicinity.

Evaluation approach – No absolute exclusionary criteria have been identified with regard to surface faulting and deformation. Suitability criteria have been established based on the occurrence of surface faulting and tectonic and non-tectonic structures within a 25-mi and 5-mi radius of the candidate sites, as follows (EPRI 2000, p.3-7):

Within 25 miles
- No such structures altogether (Most Suitable)
- Potential non-capable structures
- Potential capable structures (Least Suitable)

Within 5 miles
- No such structures altogether (Most Suitable)
- Potential non-capable structures
- Potential capable structures
- Fault exceeding 1,000 feet in length (Least Suitable)

The potential for surface faulting or deformation primarily concerns plant design; therefore, features identified within 5 miles of a candidate site receive a higher weight. Following are the assigned weights and ratings for surface faulting and deformation.

Weight	Range	Rating	GEOL Index Range
Between 5 and 25 miles – 1	No structures Potential non-capable structures Potential capable structures	0 1 5	0–5
Within 5 miles – 2	No structures Potential non-capable structures Potential capable structures Fault exceeding 1,000 feet in length Capable fault exceeding 1,000 feet in length	0 2 3 4 5	0–10

Discussion/Results – Over several decades, various faults have been proposed across Florida. Communications with the Florida Geologic Survey confirm that many of these have since been discounted, and conclusive proof is lacking for others. The current Geologic Map of Florida does not show faulting, and various structural maps of the State show deep-seated basins, platforms, and other structures, but no faulting. Therefore, it is not apparent that significant faulting occurs within 25 miles of any of the FPL sites. Based upon this information, the sites receive the following ratings and computed index numbers for surface faulting and deformation.

Within 25 miles

Site	Rating	Index No.
DeSoto	0	0
Glades	0	0
Hardee	0	0
Hendry 1	0	0
Martin	0	0
Okeechobee 2	0	0
St. Lucie	0	0
Turkey Point	0	0

Within 5 miles

Site	Rating	Index No.
DeSoto	0	0
Glades	0	0
Hardee	0	0
Hendry 1	0	0
Martin	0	0
Okeechobee 2	0	0
St. Lucie	0	0
Turkey Point	0	0

C.1.1.1.4 Geologic Hazards

Objective – Based on EPRI guidance (2000, p. 3-7), sites having the following geologic and man-made conditions should be avoided:

- Areas of active (and dormant) volcanic activity,
- Subsidence areas caused by withdrawal of subsurface fluids such as oil or groundwater, including areas which may be affected by future withdrawals,
- Potential unstable slope areas, including areas demonstrating paleolandslide characteristics,
- Areas of potential collapse (e.g. karst areas, salt, or other soluble formations),
- Mined areas, such as near-surface coal mined-out areas, as well as areas where resources are present and may be exploited in the future, and
- Areas subject to seismic and other induced water waves and floods.

Evaluation approach – Sites farthest away from these features would be considered the most suitable sites; sites were rated in accordance with the presence of – and distance from – these features. Following are the assigned weight and rating used for geologic hazards:

Weight	Range	Rating	GEOL Index Range
1	Geologic hazard(s) present	1	0–1

Discussion/Results – The following Geologic Hazard applies to six of the sites (DeSoto, Glades, Hardee, Hendry 1, Martin and Okeechobee 2):

> The Geologic Map of Florida, other maps, and site vicinity reports indicate that each site area is underlain by several tens of feet of sand and shelly material, which in turn overlie at least 350 feet of Hawthorn Group sediments (300 feet of Hawthorn Group sediments for the DeSoto and Hardee sites) consisting primarily of phosphatic sands and clays. Discontinuous lenses of limestone or dolostone may occur. Topographic maps of the general site vicinity exhibit some evidence of sinkhole formation.

The following Geologic Hazard applies to the two coastal sites (St. Lucie and Turkey Point):

> The site is located adjacent to the Atlantic Ocean, and is subject to seismic and other induced water waves and floods. Design specifications for a new nuclear facility at this site must address the possibility of large water waves and floods.

Design specifications for a new nuclear facility must address the possibility of solutioning and sinkhole formation, and of large water waves and floods. The eight candidate sites received the following computed rating and index number for geologic hazards:

Site	Rating	Index No.
DeSoto	1	1
Glades	1	1
Hardee	1	1
Hendry 1	1	1
Martin	1	1
Okeechobee 2	1	1
St. Lucie	1	1
Turkey Point	1	1

C.1.1.1.5 Soil Stability

Objective – Evaluate the sites with respect to the difficulty of expected soil conditions.

Evaluation approach – No absolute exclusionary criteria have been identified with respect to soil stability. Soil stability is addressed as an avoidance criterion. Certain soil properties have unfavorable characteristics in association with vibratory ground motion. These soil properties include poor mineralogy, low density soil (lack of compaction), and high water content (or high water table). Sites with the highest values of PGA in combination with deleterious site soils would receive a relatively lower rating. Sites having rock foundations or more suitable soil conditions are considered to be better sites.

Following are the assigned weights and ratings for soil stability:

Weight	Range	Rating	Index Range
2	Rock site	0	0 – 4
	Deep soil site, no known deleterious soil conditions	1	
	Deep soil site with potential stability issues, or insufficient information available to assign a rating of 1	2	

Discussion/Results – According to the Geologic Map of Florida, and other maps and reports, seven of the eight sites (DeSoto, Glades, Hardee, Hendry 1, Martin, Okeechobee 2, and St. Lucie) are underlain by hundreds of feet of predominately unconsolidated sediments (sands and clays) with some possible limestone or dolostone. Accordingly, each of these seven sites is a deep soil site. Deep soil sites will require specific site investigations to determine if deleterious soil conditions exist.

According to extensive investigations for nuclear and other facilities near the Turkey Point site, the site is underlain by a few feet of sandy material followed by approximately 70 feet of limestone. This limestone is reported to be competent and capable of supporting heavy loads. The limestone is underlain by many hundreds of feet of competent sand, clay, and rock. The Turkey Point site is a rock site.

Based upon this information the eight sites receive the following rating and computed index number for soil stability:

Site	Rating	Index No.
DeSoto	1	2
Glades	1	2
Hardee	1	2
Hendry 1	1	2
Martin	1	2
Okeechobee 2	1	2
St. Lucie	1	2
Turkey Point	0	0

C.1.1.1.6 Overall Rating for Geology/Seismology

The index numbers for this ranking scheme range from 5 to 85. This range of indexes was used to develop a ranking system to compare the suitability of sites as follows:

Index Range	Rating
5 – 21	5
22 – 37	4
38 – 53	3
54 – 69	2
70 – 85	1

The index numbers for each site were summed. The resulting index was compared to the index ranges in the above table to determine the overall rating for each site. Based upon this evaluation, the candidate sites are ranked as follows:

Site	Index Number	Rating
DeSoto	13	**5**
Glades	13	**5**
Hardee	13	**5**
Hendry 1	13	**5**
Martin	13	**5**
Okeechobee 2	13	**5**
St. Lucie	8-13	**5**
Turkey Point	6	**5**

Table C.1.1-1 Ratings for FPL
DeSoto Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 3.58 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	2	10
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the DeSoto site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the DeSoto site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation is known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation is known to occur at the site.	2	0	0
Geologic Hazards	The site is located in an area of potential solutioning and sinkhole formation.	1	1	1
Soil Stability	The DeSoto site is presumed to be a deep-soil site.	2	1	2
			Total Index	13

Table C.1.1-2 Ratings for FPL Glades Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 3.57 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	2	10
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the Glades site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the Glades site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation is known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation is known to occur near the site.	2	0	0
Geologic Hazards	The site is located in an area of potential solutioning and sinkhole formation.	1	1	1
Soil Stability	The Glades site is presumed to be a deep-soil site.	2	1	2
			Total Index	**13**

Table C.1.1-3 Ratings for FPL Hardee Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 3.56 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	2	10
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the Hardee site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the Hardee site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation is known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation is known to occur at the site.	2	0	0
Geologic Hazards	The site is located in an area of potential solutioning and sinkhole formation.	1	1	1
Soil Stability	The Hardee site is presumed to be a deep-soil site.	2	1	2
			Total Index	**13**

Table C.1.1-4 Ratings for FPL Hendry 1 Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 3.52 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	2	10
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the Hendry 1 site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the Hendry 1 site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation is known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation is known to occur at the site.	2	0	0
Geologic Hazards	The site is located in an area of potential solutioning and sinkhole formation.	1	1	1
Soil Stability	The Hendry 1 site is presumed to be a deep-soil site.	2	1	2
			Total Index	**13**

Table C.1.1-5 Ratings for FPL Martin Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 3.33 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	2	10
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the Martin site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the Martin site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation is known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation is known to occur at the site.	2	0	0
Geologic Hazards	The site is located in an area of potential solutioning and sinkhole formation.	1	1	1
Soil Stability	The Martin site is presumed to be a deep-soil site.	2	1	2
			Total Index	**13**

Table C.1.1-6 Ratings for FPL Okeechobee 2 Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 3.55 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	2	10
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the Okeechobee 2 site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the Okeechobee 2 site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation is known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation is known to occur at the site.	2	0	0
Geologic Hazards	The site is located in an area of potential solutioning and sinkhole formation.	1	1	1
Soil Stability	The Okeechobee 2 site is presumed to be a deep-soil site.	2	1	2
			Total Index	**13**

Table C.1.1-7 Ratings for FPL St. Lucie Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 3.00 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	1 - 2	5 - 10
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the St. Lucie site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the St. Lucie site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation are known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation are known to occur at the site.	2	0	0
Geologic Hazards	The site is located in an area susceptible to seismic and other induced water waves and floods.	1	1	1
Soil Stability	The St. Lucie site is presumed to be a deep-soil site.	2	1	2
			Total Index	**8-13**

Table C.1.1-8 Ratings for FPL Turkey Point Site

Feature	Source	Weight	Rating	Index No.
Vibratory Ground Motion	PGA 2.11 %g with 2% PE in 50 years (USGS National Seismic Hazards Mapping Project, 2002).	5	1	5
Capable Tectonic Source (Class A)	No Class A features occur within 200 miles of the Turkey Point site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	2	0	0
Capable Tectonic Source (Class B)	No Class B features occur within 200 miles of the Turkey Point site (USGS Fault and Fold Database, 2003. Crone & Wheeler, 2000).	1	0	0
Surface Faulting & Deformation within 25 miles	No surface faulting or deformation are known to occur near the site.	1	0	0
Surface Faulting & Deformation within 5 miles	No surface faulting or deformation are known to occur at the site.	2	0	0
Geologic Hazards	The site is located in an area susceptible to seismic and other induced water waves and floods.	1	1	1
Soil Stability	The Turkey Point site is presumed to be a rock site.	2	0	0
			Total Index	**6**

References

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USGS. Topographic Maps of Florida, various.

C.1.1.2 Cooling System Requirements

Objective – Cooling system requirements are important siting considerations for new power generating facilities. The objective of this criterion is to rate the candidate sites with respect to specific cooling system requirements, using to the extent possible the same or similar criteria previously utilized to evaluate other potential nuclear power plant sites.

Evaluation approach – The principle requirements of interest are the quantity of cooling water available and the ambient air temperature (EPRI, 2001, Section 3.1.1.2.1). Exclusionary and avoidance conditions apply to the evaluation of candidate sites with respect to these cooling

system requirements. Water requirements presented below have been established in the FPL Site Requirements Document.

Cooling System Type	Cooling System Requirement
Closed-cycle	Make-up flow rate: 80,000gpm / 178cfs

Ambient air temperature characteristics of a potential site affect the design of heat removal systems. The candidate sites are all located within a region of similar ambient air characteristics; this aspect is evaluated in section C.1.1.2.2.

Discussion/Results – Site data and results are presented for each of the sub-criteria in Sections C.1.1.2.1 and C.1.1.2.2, below. Overall ratings for the Cooling System Requirements criterion are provided in Section C.1.1.2.3.

C.1.1.2.1 Cooling Water

The eight sites were evaluated with respect to the cooling water criterion during the initial screening phase (P1 criterion), and all were found to have an adequate flow or some potential to develop reservoir capacity to support the requirements of a closed-cycle cooling water system. The rating approach used in this evaluation, as well as the site data and screening results, were described previously in the screening criteria report (Criterion P1).

For the screening phase, the metrics of flow, flexibility, risk and regulatory challenge were considered in developing the ratings. These metrics were combined to form the cooling water supply ratings reported in the screening criteria report and are incorporated into the evaluation of the general site criteria. Site attributes associated with pipeline routing or pumping are reflected in section C.4.1.

Screening Phase Ratings for Cooling Water Supply

Cooling Water	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	1	3	1	2	3	3	4	4

For the evaluation of the general criteria, additional aspects of developing a cooling water supply were evaluated. These additional aspects were selected to promote further differentiation of the eight sites. The additional aspects of the sites included the identification of a single existing water source that would be capable of providing the required flow and the proximity of the site to sensitive areas from either an environmental or water-supply basis. Sensitive areas, for the purpose of evaluating this general criterion, were selected to consist of water supplies in or near to 303(d), Water Conservation Areas or Outstanding Florida Waters designations. Once again, the sub-ratings were averaged to compile a consolidated rating for each site.

This analysis has resulted in ratings of 4 for the Martin, Okeechobee 2, St. Lucie and Turkey Point sites, primarily because these sites rated well in the screening phase and each site presented a water source capable of meeting the requirements of the project. The Glades and Hendry 1

sites were rated 3 as a result of their proximity to sensitive areas. The DeSoto and Hardee sites were rated 1 due to less favorable ratings in all three sub-criteria.

This evaluation has been performed in the absence of agency contact using publicly available flow data (e.g., USGS Daily Streamflow Data and low flow of record data were used when appropriate data were available). Flow in some of the source water systems is complex and requires further investigation. Water usage in all source waters is governed by individual water management districts in Florida. Approval for proposed water usage by the cognizant water management district will ultimately be required. It will be necessary to meet with the appropriate agencies to obtain preliminary confirmation of available water and to define requirements for obtaining final approval of any proposed water use.

Cooling Water	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Cooling Water Supply	1	3	1	2	3	3	4	4
Supply ID'd?[1]	1	5	1	5	5	5	5	5
OFW-303(d) – WCA[2]	2	2	2	2	3	3	3	3
Composite Rating	**1**	**3**	**1**	**3**	**4**	**4**	**4**	**4**

[1] Required flow identified from a single existing source = 5, No single adequate existing supply identified = 1

[2] No sensitive areas nearby = 4, one designated area nearby = 3, one designated area nearby + proximity to a second designated area = 2

C.1.1.2.2 Ambient Temperature Requirements

Temperature data were obtained from local weather stations as compiled by the Southeast Regional Climate Center – historical climate summaries and normals – which is part of the National Oceanic and Atmospheric Administration's National Climate Data Center (NOAA NCDC). Closest daily weather stations with a reasonable period of record (e.g., more than 20 years) were selected for each site. Data indicate that each site meets the ambient temperature exclusionary and avoidance criteria addressed in EPRI 2001 (Section 3.1.1.2.2). Maximum and minimum annual temperature values, as well as the highest and lowest average monthly temperatures values, and the annual average monthly mean values, were compared between sites. Actual meteorological conditions at the eight sites, however, may vary from the data collected and evaluated for the closest reporting (representative) weather stations: Arcadia for DeSoto and Hardee; Moore Haven for Glades; Clewiston for Hendry 1, Canal Point USDA for Martin; Okeechobee for Okeechobee 2; Fort Pierce for St. Lucie; and Miami for Turkey Point. The period of record for all sites includes a minimum of 30 years varying between 1931 and 2005.

Ambient Temperature (degrees F)	Highest temperature of record	Highest monthly average	Lowest temperature of record	Lowest monthly average	Annual Monthly Average Mean	Rating
DeSoto	104 (6/5/85) Arcadia	91.8 (July/ August)	18 (1/13/81)	49.2 (January)	72.5	3
Glades	103 (7/8/32) Moore Haven	91.2 (July)	23 (1/28/40)	51.8 (January)	73.2	3
Hardee	104 (6/5/85) Arcadia	91.8 (July/ August)	18 (1/13/81)	49.2 (January)	72.5	3
Hendry 1	101 (8/7/95) Clewiston	91.4 (July)	26 (1/12/82)	54.3 (January)	74	3
Martin	100 (7/17/81) Canal Point USDA	91.2 (August)	25 (1/12/82)	52.7 (January)	73.3	3
Okeechobee 2	99 (8/7/72) Okeechobee	93 (August)	31 (12/28/72)	47.7 (Feb)	72.7	3
St. Lucie	101 (7/23/89) Ft. Pierce	90.1 (July)	10 (1/23/52)	53.1 (January)	73.3	3
Turkey Point	98 (5/25/05) Miami Beach	87.9 (August)	32 (12/24/89)	62.7 (January)	81.1	3

Source: www.sercc.net/climateinfo/historical/historical.html [for Florida]
NOAA National Climatic Data Center, Ashville, NC: 2005 Local Climatological Data, Annual Summary with Comparative Data for the following Florida locations: Arcadia, Moore Haven, Clewiston, Canal Point/USDA, Okeechobee, Ft. Pierce, and Miami Beach.

Discussion/Results – The candidate sites were compared to one another to assess their relative suitability with respect to selected temperature extremes and frequency values.

With the exception of extreme low temperature values, sites with the lowest dry bulb temperatures are considered to be the most suitable. Based on a comparison of highest and lowest temperature (daily extremes), average high and low temperature records, annual average monthly mean temperatures, and consideration of general climate conditions at the sites, the variation in temperatures between sites was very small. This is not surprising given that they are located in the same geographic area of south Florida. The differences were small enough that identical ratings were assigned to each site. In addition, because the temperatures in Florida are, in general, higher than other parts of the country, and the maximum temperatures exceeded 100 in all cases except Okeechobee and Turkey Point, a conservative rating of 3 was given to all sites.

C.1.1.2.3 Cooling System Summary Rating

The sites were assigned relative ratings for the suitability of the cooling system based on the average of the ratings for cooling water supply and the ambient air temperature characteristics.

Cooling Water	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Cooling Water Supply	1	3	1	3	4	4	4	4
Ambient Temperature	3	3	3	3	3	3	3	3
Composite Rating	**2**	**3**	**2**	**3**	**3.5**	**3.5**	**3.5**	**3.5**

References

U.S. Nuclear Regulatory Commission Office of Nuclear Reactor Regulation. NUREG-1038 Supplement No. 4.

USGS: The National Streamflow Information Program, Florida Active Streamgages, http://water.usgs.gov/nsip/nsipmaps/fl_base.html.

FDEP: The Watershed Management Basin Rotation Project, IMS Website, http://wrmims2.dep.state.fl.us/basinmap/open.htm?BasinList=21&Submit1=Go%21.

Site Requirements Document to Support Combined Construction and Operating License Application, Draft B, July 24, 2006, FPL Nuclear Components and Replacement Group.

C.1.1.3 Flooding

Objective – The objective of this criterion is to evaluate the suitability of the candidate sites with respect to potential flooding. Some potential sites are located within the 100-year floodplain and may not meet the exclusionary and avoidance criteria outlined in EPRI 2001 (Section 3.1.1.3). These criteria exclude potential sites within major wetlands and areas less than one foot above the maximum flood elevation.

Evaluation Approach – The relative suitability of the candidate sites was evaluated with respect to flooding in the Preliminary Screening Evaluation, but was limited to a comparison of existing surface water elevations and anticipated (and approximate) plant elevations. A further comparison was conducted in this detailed evaluation, between site grade elevation and the 100-year flood elevation for the major river or lake on which the plant is located. The 100-year flood elevations were based on Flood Insurance Rate Maps (FIRM) from FEMA for the respective counties in which the sites are located. Primary emphasis was on flood elevations for the main water bodies (rivers and reservoirs) and their major tributaries where flood elevations were identified. Finally, other potential flooding sources (e.g., upstream dam failure concerns) were also considered.

Because of the more accurate floodplain data and consideration of upstream dam failure concerns, the rating scale was modified from that used in the Preliminary Screening Evaluation. The revised scale is as follows:

5 = Site is not located within 100-year floodplain, and no potential upstream flooding concerns exist (e.g., dam failure).
4 = Site is not located within 100-year floodplain, but potential upstream flooding concerns exist.
3 = Site is on border of 100-year floodplain.
2 = Site is located within 100-year floodplain, but no potential upstream flooding concerns exist.
1 = Site is located within 100-year floodplain, and potential upstream flooding concerns exist.

Discussion/Results – Additional pertinent flood-related information for the candidate sites is shown in the following table, followed by the site ratings.

Site	Evaluation
DeSoto	DeSoto elevation = 81 feet. Peace River current elevation (at Arcadia, FL) ~ 10 feet. River flood stage = 17 feet. Difference = 64 feet above flood stage. Site is located in Zone X (outside 500-year flood zone). Swamp areas exist in the vicinity of the proposed site; however ample areas exist for precise site location to avoid swamp areas and areas within the 100-year flood zone. Site is not located in 100-year flood zone. No dams or other flooding concerns are located on the Peace River within 40 miles upstream of the proposed site. The Sand Gully (west of the proposed site) has been known to flood up to 2 miles west of the proposed site.

Site	Evaluation
Glades	Glades elevation = 15 feet. Caloosahatchee Canal (Okeechobee Waterway) and Lake Hicpochee elevation = 11 feet. Difference = 4 feet. Site is in Zone A (located in 100-year flood zone). The proposed site is located ~ 5.0 miles southwest of Lake Okeechobee. Lake Okeechobee is reinforced from flooding by the Herbert Hoover Dike. The failure of this dike has been examined, and resulting flood predictions in the event of dike failure have been prepared. Two failure scenarios could potentially impact the proposed site. Scenario #1: If the lake level is at 26 feet and a break in Reach 2 occurs (southeast of Moore Haven, FL), flood waters could reach the proposed site in 5-18 days, and flood depths of 6 feet are predicted. Scenario #2: If the lake level is at 26 feet and a break in Reach 4 occurs (north of Moore Haven, FL), flood waters could reach the proposed site in 1-3 days, and flood depths of 6 feet are predicted. Additionally, the Moore Haven Lock and Spillway (dam) is located at the entry of the Caloosahatchee Canal into Lake Okeechobee. Should this structure fail, flooding at the proposed site is predicted to be observed within 24 hours and could reach depths of 2 feet.
Hardee	Hardee elevation = 63 feet. Peace River current elevation (at Zolfo Springs, FL) ~ 39 feet. River flood stage = 46 feet. Difference = 17 feet above flood stage. Site is in Zone X (not located in 100-year flood zone). No dams or other flooding concerns are located on the Peace River within 40 miles upstream of the proposed site.
Hendry 1	Hendry 1 elevation = 19 feet. Lake Okeechobee elevation = 14 feet. Difference = 5 feet. Site is located near swamp areas. Site is located in Zone A3 (located in 100-year flood zone). The proposed site is located ~ 10.9 miles south of Lake Okeechobee. Lake Okeechobee is reinforced from flooding by the Herbert Hoover Dike. The failure of this dike has been examined, and resulting flood predictions in the event of dike failure have been prepared. The proposed site is located south of the L-1 canal/levee, and this structure is predicted to protect the proposed site location in the event of a break in either Reach 2 (southeast of Moore Haven, FL) or Reach 4 (north of Moore Haven, FL) with a lake level of 26 feet. No other potential failures resulting in flooding are located in the proposed site area.

Site	Evaluation
Martin	Martin site elevation = 28 feet. Lake Okeechobee elevation = 14 feet. Difference = 14 feet. Site is not located in 100-year flood zone, but is located near swamp lands. Site is in Zone X (area of 500-year flood, area of 100-year flood with average depths of < 1 foot or with drainage area < 1 sq. mi., or area protected by levees from 100-year flood). Lake Okeechobee is located ~ 5.1 miles west of the proposed site. The proposed site is located east of the boundary limit of flooding from Lake Okeechobee caused by breaching of Herbert Hoover Dike (as shown on FIRM). No other potential failures resulting in flooding are located in the proposed site area.
Okeechobee 2	Okeechobee 2 elevation = 28 feet. Kissimmee River ~ 20 feet. Difference = 8 feet. Swamp areas exist in the vicinity of the proposed site. Site is at border of Zone A and Zone C. Site is at border of 100-year flood zone. Lake Okeechobee is located ~ 7.6 miles southeast of the proposed site. Lake Okeechobee is reinforced from flooding by the Herbert Hoover Dike. The failure of this dike has been examined, and resulting flood predictions in the event of dike failure have been prepared. The proposed site is located east of the Kissimmee River, and this feature is predicted to protect the proposed site location in the event of a break in either Reach 6 or Reach 8 (both on the northwest side of Lake Okeechobee) with a lake level of 26 feet. A lock structure is located on the south side of Lake Kissimmee, ~ 41 miles north of the site. The Kissimmee River has been canalized between Lake Kissimmee and Lake Okeechobee for flood control purposes.
St. Lucie	St. Lucie elevation = 0-5 feet. Atlantic Ocean elevation = 0 feet. Difference = 0-5 feet. Site is located in Zone AE with base flood elevations of 7-8 feet. Site is located in 100-year flood zone. With the exception of flooding caused by adverse climatic events, no other potential failures resulting in flooding are located in the proposed site area.
Turkey Point	Turkey Point elevation = 1-2 feet. Site is located in Zone AE with base flood elevations of 12 feet. Site is located in 100-year flood zone. With the exception of flooding caused by adverse climatic events, no other potential failures resulting in flooding are located in the proposed site area.

Flooding	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	5	1	5	2	3	3	1	1

References

FEMA Digital Flood Insurance Rate Maps, http://www.msc.fema.gov.

Google Earth, http://earth.google.com.

Herbert Hoover Dike Major Rehabilitation Study.

NOAA Stream and Flood Data, http://www.weather.gov/ahps/.

Site Drainage and Interim Land Use Study, Brown & Root, Inc., March 1976.

USGS Topographic Maps (1:100,000 and 1:24,000 scale).

U.S. Flood Hazard Areas, http://www.esri.com/hazards/makemap.html.

C.1.1.4 Nearby Hazardous Land Uses

C.1.1.4.1 Existing Facilities
C.1.1.4.2 Projected Facilities

Objective – The objective of this criterion is to include NRC guidance on considerations regarding the nature and proximity of man-related hazards (dams, airports, transportation routes, and military and chemical manufacturing and storage facilities).

Evaluation approach – For the purpose of this evaluation, it was assumed that all eight sites can be developed to meet the exclusionary criteria outlined in 10 CFR 100. The suitability of the candidate sites was, therefore, evaluated based on the relative number and distance of the following off-site man-made hazards that could be identified on USGS topographic maps, supplemented by information found in existing environmental reports for each site. The evaluation was limited to only existing hazards within a 5- to 10-mile radius of each site, to the extent such information was available. This included primarily airports, pipelines, and rail. Note that information relating to projected man-made hazards was not readily available and could not be evaluated during this phase of the siting process.

The relative suitability of the eight sites with respect to nearby hazardous land uses was evaluated in the screening criteria report (Criterion P4), although the rating approach was revised slightly to better reflect a comparison of the eight candidate sites (as compared to the 15 sites evaluated previously). The following revised scale was used:

5 = No major or minor hazardous land uses within 10 miles
4 = No major hazardous land uses within 10 miles, but minor hazardous land uses within 10 miles (single or multiple, e.g., landing strips or small airports)

3 =No major hazardous land use within 10 miles but minor hazardous land use within 5 miles (one rail and/or between 2 and 4 small airports/landing strips)
2 = Major hazardous land use within 10 miles or multiple minor hazardous land use within 5 miles (more than 4)
1 = Major hazardous land use within 5 miles

Discussion – To summarize from the screening evaluation, identified hazards at each of the sites are as follows:

DeSoto
Airports: No major airports; smaller airports at Arcadia (9.6 miles SW) and Sebring (24.8 miles NW); other small airport/landing strips at 2.5, 7.4, 8.2, 8.4, 12.7, 13.5, and 15.4 miles [closest general aviation airports include DeSoto County in Arcadia and Port Charlotte/Punta Gorda].
Freight Rail: Rail: 7.1 miles to W [rail in county includes CSX and Seminole Gulf rail line].
Other Potential Hazards: local deepwater ports – Manatee Port Authority – 49 miles.

Glades
Airports: Clewiston Municipal Airport is 12.4 miles SE of site; other smaller airports at 2 and 3 miles from site (landing strips) [county profile website mentions Airglades airport at unknown distance].
Freight Rail: 3.1 miles to NE [South Central Florida Express]; 11 miles W.
Other Potential Hazards: local deep water port – Port of Ft. Pierce – 64 miles.
Also in Glades County: includes mining industry; Florida Rock, Witherspoon sand mine [location/distance to site is unknown].

Hardee
Airports: no major airports; airport at Arcadia (9 miles) and smaller airstrips located 9.5 and 12.5 miles away [nearest with commercial service – Sarasota-Bradenton; general aviation is Hardee County Municipal Airport].
Freight Rail: located 0.4 miles W [CSX].
Other Potential Hazards: closest local deepwater port – Manatee County Port Authority – 25 miles.
Industry in county includes two large companies in phosphate business but we are not sure of any associated mining activities.

Hendry 1
Airports: general aviation: Clewiston Airport (7.3 miles); smaller airports at 4.5, 9.8, 10.5, 10.9, 16.6 miles [airport in LaBelle].
Freight Rail: 8.7 miles to NE.
Other Potential Hazards: closest deep water port – Ft. Pierce – 84 miles.

Martin
Airports: No major airports; Stuart Airport 25 miles to E; smaller airports at 2.5, 6.4, 6.8, and 11 miles away. General aviation – Witham Field.
Freight Rail: 1.5 miles NE and 2.8 miles W.
Other Potential Hazards: Existing power plant with natural gas pipeline service to site [3,700 MW – 2 steam units, 3 combined cycle units, 6,800 acre cooling pond]; 40 miles from Port of Palm Beach; existing plant bounded on west by Florida East Coast Railway and adjacent SFWMD L-65 Canal, and on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway) and northeast by SR 710 and the adjacent CSX Railroad [from 10 year plan].

Okeechobee 2
Airports: Okeechobee County airport 7.3 miles E; smaller airports located 1.3, 4.3, 8.1 and 10 miles away [Palm beach International – closest with scheduled commercial airline service].
Freight Rail: 2.2 miles NW.
Military Installation: Avon Bombing Range – 27 miles to NW.
Other Potential Hazards: Port of Ft. Pierce and Port of Palm Beach – 35 miles.

St. Lucie
Airports: Major airport 12.4 miles to NW (St. Lucie County International); smaller airport (Witham field in Stuart) 10.4 miles to SW.
Freight Rail: 2.1 miles W.
Pipeline: Did not see on topographic maps, but other reports show nearby line extending down Atlantic coast.
Other Potential Hazards: Site located on navigable waterway; Port of Ft. Pierce is 1 mile away; Existing nuclear power plant.

Turkey Point
Airports: Homestead general aviation airport – 5 miles NW of site; 14+ miles to Kendall-Tamiami Executive Airport (NW of site).
Freight Rail: 10 miles W.
Pipeline: did not see any major pipeline routes marked on topographic maps, but natural gas pipeline service to site.
Military Installation: Homestead AFB—5.2 miles NW of site (unclear what operations occur at base now, but assume fully operational as AFB for purposes of evaluation). US Naval Reservation with heliport and radio facility, located 7 miles SW.
Other Potential Hazards: Site located on navigable waterway; Port of Miami less than 5 miles away; Existing power plants (2 nuclear units, 2 conventional boiler fossil units plus building new combined cycle unit).

Results -- Most sites had numerous smaller airports or landing strips and possibly a rail line within 5 or 10 miles and received ratings of 3 or 4 accordingly. Turkey Point received the lowest rating due to its close proximity to a larger airport and US Air Force Base, as well as being on a navigable waterway and located near the Port of Miami. Its co-location with other existing power plant facilities also was considered.

Nearby Hazardous Land Uses	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	4	3	3	4	3	3	3	2

References

Google Earth, http://earth.google.com.

USGS Topographic Maps.

FPL 10 Year Plan.

County profile data.

C.1.1.5 Extreme Weather Conditions
C.1.1.5.1 Winds
C.1.1.5.2 Precipitation

Objective – The objective of this criterion is to rate the suitability of the eight candidate sites with respect to extreme weather conditions. Extreme weather conditions of interest are related to specific PPE criteria regarding tornado design, wind and precipitation (EPRI Siting Guide, Section 3.1.1.5).

Evaluation approach – During the review of available meteorological information on the sites, no information was found that indicated the eight sites could not meet the exclusionary and avoidance criteria specified for the PPE values. Extreme weather readily available for the eight sites included fastest mile speed (available for selected cities – although not necessarily the most representative of site conditions); number of tornadoes and violent tornadoes per 10,000 square miles (state average); and maximum 24-hour precipitation values. The number of hurricanes making landfall in Florida was also considered. Available extreme weather data were obtained from government sources (National Climate Data Center and Southeast Regional Climate Center), including NCDC Climatic Wind Data for US [ncdc.noaa.gov/documentlibrary.pdf/wind1996.pdf.].

Discussion/Results – Rating of the sites was performed based on a comparison of fastest mile (wind) speeds, maximum 24-hour precipitation and severe storm records, although greater emphasis was placed on the most distinguishing site feature – site location in relation to the coast – as an indicator of greater probability of hurricane threat – and the number of hurricanes to hit Florida (broken up into four geographic quadrants) as follows:

Hurricane direct hits on the mainland U.S. coastline and for individual states 1851-2004 by Saffir/Simpson category.

Area	Category Number					All (1-5)	Major (3-5)
	1	2	3	4	5		
U.S. (Texas to Maine)	109	72	71	18	3	273	92
Florida	43	32	27	6	2	110	35
(Northwest)*	27	16	12	0	0	55	12
(Northeast)*	13	8	1	0	0	22	1
(Southwest)*	16	8	7	4	1	36	12
(Southeast)*	13	13	11	3	1	41	15

- Assume Southeast area includes Glades, Hendry, Martin, Okeechobee, St. Lucie and Turkey Point, and DeSoto and Hardee are in southwest Florida, with inland sites being preferred over coastal sites.
- Hurricane that may strike more than one region in Florida would be counted separately for each region (i.e., individual regional totals may exceed state totals)

Source: National Hurricane Center at http://www.nhc.noaa.gov/paststate.shtml

Site	Fastest Mile (1970-2001)	Tornado Frequency: Strong violent/ strong violent per 10,000 sq mi [state annual average, 1953-2004]	Proximity to Coast/ Hurricane Threat	Hurricane direct hits on Florida region (1851-2004)	Maximum 24-hr precip. [in]
DeSoto	92 (Ft. Myers) Or 79 (Orlando for inland counties)	7/1.2	Inland	36 (12 major)	7.38 (Arcadia)
Glades	86 (W. Palm)	7/1.2	Inland	41 (15 major)	8.4 (Moore Haven)
Hardee	67 (Tampa)	7/1.2	Inland	36 (12 major)	7.38 (Arcadia)
Hendry 1	86 (W. Palm) 92 (Ft. Myers)	7/1.2	Inland	41 (15 major)	9.6 (Clewiston)
Martin	86 (W. Palm)	7/1.2	Inland	41 (15 major)	9.68 (USDA Canal)
Okeechobee 2	86 (W. Palm)	7/1.2	Inland	41 (15 major)	8.08 (Okeechobee)
St. Lucie	86 (W. Palm)	7/1.2	Coast	41 (15 major)	10.00 (Ft. Pierce)
Turkey Point	86 (Miami)	7/1.2	Coast	41 (15 major)	10.06 (Miami)

In general, the sites were fairly similar and were assigned equally conservative ratings of 3, with the exception of the two coastal sites: St. Lucie and Turkey Point. Given their proximity to the coast and higher potential for extreme storm events (precipitation, winds, and number of

hurricanes) [also based on annual probability of experiencing hurricane force winds from a hurricane (http://www.floridadisaster.org/bpr/Response/Plans/Nathaz/hurricanes/hurr_freq.htm) compared to the other sites] they were given slightly lower ratings of 2.

Extreme Weather Conditions	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	3	3	3	3	3	3	2	2

C.1.2 ACCIDENT EFFECTS-RELATED

Objective – The overall objective of this criterion is to evaluate sites with respect to design-related accident evaluations and potential effects of accidents.

Evaluation approach – Site ratings for this criterion are developed as a composite of three sub-criteria that address site characteristics relevant to consideration of accidents: Population, Emergency Planning Considerations, and Atmospheric Dispersion.

Discussion/Results – A discussion of each of the sub-criteria appears in the following sections C.1.2.1, C.1.2.2, and C.1.2.3. A discussion of the roll-up of the sub-criterion ratings into a single rating for the Accident-Effects-Related criterion appears in Section C.1.2.4.

C.1.2.1 Population

Objective – The objective of this criterion is to evaluate the relative suitability of the candidate sites with respect to the population density in the vicinity of the sites. For the purposes of this evaluation, it was assumed the existing licensed units at three of the candidate sites meet the population density conditions codified in 10 CFR 100.21. These conditions are:

- The sites have exclusion area authority,
- A low population zone exists beyond the exclusion area, and
- Sufficient distance exists to high-population centers.

Evaluation approach – As outlined in Regulatory Guide 4.7, low-population areas are preferred and low-population zones should have densities less than 500 people per square mile (EPRI 2001) (equivalent to less than 25,000 persons within 4 miles).

All sites meet population density exclusion criteria since population density was a criterion in the regional screening process. Available census data regarding the nearest population centers and area population densities were reviewed for the candidate sites in the screening criteria report (Criterion P3), and confirmed that each met the exclusion criteria. Online data were obtained from the US Census Bureau.

Discussion/Results – Ratings and the population data and distance to population centers that drive the ratings are presented for each site in the following table.

Nearest Population Center (2000 Population)	Population and Population Density (By County)	Notes
DeSoto (DeSoto County)		
Nearest population center: Arcadia, 8.5 miles County Seat: Arcadia Largest City: Arcadia	32,309 (2000); 35,406 (2005); 9.9% growth Population Projections (County): 40,400 (2015) 48,500 (2030) Pop. Density: 50.5 psm (2000)	Population Center within 10 miles: Arcadia (6,604) Population Centers within 20 miles: Zollo Springs (no data), Wauchula (4,368), Sebring (3,667)/Lake Placid (1,668) Nearest MSA – Port Charlotte/Punta Gorda (30 miles) Tampa/Gulf Coast – 65 miles
Glades (Glades County)		
Nearest population center: Moore Haven, 2 miles County Seat: Moore Haven Largest City: Moore Haven	10,576 (2000); 11,252 (2005); 6.4% growth Population Projections (County): 12,200 (2015) 13,700 (2030) Pop. Density: 13.7 psm	Population Center within 10 miles: Moore Haven (1,635) Population Centers within 20 miles: Clewiston (6,460), Belle Glade (14,906), LaBelle (4,210) Nearest MSA - Ft. Myers/Cape Coral (38 miles) Miami/East Coast – 95 miles
Hardee (Hardee County)		
Nearest population center: Zollo Springs, 12 miles County Seat: Wauchula Largest Cities: Wauchula, Bowling Green, Zollo Springs	26,938 (2000); 28,286 (2005); 5.0% growth Population Projections (County): 30,300 (2015) 34,000 (2030) Pop. Density: 42.3 psm	No Population Centers within 10 miles; Population Centers within 15 miles: Zollo Springs (no data), Wauchula (4,368), and Arcadia (6,604) Nearest MSA – Port Charlotte (30 miles) Tampa/Gulf Coast – 48 miles Orlando – 70 miles
Hendry 1 (Hendry County)		
Nearest population center: Clewiston (7.3 miles) County Seat: LaBelle Largest Cities: La Belle, Clewiston	36,210 (2000); 39,561 (2005); 9.3% growth Population Projections (County): 46,500 (2015) 56,000 (2030) Pop. Density: 31.4 psm	Population Centers within 10 miles: Clewiston (6,460) Population Centers within 20 miles: Belle Glade (14,906) Nearest MSA – Ft. Myers/Cape Coral (45 miles) and West Palm Beach (50 miles) Miami/East Coast – 103 miles Tampa/Gulf Coast – 106 miles

Nearest Population Center (2000 Population)	Population and Population Density (By County)	Notes
Martin (Martin County)		
Nearest population center: Indiantown (7 miles) County Seat: Stuart Largest Cities: Stuart, Sewalls Point, Jupiter Island	126,731 (2000); 139,728 (2005); 10.3% growth Population Projections (County): 170,300 (2015); 205,100 (2030) Pop. Density: 228.1 psm	Population Centers within 10 miles: Indiantown (5,588) Population Centers within 20 miles: Port St. Lucie (88,769), Okeechobee (5,376) Nearest MSA – Ft. Pierce/Port St. Lucie (23 miles) and West Palm Beach (40 miles) Miami/East Coast – 96 miles
Okeechobee 2 (Okeechobee County)		
Nearest population center: Okeechobee (8 miles) County Seat: Okeechobee Largest Cities: Okeechobee	35,910 (2000); 39,836 (2005); 10.9% growth Population Projections (County): 41,200 (2015) 45,700 (2030) Pop Density: 46.4 psm	Population Center within 10 miles Okeechobee (5,376) Population Centers within 20 miles: Lake Placid (1,668) Nearest MSA – Ft. Pierce/Port St. Lucie (35 miles) Miami/East Coast – 111 miles Orlando – 93 miles
St. Lucie (St. Lucie County)		
Nearest population center: Port St. Lucie (4.5 miles) County Seat: Ft. Pierce-Port St. Lucie Largest Cities: Port St. Lucie, Ft. Pierce, St. Lucie Village	192,695 (2000); 241,305 (2005); 25.2% growth Population Projections (County): 320,500 (2015); 419,200 (2040) Pop. Density: 336.3 psm	Population Center within 5 miles Port St. Lucie (88,769) Population Centers within 10 miles Stuart (14,633), Ft. Pierce (37,516) Nearest MSA – Ft. Pierce/Port St. Lucie (within 5 miles) Miami/East Coast – 115 miles Orlando – 100 miles
Turkey Point (Miami-Dade County)		
Nearest population center: Leisure City (7.2 miles) County Seat: Miami Largest Cities: Miami, Hialeah, Miami Beach	2,253,362 (2000); 2,376,914 (2005); 5.4% growth Population Projections (County): 2,771,500 (2015); 3,196,800 (2030) Pop. Density 1,157.9 psm)	Population Centers within 10 miles Homestead (31,909), Florida City (7,843) Key Largo (11,806) Population Centers within 20 miles Miami Nearest MSA – Miami (within 20 miles)

Based on the above information, the following site ratings were assigned. In the case of proximity to nearest population center, sites within 5 miles of the nearest population center were given a rating of 2 (less than 2 miles would receive a rating of 1), within 10 miles were given a rating of 3, within 15 miles were given a rating of 4, and within 20 miles were given a rating of 5. Ratings for proximity to densely populated areas also were considered and were based on the distance to the nearest metropolitan statistical area (MSA).

Population	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
County population	5	5	5	5	4	5	3	1
Distance to population center	2	1	3	2	2	2	1	2
Proximity to densely populated area	4	4	4	4	3	4	2	1
Composite Rating	**4**	**3**	**4**	**4**	**3**	**4**	**2**	**1**

References

US Census Bureau, 2000 population data.

Florida Atlas and Gazetteer 2003; detailed topographic maps.

C.1.2.2 Emergency Planning

Objective – The objective of this criterion is to evaluate the relative suitability of the eight candidate sites with respect to emergency planning characteristics of the general area around each site. (No exclusionary or avoidance criteria apply to this issue.) In particular, this evaluation relied on information pertaining to general population in surrounding area, road conditions near site, access to major traffic networks, terrain features, and climatic conditions.

Evaluation approach – Sites with the least constrained evacuation planning issues (low population, good access from site to major traffic networks, and no terrain or climate limitations) were considered the most suitable and were assigned a score of 5. Ratings are based on review of county websites (transportation information), USGS topographic maps, and best professional judgment. Ratings relate to extent of development in the general area, the number of roads providing egress from the site area, and proximity to major US highway systems.

Discussion/Results – A summary of information for each site is shown in the table below. In general, the sites with lower populations were found in the more rural areas with less developed traffic networks, so the two factors balanced each other out. In general, given Florida's flat topography, no limiting terrain features were identified. Limiting climate conditions identified for the coastal sites included the potential for hurricanes. Site ratings follow the table.

Site	Evaluation
DeSoto	Proposed site is located ~ 2.5 miles east of U.S. Highway 17 and ~ 7.3 miles north of State Highway 70. Brownville, FL is located ~ 3.2 miles southwest of the proposed site, and Arcadia, FL is located ~ 8.6 miles southwest of the proposed site. Area evacuation is possible in all directions. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered.
Glades	Proposed site is located ~ 1.0 miles south of U.S. Highway 27 and State Highway 78. Moore Haven, FL is located ~ 4.8 miles east of the proposed site, and Clewiston, FL is located ~ 15.2 miles southeast of the proposed site. Area evacuation is possible in all directions, but immediate area evacuation is limited to the south due to minimal crossings of the Caloosahatchee Canal. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered.
Hardee	Proposed site is located ~ 5.0 miles south of State Highway 64 and ~ 6.4 miles west of U.S. Highway 17. Zolfo Springs, FL is located ~ 8.7 miles northeast of the proposed site, and Arcadia, FL is located ~ 13.7 miles south of the proposed site. Area evacuation is possible in all directions. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered.
Hendry 1	Proposed site is located ~ 5.4 miles east of State Highway 833 and ~ 6.4 miles south of U.S. Highway 27. Clewiston, FL is located ~ 9.2 miles northeast of the proposed site. Area evacuation is possible in all directions, although northerly evacuation routes go around Lake Okeechobee and southerly evacuation routes go through swampy areas. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered.
Martin	Proposed site is located ~ 1.1 miles southwest of State Highway 710 and ~ 5.6 miles east of U.S. Highway 98/441. Indiantown, FL is located ~ 6.3 miles southeast of the proposed site, and Port St. Lucie, FL is located ~ 20.4 miles northeast of the proposed site. Area evacuation is possible in three directions, being limited to the west by Lake Okeechobee. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered.
Okeechobee 2	Proposed site is located ~ 0.4 miles north of State Highway 70 and ~ 4.3 miles southwest of U.S. Highway 98. Okeechobee, FL is located ~ 6.8 miles east of the proposed site. Area evacuation is possible in all directions, although southerly evacuation routes go around Lake Okeechobee. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered.

Site	Evaluation
St. Lucie	Proposed site is located on Hutchinson Island adjacent to Highway A1A and ~ 9.8 miles from access to U.S. Highway 1. Port St. Lucie, FL is located ~ 7.2 miles southwest of the proposed site, and Fort Pierce, FL is located ~ 8.7 miles northwest of the proposed site. Area evacuation is possible in two directions, being limited to the east by the Atlantic Ocean and to the west by the Intercoastal Waterway. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered and more prevalent at the proposed site due to its coastal location. The site is adjacent to the existing St. Lucie nuclear power plant and brings the advantage of already having an Emergency Plan that could easily be adapted to include the new site. However, both sites would require evacuation under emergency conditions.
Turkey Point	Proposed site is located ~ 9.1 miles east of U.S. Highway 1 and the Florida Turnpike. Homestead, FL is located ~ 9.8 miles west of the proposed site. Area evacuation is possible in three directions, being limited to the east by the Atlantic Ocean/Biscayne Bay. Westerly evacuation routes are available, but are limited by the Everglades. Florida is prone to impact by hurricanes, and site evacuations coinciding with such climatic conditions would be hampered and more prevalent at the proposed site due to its coastal location. The site is adjacent to the existing Turkey Point nuclear power plant and brings the advantage of already having an Emergency Plan that could easily be adapted to include the new site. However, both sites would require evacuation under emergency conditions.

Emergency Planning	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	5	4	5	5	3	5	3	4

References

Rand McNally Road Atlas.

USGS Topographic Maps.

C.1.2.3 Atmospheric Dispersion

Objective – The objective of this criterion is to evaluate the suitability of the eight candidate sites with respect to short-term atmospheric dispersion characteristics, as a measure of the relative level of concentrations that could occur during accident conditions at the sites.

Evaluation Approach – The efficiency of atmospheric diffusion is primarily dependent on wind speed, wind direction, and the change in air temperature with height which affects atmospheric stability. These factors are used to calculate an atmospheric dispersion function referred to X/Q.

Discussion/Results – The best way to calculate atmospheric dispersion (X/Q) is using on-site meteorological data; however, no such data were readily available for all candidate sites. Sites near the coast would generally experience windier conditions, and were given a rating of 5. Inland locations would generally experience less wind, and were given a rating of 4. Should atmospheric dispersion become a sensitive criterion for site selection, site-specific meteorological data should be obtained to calculate an atmospheric dispersion function (X/Q) for more accurate site comparison.

Site	Evaluation
DeSoto	Site is located ~ 50 miles inland from the Gulf of Mexico.
Glades	Site is located ~ 70 miles inland from the Gulf of Mexico. Site is located ~ 70 miles inland from the Atlantic Ocean.
Hardee	Site is located ~ 40 miles inland from the Gulf of Mexico.
Hendry 1	Site is located ~ 65 miles inland from the Atlantic Ocean. Site is located ~ 75 miles inland from the Gulf of Mexico.
Martin	Site is located ~ 25 miles inland from the Atlantic Ocean. During the daytime with strong solar heating, the atmosphere is unstable and disperses pollutants quickly for short periods of time. The majority condition is neutral and disperses pollutants at moderate rates. During nighttime, the atmosphere becomes stable and minimally disperses pollutants.
Okeechobee 2	Site is located ~ 45 miles inland from the Atlantic Ocean.
St. Lucie	Site is located in the Atlantic Ocean coastal region.
Turkey Point	Site is located in the Atlantic Ocean coastal region.

Atmospheric Dispersion	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	4	4	4	4	4	4	5	5

References

Site Certification Application, Martin Expansion Project. January 2002.

USGS Topographic Maps (1:100,000 and 1:24,000 scale).

C.1.2.4 Accident-Effect Related Summary Rating

Composite ratings for this criterion (Accident Effects) are a composite of those for sub-criteria C.1.2.1, C.1.2.2, and C.1.2.3; the ratings for these sub-criteria, along with the summary rating for this criterion, are provided in the following table.

Sub-criterion	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Population	4	3	4	4	3	4	2	1
Emergency Planning	5	4	5	4	3	5	3	4
Atmospheric Dispersion	4	4	4	4	4	4	5	5
Overall Rating	4	4	4	4	3	4	3	3

C.1.3 OPERATIONAL EFFECTS-RELATED

C.1.3.1 Surface Water – Radionuclide Pathway
C.1.3.1.1 Dilution Capacity
C.1.3.1.2 Baseline Loadings
C.1.3.1.3 Proximity to Consumptive Users

Objective – The purpose of this criterion is to evaluate candidate sites with respect to potential liquid pathway dose consequences. (No site exclusionary or avoidance criteria apply to this issue.) Besides potential source terms, dilution in the receiving surface water body is of primary importance. Three factors considered in evaluating the potential dilution for a receiving water body are dilution capacity, baseline loadings, and proximity to consumptive users.

Evaluation Approach – Site ratings for this criterion are developed as a composite of three sub-criteria that address site characteristics relevant to consideration of operation: Dilution Capacity, Baseline Loadings, and Proximity to Consumptive Users.

- Dilution Capacity – The purpose of this sub-criterion is to rate sites based on the overall capacity of the receiving water body to dilute effluents from a nuclear power plant. Information on the radioactive source term dilution at a new power plant will be site specific. For siting consideration where such information is not available, however, surrogate parameters, representing the dilution capacity of a stream, can be used. The greater the dilution capacity of the receiving water body, the shorter will be the mixing length downstream defined as the zone within which complete mixing of a discharge contaminant occurs. Sites with higher dilution capacity are rated higher.
- Baseline Loadings – The capacity of a stream to impact health and safety of downstream consumers is related to the existing, or baseline loadings of, radionuclides that are present in the system or can be anticipated in the future. The purpose of this sub-criterion is to characterize sites in accordance with existing levels of radioactive contamination in the receiving water body. Sites are given a rating of 5 for no baseline loadings; proportionally lower ratings are assigned as higher existing levels of radionuclide contamination are identified.
- Proximity to Consumptive Users – The purpose of this sub-criterion is to rate sites in accordance with the proximity of plant effluent release point to the location(s) public water supply withdrawal(s). More proximal withdrawals present higher potential for

dose impacts from the surface water ingestion pathway and can require additional design and licensing efforts. Downstream locations of public water supply withdrawals and recreational contact were identified for each site. Sites with greater pathway lengths to users were more suitable and were assigned a score of 5.

Discussion/Results – An evaluation of each site and a summary of the sub-criterion and overall ratings for the surface water-radionuclide pathway criterion are presented in the following tables.

Site	Evaluation
DeSoto	Dilution Capacity: The Peace River is the nearest receiving body of water from the site (~ 4 miles west of the proposed site). Recent river flow rates have been near 2,500 cubic feet per second. Under these conditions, the receiving body of water is likely capable of diluting potential liquid pathway dose. Baseline Loading: No sources of existing radionuclide loadings were identified for the site. Proximity to Consumptive Users: The majority of DeSoto County, including Arcadia, FL, relies on groundwater as the primary source of public water use. The Peace River is not widely used for consumptive uses.
Glades	Dilution Capacity: Lake Okeechobee is the nearest receiving body of water from the site (~ 5 miles east of the proposed site). The receiving body of water is likely capable of diluting effluents from a nuclear power plant. The C-43 canal (Okeechobee Waterway / Caloosahatchee Canal) is another potential receiving body of water from the site. The C-43 canal flows west to the Gulf of Mexico (~ 60 miles). Baseline Loading: No sources of baseline radionuclide loadings were identified for the site. Proximity to Consumptive Users: Lake Okeechobee is classified as a drinking water source. Moore Haven, FL is located ~ 5 miles east of the proposed site.
Hardee	Dilution Capacity: The Peace River is the nearest receiving body of water from the site (~ 3 miles east of the proposed site). Recent river flow rates have been near 2,500 cubic feet per second. Under these conditions, the receiving body of water is likely capable of diluting potential liquid pathway dose. Baseline Loading: No sources of existing radionuclide loadings were identified for the site. Proximity to Consumptive Users: The majority of DeSoto County, including Arcadia, FL, relies on groundwater as the primary source of public water use. The Peace River is not widely used for consumptive uses.
Hendry 1	Dilution Capacity: Lake Okeechobee is the nearest receiving body of water from the site (~ 11 miles north of the proposed site). The receiving body of water is likely capable of diluting effluents from a nuclear power plant. Baseline Loading: No sources of baseline radionuclide loadings were identified for the site. Proximity to Consumptive Users Lake Okeechobee is classified as a drinking water source. Clewiston, FL is located ~ 9 miles northeast of the proposed site.

Site	Evaluation
Martin	Dilution Capacity: Lake Okeechobee is the nearest receiving body of water from the site (~ 5 miles west of the proposed site). The receiving body of water is likely capable of diluting effluents from a nuclear power plant. The C-44 canal (Okeechobee Waterway / St. Lucie Canal) is another potential receiving body of water from the site. The C-44 canal flows east to the Atlantic Ocean (~ 25 miles). Baseline Loading: No sources of baseline radionuclide loadings were identified for the site. Proximity to Consumptive Users: The Okeechobee Utility Authority is permitted to withdraw water from the northern bank of Lake Okeechobee for a public potable water source. This plant is located ~ 18 miles northwest of the site.
Okeechobee 2	Dilution Capacity: The Kissimmee River is the nearest receiving body of water from the site (~ 2 miles southwest of the proposed site). The receiving body of water is likely capable of diluting effluents from a nuclear power plant. Baseline Loading: No sources of baseline radionuclide loadings were identified for the site. Proximity to Consumptive Users: The Okeechobee Utility Authority is permitted to withdraw water from the northern bank of Lake Okeechobee for a public potable water source. This plant is located ~ 9 miles southeast of the site.
St. Lucie	Dilution Capacity: The Atlantic Ocean is the receiving body of water from the site and is sufficiently large to easily dilute effluents from a nuclear power plant. Baseline Loading: While an existing nuclear power plant is located near the proposed site, the receiving body of water is sufficiently large to render any baseline radionuclide loadings negligible. Proximity to Consumptive Users: No downstream locations of public water supply withdrawals were identified for the site.
Turkey Point	Dilution Capacity: The Atlantic Ocean/Biscayne Bay and groundwater (via the cooling canals) are the receiving bodies of water from the site and are sufficiently large to easily dilute effluents from a nuclear power plant. Baseline Loading: While an existing nuclear power plant is located near the proposed site, the receiving body of water is sufficiently large to render any baseline radionuclide loadings negligible. Proximity to Consumptive Users: No downstream locations of public water supply withdrawals were identified for the site.

Site	Dilution Capacity	Baseline Loadings	Proximity to Downstream public water supply	Composite Rating
DeSoto	3	5	5	4
Glades	4	5	3	4
Hardee	3	5	5	4
Hendry 1	4	5	3	4

Site	Dilution Capacity	Baseline Loadings	Proximity to Downstream public water supply	Composite Rating
Martin	4	5	4	4
Okeechobee 2	3	5	3	4
St. Lucie	5	4	5	5
Turkey Point	5	4	5	5

References

Estimated Water Use 2002, Southwest Florida Water Management District.

USGS Topographic Maps.

C.1.3.2 Groundwater Radionuclide Pathway

Objective – The purpose of this section is to evaluate the candidate sites with respect to the relative vulnerability of shallow groundwater resources to potential contamination.

Evaluation Approach – All candidate sites overlie aquifers that have not been designated by EPA's (1986) classification scheme. EPA guidelines were, however, used to assign a designation to candidate site aquifers. In addition, the relative vulnerability of these aquifers to groundwater pollution was evaluated using a standard numerical ranking system called DRASTIC (Aller et al. 1987). Sites considered most suitable are those that are least vulnerable to groundwater contamination within a 2-mile radius of a site.

Discussion/Results – Class I groundwater is addressed as an avoidance criteria (EPRI 2000). This classification includes groundwater resources of unusually high value. They are highly vulnerable to contamination and are irreplaceable sources of drinking water and or ecologically vital. Groundwater underlying the candidate sites are either currently used or are potential sources of drinking water, hence, they would be considered Class II aquifers according to the EPA classification guidelines. The Biscayne Aquifer in South Florida has been designated a Sole Source Aquifer by EPA. One site, Turkey Point, is located above the Biscayne Aquifer. Projects that receive Federal financial assistance and have the potential to contaminate a sole source aquifer are subject to EPA review. The Okeechobee 2 site is located in the recharge zone for the Biscayne Aquifer, and the Martin and Glades sites are located either within or along the border of the recharge zone. These sites, while not located above the Biscayne Aquifer, would have a potential for contamination since they are located within or very near the aquifer's recharge zone.

The DRASTIC evaluation was completed using site-specific data, where available, or data from published sources. The most important variables that control the groundwater pollution potential are:

- D–Depth to water,
- R–Recharge (net),
- A–Aquifer media,
- S–Soil media,
- T–Topography (slope),
- I–Impact of the vadose zone,
- C–Conductivity (hydraulic) of the groundwater flow system.

DRASTIC assigns a weighted numeric value to each characteristic, depending on its relative contribution to risk of groundwater contamination. This results in a numeric ranking for each site, allowing the sites to then be ranked in order of suitability. The higher an area scores on the DRASTIC index, the more susceptible a site is to groundwater contamination. Following is a summary of the DRASTIC evaluations.

DeSoto				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	5-15 ft bgs (USGS topographic maps)	5	9	45
Net Recharge	10^{+} in/yr	4	9	36
Aquifer Media	Sands with silt and clay (Florida geologic maps and text)	3	6	18
Soil Media	Sandy Loam (Florida geologic map and text)	2	6	12
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Sand (Florida geologic map and text)	5	6	30
Hydraulic Conductivity	300 - 700 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	4	12
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Glades				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	5-15 ft bgs (USGS topographic maps)	5	9	45
Net Recharge	10^{+} in/yr	4	9	36
Aquifer Media	Sands with silt and clay (Florida geologic maps and text)	3	6	18
Soil Media	Sandy Loam (Florida geologic map and text)	2	6	12
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Sand (Florida geologic map and text)	5	6	30
Hydraulic Conductivity	300 - 700 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	4	12
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Hardee				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	5-15 ft bgs (USGS topographic maps)	5	9	45
Net Recharge	10+ in/yr	4	9	36
Aquifer Media	Sands with silt and clay (Florida geologic maps and text)	3	6	18
Soil Media	Sandy Loam (Florida geologic map and text)	2	6	12
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Sand with significant silt and clay (Florida geologic map and text)	5	5	25
Hydraulic Conductivity	100 - 300 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	2	6
			INDEX	**152**

Hendry 1				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	5-15 ft bgs (USGS topographic maps)	5	9	45
Net Recharge	10^{+} in/yr	4	9	36
Aquifer Media	Sands with silt and clay (Florida geologic maps and text)	3	6	18
Soil Media	Sandy Loam (Florida geologic map and text)	2	6	12
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Sand (Florida geologic map and text)	5	6	30
Hydraulic Conductivity	300 - 700 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	4	12
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Martin				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	5-15 ft bgs (USGS topographic maps)	5	9	45
Net Recharge	10^{+} in/yr	4	9	36
Aquifer Media	Sands with silt and clay (Florida geologic maps and text)	3	6	18
Soil Media	Sandy Loam (Florida geologic map and text)	2	6	12
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Sand (Florida geologic map and text)	5	6	30
Hydraulic Conductivity	300 - 700 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	4	12
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Okeechobee 2				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	0-5 ft bgs (USGS topographic maps)	5	10	50
Net Recharge	10^{+} in/yr	4	9	36
Aquifer Media	Sands with silt and clay (Florida geologic maps and text)	3	6	18
Soil Media	Sandy Loam (Florida geologic map and text)	2	6	12
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Thin sand (Florida geologic map and text)	5	8	40
Hydraulic Conductivity	300 - 700 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	4	12
			INDEX	**178**

St. Lucie				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	5-15 ft bgs (USGS topographic maps)	5	9	45
Net Recharge	10^{+} in/yr	4	9	36
Aquifer Media	Sands with silt and clay (Florida geologic maps and text)	3	6	18
Soil Media	Sand (Florida geologic map and text)	2	7	14
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Sand (Florida geologic map and text)	5	7	35
Hydraulic Conductivity	300 - 700 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	4	12
			INDEX	**170**

Turkey Point				
DRASTIC Variable	**Range and Source of Information**	**Weight**	**Rating**	**Number**
Depth to Water	0-5 ft bgs (USGS topographic maps)	5	10	50
Net Recharge	10^{+} in/yr	4	9	36
Aquifer Media	Bedded limestone (Florida geologic maps and text)	3	7	21
Soil Media	Thin (Florida geologic map and text)	2	10	20
Topography	Less than 1% (USGS site topographic maps)	1	10	10
Impact Vadose Zone	Thin sand and limestone (Florida geologic map and text)	5	7	35
Hydraulic Conductivity	700 - 1000 gpd/ft^2 (Driscoll, 1986; DRASTIC, 1987)	3	6	18
			INDEX	**190**

DRASTIC indexes for all typical hydrogeologic settings range from 65 to 223 (Aller et al. 1987, p. 82). This range of indexes was used to develop a ranking system to compare vulnerability of candidate sites, as follows:

DRASTIC Index Range	Relative Vulnerability	Rating
65–98	Low	5
98–132	Low to Moderate	4
132–166	Moderate	3
166–199	High	2
199–233	Very High	1

Based on these DRASTIC Index Ranges for qualitative vulnerability, candidate sites were ranked as follows:

Candidate Site	DRASTIC Index	Rating
DeSoto	163	3
Glades	163	3
Hardee	152	3
Hendry 1	163	3
Martin	163	3
Okeechobee 2	178	2
St. Lucie	170	2
Turkey Point	190	2

References

Aller, L., Bennett, T., Lehr, J., Petty, R. and G. Hackett. 1987. DRASTIC: A Standardized System for Evaluating Ground Water Pollution Potential Using Hydrogeologic Settings. EPA/600/2-87/035, June 1987.

DRASTIC: A Standardized System for Evaluating Ground Water Pollution Potential Using Hydrogeologic Settings; EPA Manual, 1987.

Driscoll, Fletcher G., Groundwater and Wells, 1986.

EPA, 1986. Guidelines for Groundwater Classification Under the EPA Groundwater Protection Strategy, Office of Groundwater Protection.

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Florida Geological Survey, Text to Accompany the Geologic Map of Florida, open-file report 80, 2001.

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USGS. Topographic Maps of Florida, various.

C.1.3.3 Air Radionuclide Pathway

C.1.3.3.1 Topographic Effects
C.1.3.3.2 Atmospheric Dispersion

Objective – The purpose of this criterion is to address the relative suitability of sites with respect to the potential for exposure to the public from routine airborne releases from a nuclear power plant.

Evaluation approach – The criterion is composed of two suitability characteristics:

> Topographic Effects – Site ratings are based on whether there are any significant topographic features that would materially affect dispersion of the plume from plant releases (e.g., channeling of releases from a site located low in a high-banked river valley).
>
> Atmospheric Dispersion – Measured in terms of long term (e.g., annual average X/Q) dispersion characteristics. Sites with lower X/Q values are rated higher than those with less favorable dispersion conditions.

Discussion/Results – None of the sites are believed to have significant potential for negative topographic effects on long-term dispersion; however, final site locations have not been identified for several of the sites. Annual average X/Q values were unavailable for candidate sites. Sites near the coast would generally experience windier conditions, and were given a rating of 5. Inland locations would generally experience less wind, and were given a rating of 4. Should atmospheric dispersion become a sensitive criterion for site selection, site-specific meteorological data should be obtained to calculate an atmospheric dispersion function (X/Q) for more accurate site comparison.

Site	Evaluation	Ranking
DeSoto	Site is located ~ 50 miles inland from the Gulf of Mexico.	4
Glades	Site is located ~ 70 miles inland from the Gulf of Mexico. Site is located ~ 70 miles inland from the Atlantic Ocean.	4
Hardee	Site is located ~ 40 miles inland from the Gulf of Mexico.	4

Site	Evaluation	Ranking
Hendry 1	Site is located ~ 65 miles inland from the Atlantic Ocean. Site is located ~ 75 miles inland from the Gulf of Mexico.	4
Martin	Site is located ~ 25 miles inland from the Atlantic Ocean.	4
Okeechobee 2	Site is located ~ 45 miles inland from the Atlantic Ocean.	4
St. Lucie	Site is located in the Atlantic Ocean coastal region.	5
Turkey Point	Site is located in the Atlantic Ocean coastal region.	5

The proposed site ratings with respect to radionuclide exposure via airborne releases are as follows:

Air Radionuclide Pathway	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**4**	**4**	**4**	**4**	**4**	**4**	**5**	**5**

References

USGS Topographic Maps.

C.1.3.4 Air-Food Ingestion Pathway

Objective – The objective of this criterion is to rate candidate sites in terms of the relative potential for exposure of humans to radioactive emissions through deposition of radioactive materials on food crops with subsequent consumption of exposed foodstuffs by individuals.

Evaluation approach – A potential exposure pathway for nuclear power plants is the emission of radionuclides into the food chain on local crops and pastures. Radiological doses and dose commitments resulting from a nuclear plant are well-known and documented. While the operational impacts on the public through food pathway exposures are negligible, sites with lower amounts of crop and pasture land uses are considered to be more suitable. No exclusionary or avoidance criteria apply to this issue. Sites with less crop production nearby are rated higher than those with larger agricultural industries.

Discussion/Results – General information regarding crop lands and pastures near the sites is summarized in the table below.

Site	Evaluation	Ranking
Florida (entire state)	Agriculture (farmland) represents 10,414,877 acres out of 34,513,280 acres in Florida (30%). Out of total farmland, 3,715,257 acres are planted in crop (36%).	N/A

Site	Evaluation	Ranking
DeSoto	Agriculture (farmland) represents 388,177 acres out of 407,680 acres in DeSoto County (95%). Out of the total farmland, **115,356** acres are planted in crop (30%). Other farmland is used for cattle (81,628 head), and lower numbers of hogs and pigs (33 head), sheep (38 head) and poultry (251 layers). Aerial imagery indicates that the proposed site is in the general vicinity of agricultural operations, and the actual impact to local crops, pastures, and livestock from radionuclide emission exposure would be greater than the county-wide percentages.	1
Glades	Agriculture (farmland) represents 407,950 acres out of 495,360 acres in Glades County (82%). Out of the total farmland, **73,043** acres are planted in crop (18%). Other farmland is used for cattle (66,423 head), and lower numbers of hogs and pigs (48 head) and poultry (210 layers). Aerial imagery indicates that the proposed site is in the general vicinity of agricultural operations, and the actual impact to local crops, pastures, and livestock from radionuclide emission exposure would be greater than the county-wide percentages.	1
Hardee	Agriculture (farmland) represents 346,191 acres out of 407,680 acres in Hardee County (85%). Out of the total farmland, **115,676** acres are planted in crop (33%). Other farmland is used for cattle (94,749 head), and lower numbers of hogs and pigs (93 head) and poultry (292 layers and 123 broilers). Aerial imagery indicates that the proposed site is in the general vicinity of agricultural operations, and the actual impact to local crops, pastures, and livestock from radionuclide emission exposure would be greater than the county-wide percentages.	1
Hendry 1	Agriculture (farmland) represents 552,352 acres out of 737,920 acres in Hendry County (75%). Out of the total farmland, **296,006** acres are planted in crop (54%). Other farmland is used for cattle (73,207 head), and lower numbers of hogs and pigs (125 head) and poultry (286 layers). Aerial imagery indicates that the proposed site is in the general vicinity of agricultural operations, and the actual impact to local crops, pastures, and livestock from radionuclide emission exposure would be greater than the county-wide percentages.	1

Site	Evaluation	Ranking
Martin	Agriculture (farmland) represents 206,198 acres out of 355,840 acres in Martin County (58%). Out of the total farmland, **97,840** acres are planted in crop (47%). Other farmland is used for cattle (27,279 head), and lower numbers of hogs and pigs (439 head) and poultry (81 broilers). Aerial imagery indicates that the proposed site is in the general vicinity of agricultural operations, and the actual impact to local crops, pastures, and livestock from radionuclide emission exposure would be greater than the county-wide percentages. Additionally, while power plants are currently located near the proposed site, the potential for radionuclide emissions would be a newly introduced area hazard.	2
Okeechobee 2	Agriculture (farmland) represents 392,495 acres out of 495,360 acres in Okeechobee County (79%). Out of the total farmland, **115,292** acres are planted in crop (29%). Other farmland is used for cattle (142,656 head), and lower numbers of hogs and pigs (82 head), sheep (1,737), and poultry (171 layers). Aerial imagery indicates that the proposed site is in the general vicinity of agricultural operations, and the actual impact to local crops, pastures, and livestock from radionuclide emission exposure would be greater than the county-wide percentages.	1
St. Lucie	Agriculture (farmland) represents 221,537 acres out of 366,080 acres in St. Lucie County (61%). Out of the total farmland, **118,847** acres are planted in crop (54%). Other farmland is used for cattle (31,944 head), and lower numbers of hogs and pigs (394 head) and poultry (317 layers). Aerial imagery indicates that the proposed site is not in the general vicinity of agricultural operations, and the actual impact to local crops, pastures, and livestock from radionuclide emission exposure would be significantly lower than the county-wide percentages.	5
Turkey Point	Agriculture (farmland) represents 90,373 acres out of 1,245,440 acres in Miami-Dade County (7%). Out of the total farmland, **66,564** acres are planted in crop (74%). Other farmland is used for cattle (3,880 head), hogs and pigs (144 head), sheep (272 head), and poultry (2,052 layers and 240 broilers). Aerial imagery indicates that the proposed site is in the general vicinity of some agricultural operations (although not as agriculturally dominated as potential greenfield sites). However, existing nuclear power plants are located at the Turkey Point location, and agricultural operations in the general vicinity are already exposed to potential radionuclide emissions. As such, the site has been given a rating of 5 as potential radionuclide emissions are not a new hazard to the area.	5

Air-Food Ingestion Radionuclide Pathway	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	1	1	1	1	2	1	5	5

References

Florida MapStats, http://www.fedstats.gov/qf/states/12000.html.

Google Earth, http://earth.google.com.

National Agricultures Statistics Service (2002 Census of Agriculture) for Florida, http://151.121.3.33:8080/Census/Create_Census_US_CNTY.jsp.

C.1.3.5 Surface Water – Food Radionuclide Pathway

Objective – The purpose of this criterion is to evaluate the relative suitability of sites in terms of the specific use of irrigation water by downstream locations as a potential pathway for potential exposure.

Evaluation approach – Sites with the fewest number of downstream irrigation uses are more suitable and are rated higher than sites with a large number of downstream irrigation withdrawals. No exclusionary or avoidance criteria apply to this issue (EPRI 2001).

Discussion/Results – General information regarding irrigated lands near the sites is summarized in the table below.

Site	Evaluation	Ranking
Florida (entire state)	Total irrigated land represents 1,815,174 acres out of 10,414,877 acres of farmland in Florida (17%).	N/A
DeSoto	Total irrigated land represents 79,147 acres out of 388,177 acres of farmland in DeSoto County (20%). Withdrawals of water for irrigation from the Peace River downstream of the site are probable.	1
Glades	Total irrigated land represents 49,147 acres out of 407,950 acres of farmland in Glades County (12%). Withdrawals of water for irrigation from area canals downstream of the site are probable.	2
Hardee	Total irrigated land represents 56,882 acres out of 346,191 acres of farmland in Hardee County (16%). Withdrawals of water for irrigation from the Peace River downstream of the site are probable.	1

Site	Evaluation	Ranking
Hendry 1	Total irrigated land represents 206,043 acres out of 552,352 acres of farmland in Hendry County (37%). Withdrawals of water for irrigation from area canals downstream of the site are probable.	1
Martin	Total irrigated land represents 55,805 acres out of 206,198 acres of farmland in Martin County (27%). Withdrawals of water for irrigation from area canals downstream of the site are probable.	1
Okeechobee 2	Total irrigated land represents 22,085 acres out of 392,495 acres of farmland in Okeechobee County (6%). Withdrawals of water for irrigation from the Kissimmee River and area canals downstream of the site are probable.	2
St. Lucie	Total irrigated land represents 102,629 acres out of 221,537 acres of farmland in St. Lucie County (46%). Withdrawals of water for irrigation downstream of the site are not expected as the site is located very near the Atlantic Ocean, and agricultural operations are not located in the vicinity of the site.	5
Turkey Point	Total irrigated land represents 43,615 acres out of 90,373 acres of farmland in Miami-Dade County (48%). Withdrawals of water for irrigation downstream of the site are not expected as the site is located very near the Atlantic Ocean (Biscayne Bay). Additionally, existing nuclear power plants are located at the Turkey Point location, and agricultural operations in the general vicinity are already exposed to potential radionuclide emissions. As such, the site has been given a rating of 5 as potential radionuclide emissions are not a new hazard to the area.	5

Surface Water-Food Radionuclide Pathway	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**1**	**2**	**1**	**1**	**1**	**2**	**5**	**5**

References

National Agricultures Statistics Service (2002 Census of Agriculture) for Florida, http://151.121.3.33:8080/Census/Create_Census_US_CNTY.jsp.

C.1.3.6 Transportation Safety

Objective – The objective of this criterion is to evaluate the suitability of the eight candidate sites with respect to potential to create fog and ice hazards to local transportation. No exclusionary or avoidance criteria apply to this issue.

Evaluation approach – Potential impacts from plant operations on transportation safety could occur as a result of increased hazards from cooling towers. Both natural draft and mechanical cooling towers can increase area fogging conditions ice formation on local roads and highways. Sites with high frequencies of naturally-occurring fog and ice events will likely be more adversely affected by cooling tower operations.

Discussion/Results – Relative information regarding existing fog and ice conditions was not readily available for candidate sites; however, cooling tower fogging or icing is not expected to be a major issue at any of the sites, given their general weather patterns, nor is it expected to be a major site discriminator. Accordingly, and in the absence of site specific data, all sites are given a conservative rating of 3 with respect to this criterion.

Transportation Safety	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**

C.2 ENVIRONMENTAL CRITERIA

C.2.1 CONSTRUCTION-RELATED EFFECTS ON AQUATIC ECOLOGY

C.2.1.1 Disruption of Important Species/Habitats

Objective – The objective of this criterion is to evaluate the candidate sites with respect to potential construction-related impacts on aquatic or marine ecology. Regulatory Guide 4.7 defines important plant and animal species if one or more of the following conditions apply.

1. the species is commercially or recreationally valuable,
2. the species is officially listed as endangered or threatened,
3. the species effects the well being of another species within (1) or (2) above,
4. the species is a critical component of the structure and function of a valuable ecosystem, or
5. the species is a biological indicator of radionuclides in the environment.

Of particular concern are potential impacts to habitat areas used by important species. These areas include those used for:

- breeding and nursery,
- nesting and spawning,
- wintering, and
- feeding.

Evaluation approach – The following siting criteria were used to evaluate the eight candidate sites.

- Exclusionary – Designated critical habitat of endangered species
- Avoidance – Areas where threatened and endangered species are known to occur
- Suitability – Areas where limited potential impact is expected

No information was obtained which would indicate that any of the sites under consideration would exceed the exclusionary or avoidance criteria relative to ecology. Therefore, the evaluation focused on the relative suitability of the site based on the number of areas where limited potential impact is expected. The number of potential impact areas was directly correlated to the number of rare, threatened, and endangered (RTE) aquatic species that may occur in the host county, their habitat (based on existing reports and professional judgment of the amount and quality of habitat available for species), and flexibility (professional judgment of the amount of space within the site circle to avoid known locations of protected species during construction of the facility). Note that the evaluation was limited to the plant site and not existing or potential (future) transmission corridors.

The suitability of the candidate sites with respect to ecology (rare, threatened and endangered aquatic and terrestrial species, and critical habitat) was initially evaluated in the screening criteria report (Criterion P5, which included Federally protected aquatic and terrestrial species combined). Additional site ecological information specific to aquatic resources at each site is included in the full discussion below. In the context of this discussion, vicinity refers to the county in which the candidate site is located.

Discussion – There are no Federally listed protected aquatic species found in Hardee County; and one protected aquatic species, the manatee, in DeSoto, Glades, Hendry and Okeechobee counties.

Martin County also has the manatee and one fish species that could be in the vicinity of the site: the smalltooth sawfish.

St. Lucie County has the manatee, two fish species (smalltooth sawfish and gulf sturgeon) and four sea turtles on the federally protected list.

Miami-Dade County, location of Turkey Point site, has the manatee, one fish species (smalltooth sawfish), four sea turtles (same as St. Lucie County), two invertebrate coral species, and one aquatic plant on the federally protected species list.

The species common and scientific names and listing status are included in the table below. The National Marine Fisheries Service (NMFS) has lead for the fish, invertebrate, and plant species, as well as for the turtle species in the water.

Scientific Name	Common Name	Federal Status
Fish		
Gulf Sturgeon	*Acipenser oxyrhynchus desotoi*	Threatened
Smalltooth sawfish	*Pristis pectinata*	Endangered
Mammals		
West Indian manatee	*Trichechus manatus*	E, CH
Reptiles		
Green Sea Turtle	*Chelonia mydas*	E
Leatherback Sea Turtle	*Dermochelys coriacea*	E
Loggerhead Sea Turtle	*Caretta caretta*	T
Hawksbill Sea Turtle	*Eretmochelys imbricata*	E
Invertebrates		
Elkhorn coral	*Acropora palmate*	PT
Staghorn coral	*Acropora cervicornis*	PT
Plants		
Johnson's seagrass	*Halophila johnsonii*	T, CH

Results – Site ratings are based on the number of Federally protected species found in a given county; Hardee has no protected species and therefore is given the highest rating. Turkey Point and St. Lucie are given the lowest ratings of 3 with 5-10 species, and the remaining sites fall in between. In general, ratings related to habitat are based on professional judgment of the amount and quality of habitat available for species, typically based on poor quality aerial photographs (Google earth). In the case of aquatic species, where habitat is limited to existing surface water bodies in a given site area or county, habitat ratings are assumed to be the same as those identified for species abundance. In general, ratings related to flexibility are based on professional judgment of the amount of space within the site area to avoid known locations of

protected species (while trying to maximize access to cooling water supply) during construction of the facility – also typically based on poor quality aerial photographs. All sites were given favorable ratings with slightly lower siting flexibility ratings given to Turkey Point and St. Lucie based on their higher level of development currently existing on site. Martin and Okeechobee 2 sites fall in the middle given existing development at Martin and presumed preference to locate sites near existing surface water resources (e.g., lake/canal for Martin and Kissimmee River for Okeechobee 2).

Site	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
T&E Species (aquatic)	4	4	5	4	4	4	3	3
Habitat	4	4	5	4	4	4	3	3
Flexibility	5	5	5	5	4	4	2	2
Overall rating	**4**	**4**	**5**	4	**4**	**4**	**3**	**3**

References

US Fish and Wildlife Service, Vero Beach/South Florida
[http://www.fws.gov/verobeach/Programs/Permits/Section7.html] – for DeSoto, Glades, Hardee, Hendry, Martin, Miami-Dade, Okeechobee, and St. Lucie Counties. Updated September 2006].

C.2.1.2 Bottom Sediment Disruption Effects

C.2.1.2.1 Contamination
C.2.1.2.2 Grain Size

Objective – The objective of the criterion is to evaluate the potential short-term impacts to aquatic/marine resources resulting from construction related dredging activities at the candidate sites.

Evaluation approach – The evaluation sought available data on the amount of contaminated sediments near the candidate sites and the grain size of sediments in the area. In general, sites with the lowest concentration of heavy metals and toxic organic compounds and the highest sediment grain size are considered to be the most suitable.

Little information exists regarding the site-specific level of sediment contamination that exists in water bodies near the candidate sites. The majority of the available information was obtained from the EPA's National Sediment Quality Survey (2001 and 2004). Information in the EPA report addresses sediment contamination levels as Tier I (adverse impacts to aquatic life are probable) and Tier II (adverse impacts to aquatic life are possible but infrequent). Using best professional judgment, the following evaluation considered the results of the EPA's Tier I/Tier II study results to determine the relative contamination potential for the candidate sites.

No information regarding sediment grain size was obtained for this evaluation. Because sediment grain size is highly variable, even within a small area of coastline or river reach, the

following evaluation of potential bottom sediment disruption effects was limited to available information regarding sediment contamination levels in principle water bodies at the eight sites.

Discussion/Results – An updated EPA study (EPA 2004) evaluated 2,874 sampling stations in the Southeast, and identified 12 water bodies as having the most significant sediment contamination in EPA Region 4. No water bodies on which the FPL candidate sites are located were identified in the EPA study.

Because dredging is not one of the parameters considered for this particular evaluation, and information on grain size was not readily available for most of the sites, the estimated potential for contaminated sediments to affect the cost and schedule of any construction-related dredging operations was based on the limited information available and professional judgment. Based on the EPA study and information provided by the Water Management Districts in Florida, and because the presence of contaminated sediments in the immediate vicinity of the candidate sites including any onsite streams cannot be confirmed, the following conservative ratings are given to the candidate sites. The coastal sites are given a slightly higher rating because their receiving body of water is so expansive (Atlantic Ocean).

Bottom Sediment Disruption Effects	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	3	3	3	3	3	3	4	4

References

The Incidence and Severity of Sediment Contamination in Surface Waters of the United States. National Sediment Quality Survey. Office of Science and Technology. EPA 823-R-04-007. November.

C.2.2 CONSTRUCTION-RELATED EFFECTS ON TERRESTRIAL ECOLOGY

C.2.2.1 Disruption of Important Species/Habitats and Wetlands

C.2.2.1.1 Important Species/Habitats
C.2.2.1.2 Groundcover/Habitat
C.2.2.1.3 Wetlands

Objective – The objective of this criterion is to evaluate the candidate sites with respect to potential construction related impacts on important species and terrestrial ecology. Regulatory Guide 4.7 defines important plant and animal species if one or more of the following conditions apply.

1. The species is commercially or recreationally valuable,
2. The species is officially listed as endangered or threatened,
3. The species affects the well-being of another species within (1) or (2) above.

4. The species is a critical component of the structure and function of a valuable ecosystem, or
5. The species is a biological indicator of radionuclides in the environment.

Of particular concern are potential impacts to habitat areas used by important species. These areas include those used for:

- breeding and nursery,
- nesting and spawning,
- wintering, and
- feeding.

Evaluation approach – The following siting criteria were used to evaluate the eight candidate sites.

- Exclusionary – Designated critical habitat of endangered species
- Avoidance – Areas where threatened and endangered species are known to occur
- Suitability – Areas where limited potential impact is expected

No information was obtained which would indicate that any of the sites under consideration would exceed the exclusionary or avoidance criteria relative to ecology. Therefore, the evaluation focused on the relative suitability of the site based on the number of areas where limited potential impact is expected. The number of potential impact areas was directly correlated to the number of rare, threatened, and endangered terrestrial species that may occur in the host county, their habitat (based on existing reports and professional judgment of the amount and quality of habitat available for species), and flexibility (professional judgment of the amount of space within the site circle to avoid known locations of protected species during construction of the facility). Note that the evaluation was limited to the plant site and not existing or potential (future) transmission corridors.

Another sub-criteria evaluated was the total acreage of wetland within the 6,000 acres, not including the lake or reservoir that would be the primary source of cooling water. This was also broken out into three components: total wetlands (acres), total acreage of higher-quality wetlands, and flexibility, or the ability to avoid wetlands during construction.

The relative suitability of the candidate sites with respect to ecology (rare, threatened, and endangered aquatic and terrestrial species; and critical habitat) and wetlands was evaluated in the screening criteria report (Criterion P5, aquatic and terrestrial species combined; P6). Additional site ecological information specific to terrestrial resources at each site is included in the full discussion below.

Discussion/Results

DeSoto

Twelve Federally listed terrestrial species: 2 mammals, 8 birds (one experimental and second historic data unknown), and 2 reptiles, and critical habitat have the potential to occur in DeSoto

County (see table below). One of the birds is an experimental population (whooping crane) and the historic data for the ivory-billed woodpecker is unknown.

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Haliaeetus leucocephalus	Bald Eagle	Threatened
Rostrhamus sociabilis plumbeus	Everglade Snail Kite	Endangered/CH
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened
Mycteria Americana	Wood Stork	Endangered
Ammodramus savannarum floridanus	Florida grasshopper sparrow	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened
Campephilus principalis	Ivory-billed woodpecker	E (historic data unknown)
Grus Americana	Whooping crane	Experimental population
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)

Glades

Fifteen Federally listed terrestrial species: 2 mammals, 9 birds, 2 reptiles, 2 plants, and critical habitat have the potential to occur in Glades County (see Table below). One of the birds is an experimental population (whooping crane) and the ivory-billed woodpecker was last documented in 1904.

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Haliaeetus leucocephalus	Bald Eagle	Threatened
Rostrhamus sociabilis plumbeus	Everglade Snail Kite	Endangered/CH
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened
Mycteria Americana	Wood Stork	Endangered
Ammodramus savannarum floridanus	Florida grasshopper sparrow	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened
Picoides borealis	Red-cockaded Woodpecker	Endangered
Campephilus principalis	Ivory-billed woodpecker	E (last documented in 1904)
Grus Americana	Whooping crane	Experimental population
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)
Warea carteri	Carter's mustard	Endangered
Cucurbita okeechobeensis ssp. *Okeechobeensis*	Okeechobee gourd	Endangered

Hardee

Twelve Federally listed terrestrial species: 2 mammals, 6 birds, 2 reptiles and 2 plants have the potential to occur in Hardee County (see Table below). One of the birds is an experimental population (whooping crane) and the historic data for the ivory-billed woodpecker is unknown.

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Haliaeetus leucocephalus	Bald Eagle	Threatened
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened
Mycteria Americana	Wood Stork	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened
Campephilus principalis	Ivory-billed woodpecker	E (historic data unknown)
Grus Americana	Whooping crane	Experimental population
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)
Bonamia grandiflora	Florida bonamia	Threatened
Chrysopsis floridana	Florida golden aster	Endangered

Hendry 1

Thirteen Federally listed terrestrial species: 2 mammals, 9 birds, 2 reptiles and critical habitat have the potential to occur in Hendry County (see Table below). One of the birds is an experimental population (whooping crane) and the ivory-billed woodpecker was last documented in 1904.

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Haliaeetus leucocephalus	Bald Eagle	Threatened
Rostrhamus sociabilis plumbeus	Everglade Snail Kite	Endangered/CH
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened
Mycteria Americana	Wood Stork	Endangered
Ammodramus savannarum floridanus	Florida grasshopper sparrow	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened
Picoides borealis	Red-cockaded Woodpecker	Endangered
Campephilus principalis	Ivory-billed woodpecker	E (last documented in 1904?)
Grus Americana	Whooping crane	Experimental population

Scientific Name	Common Name	Federal Status
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)

Martin

Twenty-one Federally listed terrestrial species: 3 mammals, 10 birds, 3 reptiles, 5 plants, and critical habitat have the potential to occur in Martin County (see Table below). Documentation for several of the species is very dated (1970s or earlier) or historic data are unknown (piping plover critical habitat), one is an experimental population (whooping crane), one is a migrant (Kirkland's warbler, 1978), and one plant species is only found at the Hobe NWR.

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Peromyscus polionotus neveiventrus	Southeastern beach mouse	T (inferred)
Haliaeetus leucocephalus	Bald Eagle	Threatened
Rostrhamus sociabilis plumbeus	Everglade Snail Kite	Endangered/CH
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened
Mycteria Americana	Wood Stork	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened
Picoides borealis	Red-cockaded Woodpecker	Endangered, last documented 1970-1978
Dendroica kirtlandii	Kirkland's warbler	E Migrant 1978
Charadrius melodus	Piping plover	T, CH, historic date unknown
Campephilus principalis	Ivory-billed woodpecker	E (last documented in 1985?)
Grus Americana	Whooping crane	Experimental population, inferred
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)
Crocodylus acutus	American crocodile	E, historic data unknown
Jacquemontia reclinata	Beach jacquemontia	E, last documented in 1921
Asimina tetramera	Four-petal pawpaw	E
Cladonia perforate	Florida perforate cladonia	E
Dicerandra immaculata	Lakela's mint	E, Hobe Sound NWR only
Polygala smallii	Tiny polygala	Endangered

Okeechobee 2

Thirteen Federally listed terrestrial species: 2 mammals, 9 birds, 2 reptiles and critical habitat have the potential to occur in Okeechobee County (see Table below). One bird species is part of experimental population and documentation for two other bird species is very dated (prior to 1970 and in 1924).

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Haliaeetus leucocephalus	Bald Eagle	Threatened
Ammodramus savannarum floridanus	Florida grasshopper sparrow	Endangered
Rostrhamus sociabilis plumbeus	Everglade Snail Kite	Endangered/CH
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened
Mycteria Americana	Wood Stork	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened
Picoides borealis	Red-cockaded Woodpecker	Endangered, last documented prior to 1970
Campephilus principalis	Ivory-billed woodpecker	E (last documented in 1924)
Grus Americana	Whooping crane	Experimental population, inferred
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)

St. Lucie

Nineteen Federally listed terrestrial species: 3 mammals, 9 birds, 3 reptiles, 3 plants, and critical habitat have the potential to occur in St. Lucie County (see Table below). Documentation for several of the bird species is very dated (1970s or earlier) or historic data are unknown; one is an experimental population (whooping crane), and two are migrant (also dated documentation).

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Peromyscus polionotus neveiventrus	Southeastern beach mouse	T (inferred)
Haliaeetus leucocephalus	Bald Eagle	Threatened
Rostrhamus sociabilis plumbeus	Everglade Snail Kite	Endangered/CH
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened
Mycteria Americana	Wood Stork	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened

Scientific Name	Common Name	Federal Status
Picoides borealis	Red-cockaded Woodpecker	Endangered, last documented 1970-1978
Dendroica kirtlandii	Kirkland's warbler	E Migrant 1978
Charadrius melodus	Piping plover	T, CH, migrant 1918
Campephilus principalis	Ivory-billed woodpecker	E (historic date unknown)
Grus Americana	Whooping crane	Experimental population, inferred
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)
Crocodylus acutus	American crocodile	E, historic data unknown
Cereus eriophorus var. *fragrans*	Fragrant prickly-apple	Endangered
Dicerandra immaculate	Lakela's mint	Endangered
Polygala smallii	Tiny polygala	Endangered

Turkey Point

Twenty-five Federally listed terrestrial species, including 2 mammal, 12 birds, 3 reptiles, 8 plants (plus 10 candidate plant species), and critical habitat have the potential to occur in Miami Dade County (see Table below). The bird species include two migrant species and several with dated documentation or with unknown historic data.

Scientific Name	Common Name	Federal Status
Puma (=Felis) concolor	Puma (=Mountain lion)	Threatened (S/A)
Puma (=Felis) concolor coryi	Florida panther	Endangered
Haliaeetus leucocephalus	Bald Eagle	Threatened
Rostrhamus sociabilis plumbeus	Everglade Snail Kite	Endangered/CH
Aphelocoma coeruluscens	Florida Scrub-jay	Threatened, last documented 1960s
Mycteria Americana	Wood Stork	Endangered
Polyborus plancus audubonii	Audubon's crested caracara	Threatened, last documented 1987-1991
Picoides borealis	Red-cockaded Woodpecker	Endangered, last documented prior to 1960
Ammodramus savannarum floridanus	Florida grasshopper sparrow	Endangered, last documented 1968
Dendroica kirtlandii	Kirkland's warbler	E Migrant 1958
Charadrius melodus	Piping plover	T, CH, historic date unknown
Campephilus principalis	Ivory-billed woodpecker	E (last documented in 1889)
Vermivora bachmanii	Bachman's warbler	E, migrant 1901?

Scientific Name	Common Name	Federal Status
Ammodramus maritimusmirabilis	Cape sable seaside sparrow	E.CH
Dymarchon corais couperi	Eastern Indigo Snake	Threatened
Alligator mississippiensis	American alligator	Threatened (S/A)
Crocodylus acutus	American crocodile	E, historic data unknown
Jacquemontia reclinata	Beach jacquemontia	E
Warea carteri	Carter's mustard	E
Amorpha crenulata	Crenulate lead-plant	E
Chaemaesyce deltoidea deltoidea	Deltoid spurge	E
Chamaesyce garberi	Gaber's spurge	T
Cucurbita okeechobeensis ssp. *Okeechobeensis*	Okeechobee gourd	E
Galactia smallii	Small's milkpea	E
Polygala smallii	Tiny polygala	E
Chamaecrista lineate keyensis	Big Pine partridge pea	C
Argythamnia blodgetetii	Blodgett's silverbush	C
Linum carteri carteri	Carter's small-flowered flax	C
Brickellia mosieri	Florida brickell-bush	C
Indigofera mucronata keyensis	Florida indigo	C
Digitaria pauciflora	Florida pineland crabgrass	C
Dalea carthagenensis floridana	Florida prairie clover	C
Consolea corallicola	Florida semaphore cactus	C
Chamaesyce deltoidea pinetorum	Pineland sandmat	C
Linum arenicola	Sand flax	C

Site ratings based on Important Terrestrial Species/Habitat

Site	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
T&E Species	3	3	3	3	2	3	2	1
Habitat	4	4	5	4	4	4	3	2
Flexibility	4	4	4	4	3	4	2	2
Overall Rating	**4**	**4**	**4**	**4**	**3**	**4**	**2**	**2**

Ratings for T&E species based on total number of species found in the host county. Habitat and flexibility ratings are based on professional judgment and other factors as discussed in Section C.2.1.1. Presence of critical habitat and number of protected species is also a consideration in habitat ratings.

Wetlands

The flexibility associated with the final location of the plant area and the presence of higher quality wetlands such as forested wetlands were considered in addition to the overall acreage of mapped wetlands indicated by NWI.

Site	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
% of wetland polygons mapped over 5,000 acre area	632 13%	489 10%	622 12%	843 17%	210 4%	961 19%	1074 21%	1476 30%
Number of acres of high quality wetlands* within site area	0	0	552	300	0	143	0	27

* = Number of acres forested/scrub-shrub wetland polygons mapped.

Taking into account the above wetlands identified, the sites were given the following composite ratings:

Site ratings based on Wetlands

Site	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Total Acres[1]	3	4	3	3	4	3	3	3
Acres of High Quality Wetlands[2]	5	5	2	2	5	4	5	5
Flexibility (based on all % wetland polygons mapped over 5,000 acres)[3]	4	5	4	4	4[4]	4	3[4]	2[4]
Overall Rating	**4**	**5**	**3**	**3**	**4**	**4**	**4**	**3**

[1] scale reflects characteristics of nominal 5,000 acre circular area with ultimate site requirement of 2,000 acre proposed site area → 5=<100 acres, 4=<500 acres, 3=<1,500 acres, 2=<3,000 acres, 1=>3,000 acres

[2] 5= <50 acres, 4= <250, 3=<500, 2=<1,000, 1= >1,000 (forested/scrub-shrub)

[3] 5=<10%, 4=<25% 3=<50%, 2=<90%, 1=>90%

[4] Martin, St. Lucie, and Turkey Point sites were reduced by 1 rating point due to constraints associated with on-site ponds and/or deep water marine areas.

Composite Site Ratings

Site	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Species	4	4	4	4	3	4	2	2
Wetlands	4	5	3	3	4	4	4	3
Avg. Score	4	4.5	3.5	3.5	3.5	4	3	2.5

References

NWI website: http://wetlandsfws.er.usgs.gov/.

US Fish and Wildlife Service, Vero Beach/South Florida [http://www.fws.gov/verobeach/Programs/Permits/Section7.html] – for DeSoto, Glades, Hardee, Hendry, Martin, Miami-Dade, Okeechobee, and St. Lucie Counties. Updated September 2006].

C.2.2.2 Dewatering Effects on Adjacent Wetlands

C.2.2.2.1 Depth to Water Table
C.2.2.2.2 Proximal Wetlands

Objective – The objective of this criterion is to evaluate the sites with respect to potential impacts from construction-related dewatering activities on area wetlands.

Evaluation approach – The evaluation included a review of information related to the depth of the water table and the distance to nearby wetlands. A determination of the extent of wetland acreage within the study area was limited. National Wetland Inventory maps were used for some sites as the basis for determining wetland acreage. Those maps can include numerous areas that do not represent jurisdictional wetlands under Section 404 of the Clean Water Act, which contributed to the difficulty in making an estimate of wetland acreage. Moreover, those maps were based primarily on interpretation of aerial photography, and the amount of field validation that was performed varies according to region of the country and local terrain. Overall site elevation is being used as an indicator of depth to groundwater.

Discussion/Results – Wetlands have been evaluated previously (Section C.2.2.1 of this appendix); depth to groundwater for each site is being evaluated by proxy using site elevation as an indicator. Potential hydraulic connections among wetlands via groundwater are not known.

In light of the previous ratings and groundwater information, the site ratings are as follows:

Site	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Total Wetland Acreage[1]	3	4	3	3	4	3	3	3
Acreage of HQ Wetlands[2]	5	5	2	2	5	4	5	5
Depth to Groundwater[3]	4	1	4	1	2	2	1	1
Overall Rating	**4**	**3**	**3**	**2**	**4**	**3**	**3**	**3**

[1] scale reflects characteristics of nominal 5,000 acre circular area with ultimate site requirement of 2,000 acre proposed site area → 5=<100 acres, 4=<500 acres, 3=<1,500 acres, 2=<3,000 acres, 1=>3,000 acres

[2] 5= <50 acres, 4= <250, 3=<500, 2=<1,000, 1= >1,000 (forested/scrub-shrub)

[3] (avg. site elev. as surrogate) 5=80'+, 4=60'+, 3=40'+, 2=20'+, 1= <20'

C.2.3 OPERATIONAL-RELATED EFFECTS ON AQUATIC ECOLOGY

C.2.3.1 Thermal Discharge Effects

C.2.3.1.1 Migratory Species Effects

C.2.3.1.2 Disruption of Important Species/Habitats

C.2.3.1.3 Water Quality

Objective – No exclusionary or avoidance criteria apply to condenser cooling water system thermal discharges on receiving water bodies (EPRI 2001, Section 3.2.3.1). The objective of this criterion is to address the relative suitability of the eight candidate sites with respect to potential thermal impacts. Two specific thermal impact issues were considered:

- disruption of important species and habitats, and
- impact on water quality of the receiving water body.

Information on migratory species (also identified in EPRI criteria) was not collected at each site and therefore is not evaluated as part of this criterion.

Evaluation approach – In December 2001, the EPA published a final regulation, which affects the location, design, construction, and capacity of intake structures for new power plants (EPA 2001). The EPA rule will strongly encourage the use of closed-cycle designs to reduce adverse cooling water system impacts, and it is assumed that new nuclear reactors at the eight candidate sites would include closed-cycle cooling water systems.

Discussion/Results – No additional site-specific data are available for the sites except for the existing plants at St. Lucie and Turkey Point. Ratings are therefore based on limited flow and water-quality data for the cooling water sources and on site ratings for disruption of aquatic species/habitat. In addition, ratings were based on the use of the source water body as the receiving water for this evaluation.

In summary, the set of ratings consisted of a composite of three sub-ratings: the disruption of important species (based on number of Federally protected aquatic species), as brought forward from Section C.2.1.1 of this appendix; existing water quality of the receiving water, based primarily on cooling water supply information, as it relates to flow and volume, where the size of the receiving water body (heat sink) was the primary factor in assigning ratings (highest rating given to the largest heat sink); and the proximity to potential sensitive areas from either an environmental or water supply basis. The presence of an existing nuclear plant in the immediate site area (St. Lucie and Turkey Point) also was taken into account, although these locations are not expected to be a problem for locating a second plant. The resulting ratings are provided below.

Thermal Discharge Effects	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Flow[1]	1	3	1	2	3	3	5	5
Presence of important aquatic species[2]	4	4	5	4	4	4	3	3
OFW-303(d) – WCA[3]	2	2	2	2	3	3	3	3
Overall rating	**2**	**3**	**3**	**3**	**3**	**3**	**4**	**4**

[1] For the flow sub-rating only
[2] zero = 5, <2 = 4, <10 = 3, <20 = 2, 20+ = 1 (fish + reptile from screening)
[3] NA = 4, one designation = 3, one designation + proximity to another =2

C.2.3.2 Entrainment/Impingement Effects

C.2.3.2.1 Entrainable Organisms
C.2.3.2.2 Impingable Organisms

Objective – No exclusionary or avoidance criteria apply to entrainment and impingement impacts from the operation of condenser cooling water systems (EPRI 2001, Section 3.2.3.1). The objective of this criterion is to address the relative suitability of the candidate sites with respect to potential entrainment and impingement impacts.

When cooling water is pumped from water bodies, several environmental impacts can occur. Entrainment refers to the removal of small, drifting organisms with the cooling water. Small fish, fish eggs, phytoplankton, zooplankton, and other aquatic/marine organisms experience high mortality rates as they pass through cooling water pumps and heat exchangers. Impingement refers to larger organisms that are screened out of the cooling water at the intake structure. Impinged organisms can include large fish, crustaceans, turtles, and other aquatic/marine organisms that can not avoid high intake velocities near the intake structure and are trapped on the intake screens.

Evaluation approach – Concerns about entrainment and impingement losses are resource dependent and vary on a site-to-site basis. Typically, power plants with once-through cooling water systems have higher entrainment and impingement impacts than power plants with closed-cycle cooling water systems. The EPA issued a final rule in December 2001 affecting the design of intake structures for new power plants (EPA 2001). These rules encourage the use of closed-cycle systems, which is the type of system assumed to be used by FPL at these sites. Developers of new power plants who choose certainty and faster permitting over greater design flexibility will be encouraged to limit intake water capacities and velocities and incorporate specific intake screen designs to reduce entrainment and impingement losses.

Discussion/Results – The eight candidate sites were evaluated with respect to relative potential for entrainment and impingement impacts for the closed-cycle cooling water system. Proposed facilities at each site will include cooling towers that will reduce the amount of cooling water withdrawal required for plant operation. In addition, proper design of the water intake structure would minimize the potential adverse impacts. In NUREG 1437, NRC concludes that, with cooling towers and appropriate intake design, potential adverse impacts due to entrainment or impingement of aquatic organism are minor and do not significantly disrupt existing populations. Assuming a two-unit closed-cycle plant at the site, and 100 percent of the local plankton passing through the plant, it appears that there would be no discernible effect on the plankton population in existing rivers and reservoirs at each site. This is due to the very small volume of water used by the plant relative to the total volume in the river or reservoir at the site. Because of the low flow velocities of a closed cycle plant at the site, impingement of adult fish would be expected to be minimal. Use of a deep water intake would have a minimal effect on entrainment of larval fish.

Another component of this criterion was the presence of important aquatic species.

Given the above information, all sites received consistent ratings in terms of intake design (conservative rating of 3), with slightly higher preference given to those sites with fewer protected aquatic species present.

Entrainment/ Impingement Potential Impact (Closed cycle cooling system design)	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Presence of important aquatic species	5	5	5	5	4	5	3	3
Regulatory/engineering design (conservative)	3	3	3	3	3	3	3	3
Rating	4	4	4	4	3	4	3	3

C.2.3.3 Dredging/Disposal Effects

C.2.3.3.1 Upstream Contamination Sources
C.2.3.3.2 Sedimentation Rates

Objective – The purpose of the section is to evaluate the sites for potential environmental impacts related to maintenance dredging at the intake structure. No specific exclusionary or avoidance criteria apply to this issue. The following evaluation, therefore, is a summary of available information related to the relative suitability of the sites.

Evaluation approach – Sites with high levels of contaminated sediment deposition at the intake structure will experience higher maintenance costs for the removal and disposal of the dredged material. Two factors were considered in performing the evaluation:

- The level of upstream contamination, and
- The rate of sedimentation at the site.

All sites are assumed to have relatively low fine-sediment-deposition rates (which are preferred), so the ratings were based on potential for contamination.

As addressed in Section C.2.1.2 (Contaminated Sediments), no site-specific information about the level of sediment contamination at the sites was identified. Results in Section C.2.1.2 were based on EPA data, which addressed general trends in levels of contamination in the water bodies at the candidate sites, and general water-quality information for the major water bodies on which the candidate sites are located. The evaluation was further expanded to consider existing background radioactive contamination at the sites. The greenfield sites were considered to be optimum because there is no known source of existing background radioactive contamination present. Turkey Point was also rated high under the assumption that the effluent is contained in the canals which presumably would not be disturbed as part of development of the new plant (hence there would not be contaminated sediments to disturb). St. Lucie also received a favorable, but slightly lower rating, because its effluent is discharged directly into the environment and there are other water-quality issues given the high levels of development along the coast in the site vicinity.

Discussion/Results – Based on available information, the sites were rated according to the expected levels of contamination. The results are summarized in the table below.

Dredging/Disposal Effects	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	5	5	5	5	5	5	4	5

C.2.4 OPERATIONAL-RELATED EFFECTS ON TERRESTRIAL ECOLOGY

C.2.4.1 Drift Effects on Surrounding Areas

C.2.4.1.1 Important Species/Habitat Areas
C.2.4.1.2 Source Water Suitability

Objective – The objective of this criterion is to evaluate the relative suitability of the candidate sites with respect to potential concerns with cooling tower drift effects. This evaluation considered the potential effects on surrounding areas and the suitability of the cooling water source (EPRI 2001). This issue does not apply to sites for which once-through cooling water systems are selected.

Cooling Tower Drift

In every cooling tower, there is a loss of water to the environment in the form of pure water, which results from the evaporative cooling process. This evaporated water leaves the tower in a pure vapor state, and thus presents no threat to the environment. Drift, however, is the undesirable loss of liquid water to the environment, via small unevaporated droplets that become entrained in the exhaust air stream of a cooling tower. These water droplets carry with them minerals, debris and microorganisms and water treatment chemicals from the circulating water, thus potentially impacting the environment. High drift losses are typically caused by fouled, inefficient or damaged drift eliminators, excessive exit velocities or imbalances in water chemistry.

Minimizing drift losses in a cooling tower reduces the risk of impacting the environment. The principle environmental concern with cooling tower drift impacts are related to the emission and downwind deposition of cooling water salts (EPA 1987). Salt deposition can adversely affect sensitive plant and animal communities through changes in water and soil chemistry.

Evaluation approach – Sites considered with the most sensitive environments were assigned lower rating values. Sites with highest concentrations of dissolved solids and other potential contaminants in cooling tower makeup were also assigned lower rating values.

Discussion/Results – Information regarding important terrestrial and aquatic plant and animal communities, habitats, and wetlands in the vicinity of the candidate sites were previously addressed in Section C.2.1.1 (Disruption of Important Species/Habitats) and Section C.2.2.1 (Disruption of Important Species/Habitats and Wetlands). Cooling water makeup water quality is also taken into account. The coastal sites were given lower ratings due to their proximity to the ocean and greater likelihood of their cooling water being brackish and containing more salt.

Given all the above information, the following ratings were assigned:

Drift Effects on Surrounding Area	DeSoto	Glades	Hardee 1	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Important Species Habitat Areas – aquatic	4	4	5	4	4	4	3	3
Important Species Habitat Areas – terrestrial	3	3	3	3	2	3	2	1
Source water[1]	3	4	3	4	5	5	1	3
Rating	**3**	**4**	**4**	**4**	**4**	**4**	**2**	**2**

[1] Fresh = 5, Primarily fresh + possible brackish = 4, Primarily brackish+ possible fresh = 3, Brackish = 2, Ocean = 1

C.3 SOCIOECONOMICS CRITERIA

C.3.1 SOCIOECONOMICS - CONSTRUCTION RELATED EFFECTS

Objective – The objective of this criterion is to evaluate the relative suitability of the site with respect to the number of construction workers who will move into the plant site vicinity with their families; and the capacity of the communities surrounding the plant site to absorb this new temporary (in-migrant) population.

Evaluation approach – The number of in-migrant workers is dependent on labor availability within commuting distance of the plant site. If an adequate supply of workers is available within reasonable commuting distance, few (if any) workers will choose to relocate to the site vicinity. The capacity of communities to absorb an increase in population depends on the availability of sufficient resources, such as adequate housing and community services to support the influx.

Steps 1 and 2 (Exclusionary and Avoidance criteria) are not applicable to this criterion. The plant construction workforce is likely to be available at any of the sites under consideration. The issue in siting, therefore, is the potential socioeconomic impact associated with any temporary influx of construction workers who live too far away to commute daily from their residence. With respect to suitability of the sites under consideration by FPL, socioeconomic impacts of nuclear power plant construction are directly related to two factors:

- number of construction workers who will move into the plant site vicinity with their families; and
- capacity of the communities surrounding the plant site to absorb this new temporary (in-migrant) population.

The number of in-migrant workers is dependent on labor availability within commuting distance of the plant site. If an adequate supply of workers is available within reasonable commuting distance, few (if any) workers would choose to relocate to the site vicinity. The capacity of communities to absorb an increase in population depends on the availability of sufficient resources, such as adequate housing and community services (e.g., schools, hospitals, police, transportation systems, and fire protection) to support the influx without straining existing services. Impacts to a small community located along the commuter route(s) (e.g., food, lodging, gas, and congestion) can also be significant and should be considered. The information that should be considered in rating sites from the perspective of construction impacts includes labor requirements, location of labor pool, number of immigrants, and the economic structure of affected communities.

Before the data could be compared between sites and the sites rated, certain assumptions were made regarding the construction labor requirements and construction schedule, labor pool, and affected area. Many of these assumptions were made without the benefit of site-specific information and may warrant future revision when site-specific data become available (i.e., full NEPA documentation for original plant construction and operation can be reviewed, and/or site-specific plant personnel can be interviewed regarding actual impacts from original plant construction). For purposes of this report, assumptions are based on professional judgment, the AP1000 Siting Guide, and information contained in the U.S. Nuclear Regulatory Commission's

Generic Environmental Impact Statement for License Renewal for Nuclear Plants (NUREG 1437) (May 1996).

Assumptions

According to the AP1000 Siting Guide, the plant workforce (construction) includes a monthly maximum construction workforce requirement of 1,000 persons per unit. Construction of a nuclear power plant is very labor-intensive, and for the AP1000 skilled and unskilled construction workers would likely be needed over a 4- to 5-year period. The following assumptions were used in this analysis.

- Ratings are based on the assumption that two units would be constructed at a given site.
- Construction would require a peak construction work force of 2,000 workers (1,000 per unit); this estimate is not necessarily the "worst-case," but assumed to be a realistic estimate for purposes of site comparison.
- Analysis assumes that no other major construction project would occur in the site vicinity concurrently with the plant construction and operation. Thus, sites were rated without consideration of potential cumulative impacts of other potential demands for labor.

Available population and economic data were obtained from the US Census Bureau for each site. The data were collected by county to determine availability of an adequate labor force within commuting distance (based on an assumed location of the labor pool). Data relating to population and labor force (primarily construction industry) were compared with the construction labor requirement to determine availability of labor.

The study of economic structure examines employment because of its pre-eminent role in determining economic well-being of an area. Specifically, impacts are determined by comparing the number of direct and indirect jobs created by plant's construction with total employment of the local study area at the time of construction. Sites were rated according to economic impacts based on the following criteria: economic effects were considered small if peak construction related employment accounted for less than 5 percent of total study area employment; moderate if it accounted for 5 to 10 percent of total study area employment; and large if it accounted for more than 10 percent of total study area employment.

Note that the study area for evaluating socioeconomic impacts from construction included the host county, adjacent counties and any other nearby counties with a major population center within a reasonable commuting distance from the site.

Discussion – The available population and work force data are presented in the following tables. Projected growth rates from 2000-2010 is assumed to be the same as growth rates found between 1990 and 2000, based on U.S. Census data.

DeSoto Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
DeSoto	32,209	43,482 (35%)	12,742	976
Sarasota	325,957	382,348 (17.3%)	133,419	12,246
Manatee	264,002	329,210 (24.7%)	111,793	13,098
Charlotte	141,627	180,716 (27.6%)	50,690	5,374
Glades	10,576	14,732 (39.3%)	3,677	368
Hardee	26,938	37,228 (38.2%)	9,901	794
Highlands	87,366	111,566 (27.7%)	30,051	2,139
Total		**1,099,282**	**352,273**	**34,995**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Glades Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
Glades	10,576	14,732 (39.3%)	3,677	368
Lee	440,888	580,208 (31.6%)	186,417	23,087
Highlands	87,366	111,566 (27.7%)	30,051	2,139
Hendry	36,210	50,875 (40.5%)	14,579	1,164
Total		**757.381**	**231,253**	**26,758**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Hardee Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
Hardee	26,938	37,228 (38.2%)	9,901	794
Polk	483,924	577,321 (19.4%)	206,460	17,335
Manatee	264,002	329,210 (24.7%)	111,793	13,098
Sarasota	325,957	382,348 (17.3%)	133,419	12,246
DeSoto	32,209	43,482 (35%)	12,742	976
Highlands	87,366	111,566 (27.7%)	30,051	2,139
Total		**1,481,155**	**504,366**	**46,588**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Hendry 1 Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
Hendry	36,210	50,875 (40.5%)	14,579	1,164
Glades	10,576	14,732 (39.3%)	3,677	368
Palm Beach	1,131,184	1,481,851 (31%)	484,760	40,152
Total		**1,547,458**	**503,016**	**41,684**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Martin Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
Martin	126,731	159,174 (25.6%)	51,054	5,357
St. Lucie	192,695	247,228 (28.3%)	77,842	8,476
Palm Beach	1,131,184	1,481,851 (31%)	484,760	40,152
Okeechobee	35,910	43,523 (21.2%)	14,169	1,352
Total		**1,931,776**	**627,465**	**55,337**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Okeechobee 2 Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
Okeechobee	35,910	43,523 (21.2%)	14,169	1,352
St. Lucie	192,695	247,228 (28.3%)	77,842	8,476
Highlands	87,366	111,566 (27.7%)	30,051	2,139
Martin	126,731	159,174 (25.6%)	51,054	5,357
Glades	10,576	14,732 (39.3%)	3,677	368
Indian River	112,947	141,410 (25.2%)	45,494	3,878
Osceola	172,493	276,161 (60.1%)	79,859	7,030
Total		**993,794**	**302,146**	**28,600**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

St. Lucie Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
St. Lucie	192,695	247,228 (28.3%)	77,842	8,476
Indian River	112,947	141,410 (25.2%)	45,494	3,878
Martin	126,731	159,174 (25.6%)	51,054	5,357
Palm Beach	1,131,184	1,481,851 (31%)	484,760	40,152
Okeechobee	35,910	43,523 (21.2%)	14,169	1,352
Total		**2,073,186**	**673,319**	**59,215**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Turkey Point Site Population and Work Force

County	Total Pop (2000)	Total Pop (2010)*	Total Employed Workforce (2000)	Total Construction Workforce (2000)
Miami-Dade	2,253,362	2,620,660 (16.3%)	921,208	63,135
Broward	1,623,081	2,098,644 (29.3%)	758,939	56,496
Total		**4,102,241**	**1,405,968**	**119,631**

* Based on growth rate for 1990-2000 (%)
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Results – Although the results show higher population and workforce numbers available at Martin, St. Lucie and Turkey Point, the overall population levels for all eight sites in 2010 when construction is anticipated to start, are sufficiently large that the impact on study area employment from construction of two new units would be low at each site. This is based on conservative workforce levels using 2000 Census Bureau data (without expected increases in 2010); although such increases might be used to support other large (non-nuclear) construction projects at that time). All sites show a percentage increase less than 5% when compared to total study area construction workforce, and a percentage increase less than 1% for total employed work force.

Because of the large population within the host county (Miami Dade) for Turkey Point, and the close proximity and easy access to the heavily populated Atlantic coastal development for the St. Lucie and Martin sites (in addition to these sites already including large power plant facilities), it was assumed that the majority of construction workers workforce would commute from within the area to these sites. There would be no in-migrant workforce population (and families), with no demands on housing or communities services. Therefore, these three sites were given a rating of 5.

Given the rural nature, the lower general population estimates – particularly in their respective host counties – and the lower (existing) construction workforce to draw from at the remaining five sites, an additional analysis was conducted for these five sites to consider the impacts of workers in-migrating to the areas. We have identified the following assumptions to help address potential impacts on local community services and housing:

- 50% of workers will in-migrate (1,000 workers)
- 50% of these workers bring their families (2.5 additional persons per family) (1,250 family members)
- Influx of direct workers also brings in influx of indirect workers (0.4 ratio of direct to indirect workers – in absence of site-specific information) pertaining to the Regional Industrial Multiplier System direct/indirect ratios calculated for each plant (as found in NUREG/CR-2749) (400 indirect workers)
- 50% of these indirect workers bring their families (2.5 additional persons per family) (500 family members)

Thus an influx of 1,000 workers is predicted to results in a total population influx of 3,150 persons.

When this population influx is compared to the total population projections in 2010 for the five areas (multiple county), the increase is less than 1%. Therefore, the impact on housing and community services would be expected to be negligible. However, when considering the population of the host county alone, Glades County has a significantly lower population compared to the other sites.

When the workforce influx is compared to the total workforce for the five sites, the increase ranges from 2% to 4%; when the workforce influx is compared to the total construction workforce for the five sites, the increase is less than 1% in every instance (see summary table below). In general, the remaining five sites are within reasonable commuting distance from at least one large city or metropolitan area, as summarized in the table below.

Site	Major population centers within commuting distance of site	Percent increase in total workforce	Percent increase in total construction workforce
DeSoto	Port Charlotte (within 25 miles)	0.3	2.8
Glades	Ft. Myers (40 miles)	0.4	3.7
Hardee	Port Charlotte (within 25 miles)	0.2	2.1
Hendry 1	Ft. Myers and West Palm (each at approximately 50 miles)	0.2	2.4
Okeechobee 2	Ft. Pierce and Port St. Lucie area (40 miles)	0.3	3.4

Each study area appears to have sufficient population centers within commuting distance and/or has experienced tremendous growth since 1990 such that its public services sector would be able to absorb the population in-migration associated with plant construction with minimal impact. However, Glades comes in slightly lower in comparison to the other five sites, two of which (Hendry 1 and Okeechobee 2) are within 50 miles of more than one large MSA.

Finally, this evaluation also incorporates more recent findings from a study conducted by Dominion Energy Inc., Bechtel Power Corporation, TLG, Inc., and MPR Associates for the US Department of Energy (2004) titled: *Study of Construction Technologies and Schedules, O&M Staffing and Cost, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs*. This report includes a more accurate and up-to-date assessment of labor availability that takes into account a U.S. labor pool that is aging and diminishing in number and skill level (with retirement of the baby boom generation that constructed the first set of nuclear power plants). It recognizes that attracting craft with the high skill levels and regulatory employment criteria for new nuclear plant construction is expected to be difficult given that the group of craft currently doing nuclear work is significantly smaller than the total construction craft population, and is in higher demand because of the higher skill levels and greater capability to meet strict employment standards (e.g., scrutiny of NRC background check). However, in an effort to reduce or minimize the labor supply concerns associated with new nuclear plant construction projects, a new strategy has been identified that would shift portions of the work force to areas of the country where skills and craft are available in sufficient quantity (national workforce). This would most effectively be done through modularizing portions of the plants to be built, and providing aggressive training of craftsmen before and during the construction phase of the project. Modularization is anticipated to become an important aspect of new nuclear construction. Such a workforce would presumably be in-migrant for the duration of the construction period and have the potential to adversely affect housing and community services at those sites located in rural, low populated areas/host counties.

Based on the results above, this latest information and using best professional judgment, a comparison of socioeconomic conditions between the five remaining sites reveals similar

conditions at each of them with perhaps a slight disadvantage to the Glades site given its lower population and workforce numbers, particularly within the host county. Because of the general rural nature of all five sites and the slightly lower results for Glades, the following conservative ratings are assigned. Martin, St. Lucie, and Turkey Point sites rate the highest as noted previously.

Socioeconomic Construction	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**3**	**2**	**3**	**3**	**5**	**3**	**5**	**5**

C.3.2 SOCIOECONOMICS – OPERATION

Socioeconomic impacts of operation relate primarily to the benefits afforded to local communities as a result of the plant's presence (e.g., tax plans, local emergency planning support, educational program support). These benefits tend to be a function of negotiations between the plant owner and local government; they are not indicative of inherent site conditions that affect relative suitability between sites. In addition, three of the eight sites have previously demonstrated that their local economies can support existing plant operations, and an additional unit will not adversely affect an area that has already shown its ability to support existing units. This criterion is not applicable to a comparison of the eight candidate sites, and in accordance with guidance in the Siting Guide, suitability scores were not developed.

C.3.3 ENVIRONMENTAL JUSTICE

Objective – The objective of this criterion is to ensure that the effects of proposed actions do not result in disproportionate adverse impacts to minority and low-income communities. In comparing sites, this principle is evaluated on the basis of whether any disproportionate impacts to these communities are significantly different when comparing one site to another.

Evaluation approach – The first step in this evaluation is to collect and compare population data for minorities and low-income populations across sites.

However, two additional questions comprising this evaluation also are relevant:

1. Does the proposed action result in significant adverse impacts?
2. Are impacts to minority or low-income populations significantly different between sites?

If the answer to the first question is "no" for all sites (i.e., no significant health and safety impacts are identified), then there would be no environmental justice concerns, regardless of the percentage of minority or low-income populations found within the surrounding communities of a site(s). If the answer to the first question is "yes" (i.e., significant health and safety impacts are expected), environmental justice concerns are relevant to site selection only if the answer to the second question is also "yes" (i.e., disproportionate adverse impacts on minority or low-income

populations are identified at one or more sites, thereby resulting in significant differences between sites).

Note that the study area for evaluating environmental justice concerns included the host county and immediately surrounding counties.

Discussion – With regard to the sites under consideration, related environmental justice information is summarized for each candidate site below. Data for white population is for one race alone.

DeSoto Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (% / pop)
DeSoto	32,209	23,619	8,590	18.3 / 5,894
Sarasota	325,957	301,985	23,972	8.4 / 27,380
Manatee	264,002	227,981	36,021	10.8 / 28,512
Charlotte	141,627	131,125	10,502	9.3 / 13,171
Glades	10,576	8,142	2,434	13.1 / 1,385
Hardee	26,938	19,035	7,903	20.6 / 5,549
Highlands	87,366	72,926	14,440	13.9 / 12,185
Total	**888,675**	**784,813**	**103,862**	**94076**

Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Glades Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (% / pop)
Glades	10,576	8,142	2,434	13.1 / 1,385
Lee	440,888	386,598	54,290	10.2 / 44,970
Highlands	87,366	72,926	14,440	13.9 / 12,185
Hendry	36,210	23,926	12,284	18 / 6,518
Total	575,037	491,592	83,448	65,058

Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Hardee Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (% / pop)
Hardee	26,938	19,035	7,903	20.6 / 5,549
Polk	483,924	385,099	98,825	14 / 67,749
Manatee	264,002	227,981	36,021	10.8 / 28,512
Sarasota	325,957	301,985	23,972	8.4 / 27,380
DeSoto	32,209	23,619	8,590	18.3 / 5,894
Highlands	87,366	72,926	14,440	13.9 / 12,185
Total	**1,220,396**	**1,030,645**	**189,751**	**147,269**

Includes some whites of Hispanic or Latino origin.
Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Hendry 1 Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (% / pop)
Hendry	36,210	23,926	12,284	18 / 6,518
Glades	10,576	8,142	2,434	13.1 / 1,385
Palm Beach	1,131,184	894,207	236,977	10.9 / 123,299
Total	**1,177,970**	**926,275**	**251,695**	**131,202**

Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Martin Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (population)
Martin	126,731	113,912	12,819	9.2 / 11,659
St. Lucie	192,695	152,504	40,191	12.9 / 24,857
Palm Beach	1,131,184	894,207	236,977	10.9 / 123,299
Okeechobee	35,910	28,468	7,442	15 / 5,386
Total	**1,486,520**	**1,189,091**	**297,429**	**165,201**

Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Okeechobee 2 Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (%/ pop)
Okeechobee	35,910	28,468	7,442	15 / 5,386
St. Lucie	192,695	152,504	40,191	12.9 / 24,857
Highlands	87,366	72,926	14,440	13.9 / 12,185
Martin	126,731	113,912	12,819	9.2 / 11,659
Glades	10,576	8,142	2,434	13.1 / 1,385
Indian River	112,947	98,754	14,193	10 / 11,295
Osceola	172,493	133,169	39,324	13.1 / 22,596
Total	**738,718**	**607,875**	**130,843**	**90,361**

Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

St. Lucie Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (% / pop)
St. Lucie	192,695	152,504	40,191	12.9 / 24,857
Indian River	112,947	98,754	14,193	10 / 11,295
Martin	126,731	113,912	12,819	9.2 / 11,659
Palm Beach	1,131,184	894,207	236,977	10.9 / 123,299
Okeechobee	35,910	28,468	7,442	15 / 5,386
Total	**1,599,467**	**1,287,845**	**311,622**	**176,496**

Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Turkey Point Site Minority and Low Income Population/Percentages

County	Population (2000)	White	Minority	Low Income (%/ pop)
Miami-Dade	2,253,362	1,570,558	682,804	18.9 / 425,885
Broward	1,623,081	1,145,287	477,794	12.5 / 202,885
Total	**3,876,443**	**2,715,845**	**1,160,598**	**628,770**

Source: U.S. Census Bureau, http://quickfacts.census.gov/qfd/ for Florida

Results – Environmental justice data for the eight sites are summarized below.

Site	Population (2000)	White (%)	Minority (%)	Low Income (%)
DeSoto	888,675	88	23	10.6
Glades	575,037	85.5	14.5	11.3
Hardee	1,220,396	84.5	15.5	12.1
Hendry 1	1,177,970	78.6	21.4	11.1
Martin	1,486,520	80	20	11.1
Okeechobee 2	738,718	82.3	17.7	12.2
St. Lucie	1,599,467	80.5	19.5	11
Turkey Point	3,876,443	70	30	16.2

*State average for Florida is 78% white (22% minority) and 13% below poverty line (low income).

All sites had minority populations greater than 10%; minority populations of 20% or higher are found at four sites (DeSoto, Hendry 1, Martin and Turkey Point), with 19.5% found at St. Lucie; although note that the state average minority population for Florida is 22%.

Low-income populations higher than the state average is found only at Turkey Point; however, when evaluating income below poverty line for the individual counties, host counties DeSoto, Hardee, Hendry and Miami-Dade have 18% or higher populations living below the poverty line.

Low-income populations in other counties in the South that currently host existing nuclear power plants have directly benefited from economic impacts of the existing plant. Similar beneficial economic impacts are expected to occur for additional units at existing Turkey Point site, as well as at the other sites with large minority populations as well.

Based on professional judgment in factoring in the above percentages alone, the initial site ratings are as follows:

Environmental Justice	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Provisional Rating	3	4	4	3	3	4	4	2

However, given that no significant impacts to any human populations are expected to occur at any of the sites under consideration, there cannot be significant disproportionate impacts to minority or low-income populations; and based on actual employment experience, positive economic benefits have been shown to be available to all members of the population, without regard to income or ethnicity.

While disproportionate adverse impacts could be expected to occur to minority or low-income populations at both sites, if significant health and safety impacts were expected from a new nuclear reactor, no significant health and safety impacts are expected to human populations from reactor operations. Therefore, if no significant health and safety impacts are identified from reactor construction and operation, then there would be no environmental justice concerns, regardless of the percentage of minority or low-income populations found within the surrounding communities. Therefore, no significant differences in environmental justice impacts are expected between the candidate sites and all should receive a final comparative rating of 5.

Based on this analysis, there is no basis for differentiation between sites from an environmental justice perspective, despite differences in the percentages of minority and low-income populations found within the surrounding communities of each site. All sites are found to be equally and highly suitable. Therefore, the site ratings are as follows:

Environmental Justice	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**

C.3.4 LAND USE

C.3.4.1 Construction- and Operation-Related Effects

Objective – The objective of this criterion is to evaluate the suitability of the eight candidate sites with respect to potential conflicts in existing land uses at each site. No exclusionary or avoidance criteria apply to this issue.

Evaluation Approach – The evaluation is based on the compatibility of a new nuclear station with existing land uses, including existing and future land uses and zoning ordinances, as well as any significant historic resources. Historic resources include those currently listed on the National Register of Historic Places (NRHP), or known (active) archaeological sites or Native American lands.

Discussion/Results – Special land use features, including proximity to National Register of Historic Places (NRHP) sites and dedicated lands/special ecological areas are summarized for each site in the table below. No major issues were identified at any of the sites; however, the potential difficulty in changing existing land use or zoning plans is unclear for the rural, heavy agricultural sites, so they were given a conservative rating of 3. There is also a similar concern at the existing St. Lucie site given the surrounding protected uses, site location on an island between the Atlantic and Indian River Lagoon, and resulting space limitations for construction of two new units. Turkey Point is rated most favorable given the suitable acreage and existing and consistent industrial (i.e. other FPL power plants) surrounding the site.

Site	Special Land Use Features in Vicinity of Site
DeSoto	Greeenfield site: Undeveloped on 13,500 acre property in unincorporated DeSoto County. Adjacent to portions of the Peace River. Land on site is currently dedicated to agricultural use (sod farming, cattle grazing and truck crops). Developed portions of the adjacent properties are primarily agricultural (sod farms, citrus groves, and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and a few isolated wetlands. Agricultural land use would not appear to be consistent for nuclear power plant. Potential difficulty in changing existing land use or zoning is unclear. Historic Sites (NRHP): None in vicinity – two sites located in Arcadia.
Glades	Remote and rural agrarian; mostly agricultural; County is the second largest producer of sugarcane in the state. Agricultural land use would not appear to be consistent for nuclear power plant. Potential difficulty in changing existing land use or zoning is unclear. Two management areas within 5 miles (north) of site: Nicodemus Slough and Fisheating Green Wildlife Management area. Located near shore of Lake Okeechobee; Brighton Indian Reservation located several miles to the north. NRHP Sites: Moore Haven (Downtown Historic District and Residential Historic District).
Hardee	Remote and rural; mostly farmland/agricultural – County is leading citrus and cattle producer in state. Agricultural land use would not appear to be consistent for nuclear power plant. Potential difficulty in changing existing land use or zoning is unclear. NRPH Sites: None in site vicinity; all located in Wauchula and Bowling Green.
Hendry 1	Remote and rural; mostly agricultural/farmland. Largest producer of sugarcane in state; crops; cattle and citrus around Lake Okeechobee. Located near shores of Lake Okeechobee. Agricultural land use would not appear to be consistent for nuclear power plant. Potential difficulty in changing existing land use or zoning is unclear. NRHP Sites: None in vicinity; all located in La Belle and Clewiston.
Martin	Industrial site with existing power plant (3,700 MW), including 6,800-acre cooling reservoir; existing power plant located on 3,000 acres. To east is area of mixed pine flat wood with scattering of small wetlands. North is 1,200 acre cooling pond set aside as mitigation. Peninsula of wetland forest on west side of reservoir that is named the Barley Barber Swamp. The Barley Barber Swamp encompasses 400 acres and is preserved as a natural area. There is also a 10 kW photovoltaic energy facility at south end of site. Located on Lake Okeechobee and near J.W. Corbett Wildlife Management Area and Loxahatchee National Wildlife Refuge. NRHP Sites: None in vicinity.

Site	Special Land Use Features in Vicinity of Site
Okeechobee 2	Remote and rural; lightly populated; agrarian. County has high levels of cattle, dairy, and citrus farms. Agricultural land use would not appear to be consistent for nuclear power plant. Potential difficulty in changing existing land use or zoning is unclear. NRHP Sites: None in vicinity; located in Okeechobee (2 sites).
St. Lucie	Existing power plant (nuclear) site. Located on Hutchinson Island. Two county parks (Blind Creek Pass and Walton Rocks Parka) lie within site boundary. Indian River Lagoon located west of facility; stretch of lagoon adjacent to site is designated as the Jensen Beach to Jupiter Inlet Aquatic Preserve. Fort Pierce Inlet State Recreation Area 9 miles north of site. Savannas State Preserve freshwater wetland is located 2 miles west. Other prominent features within 50 miles of site include Lake Okeechobee, Blue Cypress Lake, Jonathan Dickinson State Park, Dupuis Reserve State Forest, JW Corbett Wildlife Management Area, portion of Brighton Seminole Indian Reservation, and Hobe Sound, Pelican Island, and Loxahatchee National Wildlife Refuges. Sand pine community containing several rare and endangered plants and animals. Hobe Sound NWR located south of the site on Jupiter Island. Includes one of the most productive sea turtle nesting areas in the US (listed leatherback, green and loggerhead sea turtles lay their eggs there). NRHP sites in Ft. Pierce (MANY including in Stuart, Jupiter island, Jensen Beach and Hobe Sound); also a shipwreck: URCA DE LIMA (shipwreck) (added 2001 - Site - #01000529). Also known as URCA DE LUCA State Underwater Archeological Preserve 200 yds offshore Jack Island Park, N of Ft. Pierce Inlet, Ft. Pierce.
Turkey Point	Existing industrial site on shore of part of Biscayne Bay with ecologically sensitive areas nearby including two National Parks: Biscayne National Park (3.2 miles from park headquarters); Everglades National Park (15 miles west of the site). Small portions of Miccosukee Indian Reservation and Big Cypress National Preserve are within 50 miles. Bill Baggs Cape Florida State Recreation Area and Key Large Hammocks State Botanical Site also found near the site. Ecologically sensitive estuarine environment along the coast. NRHP Sites: Numerous, including many in Homestead and Biscayne National Park but presumably would not be affected by the plant since land is owned by FPL and existing power plants/nuclear units located there now.

Land Use	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	3	3	3	3	3	3	3	4

References

Glades Environmental Site Assessment.

St. Lucie and Turkey Point Relicensing Environmental Reports and Supplemental NRC EISs (License Renewal Generic EIS, NUREG 1427, Supplements 5 (Turkey Point Units 3 & 4, January 2002) and 11 (St. Lucie Units 1 and 2, May 2003).

Florida Wildlife Viewing Guide, 1998.

C.4 ENGINEERING AND COST-RELATED CRITERIA

C.4.1 HEALTH AND SAFETY RELATED CRITERIA

C.4.1.1 Water Supply

Objective – The purpose of this criterion is to evaluate relative differences in the design and construction cost of developing water supply facilities.

Evaluation approach – Sites with local conditions that would require additional engineering costs to develop water supply capability (e.g., reservoirs to address water supply limitations or reliability issues such as low flow constraints) are rated lower than sites with no such requirements. Because topography in the vicinity of the candidate sites does not provide natural drainages that can easily be developed for reservoirs, actual construction of reservoirs would likely be very expensive, if feasible at all. Sites are characterized below in terms of the relative difficulty and expense of dealing with low-flow conditions at the sites, regardless of whether a reservoir or some other means of addressing drought conditions is adopted.

Discussion/Results – Because water flows vary among the sites, particularly during periods of low flow, reservoir requirements also will differ. Site ratings are based on professional judgment – taking into account major river body flows (average annual and low flow/drought conditions) (see section C.1.1.2), as well as the size and extent of on-site tributaries. Sites with no anticipated low-flow constraints received a 5; other ratings relate to the likelihood that a reservoir or other means to address low-flow conditions would be required.

Site	Evaluation	Ranking
DeSoto	The water supply for the proposed site is a combination of groundwater, the Peace River, and reclaimed water. Costs to engineer the combined water supply are anticipated to be relatively high.	1
Glades	Potential water supplies for the proposed site include groundwater, the C-43 Canal, and Lake Okeechobee. Due to the flexibility and proximity of water supplies (~ 5 miles to Lake Okeechobee), construction costs to deliver the water supply are anticipated to be moderately low.	4
Hardee	The water supply for the proposed site is a combination of groundwater, the Peace River, and reclaimed water. Costs to engineer the combined water supply are anticipated to be relatively high.	1
Hendry 1	Potential water supplies for the proposed site include groundwater and Lake Okeechobee. Due to the flexibility and proximity of water supplies (~ 11 miles to Lake Okeechobee), construction costs to deliver the water supply are anticipated to be moderate.	3

Site	Evaluation	Ranking
Martin	Potential water supplies for the proposed site include the C-44 Canal and Lake Okeechobee. Due to the flexibility and proximity of water supplies (~ 5 miles to Lake Okeechobee), construction costs to deliver the water supply are anticipated to be moderately low.	4
Okeechobee 2	Potential water supplies for the proposed site include groundwater, the Kissimmee River, and Lake Okeechobee. Due to the flexibility and proximity of water supplies (~ 2 miles to the Kissimmee River and ~ 8 miles to Lake Okeechobee), construction costs to deliver the water supply are anticipated to be moderately low.	4
St. Lucie	Potential water supplies for the proposed site include Ocean Intake and reclaimed water. Due to the proximity of water supplies (site is coastal), construction costs to deliver the water supply are anticipated to be relatively low.	5
Turkey Point	Potential water supplies for the proposed site include Ocean Intake and reclaimed water. Due to the proximity of water supplies (site is coastal), construction costs to deliver the water supply are anticipated to be relatively low.	5

Water Supply	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**1**	**4**	**1**	**3**	**4**	**4**	**5**	**5**

References

USGS Topographic Maps.

C.4.1.2 Pumping Distance

Objective – The purpose of this criterion is to evaluate relative differences in the operational costs associated with pumping makeup water from the source water body to the plant.

Evaluation approach – Sites located large distances from their makeup water supply source are rated lower than those located adjacent to the source. In general, the cost differential is expected to be a linear function of distance from the water source.

Discussion/Results – Precise intake and discharge locations have not yet been determined for candidate sites as final plant locations and reservoir requirements/locations have yet to be determined. It is assumed that cooling facilities will be located as close to the water supply as possible; sites are given a rating between 2 and 5 based on the estimated distance between the site location and the water supply.

Site	Evaluation	Ranking
DeSoto	The water supply for the proposed site is a combination of groundwater, the Peace River, and reclaimed water. The Peace River is located ~ 4 miles west of the proposed site. Pumping costs required to deliver the combined water supply are anticipated to be relatively high.	2
Glades	Potential water supplies for the proposed site include groundwater, the C-43 Canal, and Lake Okeechobee. Lake Okeechobee is located ~ 5 miles east of the proposed site. Pumping costs required to deliver the water supply are anticipated to be moderately low.	4
Hardee	The water supply for the proposed site is a combination of groundwater, the Peace River, and reclaimed water. The Peace River is located ~ 3 miles east of the proposed site. Pumping costs required to deliver the combined water supply are anticipated to be relatively high.	2
Hendry 1	Potential water supplies for the proposed site include groundwater and Lake Okeechobee. Lake Okeechobee is located ~ 11 miles north of the proposed site. Pumping costs required to deliver the water supply are anticipated to be moderate.	3
Martin	Potential water supplies for the proposed site include the C-44 Canal and Lake Okeechobee. Lake Okeechobee is located ~ 5 miles west of the proposed site. Pumping costs required to deliver the water supply are anticipated to be moderately low.	4
Okeechobee 2	Potential water supplies for the proposed site include groundwater, the Kissimmee River, and Lake Okeechobee. The Kissimmee River is located ~ 2 miles southwest of the proposed site, and Lake Okeechobee is located ~ 8 miles southeast of the proposed site. Pumping costs required to deliver the water supply are anticipated to be moderately low.	4
St. Lucie	Potential water supplies for the proposed site include Ocean Intake and reclaimed water. Due to the proximity of water supplies (site is coastal), pumping costs required to deliver the water supply are anticipated to be relatively low.	5
Turkey Point	Potential water supplies for the proposed site include Ocean Intake and reclaimed water. Due to the proximity of water supplies (site is coastal), pumping costs required to deliver the water supply are anticipated to be relatively low.	5

Pumping Distance	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	2	4	2	3	4	4	5	5

References

USGS Topographic Maps (1:100,000 and 1:24,000 scale).

C.4.1.3 Flooding

Objective – The purpose of this criterion is to rate sites with respect to differential costs associated with construction of flood protection structures necessary to address probable maximum floods at the sites under consideration.

Evaluation approach – Sites with the largest differences between site-grade elevation and likely flood elevations are rated highest; sites with plant grade at or near flood level are rated lowest.

Discussion/Results – Although final plant layout locations have not been set for candidate sites, an initial comparison of potential site locations with floodplain information indicate that some proposed plant facilities may require protection from flooding.

Site	Evaluation	Ranking
DeSoto	The proposed site is not located in the 100-year flood zone. While swamp areas exist in the vicinity of the proposed site, ample areas exist for precise site location to avoid swamp areas and areas within the 100-year flood zone. No other neighboring flooding concerns exist. If required, construction of flood protection structures would be minimal.	5
Glades	The proposed site is located within the 100-year flood zone (located in the vicinity of the Caloosahatchee Canal and Lake Okeechobee). Failure of the Herbert Hoover Dike on Lake Okeechobee would present flooding concerns to the proposed site and could result in flood depths of 6 feet. Therefore, construction of flood protection structures or fill to elevate the proposed site is likely to be necessary.	3
Hardee	The proposed site is not located in the 100-year flood zone. No other neighboring flooding concerns exist. If required, construction of flood protection structures would be minimal.	5
Hendry 1	The proposed site is located in the 100-year flood zone and is near swamp areas. Existing secondary levees protect the proposed site from flooding due to failure of the Herbert Hoover Dike on Lake Okeechobee. No other neighboring flooding concerns exist. Construction of flood protection structures or fill to elevate the proposed site is likely to be necessary, but would be minimal.	4

Site	Evaluation	Ranking
Martin	The proposed site is not located in the 100-year flood zone. While swamp areas exist in the vicinity of the proposed site, ample areas exist for precise site location to avoid swamp areas and areas within the 100-year flood zone. Existing secondary levees protect the proposed site from flooding due to failure of the Herbert Hoover Dike on Lake Okeechobee. No other neighboring flooding concerns exist. If required, construction of flood protection structures would be minimal.	5
Okeechobee 2	The proposed site is located on the border of the 100-year flood zone. While swamp areas exist in the vicinity of the proposed site, ample areas exist for precise site location to avoid swamp areas. The location of the Kissimmee River protects the proposed site from flooding due to failure of the Herbert Hoover Dike on Lake Okeechobee. No other neighboring flooding concerns exist. Construction of flood protection structures or fill to elevate the proposed site is likely to be necessary, but would be minimal.	4
St. Lucie	The proposed site is located in the 100-year flood zone with base flood elevations of 7-8 feet. Adverse climatic events (e.g., area hurricanes) would likely result in flooding of the proposed site. Construction of flood protection structures or fill to elevate the proposed site will be required and would likely be more robust than other proposed sites.	2
Turkey Point	The proposed site is located in the 100-year flood zone with base flood elevations of 12 feet. Adverse climatic events (e.g., area hurricanes) would likely result in flooding of the proposed site. Construction of flood protection structures or fill to elevate the proposed site will be required and would likely be more robust than other proposed sites.	2

Flooding	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	5	3	5	4	5	4	2	2

References

FEMA Digital Flood Insurance Rate Maps, http://www.fema.gov/fhm/.

USGS Topographic Maps.

C.4.1.4 Vibratory Ground Motion -- *Deleted from evaluation*

The objective of this criterion is to provide a relative measure of cost associated with designing to different seismic requirements at different sites. Because all of the sites under consideration are expected to meet the site parameters for seismic design of the standardized designs under

consideration, this criterion is not applicable to the FPL Florida service territory site selection process.

C.4.1.5 Civil Works

Objective – The objective of this criterion (formerly titled "soil stability") is to rate sites according to differences in the cost of civil works (e.g., non-flood related berms, stabilizing of graded slopes and banks) necessary to prepare the site for nuclear plant development.

Evaluation approach – Sites are rated highest to lowest according to the estimated level of cost of civil works required at each site.

Discussion/Results – The existing candidate sites (St. Lucie and Turkey Point) are located at operating plants that has been previously developed and has been shown to be capable of supporting conventional foundation designs. Accordingly, the existing sites are assigned a median rating of 3.

Given the general lack of site specific geotechnical information on the six remaining sites, consideration was allotted to the overall elevation above sea level as a potential indicator of dewatering needs and overall site relief as an indicator of potential grading and excavation. Due to the average elevation of the sites, all sites except DeSoto and Hardee will require excavation below MSL to accommodate reactor construction because of their lower elevations. Therefore these sites receive lower ratings in consideration of the potential dewatering and stability concerns. Due to the site topography, all sites except St. Lucie and Turkey Point exhibit over 10' site relief. Therefore, these sites receive lower ratings in consideration of the potentially higher level of earthwork at these sites as compared to the relatively flat coastal sites.

Civil Works	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Avg. elev.[1]	4	1	4	1	2	2	1	1
Relief[2]	2	3	1	3	3	2	5	5
Rating	3	2	2	2	2.5	2	3	3

[1] 80'+ = 5, 60'+ = 4, 40'+ =3, 20'+=2, 0'+ = 1
[2] 0'=5, <5'=4, <10'=3, <20'=2, 20'+=1

C.4.2 TRANSPORTATION OR TRANSMISSION-RELATED CRITERIA

C.4.2.1 Railroad Access

Objective – The purpose of this criterion is to rate sites according to the relative costs associated with providing rail access.

Evaluation approach – Sites are rated from highest to lowest in accordance with the length of additional or new rail spur construction required to provide rail access, scaled from those discussed in the screening criteria report, Criterion P7. Sites having rail access within 2 miles or less receive a rating of 5; sites with rail access between 2 and 5 miles away receive a rating of 4, and sites with rail access greater than 5 miles away receive a rating of 3.

Some sites are located near abandoned rail lines. The site-specific condition of abandoned rail lines is unknown and could range from removed/revegetated to present and operable with minimal upgrade. Therefore, distances used in this analysis are to the nearest rail line in service and assume abandoned rail lines have been removed/revegetated. Should rail access become a sensitive criterion for site selection, site-specific conditions of abandoned rail lines should be more fully evaluated.

Discussion/Results – Distances to rail service at each of the sites were measured in the Preliminary Screening Evaluation (based on USGS topographic maps and summarized in Appendix B). Assuming that (1) passenger lines may be used for a one-time delivery of plant equipment to the site, (2) abandoned lines have been removed/revegetated, and (3) costs are based on a straight linear scale of costs for construction of rail spurs to the sites from these lines, ratings for the sites are assigned in the table below.

Site	Evaluation	Ranking
DeSoto	Rail is ~ 7.1 miles W (operated by CSX Transportation). A rail line between Arcadia, FL and Bowling Green, FL (~ 2.3 miles west of the proposed site) formerly operated by Seaboard System RR has since been abandoned.	3
Glades	Rail is ~ 3.1 miles NE (operated by South Central Florida Express, CSX Transportation has trackage rights).	4
Hardee	Rail is ~ 0.4 miles W (operated by CSX Transportation). A rail line between Arcadia, FL and Bowling Green, FL (~ 6.4 miles east of the proposed site) formerly operated by Seaboard System RR has since been abandoned.	5
Hendry 1	Rail is ~ 8.7 miles NE (operated by South Central Florida Express, CSX Transportation and Florida East Coast Railway have trackage rights).	3

Site	Evaluation	Ranking
Martin	Rail is ~ 1.5 miles NE (operated by CSX Transportation). Rail is ~ 2.8 miles W (operated by Florida East Coast Railway). However, lake/reservoir is located between the Martin site and this rail line. A rail spur has been constructed from the Florida East Coast Railway line to access the existing Martin power plant.	5
Okeechobee 2	Rail is ~ 2.2 miles NE (operated by CSX Transportation).	4
St. Lucie	Rail is ~ 2.1 miles W (operated by Florida East Coast Railway). However, the Intercoastal Waterway is located between the St. Lucie site and this rail line. Due to the coastal location of the St. Lucie site, barge access is accessible in the immediate vicinity for delivery of heavy/large items. However, since rail access is not immediately accessible, a rating of 5 was not assigned.	4
Turkey Point	Rail is ~ 10.3 miles W (operated by CSX Transportation). Homestead, FL marks the southernmost point of Florida served by rail. A rail line to Homestead, FL formerly operated by Florida East Coast Railway has since been abandoned. Due to the coastal location of the Turkey Point site, barge access is immediately accessible for delivery of heavy/large items. A barge channel has been constructed in Biscayne Bay providing direct access to the site. As barge access provides an alternative to rail access, the rating has been increased to 4 (however, since rail access is not immediately accessible, a rating of 5 was not assigned).	4

Railroad Access	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**3**	**4**	**5**	**3**	**5**	**4**	**4**	**4**

References

North American Railroad Map, version 2.14, http://www.RailroadMap.com.

USGS Topographic Maps (1:100,000 and 1:24,000 scale).

C.4.2.2 Highway Access

Objective – The purpose of this criterion is to rate sites according to the relative costs associated with providing highway access.

Evaluation approach – Sites are rated from highest to lowest in accordance with the length of additional or new highway construction required to provide car and truck access.

Discussion/Results – The following table evaluates the existing roads serving the site areas. All sites are located near existing roads, and construction of site access is predicted to be minimal. Therefore, each site has been assigned a rating of 5, with the exception of Hendry 1 which would likely require more construction than other sites.

Site	Evaluation	Ranking
DeSoto	Proposed site is located ~ 2.5 miles east of U.S. Highway 17 and ~ 7.3 miles north of State Highway 70. These roads provide main access to the area. U.S Highway 27 is also located ~ 23 miles east of the proposed site at Lake Placid, FL. Construction of local access would be required but should be minimal.	5
Glades	Proposed site is located ~ 1.0 miles south of U.S. Highway 27 and State Highway 78. These roads provide main access to the area. Construction of local access would be required but should be minimal.	5
Hardee	Proposed site is located ~ 5.0 miles south of State Highway 64 and ~ 6.4 miles west of U.S. Highway 17. These roads provide main access to the area. Additionally, Interstate 75 is located ~ 40 miles west of the proposed site. Construction of local access would be required but should be minimal.	5
Hendry 1	Proposed site is located ~ 5.4 miles east of State Highway 833 and ~ 6.4 miles south of U.S. Highway 27. These roads provide main access to the area. Construction of local access would be required but should be minimal, although greater than other sites.	4
Martin	Proposed site is located ~ 1.1 miles southwest of State Highway 710 and ~ 5.6 miles east of U.S. Highway 98/441. Area access exists due to co-location with the existing Martin power plant. Construction of local access would be required but should be minimal.	5
Okeechobee 2	Proposed site is located ~ 0.4 miles north of State Highway 70 and ~ 4.3 miles southwest of U.S. Highway 98. These roads provide main access to the area. Construction of local access would be required but should be minimal.	5
St. Lucie	Proposed site is located on Hutchinson Island adjacent to Highway A1A and ~ 9.8 miles from access to U.S. Highway 1 and Interstate 95. Area access exists due to co-location with the existing St. Lucie nuclear power plant. Construction of local access would be required but should be minimal.	5
Turkey Point	Proposed site is located ~ 9.1 miles east of U.S. Highway 1 and the Florida Turnpike. Privately owned access exists to the existing Turkey Point nuclear power plant. Additional local access construction would be required but should be minimal.	5

Highway Access	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	5	5	5	4	5	5	5	5

References

Rand McNally Road Atlas.

USGS Topographic Maps (1:100,000 and 1:24,000 scale).

C.4.2.3 Barge Access

Objective – The purpose of this criterion is to rate sites according to the relative costs associated with providing barge access.

Evaluation approach – Sites are rated from highest to lowest in accordance with estimated cost of facilities construction required to provide barge access.

Discussion/Results – The following table evaluates the area geography permitting barge access to the candidate sites.

Site	Evaluation	Ranking
DeSoto	The proposed site is located ~ 55 miles southeast of the Tampa Cargo Seaport. Intermodal transport of heavy/large items would be required.	1
Glades	The proposed site is located ~ 5 miles west of Lake Okeechobee, which is accessible by barge (Okeechobee Waterway) from either the Atlantic Ocean (Stuart, FL via 2 locks) or the Gulf of Mexico (Ft. Myers, FL via 3 locks). The barge channel is 8 feet deep with an 80 foot bottom width.	3
Hardee	The proposed site is located ~ 45 miles southeast of the Tampa Cargo Seaport. Intermodal transport of heavy/large items would be required. As rail access is available immediately adjacent to the proposed site and provides an alternative to barge transport, the rating has been increased to 4 (however, since barge access is not immediately accessible, a rating of 5 was not assigned).	4
Hendry 1	The proposed site is located ~ 11 miles south of Lake Okeechobee, which is accessible by barge (Okeechobee Waterway) from either the Atlantic Ocean (Stuart, FL via 2 locks) or the Gulf of Mexico (Ft. Myers, FL via 3 locks). The barge channel is 8 feet deep with an 80 foot bottom width.	3

Site	Evaluation	Ranking
Martin	The proposed site is located ~ 5 miles east of Lake Okeechobee, which is accessible by barge (Okeechobee Waterway) from either the Atlantic Ocean (Stuart, FL via 2 locks) or the Gulf of Mexico (Ft. Myers, FL via 3 locks). The barge channel is 8 feet deep with an 80 foot bottom width. As rail access is available immediately adjacent to the proposed site and provides an alternative to barge transport, the rating has been increased to 4 (however, since barge access is not immediately accessible, a rating of 5 was not assigned).	4
Okeechobee 2	The proposed site is located ~ 8 miles north of Lake Okeechobee, which is accessible by barge (Okeechobee Waterway) from either the Atlantic Ocean (Stuart, FL via 2 locks) or the Gulf of Mexico (Ft. Myers, FL via 3 locks). The barge channel is 8 feet deep with an 80 foot bottom width.	3
St. Lucie	The proposed site is located on the coast of the Atlantic Ocean. The Fort Pierce Cargo Seaport is located ~ 8.8 miles northwest of the proposed site.	4
Turkey Point	The proposed site is located on the coast of the Atlantic Ocean/Biscayne Bay. A barge canal has been constructed from the northeast and provides direct barge access to the proposed site.	5

Barge Access	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**1**	**3**	**4**	**3**	**4**	**3**	**4**	**5**

References

Florida Intracoastal and Inland Waterway Study, Final Report, May 2003.

USGS Topographic Maps (1:100,000 and 1:24,000 scale).

C.4.2.4 Transmission Cost and Market Price Differentials

Objective – The purpose of this criterion is to rate sites according to the relative costs associated with construction of power transmission systems and issues related to market price differentials.

Evaluation approach – Sites are rated from highest to lowest in accordance with estimated transmission system construction costs and consideration of other identified issues related to power transmission. Because all eight sites are located within the FPL Florida service area, no electricity market price differentials are expected between the sites, and this sub-criterion was not evaluated.

Discussion/Results – Transmission access is evaluated in terms of distance to the load center in the greater Miami area, and amount of new right of way (ROW) that needs to be acquired. The highest ranked sites already have the ROW, and the lowest-ranked sites require significant ROW acquisition, which will be difficult to obtain. In addition the plant switchyard is assumed the same for all sites.

Site	Evaluation	Ranking
DeSoto	~ 125 miles to Miami Load Center. 135 miles of new 500 kV ROW acquisition, 2 autotransformers, 8 – 500 kV line terminals. ROW near Orange River substation will be difficult to obtain.	3
Glades	~ 75 miles to Miami Load Center. 146 miles of new 500 kV ROW, of which approximately 60 miles of new ROW acquisition, 1 autotransformer, 6 – 500 kV line terminals; rebuild 120 miles of 230 kV lines.	4
Hardee	~ 135 miles to Miami Load Center. 165 miles of new 500 kV ROW acquisition, 2 autotransformers, 6 – 500 kV line terminals.	2
Hendry 1	~ 60 miles to Miami Load Center. 72 miles of new 500 kV ROW, of which approximately 40 miles of new ROW acquisition, 1 autotransformer, 6 – 500 kV line terminals; rebuild 120 miles of 230 kV lines.	4
Martin	~ 65 miles to Miami Load Center. 35 miles of new 500 kV in existing ROW, 6 – 500 kV line terminals.	5
Okeechobee 2	~ 90 miles to Miami Load Center. 95 miles of new 500 kV ROW, of which approximately 40 miles of new ROW acquisition, 2 autotransformers, 8 – 500 kV line terminals.	4
St. Lucie	~ 85 miles to Miami Load Center. 80 miles of new 500 kV ROW acquisition, 2 autotransformers, 8 – 500 kV line terminals. ROW will be difficult to obtain.	1
Turkey Point	~ 50 miles to Miami Load Center. 64 miles of existing 500 kV ROW, 1 autotransformer, 8 – 500 kV line terminals.	5

Transmission	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	3	4	2	4	5	4	1	5

C.4.3 CRITERIA RELATED TO LAND USE AND SITE PREPARATION

C.4.3.1 Topography

Objective – The purpose of this criterion is to rate sites according to the relative costs associated with site grading and earth-moving necessary to prepare the site for construction of a nuclear power plant.

Evaluation approach – Ratings are based on the amount of topographic relief currently found at the site, with the most severe relief resulting in the highest estimated grading costs and therefore the poorest rating. Sites are rated from highest to lowest in accordance with estimated grading costs.

Discussion/Results –Given the general flat topography found in central Florida, ratings were favorable across all sites.

Site	Evaluation	Ranking
DeSoto	The proposed site is located in a relatively flat area, with minor relief (+/- ~ 4 feet). At ~ 2 miles west of the proposed site, the area begins to slope downward to the Peace River. Costs associated with site grading are expected to be relatively low.	5
Glades	Topographic relief across the area is relatively flat (+/- 1 foot) with a system of ditches and water retention areas for irrigation and drainage purposes. Areas north and west of the proposed site begin to slope upward. Costs associated with site grading are expected to be relatively low.	5
Hardee	The proposed site is located in an area with moderate relief (+/- ~ 15 feet). East of the proposed site, the area begins to slope downward to the Peace River. Costs associated with site grading are expected to be moderate.	4
Hendry 1	The proposed site is located in a relatively flat area, with minor relief (+/- 1 foot). Costs associated with site grading are expected to be relatively low.	5
Martin	The proposed site is located in a relatively flat area, with minor relief (+/- 4 feet). The area generally slopes from east to west (toward Lake Okeechobee). Costs associated with site grading are expected to be relatively low.	5
Okeechobee 2	Topographic relief across the area is relatively flat (+/- 2 feet) with a system of ditches and water retention areas for irrigation and drainage purposes. The area generally slopes down to the southwest (toward the Kissimmee River). Costs associated with site grading are expected to be relatively low.	5
St. Lucie	The proposed site is located in a relatively flat area, with minor relief (+/- 1 foot). Costs associated with site grading are expected to be relatively low.	5

Site	Evaluation	Ranking
Turkey Point	The proposed site is located in a relatively flat area, with minor relief (+/- 1 foot). Costs associated with site grading are expected to be relatively low.	5

Topography	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**5**	**5**	**4**	**5**	**5**	**5**	**5**	**5**

References

Draft Phase I Environmental Site Assessment, A. Duda & Sons Inc. URS Corporation. July 2006.

Phase I Environmental Site Assessment, Pelaez & Sons Inc. Ranch. URS Corporation. May 2006.

Site Drainage and Interim Land Use Study. Brown & Root, Inc. March 1976.

USGS Topographic Maps (1:100,000 and 1:24,000 scale).

C.4.3.2 Land Rights

Objective – The purpose of this criterion is to rate sites according to the relative costs associated with purchasing land required to construct and operate a nuclear station on the site.

Evaluation approach –Sites are rated from highest to lowest in accordance with estimated land costs based on information provided by FPL real estate and County profile data.

Discussion/Results – This criterion was evaluated previously in the screening criteria report (Criterion P9), although for a larger land size area. Results are provided below.

Site	Comments and Discussion	Rating
DeSoto	FPL owns sufficient land Undeveloped site in 13,500-acre property	5
Glades	Does not own – Farmland; [$35 M] [actually now appears FPL has bought for a coal fired power plant site, but not assumed for purposes of siting evaluation]	3
Hardee	Does not own – Farmland; [$35 M]	3
Hendry 1	Does not own – Farmland; [$35 M]	3
Martin	FPL owns sufficient land – 11,300 acres Existing industrial site	5

Site	Comments and Discussion	Rating
Okeechobee 2	Does not own – Farmland [$35 M]	3
St. Lucie	FPL owns sufficient land	5
Turkey Point	FPL owns sufficient land	5

Note: Land requirements of 2,000 acres per site where FPL does not own. Costs per acre are assumed to be $10,000 in rural areas; $17,500 for farmland; $35,000 for sites near urban/developed areas.

Land Rights	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	**5**	**3**	**3**	**3**	**5**	**3**	**5**	**5**

C.4.3.3 Labor Rates

Objective – The purpose of this criterion is to rate sites according to the relative costs associated with local labor costs that would be incurred during plant construction.

Evaluation approach – Sites are rated from highest to lowest in accordance with estimated local labor costs, with the lower cost resulting in higher ratings.

Discussion/Results – Economic data are typically available by county, but were found to be provided in a variety of forms (e.g., by hour, by week, by year; by job type) that were not necessarily consistent between counties. For purposes of consistency, this evaluation relied on Economic data based on County Data for Florida (eFlorida profile data for 2004), average annual wage for construction worker, 2004 data, as follows:

DeSoto: Average annual construction wage – $24,276
Glades: No data [assumed to be low wage given rural nature and emphasis on agriculture]
Hardee: $33,221
Hendry 1: $24,306
Martin: $33,667
Okeechobee 2: $26,147
St. Lucie: $31,894
Turkey Point: $40,149

Comparisons of the above construction labor wages reveals that the highest rates are in Miami Dade County (Turkey Point), the lowest rates in DeSoto, Hendry and presumably Glades counties, with the remaining sites falling somewhere in between. The slight differences are noted in the rankings. Finally, it should be noted that a significant portion of the construction workforce is expected to come from a national workforce of journeymen, whose rates will be set based on supply and demand within the overall nuclear industry, rather than by local workforce rates or skill sets. While the ratings below are based solely on current and local wage differentials, this additional factor could mitigate differences in labor costs between the sites.

Labor Rates	DeSoto	Glades	Hardee	Hendry 1	Martin	Okee 2	St. Lucie	Turkey Point
Rating	5	5	3	5	3	4	3	2

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 25
COMPANY FL Power & Light (Direct)
WITNESS Steven D. Scroggs (SDS-3)
DATE 01/30 - 02/01/08

Engineering Evaluation of Current Technology Options for New Nuclear Power Generation

(Proprietary and Confidential Business Information)

Combined License Application (COLA) Content

Cover Letter
- Oath or Affirmation, contacts, reference plant

General and Administrative Information
- The identity and financial/technical qualifications of the owner and operator
- Decommissioning funding assurance plan

Final Safety Analysis Report
- Information which is site-specific including hydrological and seismic attributes of the site.
- The detailed design of the plant (to the extent not certified)
- Only need to reference the Certified Design Information.

Environmental Report
- A description of the affect on the environment along with the impact and any adverse effects which can not be avoided.
- All Federal permits, licenses, approvals and other entitlements, applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection.

Technical Specifications
- A Technical Specification establishes plant operating requirements for items such as safety limits, limiting safety system settings, limiting control settings, limiting conditions for operation, surveillance requirements, design features, and administrative controls.

Emergency Plan
- Integrated plans for addressing radiological emergencies at the facility

Limited Work Authorization Requests
- Any site preparation and or construction of any system or component delineated by the NRC which could affect nuclear safety and would require some form of NRC approval.
- Site Redress Plan for any on-site physical work.

Generic Design Control Document (DCD) Departures Report
- Any deviation from the Design Certification which is referenced in the COLA must be addressed.

Safeguards/Security Plans
- Physical security plan
- Proprietary, Sensitive & SUNSI information not for general public dissemination.

ITAAC, and Other proposed License Conditions
- Required inspections, tests, analysis, acceptance criteria to verify that the facility, as constructed, meets the design requirements and is in conformance with the COL once it is granted including all operational programs

COLA Specific Information
- Example: Quality Assurance Plan

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COMPANY FL Power & Light (Direct)
WITNESS Steven D. Scroggs (SDS-4)
DATE 01/30-02/01/08

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 27
COMPANY FL Power + Light (Direct)
WITNESS Steven D. Scroggs (SDS-5)
DATE 01/30-02/01/08

Project Year	Estimated Project Milestones
2008	Site Selection complete, COLA Preparation begins, Detailed Engineering begins Optional: Long Lead Procurement (Ultra-Heavy Forgings: Pressure Vessels, Steam Generator Vessels)
2009	COLA filed at NRC, SCA filed at FDEP, Application Review begins, Detailed Engineering Optional: Long Lead Procurement (Forgings, Training Simulator)
2010	Detailed Engineering and COLA review continues, SCA Hearing, Optional: Site clearing and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)
2011	COLA review complete, Detailed Engineering continues Optional: Site Preparation and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)
2012	ASLB convenes license hearing, Detailed Engineering continues, Non-nuclear Construction commences Optional: Site Preparation completes
2013	Safety Related (NRC jurisdictional) Construction commences, foundation for Unit 1 constructed
2014	Reactor Pressure Vessel and major components for Unit 1 delivered and set
2015	Unit 1 system construction, foundation for Unit 2 constructed
2016	Reactor Pressure Vessel and major components for Unit 2 delivered and set
2017	Unit 1 Substantial Completion and ITAAC Hearing
2018	Unit 1 Fuel Load, testing and commercial operation.
2019	Unit 2 Substantial Completion and ITAAC Hearing
2020	Unit 2 Fuel Load, testing and commercial operation.

Note: Optional items needed to support earliest practical deployment schedule

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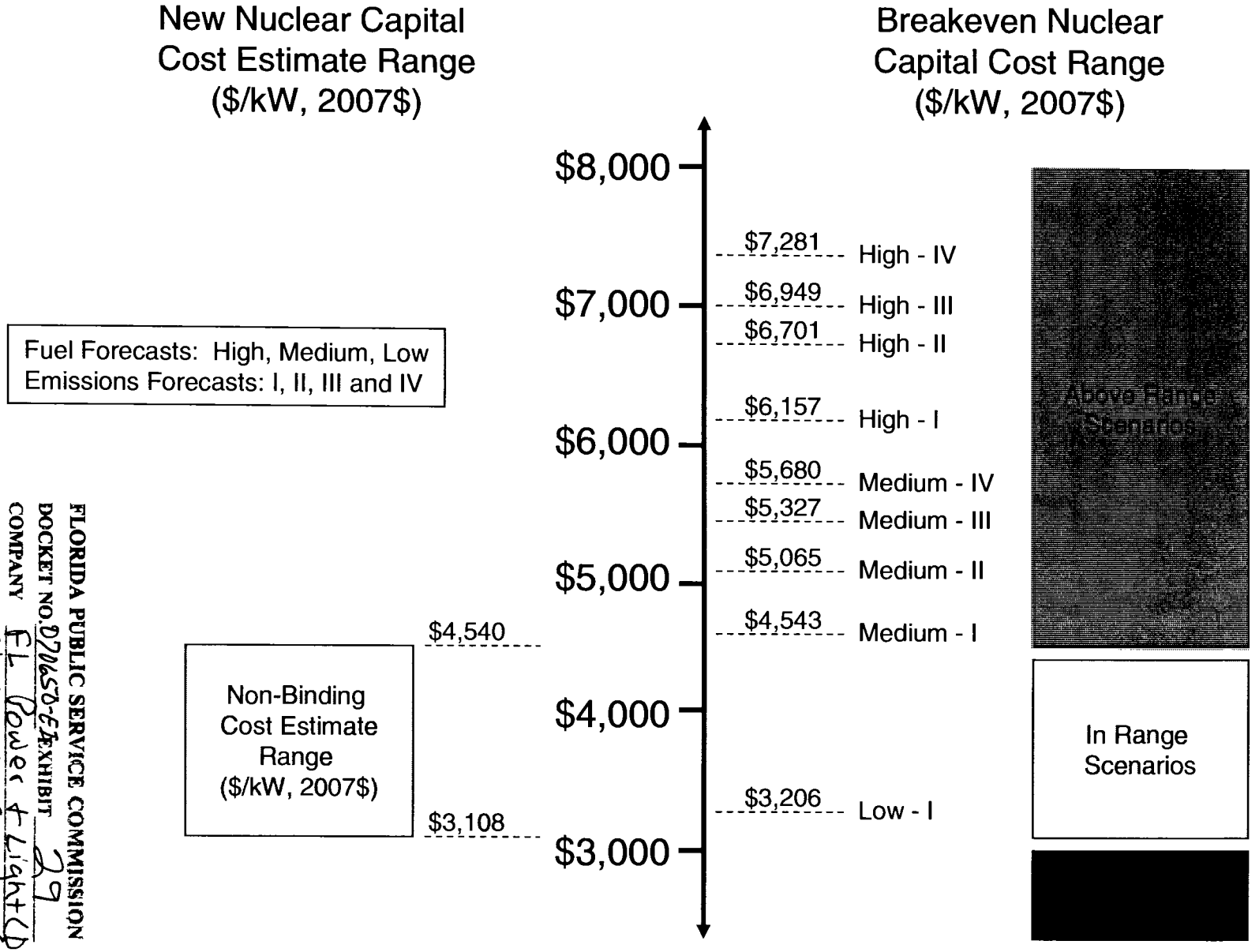
DOCKET NO. 070650-EI EXHIBIT 28
COMPANY FL Power & Light (Direct)
WITNESS Steven D. Scroggs (SDS-6)
DATE 01/30-02/01/08

Overnight Cost Estimate Range ($/kW, 2007$)

Construction Unit Cost Estimate Range Based on TVA Study - Two Unit ABWR Project, at 1,371 MW per unit	CASE A: TVA Study Adjusted to 2007$ (Index 206/238) and Modified for FPL Owners Scope and PTN Site Cost Estimates		CASE B: Reduced Material Escalation (Index 170/192), Reduced Owner Scope, 10% lower Owners Costs, Low Transmission Estimate		CASE C: Increased Material Escalation (Index 242/284), Added Owner Scope, 10% higher Owner's Costs, High Labor & Transmission Estimate	
	2007 $	$/kWe	2007 $	$/kWe	2007 $	$/kWe
Power Plant Island and Supporting Construction						
Structure & Improvements	$792,000,000	$289	$654,000,000	$239	$931,000,000	$340
Reactor Plant Equipment	$1,399,000,000	$510	$1,155,000,000	$421	$1,644,000,000	$600
Turbine Plant Equipment	$934,000,000	$341	$771,000,000	$281	$1,097,000,000	$400
Electric Plant Equipment	$413,000,000	$151	$333,000,000	$121	$493,000,000	$180
Misc. Plant Equipment	$146,000,000	$53	$118,000,000	$43	$174,000,000	$63
Main Cond. Heat Reject Sys	$84,000,000	$31	$84,000,000	$31	$84,000,000	$31
Circ. Water Pumps & Pipe	$26,000,000	$9	$26,000,000	$9	$26,000,000	$9
Construction Labor, Manual	$1,422,000,000	$519	$1,422,000,000	$519	$1,848,600,000	$674
Construction Services	$534,000,000	$195	$431,000,000	$157	$694,200,000	$253
Engineers Home Office Services	$834,000,000	$304	$834,000,000	$304	$1,084,200,000	$395
Additional Required Scope	$98,000,000	$36	$0	$0	$107,800,000	$39
Allowance for Cost Risk	$1,002,300,000	$366	$874,200,000	$319	$1,636,760,000	$597
Subtotal	$7,684,300,000	$2,802	$6,702,200,000	$2,444	$9,820,560,000	$3,582
Owners Costs						
Security infrastructure	$109,000,000	$40	$98,100,000	$36	$119,900,000	$44
Cooling Towers	$131,000,000	$48	$0	$0	$144,100,000	$53
Aux Boilers	$16,000,000	$6	$0	$0	$17,600,000	$6
Switch Yard	$93,000,000	$34	$83,700,000	$31	$102,300,000	$37
Site work	$257,000,000	$94	$231,300,000	$84	$282,700,000	$103
EPC startup costs	$139,000,000	$51	$125,100,000	$46	$152,900,000	$56
Fuel	$45,000,000	$16	$40,500,000	$15	$49,500,000	$18
Site Security	$91,000,000	$33	$81,900,000	$30	$100,100,000	$37
Permits/Licensing	$104,000,000	$38	$93,600,000	$34	$114,400,000	$42
Other Owner costs	$38,000,000	$14	$34,200,000	$12	$41,800,000	$15
Owner Project Management	$166,000,000	$61	$149,400,000	$54	$237,380,000	$87
Owner Transition	$192,000,000	$70	$172,800,000	$63	$274,560,000	$100
Land Costs - Site	$0	$0	$0	$0	$0	$0
Land Costs - Offsite	$0	$0	$0	$0	$0	$0
Allowance for Cost Risk	$207,150,000	$76	$166,590,000	$61	$327,448,000	$119
Subtotal	$1,588,150,000	$579	$1,277,190,000	$466	$1,964,688,000	$717
Additional Project Related Costs						
Transmission Integration	$512,000,000	$187	$471,000,000	$172	$553,000,000	$202
Allowance for Cost Risk	$76,800,000	$28	$70,650,000	$26	$110,600,000	$40
Subtotal	$588,800,000	$215	$541,650,000	$198	$663,600,000	$242
Grand Total	**$9,861,250,000**	**$3,596**	**$8,521,040,000**	**$3,108**	**$12,448,848,000**	**$4,540**

Docket No. 07____-EI
Overnight Cost Estimate Range
(2007S)
Exhibit SDS-6, Page 1 of 1

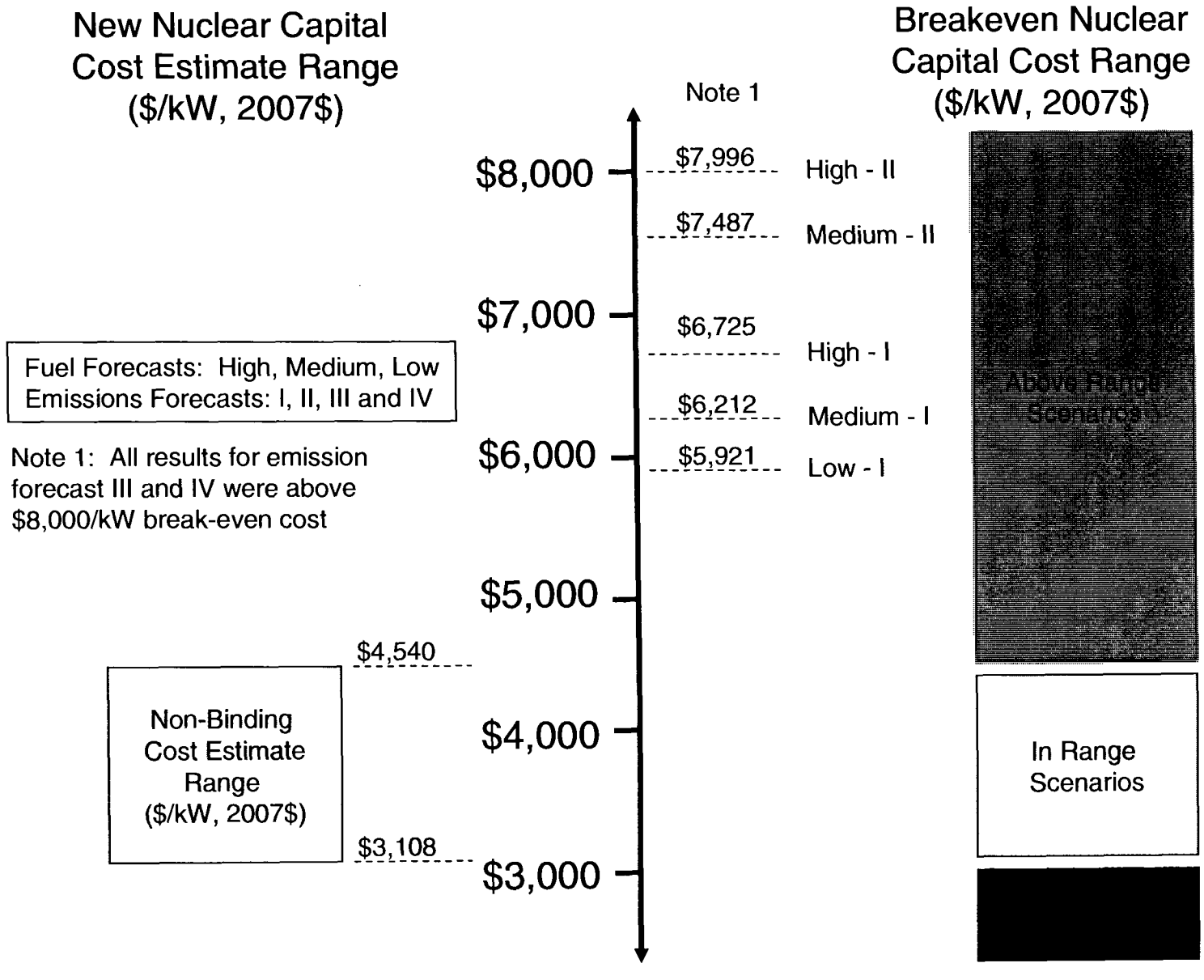
Comparison of Cost Estimate Range to Breakeven Capital Cost Range - Combined Cycle



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 29
COMPANY FL Power & Light (Direct)
WITNESS Steven D. Scroggs (SDS-7)
DATE 01/30 - 02/01/08

Docket No. 07____-EI
Comparison to Economically Viable Range (2007$)
Exhibit SDS-7, Page 1 of 2

Comparison of Cost Estimate Range to Breakeven Capital Cost Range - IGCC



Docket No. 07____-EI
Comparison to Economically Viable Range (2007$)
Exhibit SDS-7, Page 2 of 2

Project Total Cost Estimate Range (Year Spent $)

	2,200 MW				3,040 MW		
	Case A	**Case B**	**Case C**		**Case A**	**Case B**	**Case C**
Total Overnight Costs ($/kW, 2007$)	$3,596	$3,108	$4,540		$3,596	$3,108	$4,540
Escalation @ 2.5%	$892	$764	$1,139		$892	$764	$1,139
AFUDC @ 11.04%	$1,837	$1,573	$2,345		$1,837	$1,573	$2,345
Preconstruction Cost Adjustment [1]	$47	$47	$47		($19)	($19)	($19)
Project Total ($/kW)	**$6,372**	**$5,492**	**$8,071**		**$6,306**	**$5,426**	**$8,005**
Project Total ($B)	**$14.0**	**$12.1**	**$17.8**		**$19.2**	**$16.5**	**$24.3**

[1] Adjusts $191/kW of preconstruction costs from the TVA study for the 2,200 or 3,040 MW project considered in the FPL estimate range

Case A includes full current escalation to 2007, full owner scope and cost, and mid-range transmission integration estimate

Case B includes reduced escalation to 2007, reduced owner scope and cost, and low-range transmission integration estimate

Case C includes increased escalation to 2007, full owner scope and cost, and high-range transmission integration estimate

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Total Project Cost Estimate Range
(Year Spent $)
Exhibit SDS-8, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 30
COMPANY FL Power & Light (Direct)
WITNESS Steven D. Scroggs (SDS-8)
DATE 01/30-02/01/08

Project Expenditure Estimates by Rule 25-6.0423 Category

Example by Category ($MM, Year Spent)	Exploratory Phase	Licensing Phase	Preparation Phase	Construction Phase
2 x 1100 MW CASE A				
Site Selection Costs	$8	$0	$0	$0
Preconstruction Costs	$0	$155	$310	$0
Construction Costs	$0	$0	$50	$9,456
AFUDC	$0	$0	$0	$4,041
Phase Total	$8	$155	$360	$13,497
Total Cost Curve	$8	$163	$523	$14,020
2 x 1100 MW CASE B				
Site Selection Costs	$8	$0	$0	$0
Preconstruction Costs	$0	$155	$310	$0
Construction Costs	$0	$0	$50	$8,099
AFUDC	$0	$0	$0	$3,461
Phase Total	$8	$155	$360	$11,559
Total Cost Curve	$8	$163	$523	$12,082
2 x 1100 MW CASE C				
Site Selection Costs	$8	$0	$0	$0
Preconstruction Costs	$0	$155	$310	$0
Construction Costs	$0	$0	$50	$12,074
AFUDC	$0	$0	$0	$5,160
Phase Total	$8	$155	$360	$17,234
Total Project Cost	$8	$163	$523	$17,757

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 31
COMPANY FL Power & Light (Direct)
WITNESS Steven D. Scroggs (SDS-9)
DATE 01/30-02/01/08

Summary Resume Of Nils J. Diaz, PhD

Dr. Nils J. Diaz is the Managing Director of The ND2 Group, an expert and policy advise group with a strong focus on the nuclear power development arena, including new and existing plant licensing, regulatory, financial, policy and communications issues.

Nils Diaz is the former Chairman of the U.S. Nuclear Regulatory Commission (NRC). Dr. Diaz was designated Chairman of the NRC by President Bush on April 1, 2003 and he served as such until his retirement from government service on June 30, 2006. As Chairman of the NRC, Dr. Diaz served as the principal executive officer of and the official spokesman for the NRC, and had ultimate authority for all NRC functions pertaining to an emergency involving an NRC license; he was directly responsible for all high level interactions with the US Executive Branch and the Congress, as well as the international relationships and the policy development under NRC's charter.

Dr. Diaz was a Commissioner with the NRC from August 1996 until he assumed the Chairmanship of the Commission. During his ten year tenure with the NRC, he championed regulatory reforms to streamline licensing and regulatory processes, to improve the focus on matters important to safety, to increase risk-informed and performance-base regulation throughout the regulatory structure, and to enhance management's functions, accountability, and communications with the Congress, the public and stakeholders. As Chairman, he led the review and improvement of security and emergency response of nuclear facilities and materials, in a manner commensurate with the new threat environment facing the nation. Dr. Diaz re-structured the organization of the NRC to more effectively conduct the agency's licensing and oversight operations, with a strong emphasis in the areas of new reactor licensing and fuel cycle and waste disposal.

Prior to his appointment to the NRC, Dr. Diaz was the Director (1985-1996) of a national consortium for advanced nuclear power and propulsion (INSPI) for the Ballistic Missile Defense Organization, Department of Defense, and Professor of Nuclear Engineering Sciences at the University of Florida. As Director of INSPI, he exercised prime contractor management responsibilities for a diverse group of industries (including Aerojet, Pratt & Whitney, Hughes Electronics, and SRI), national laboratories (including LANL, SNL, and LLNL) and seven universities, under contracts with the Air Force, DNA, NASA, and DOE.

FLORIDA PUBLIC SERVICE COMMISSION
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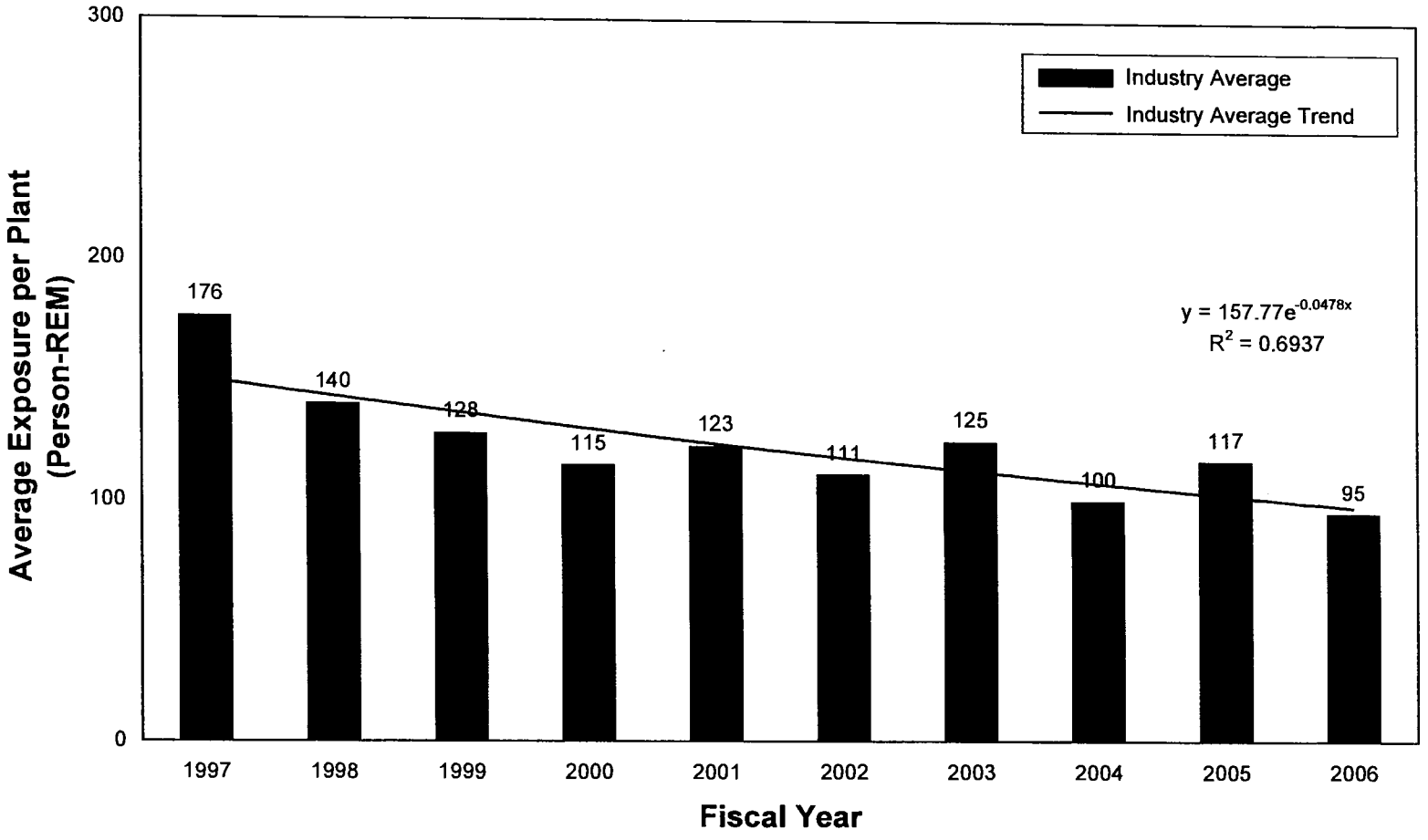
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Nils J. Diaz (NJD-1)
DATE 01/30 - 02/01/08

From 1969 to 1996, Dr. Diaz held positions as Professor at the University of Florida and as Dean for Research at CSULB, consulted on nuclear energy and energetics to private industry, the U.S. Government and other Governments. He also co-owned and managed six small corporations serving the nuclear industry and government, and conducting high technology development. He spent six years at nuclear utilities and corporations, often troubleshooting major performance issues using novel approaches to improving organizational effectiveness and accountability. He lived in Europe in 1981-1982, while serving as the Principal Advisor to Spain's Consejo de Seguridad Nuclear, and consulting for other entities. From 1971 to 1984, at the University of Florida, he managed the reactor, the accelerator facilities, the fuels and SNMs, as well as several multi-disciplinary programs.

Dr. Diaz is internationally recognized for his broad expertise and contributions to nuclear sciences, reactor systems and fuels, to the regulation of nuclear facilities and radioactive materials, and to nuclear policy analysis and development. He has worked extensively in the international arena, including interacting and contributing to major policy, fora and decision-making efforts. He has published extensively, and is recognized worldwide for his statesmanship on nuclear affairs.

Dr. Diaz holds a Ph.D. and M.S. in Nuclear Engineering Sciences from the University of Florida, and a B.S. Degree in Mechanical Engineering from the University of Villanova, Havana. He was licensed as a Senior Reactor Operator by the NRC and has formal training and practice in health physics, radiological sciences and nuclear medicine. He is a Fellow of the American Nuclear Society, the American Society of Mechanical Engineers, and the American Association for the Advancement of Science.

Collective Radiation Exposure



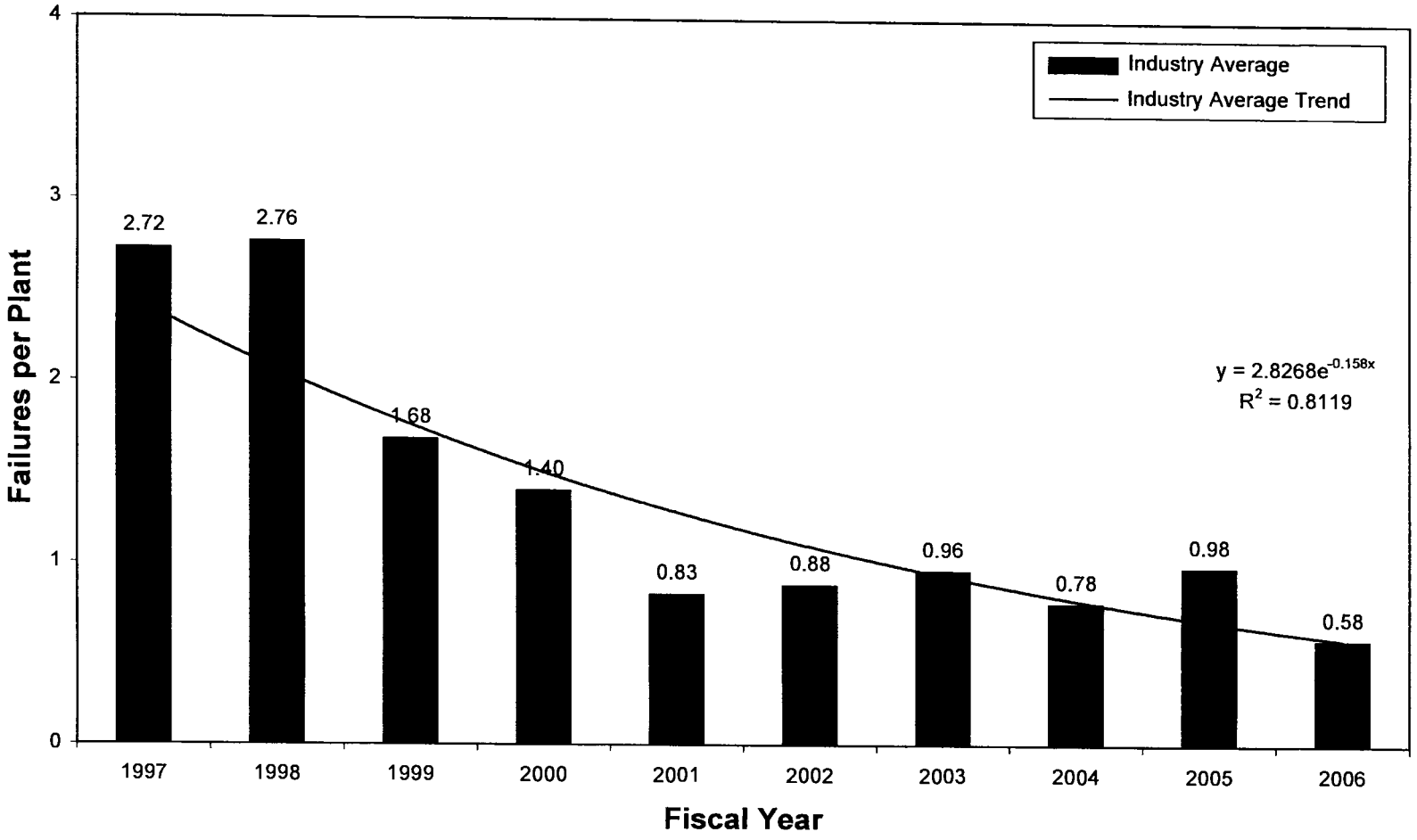
Source: United States Nuclear Regulatory Commission (NRC)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 33
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Nils J. Diaz (NJD-2)
DATE 01/30 - 02/01/08

Docket No. 07____-EI
Collective Radiation Exposure of Nuclear Power Plant Personnel
Exhibit NJD-2, Page 1 of 1

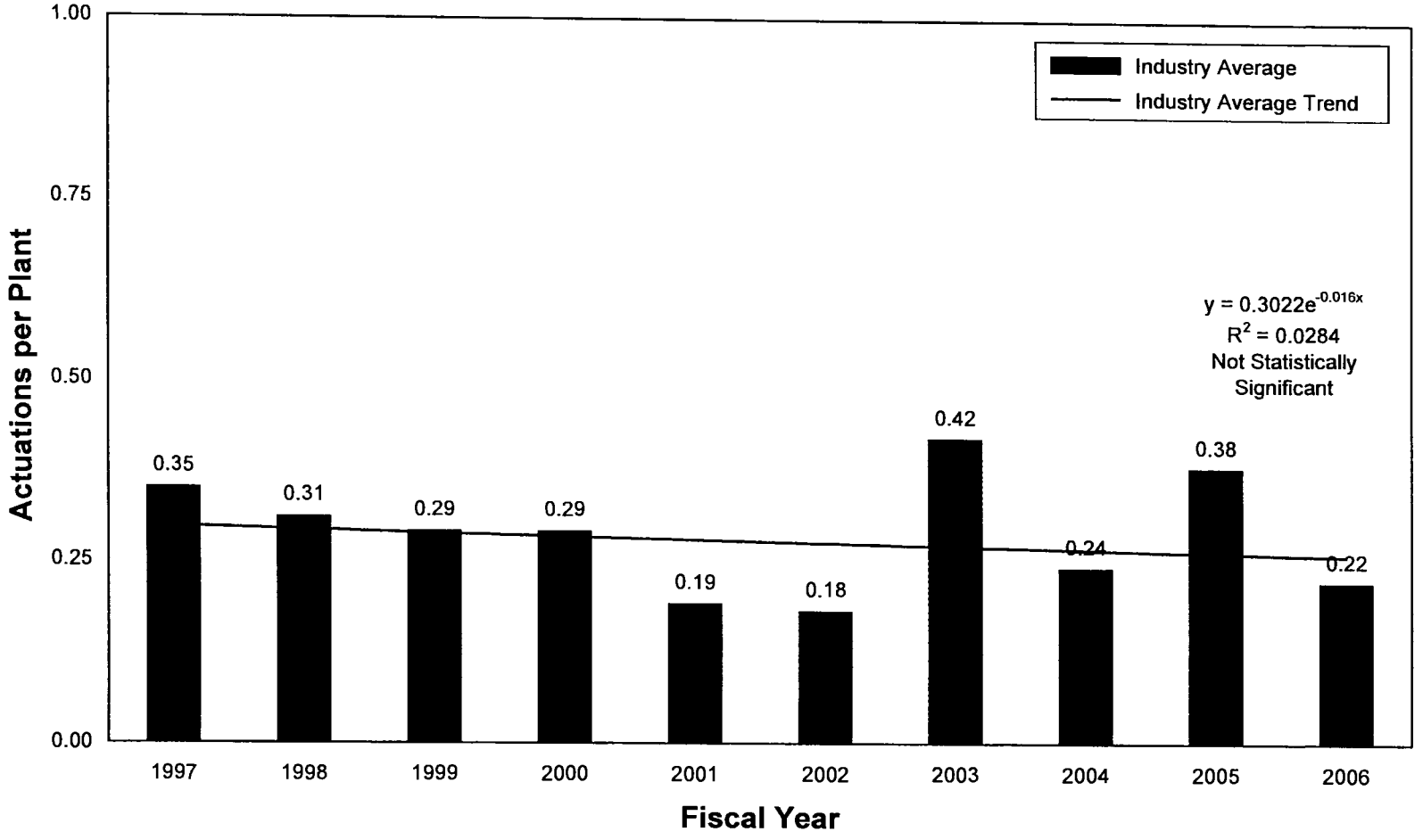
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 34
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Nils J. Diaz (NJD-3)
DATE 01/30 - 02/01/08

Safety System Failures



Source: United States Nuclear Regulatory Commission (NRC)

Safety System Actuations



Source: United States Nuclear Regulatory Commission (NRC)

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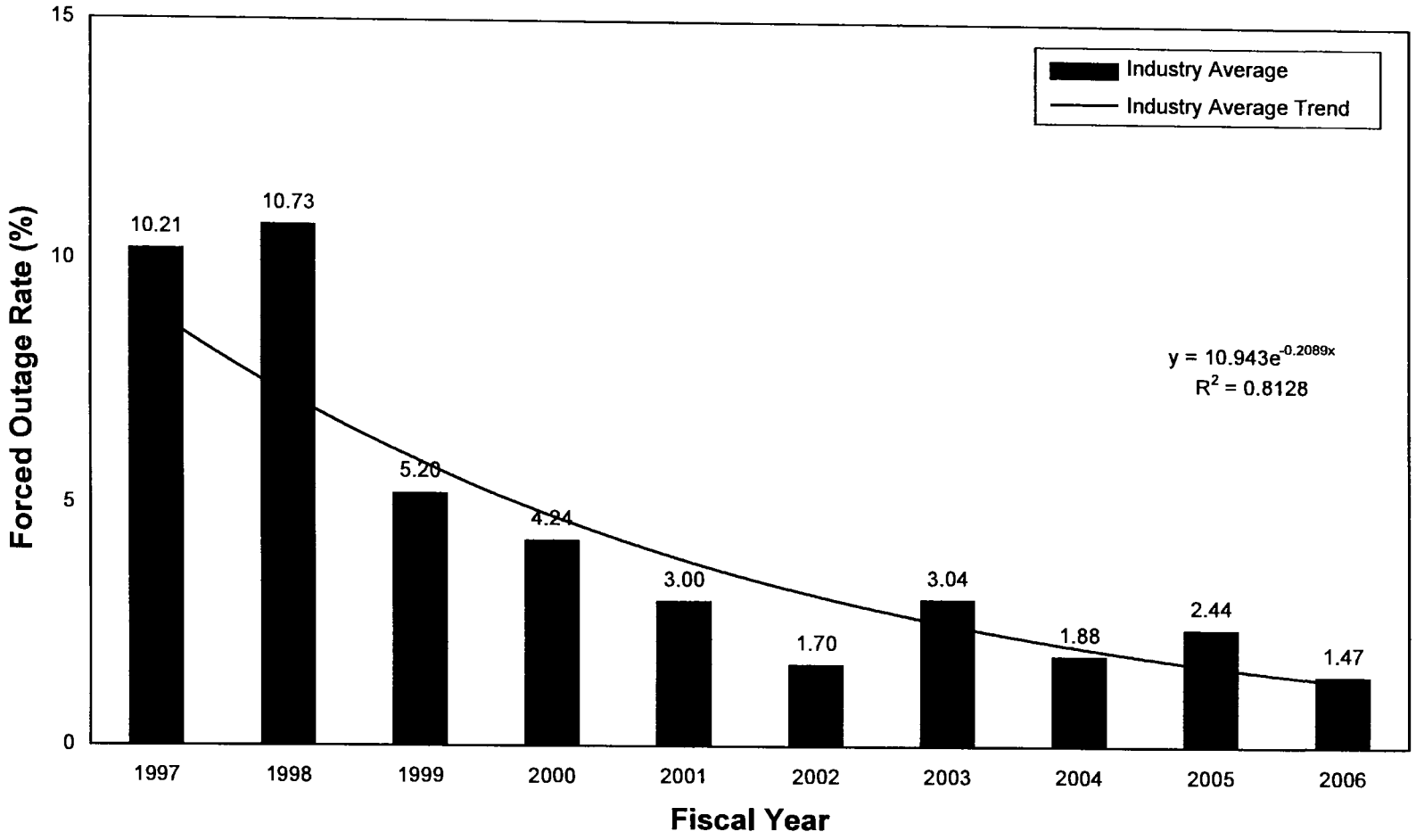
10 Years of NRC's Safety Indicators
Exhibit NJD-3, Page 2 of 5

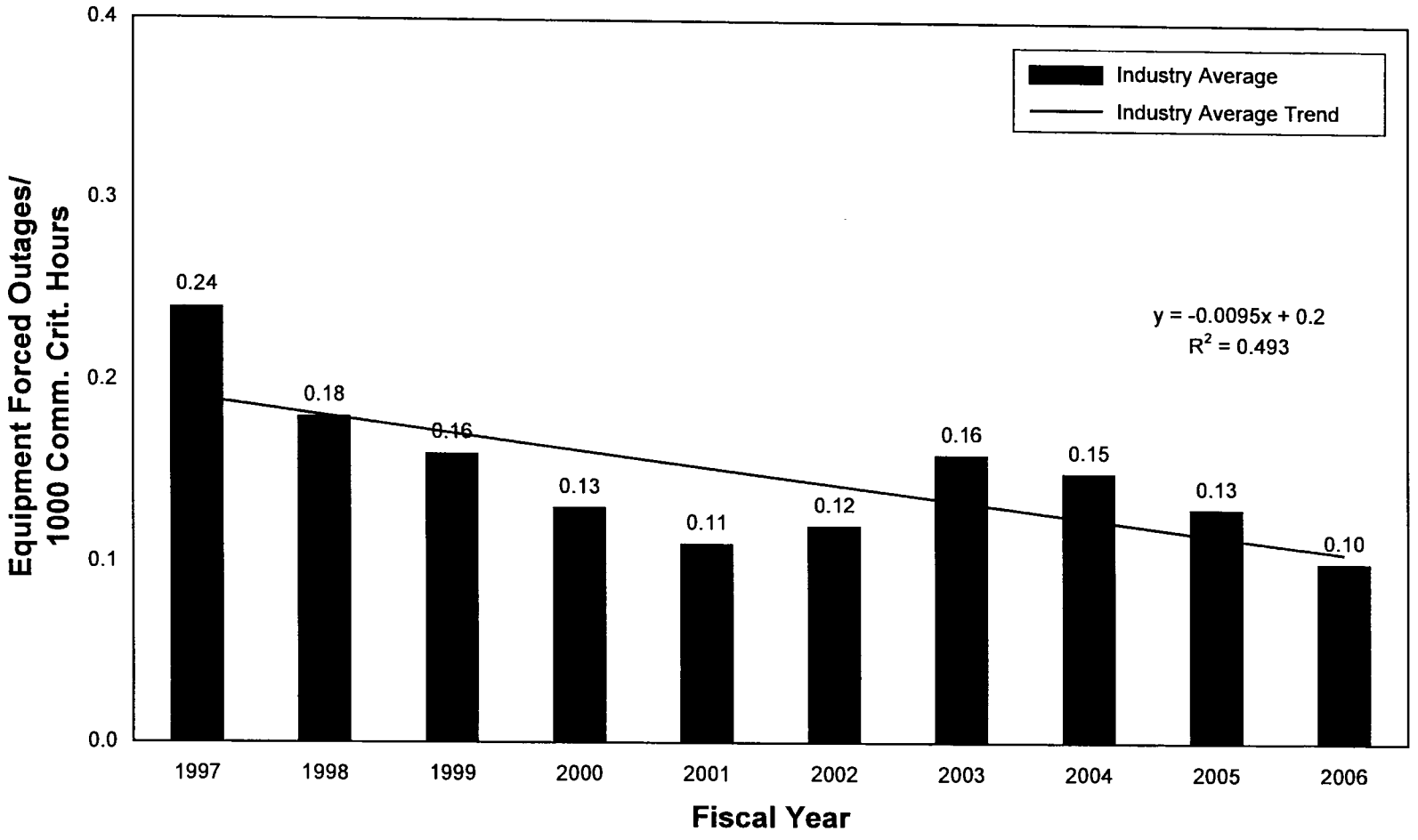
Forced Outage Rate (%)



Source: United States Nuclear Regulatory Commission (NRC)

Docket No. 07____ - EI
10 Years of NRC's Safety Indicators
Exhibit NJD-3, Page 3 of 5

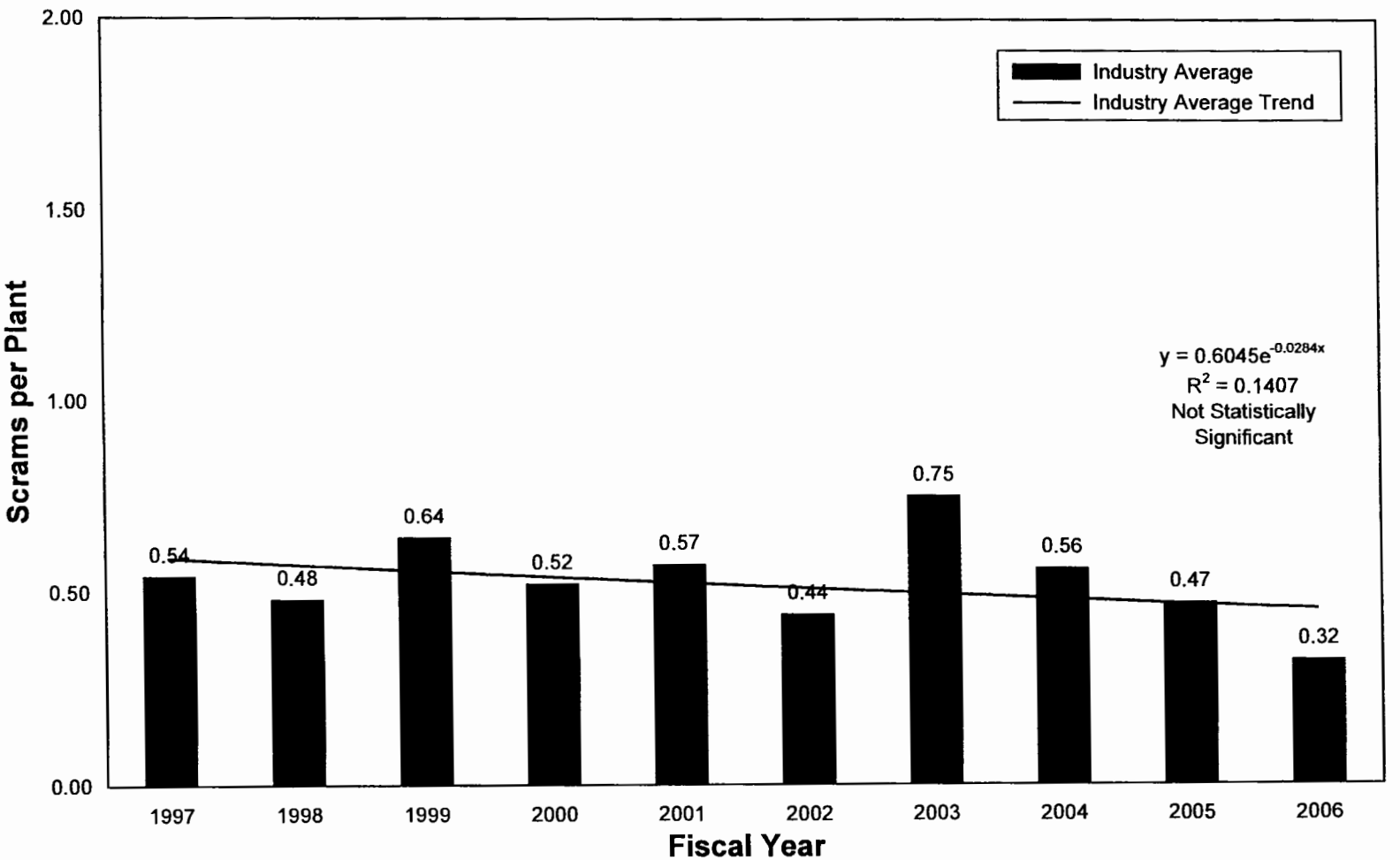
Equipment Forced Outages/1000 Commercial Critical Hours



Source: United States Nuclear Regulatory Commission (NRC)

Docket No. 07_____ - EI
10 Years of NRC's Safety Indicators
Exhibit NJD-3, Page 4 of 5

Automatic Scrams While Critical



Source: United States Nuclear Regulatory Commission (NRC)

WANO Indicators & Weighting Factors

WANO Indicator	Weighting Factor (%)
Unit Capability Factor	15%
Forced Loss Rate	15%
Unavailability of High Pressure Safety Injection Systems	10%
Unavailability of Auxiliary Feedwater System	10%
Unavailability of Emergency AC Power Systems (Site Average)	10%
Unplanned Automatic Reactor Trips	10%
Collective Radiation Exposure	10%
Fuel Reliability Index	8%
Fuel Rod Defects	2%
Chemistry Performance Index	5%
Industrial Safety rate	5%

Source: World Association of Nuclear Operators (WANO)

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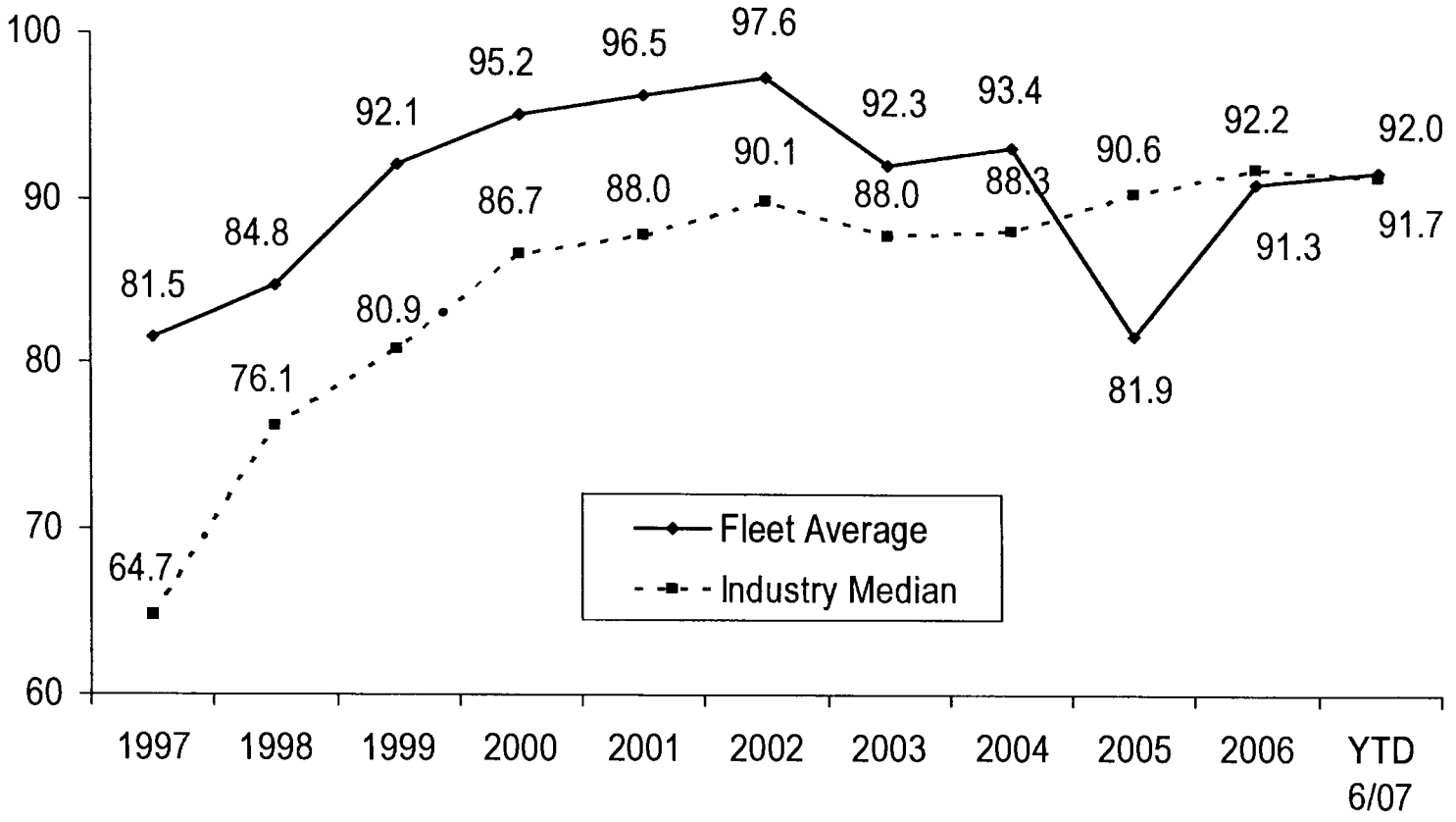
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Nils J. Diaz (NJD-4)
DATE 01/30 - 02/01/08

WANO Index – Fleet Performance

1997 – Year-to-Date 6/30/07

(Average of 4 sites)



Seabrook added to fleet in 2003; Duane Arnold added to fleet in 2006

Source: World Association of Nuclear Operators (WANO)

Docket No.07____ - EI
WANO Indices
Exhibit NJD-4, Page 2 of 2

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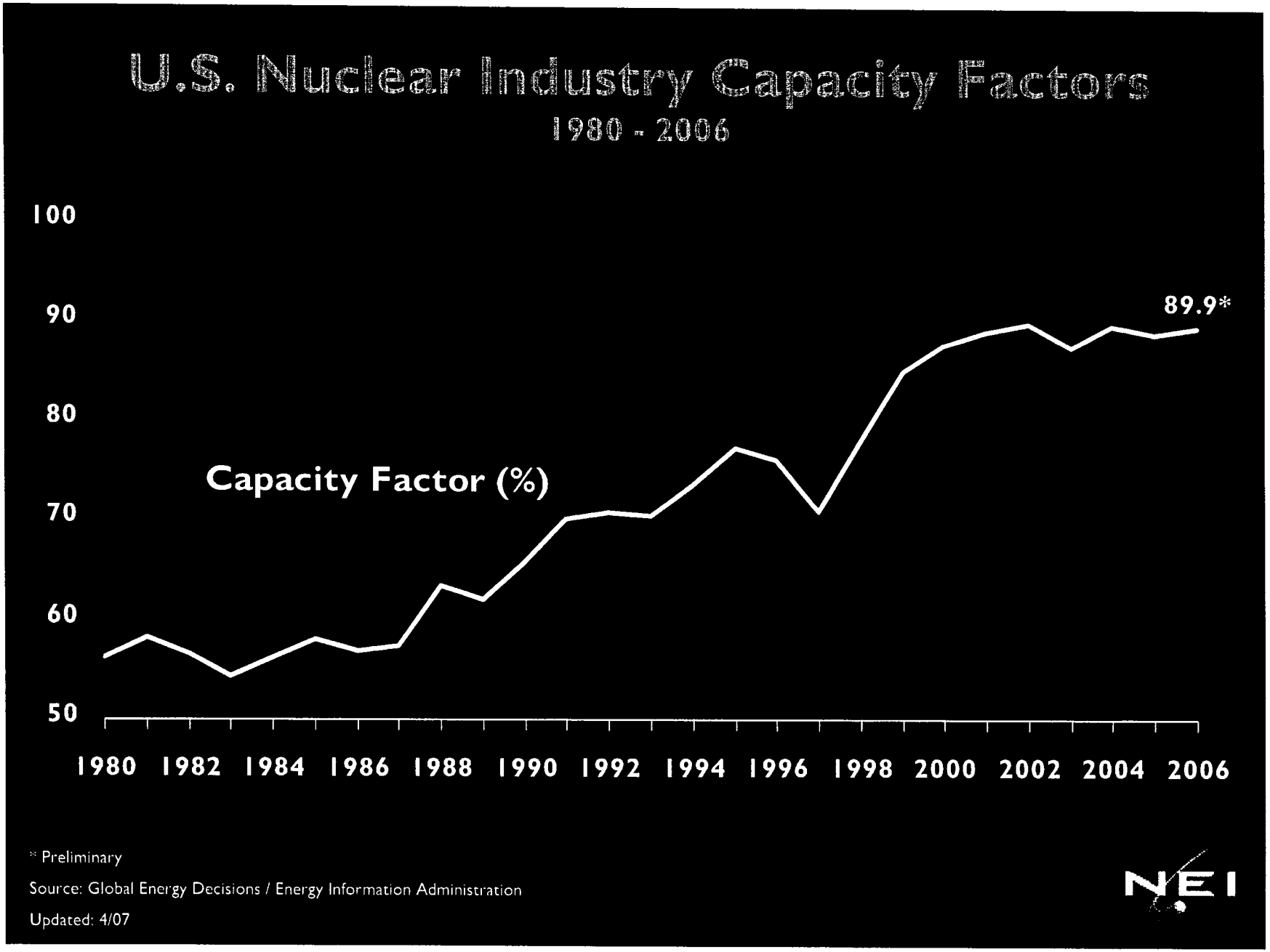
DOCKET NO. 070650-EI **EXHIBIT** 36
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Nils J. Diaz (NJD-5)
DATE 01/30 - 02/01/08



Source: Nuclear Energy Institute (NEI)

Docket No. 07-____-EI
U.S. Nuclear Industry Capacity Factors
Exhibit NJD-5, Page 1 of 1

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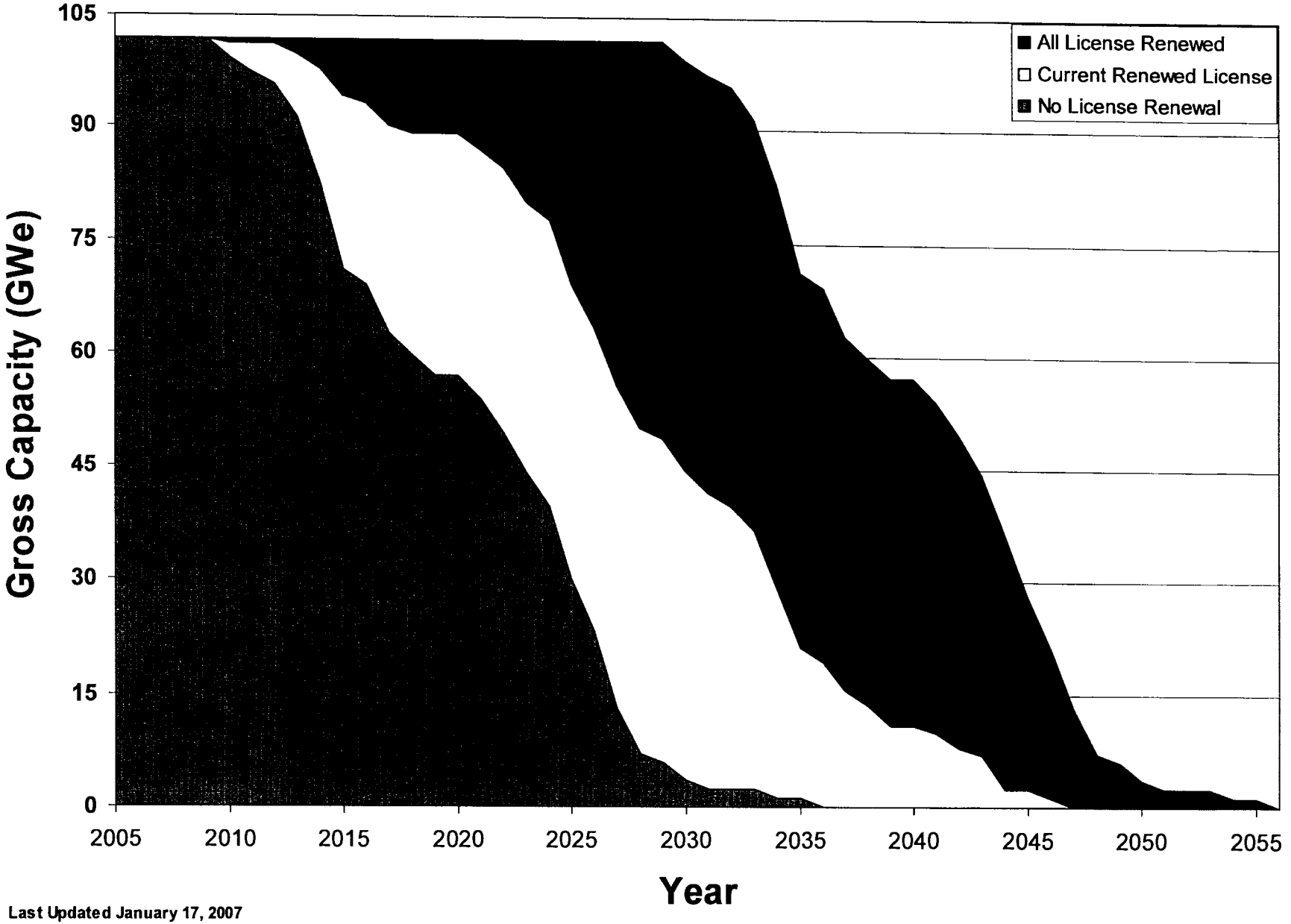
DOCKET NO. 070650-EI EXHIBIT 37
COMPANY Florida Power & Light (Direct).
WITNESS Dr. Nils J. Diaz (NJD-6)
DATE 01/30 - 02/01/08

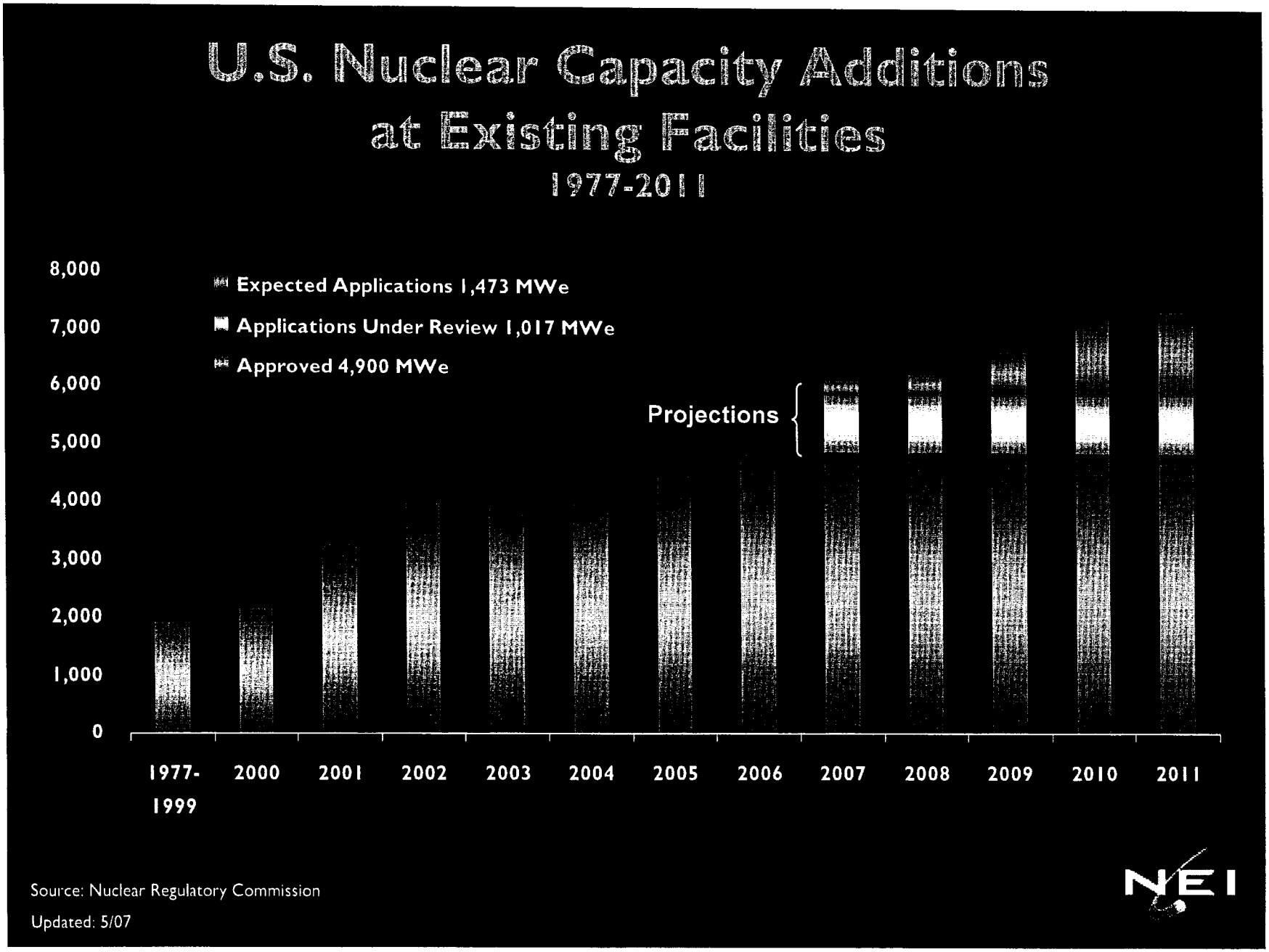
License Renewal Impact on Nuclear Power



Last Updated January 17, 2007

Source: United States Nuclear Regulatory Commission (NRC)

Docket No. 07____ - EI
License Renewal Impact on
Nuclear Power
Exhibit NJD-6, Page 1 of 2



Source: Nuclear Energy Institute (NEI)

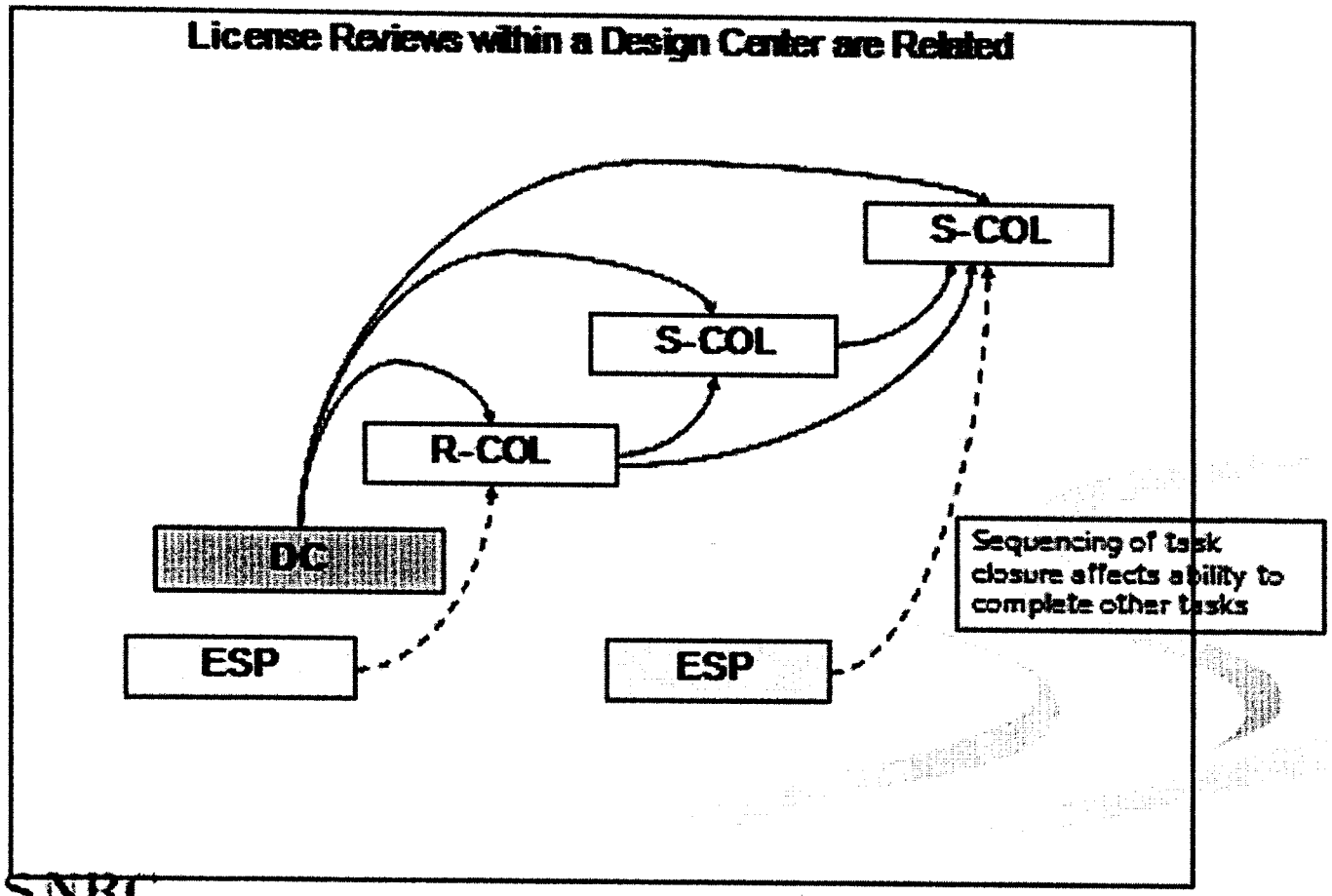
Docket No. 07-____-EI
U.S. Nuclear Capacity Additions at Existing Facilities (1977-2001)
Exhibit NJD-6, Page 2 of 2

Expected New Nuclear Power Plant Applications Updated September 11, 2007				
Company	**Design Type**	**Site Under Consideration**	**State**	**Existing Operating Plants**
Duke	AP1000	William Lee Nuclear Station (2 units)	SC	N
NuStart Energy	AP1000	Bellefonte (2 units)	AL	N
Progress Energy	AP1000	Harris (2 units)	NC	Y
Dominion	ESBWR	North Anna (1 unit)	VA	Y
NuStart Energy	ESBWR	Grand Gulf (1 unit)	MS	Y
South Carolina Electric & Gas	AP1000	Summer (2 units)	SC	Y
NRG Energy	ABWR	South Texas Project (2 units)	TX	Y
2007 TOTAL NUMBER OF APPLICATIONS =7 TOTAL NUMBER OF UNITS = 12				
Progress Energy	AP1000	Levy County (2 units)	FL	N
Southern Nuclear Operating Co.	AP-1000	Vogtle (2 units)	GA	Y
Entergy	ESBWR	River Bend (1 unit)	LA	Y
UNISTAR	EPR	Calvert Cliffs (1 unit)	MD	Y
PPL Generation	EPR	Susquehanna (1 unit)	PA	Y
AmerenUE	EPR	Callaway (1 unit)	MO	Y
UNISTAR	EPR	Nine Mile Point (1 unit)	NY	Y
TXU Power	US APWR	Comanche Peak (2 units)	TX	Y
Exelon	TBD	TBD (2 units)	TX	UNK
Detroit Edison	TBD	Fermi (1 unit)	MI	Y
Amarillo Power	EPR	Vicinity of Amarillo (2 units)	TX	UNK
Alternate Energy Holdings	EPR	Bruneau (1 unit)	ID	N
2008 TOTAL NUMBER OF APPLICATIONS = 12 TOTAL NUMBER OF UNITS = 17				
Florida Power & Light	TBD	TBD (2 units)	UNK	UNK
Unannounced	TBD	TBD (1 unit)	UNK	UNK
2009 TOTAL NUMBER OF APPLICATIONS = 2 TOTAL NUMBER OF UNITS = 3				
2007 – 2009 Total Number of Applications = 21 Total Number of Units = 32				

Source: United States Nuclear Regulatory Commission (NRC)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 38
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Nils J. Diaz (NJD-7)
DATE 01/30 - 02/01/08

How the DC–RCOL–SCOL Concept Works



U.S.NRC

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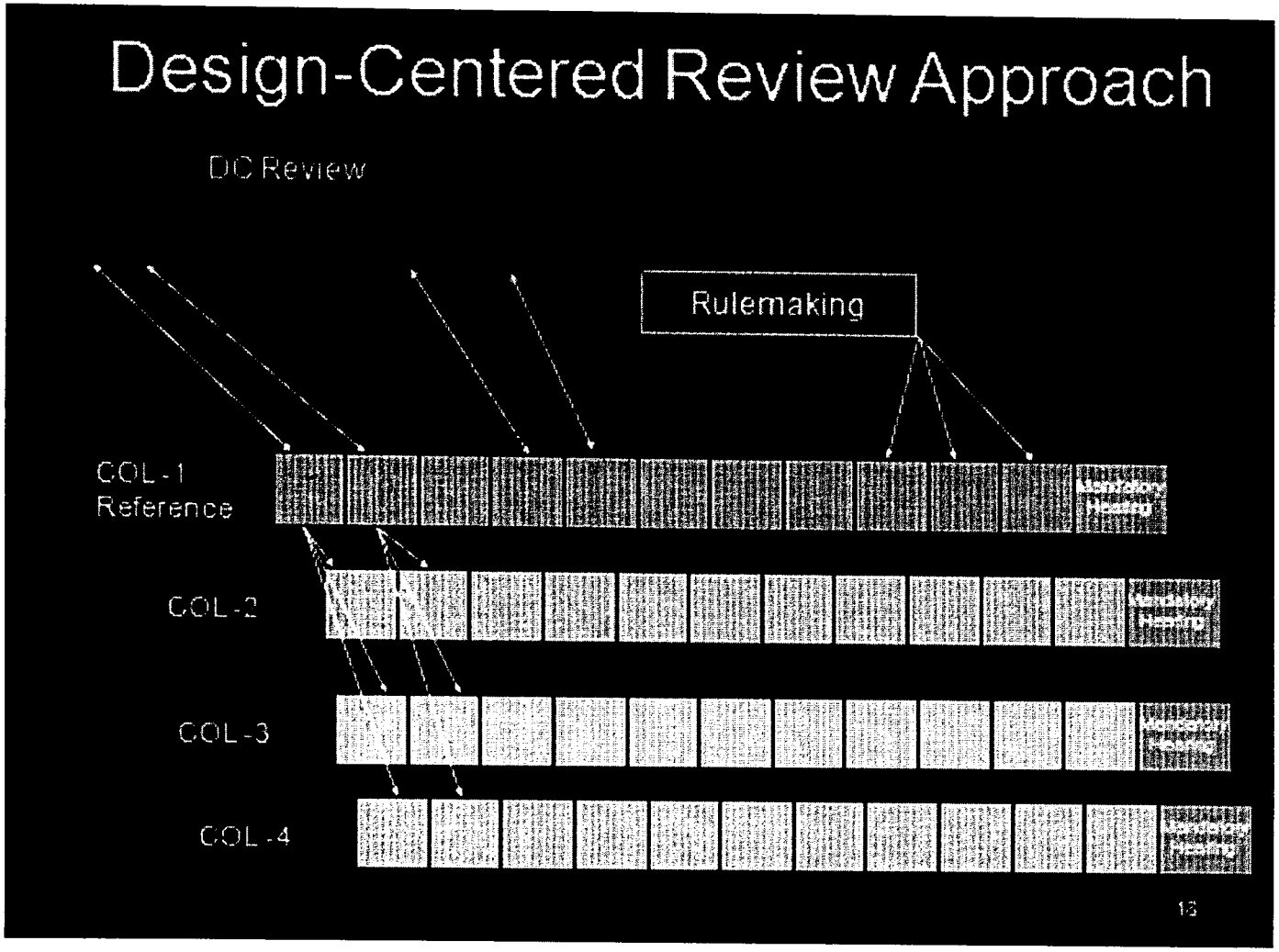
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 39
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Nils J. Diaz (NJD-8)
DATE 01/30 - 02/01/08

Source: United States Nuclear Regulatory Commission (NRC)



Source: United States Nuclear Regulatory Commission (NRC)

Docket No. 07_____ - EI
Design Centered Review Approach
Exhibit NJD-8, Page 2 of 2

TOTAL AVERAGE CUSTOMERS

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	85,882	2.2%
FORECAST (2007 to 2020)	84,768	1.7%

HISTORY

		GROWTH	
		ABSOLUTE	%
1996	3,550,747	61,951	1.8%
1997	3,615,485	64,738	1.8%
1998	3,680,470	64,985	1.8%
1999	3,756,009	75,539	2.1%
2000	3,848,350	92,341	2.5%
2001	3,935,281	86,931	2.3%
2002	4,019,805	84,523	2.1%
2003	4,117,221	97,416	2.4%
2004	4,224,509	107,289	2.6%
2005	4,321,895	97,386	2.3%
2006	4,409,563	87,668	2.0%

FORECAST

		GROWTH	
		ABSOLUTE	%
2007	4,498,169	88,606	2.0%
2008	4,590,561	92,393	2.1%
2009	4,683,749	93,188	2.0%
2010	4,775,460	91,710	2.0%
2011	4,864,831	89,371	1.9%
2012	4,951,957	87,126	1.8%
2013	5,037,427	85,471	1.7%
2014	5,121,200	83,772	1.7%
2015	5,203,878	82,678	1.6%
2016	5,285,732	81,854	1.6%
2017	5,366,787	81,055	1.5%
2018	5,446,324	79,536	1.5%
2019	5,524,219	77,895	1.4%
2020	5,600,152	75,933	1.4%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 40
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-1)
DATE 01/30 - 02/01/08

SUMMER PEAK LOAD PER CUSTOMER (KW)

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	0.04	0.9%
FORECAST (2007 to 2020)	0.03	0.6%

HISTORY

		GROWTH ABSOLUTE	GROWTH %
1996	4.54	(0.10)	-2.1%
1997	4.60	0.06	1.4%
1998	4.88	0.27	5.9%
1999	4.80	-0.07	-1.5%
2000	4.70	-0.11	-2.2%
2001	4.76	0.06	1.4%
2002	4.77	0.01	0.3%
2003	4.78	0.01	0.1%
2004	4.85	0.07	1.5%
2005	5.15	0.30	6.2%
2006	4.95	-0.21	-4.0%

FORECAST

		GROWTH ABSOLUTE	GROWTH %
2007	4.95	0.00	0.0%
2008	4.96	0.01	0.2%
2009	5.00	0.04	0.9%
2010	5.03	0.02	0.5%
2011	5.06	0.03	0.7%
2012	5.07	0.01	0.2%
2013	5.08	0.01	0.2%
2014	5.10	0.02	0.3%
2015	5.14	0.05	0.9%
2016	5.19	0.04	0.8%
2017	5.23	0.05	0.9%
2018	5.28	0.04	0.8%
2019	5.32	0.04	0.8%
2020	5.37	0.05	1.0%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 41
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-2)
DATE 01/30 - 02/01/08

SUMMER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	576	3.1%
FORECAST (2007 to 2020)	602	2.3%

HISTORY

		GROWTH ABSOLUTE	GROWTH %
1996	16,064	-108	-0.7%
1997	16,613	549	3.4%
1998	17,897	1,284	7.7%
1999	18,040	143	0.8%
2000	18,086	46	0.3%
2001	18,754	668	3.7%
2002	19,219	465	2.5%
2003	19,668	449	2.3%
2004	20,545	877	4.5%
2005	22,276	1,731	8.4%
2006	21,819	-457	-2.1%

FORECAST

		GROWTH ABSOLUTE	GROWTH %
2007	22,259	440	2.0%
2008	22,770	511	2.3%
2009	23,435	665	2.9%
2010	24,003	568	2.4%
2011	24,612	609	2.5%
2012	25,115	503	2.0%
2013	25,590	475	1.9%
2014	26,100	510	2.0%
2015	26,772	672	2.6%
2016	27,410	638	2.4%
2017	28,079	669	2.4%
2018	28,737	658	2.3%
2019	29,391	654	2.3%
2020	30,091	700	2.4%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 42
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-3)
DATE 01/30 - 02/01/08

WINTER PEAK LOAD PER CUSTOMER (KW)

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	-0.07	-1.4%
FORECAST (2007 to 2020)	0.02	0.4%

HISTORY

		GROWTH	
		ABSOLUTE	%
1996	5.14	0.39	8.3%
1997	4.78	-0.36	-6.9%
1998	3.55	-1.24	-25.8%
1999	4.47	0.92	26.1%
2000	4.43	-0.04	-0.9%
2001	4.62	0.19	4.3%
2002	4.38	-0.25	-5.3%
2003	4.90	0.53	12.0%
2004	3.49	-1.41	-28.8%
2005	4.26	0.76	21.9%
2006	4.46	0.21	4.8%

FORECAST

		GROWTH	
		ABSOLUTE	%
2007	4.95	0.48	10.8%
2008	4.93	-0.02	-0.3%
2009	4.94	0.01	0.1%
2010	4.94	0.00	0.1%
2011	4.94	0.00	0.1%
2012	4.95	0.00	0.1%
2013	4.95	0.01	0.1%
2014	4.96	0.01	0.2%
2015	5.01	0.04	0.9%
2016	5.05	0.04	0.9%
2017	5.09	0.04	0.9%
2018	5.14	0.05	0.9%
2019	5.19	0.05	0.9%
2020	5.23	0.05	0.9%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 43
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-4)
DATE 01/30 - 02/01/08

WINTER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	143	0.8%
FORECAST (2007 to 2020)	543	2.1%

HISTORY

		GROWTH	
		ABSOLUTE	%
1996	18,252	1,689	10.2%
1997	16,490	-1,762	-9.7%
1998	13,060	-3,430	-20.8%
1999	16,802	3,742	28.7%
2000	17,057	255	1.5%
2001	18,199	1,142	6.7%
2002	17,597	-602	-3.3%
2003	20,190	2,593	14.7%
2004	14,752	-5,438	-26.9%
2005	18,108	3,356	22.7%
2006	19,682	1,574	8.7%

FORECAST

		GROWTH	
		ABSOLUTE	%
2007	22,247	2,565	13.0%
2008	22,627	381	1.7%
2009	23,115	488	2.2%
2010	23,587	472	2.0%
2011	24,047	460	1.9%
2012	24,498	451	1.9%
2013	24,952	454	1.9%
2014	25,416	464	1.9%
2015	26,048	632	2.5%
2016	26,692	644	2.5%
2017	27,342	650	2.4%
2018	27,994	652	2.4%
2019	28,649	655	2.3%
2020	29,308	659	2.3%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 44
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-5)
DATE 01/30 - 02/01/08

Summer Peak Weather

Year	Average Temperature	Sum of Cooling Degree Hours
1985	84.5	1,020
1986	83.1	1,053
1987	85.7	1,228
1988	83.9	1,065
1989	85.0	1,164
1990	84.5	1,176
1991	84.7	1,129
1992	84.9	1,135
1993	86.2	1,279
1994	84.9	987
1995	84.5	1,013
1996	84.4	1,147
1997	84.8	1,136
1998	86.0	1,227
1999	83.1	1,196
2000	83.0	1,122
2001	84.5	1,141
2002	83.3	1,115
2003	84.1	1,133
2004	84.4	1,065
2005	86.9	1,257
2006	85.0	1,208
2007	84.7	1,143
2008	84.7	1,143
2009	84.7	1,143
2010	84.7	1,143
2011	84.7	1,143
2012	84.7	1,143
2013	84.7	1,143
2014	84.7	1,143
2015	84.7	1,143
2016	84.7	1,143
2017	84.7	1,143
2018	84.7	1,143
2019	84.7	1,143
2020	84.7	1,143

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 45
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-6)
DATE 01/30 - 02/01/08

Florida Real Personal Income

Historical Growth Rates	Annual Average Growth (Millions)	CAAGR (%)
1985 - 2005	14,081	3.9
1995 - 2005	16,979	3.9
2001 - 2005	15,507	3.2
Global Insight's Forecast Growth Rates		
2006 - 2020	30,455	4.2
Assumed Growth Rates		
2006 - 2020	21,897	3.3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 46
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-7)
DATE 01/30 - 02/01/08

NET ENERGY FOR LOAD USE PER CUSTOMER (KWH)

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	145	0.7%
FORECAST (2007 to 2020)	344	1.2%

HISTORY

		GROWTH	
		ABSOLUTE	%
1996	23,937	-129	-0.5%
1997	24,022	86	0.4%
1998	25,177	1,155	4.8%
1999	24,350	-827	-3.3%
2000	24,943	593	2.4%
2001	25,006	63	0.3%
2002	25,907	901	3.6%
2003	26,326	418	1.6%
2004	25,587	-738	-2.8%
2005	25,759	172	0.7%
2006	25,657	-102	-0.4%

FORECAST

		GROWTH	
		ABSOLUTE	%
2007	26,133	476	1.9%
2008	26,582	448	1.7%
2009	26,959	378	1.4%
2010	27,327	368	1.4%
2011	27,702	375	1.4%
2012	28,077	375	1.4%
2013	28,264	187	0.7%
2014	28,559	295	1.0%
2015	28,881	322	1.1%
2016	29,240	359	1.2%
2017	29,474	233	0.8%
2018	29,770	297	1.0%
2019	30,067	297	1.0%
2020	30,474	407	1.4%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 47
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-8)
DATE 01/30 - 02/01/08

NET ENERGY FOR LOAD (GWH)

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	2,814	2.9%
FORECAST (2007 to 2020)	4,109	2.9%

HISTORY

		GROWTH	
		ABSOLUTE	%
1996	84,993	1,032	1.2%
1997	86,852	1,859	2.2%
1998	92,663	5,811	6.7%
1999	91,460	-1,203	-1.3%
2000	95,989	4,529	5.0%
2001	98,404	2,415	2.5%
2002	104,141	5,737	5.8%
2003	108,388	4,247	4.1%
2004	108,093	-294	-0.3%
2005	111,301	3,207	3.0%
2006	113,137	1,837	1.7%

FORECAST

		GROWTH	
		ABSOLUTE	%
2007	117,551	4,414	3.9%
2008	122,024	4,473	3.8%
2009	126,270	4,246	3.5%
2010	130,499	4,229	3.3%
2011	134,766	4,267	3.3%
2012	139,038	4,273	3.2%
2013	142,379	3,341	2.4%
2014	146,257	3,878	2.7%
2015	150,291	4,035	2.8%
2016	154,556	4,264	2.8%
2017	158,179	3,623	2.3%
2018	162,140	3,961	2.5%
2019	166,097	3,957	2.4%
2020	170,661	4,563	2.7%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 48
COMPANY Florida Power + Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-9)
DATE 01/30 - 02/01/08

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 49
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-10)
DATE 01/30 - 02/01/08

NON-AGRICULTURAL EMPLOYMENT

(Seasonally Adjusted)

	2001	2002	2003	2004	2005	2006
	131,833	130,345	129,999	131,435	133,458	135,374
Annual Absolute Growth	41	-1,487	-347	1,436	2,023	1,916
Annual Percent Growth	0.0%	-1.1%	-0.3%	1.1%	1.5%	1.4%

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	132,471	132,736	132,876	133,104	133,210	133,376	133,617	133,792	133,840	133,877	134,231	134,371
Annual Absolute Growth	2,099	2,270	2,090	1,981	1,837	1,897	2,055	2,042	1,960	1,715	1,937	1,922
Annual Percent Growth	1.6%	1.7%	1.6%	1.5%	1.4%	1.4%	1.6%	1.5%	1.5%	1.3%	1.5%	1.5%
2006(1)	134,530	134,730	134,905	135,017	135,117	135,251	135,374	135,604	135,807	135,893	136,047	136,214
Annual Absolute Growth	2,059	1,994	2,029	1,913	1,907	1,875	1,757	1,812	1,967	2,016	1,816	1,843
Annual Percent Growth	1.6%	1.5%	1.5%	1.4%	1.4%	1.4%	1.3%	1.4%	1.5%	1.5%	1.4%	1.4%

	2001	2002	2003	2004	2005	2006
	7,171	7,180	7,261	7,510	7,805	8,006
Annual Absolute Growth	91	9	81	249	295	201
Annual Percent Growth	1.3%	0.1%	1.1%	3.4%	3.9%	2.6%

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005(1)	7,672	7,695	7,698	7,753	7,774	7,779	7,821	7,851	7,874	7,890	7,915	7,944
Annual Absolute Growth	288.2	296.0	278.5	282.5	299.9	276.7	277.0	304.2	351.3	304.2	290.7	290.5
Annual Percent Growth	3.9%	4.0%	3.8%	3.8%	4.0%	3.7%	3.7%	4.0%	4.7%	4.0%	3.8%	3.8%
2006(1)	7,930	7,946	7,980	7,969	7,994	8,018	8,008	8,024	8,040	8,036	8,059	8,070
Annual Absolute Growth	257.9	251.3	281.4	216.2	219.2	239.0	186.8	173.5	165.5	145.8	144.4	126.1
Annual Percent Growth	3.4%	3.3%	3.7%	2.8%	2.8%	3.1%	2.4%	2.2%	2.1%	1.8%	1.8%	1.6%

(1) Revised as of December 2006

Docket No. 07____-EI
Non-Agricultural Employment
Exhibit LEG-10, Page 1 of 1

REAL PRICE OF ELECTRICITY (¢/KWH)

AVERAGE ANNUAL GROWTH

HISTORY (1996 to 2006)	0.08	1.6%
FORECAST (2007 to 2020)	-0.03	-0.6%

HISTORY

		GROWTH	
		ABSOLUTE	%
1996	4.71	0.39	8.3%
1997	4.59	-0.12	-2.5%
1998	4.37	-0.22	-4.9%
1999	4.10	-0.27	-6.1%
2000	3.98	-0.12	-2.9%
2001	4.55	0.56	14.1%
2002	4.07	-0.48	-10.5%
2003	4.32	0.25	6.2%
2004	4.43	0.11	2.4%
2005	4.55	0.12	2.7%
2006	5.53	0.98	21.6%

FORECAST

		GROWTH	
		ABSOLUTE	%
2007	5.25	(0.28)	-5.0%
2008	4.89	-0.36	-6.9%
2009	4.40	-0.48	-9.9%
2010	4.22	-0.18	-4.2%
2011	3.86	-0.36	-8.5%
2012	3.84	-0.02	-0.5%
2013	3.94	0.10	2.5%
2014	3.97	0.03	0.7%
2015	4.03	0.06	1.5%
2016	4.25	0.22	5.4%
2017	4.38	0.14	3.2%
2018	4.56	0.18	4.2%
2019	4.77	0.20	4.4%
2020	4.85	0.08	1.8%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 50
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-11)
DATE 01/30 - 02/01/08

IMPACT OF THE 2005 ENERGY POLICY ACT ADJUSTMENT

	MW
2006	133
2007	259
2008	387
2009	518
2010	660
2011	806
2012	953
2013	1103
2014	1256
2015	1256
2016	1256
2017	1256
2018	1256
2019	1256
2020	1256

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 51
COMPANY Florida Power & Light (Direct)
WITNESS Dr. Leonardo E. Green (LEG-12)
DATE 01/30 - 02/01/08

FPL Current FPSC DSM Goals

Residential and Commercial/Industrial

	Winter Peak mW Reduction			Summer Peak mW Reduction			gWh Energy Reduction		
Year	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance
2005	36.3	38.8	-6%	92.5	74.0	25%	184.2	121.8	51%
2006	110.8	79.3	40%	219.8	141.7	55%	383.9	216.8	77%
2007		122.5			211.9			306.0	
2008		170.6			287.2			401.1	
2009		221.5			365.9			501.2	
2010		275.2			447.9			606.1	
2011		330.9			532.1			714.3	
2012		388.5			618.8			825.8	
2013		448.1			707.9			940.5	
2014		512.4			801.7			1,058.6	

Residential

	Winter Peak mW Reduction			Summer Peak mW Reduction			gWh Energy Reduction		
Year	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance
2005	21.4	26.0	-18%	49.8	47.8	4%	91.6	90.3	1%
2006	62.5	55.6	12%	118.5	91.9	29%	191.2	166.0	15%
2007		89.2			140.6			246.9	
2008		127.3			194.6			333.3	
2009		168.0			252.1			424.1	
2010		211.3			313.2			519.5	
2011		256.3			377.1			617.9	
2012		303.3			443.6			719.3	
2013		352.0			512.8			823.7	
2014		405.1			586.9			931.0	

Commercial/Industrial

	Winter Peak mW Reduction			Summer Peak mW Reduction			gWh Energy Reduction		
Year	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance	Cumulative Total Achieved	Cumulative Commission Approved Goal	% Variance
2005	14.9	12.8	16%	42.7	26.3	62%	92.6	31.5	194%
2006	48.3	23.7	104%	101.3	49.8	103%	192.7	50.8	279%
2007		33.3			71.3			59.1	
2008		43.2			92.6			67.8	
2009		53.5			113.8			77.0	
2010		63.9			134.6			86.5	
2011		74.4			155.1			96.4	
2012		85.1			175.2			106.5	
2013		96.1			195.1			116.9	
2014		107.3			214.9			127.6	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 52
COMPANY Florida Power & Light (Direct)
WITNESS C. Dennis Brandt (DB-1)
DATE 01/30 - 02/01/08

FPL DSM Programs & Measures

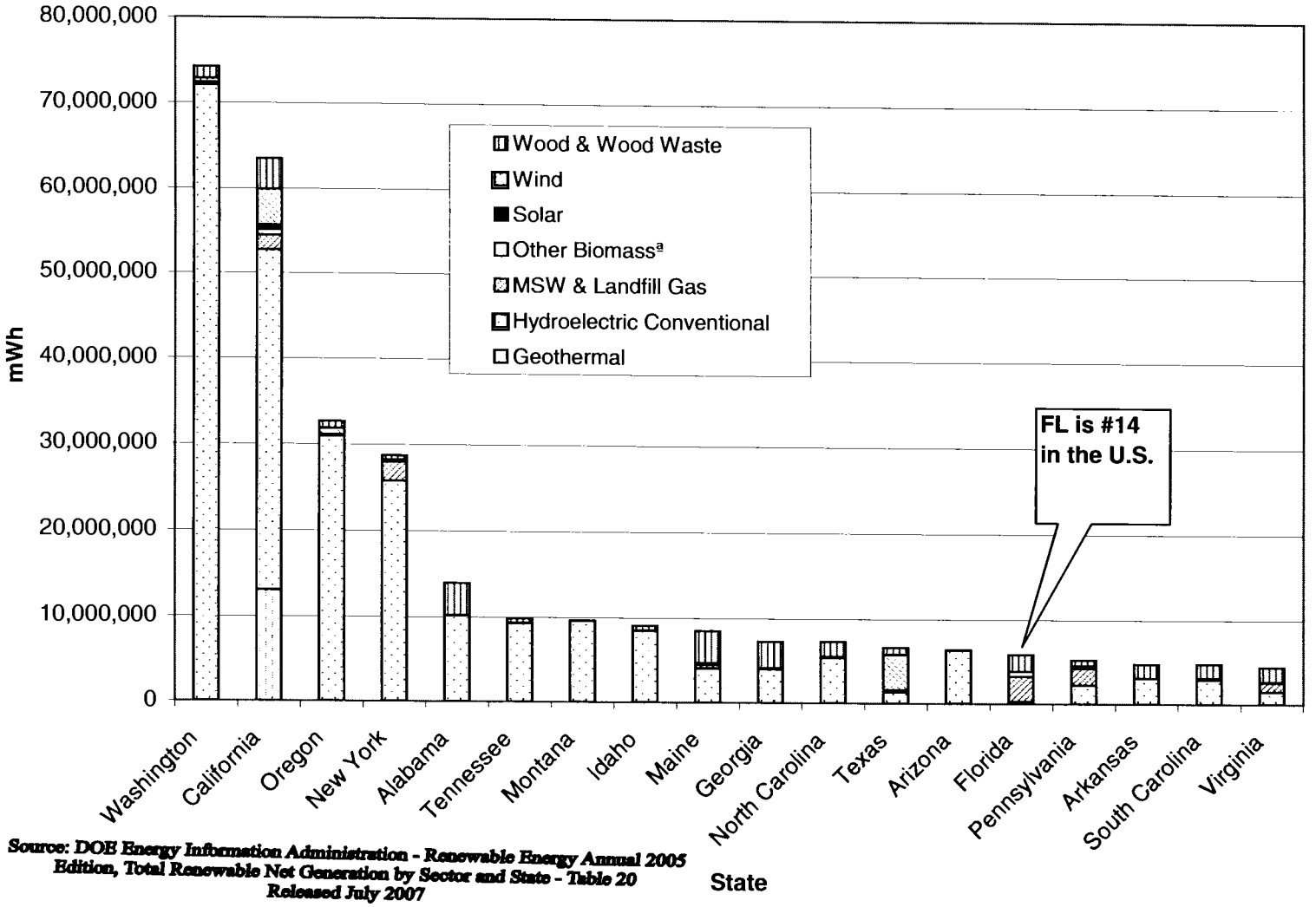
Residential Programs	**Measures**
Residential Conservation Service	On-site Energy Audit
	Telephone Energy Audit
	On-line Energy Audit
Residential Building Envelope	Ceiling Insulation - Cooling Ony
	Ceiling Insulation - Heat Pump
	Reflective Roof
	Multi-family Roof Coating
	Multi-family Reflective Roof
Duct System Testing & Repair	Duct Repair - Cooling Ony
	Duct Repair - Heat Pump
Residential Air Conditioning	Air Conditioning - Cooling Only
	Heat Pumps
	Ground Source Heat Pump
	Proper Sizing - Cooling Ony
	Proper Sizing - Heat Pump
	Plenum Repair - Cooling Ony
	Plenum Repair - Heat Pump
	Electronically Commutated Motor - Cooling Ony
	Electronically Commutated Motor - Heat Pump
Residential Load Management (On Call)	Air Conditioning Cycle
	Air Conditioning Shed
	Space Heating Cycle
	Space Heating Shed
	Water Heating
	Pool Pump
Residential New Construction (BuildSmart)	Prescriptive
	Flexible
Residential Low Income Weatherization	Room Air Conditioner
	Air Conditioner Maintenance
	Reduced Infiltration

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 53
COMPANY Florida Power & Light (Direct)
WITNESS C. Dennis Brandt (DB-2)
DATE 01/30-02/01/08

FPL DSM Programs & Measures

Business Programs	**Measures**
Business Energy Evaluation	New Construction Energy Audit
	Existing Construction Energy Audit
Business Heating, Ventilating & Air Conditioning	Chillers
	Direct Expansion Air Conditioner
	Room / PTAC Air Conditioner
	Thermal Energy Storage
	Demand Control Ventilation - Heat
	Demand Control Ventilation - No Heat
	Electronically Commutated Motor
	Energy Recovery Ventilator - Strip Heat No Bypass
	Energy Recovery Ventilator - Strip Heat Active Bypass
	Energy Recovery Ventilator - No Heat No Bypass
	Energy Recovery Ventilator - No Heat Active Bypass
Business Efficient Lighting	Standard High Efficiency Retrofit
	Low Mercury High Efficiency Retrofit
Business Custom Incentive	Customer Specific Measure >= 25 kw
Commercial/Industrial Load Control	Load Reduction >= 200 kw
Commercial Demand Reduction	Load Reduction >= 200 kw
Business Building Envelope	Roof Insulation
	Reflective Roof Coating
	Ceiling Insulation
	Window Treatments
Business On Call	Air Conditioning Cycle
Business Water Heating	Heat Recovery Units
	Heat Pump Water Heaters
Business Refrigeration	Anti-Condensate Heat Control

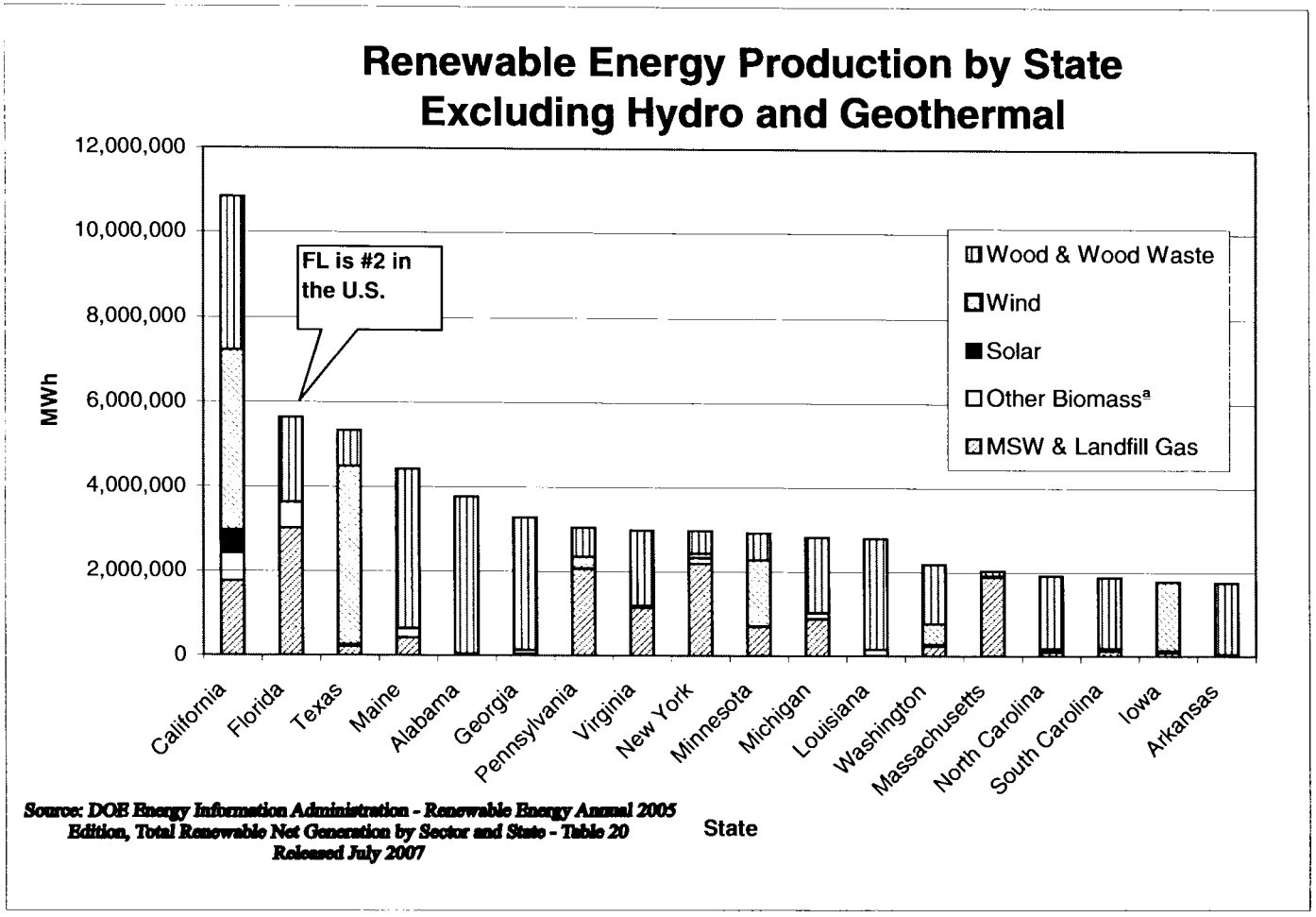
Renewable Energy Production by State



Source: DOE Energy Information Administration - Renewable Energy Annual 2005 Edition, Total Renewable Net Generation by Sector and State - Table 20 Released July 2007

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 54
COMPANY Florida Power + Light (Direct)
WITNESS Henrietta G. McBee (HGM-1)
DATE 01/30 - 02/01/08

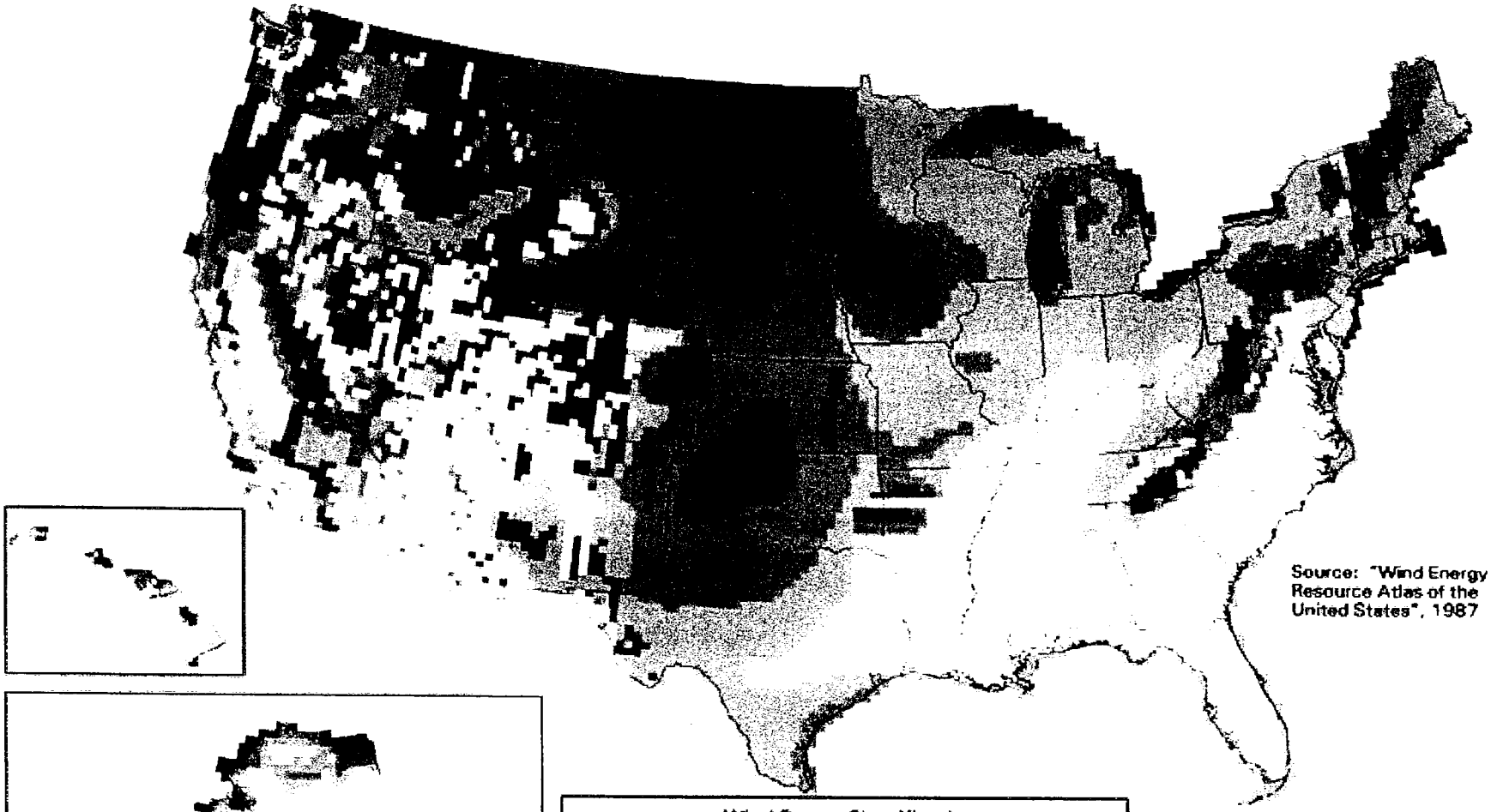
Docket No. 07____-EI
Renewables By State
Exhibit HGM-1, Page 1 of 1



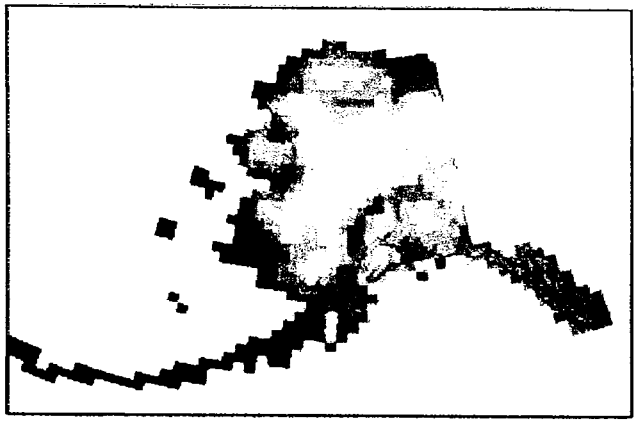
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 55
COMPANY Florida Power + Light (Direct)
WITNESS Henrietta G. McBee (HGM-2)
DATE 01/30 - 02/01/08

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 56
COMPANY Florida Power + Light (Direct)
WITNESS Henrietta G. McBee (HGM-3)
DATE 01/30 - 02/01/08

United States - Wind Resource Map



Source: "Wind Energy Resource Atlas of the United States", 1987



Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m²	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
2	Marginal	200 - 300	5.6 - 6.4	12.5 - 14.3
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

[a] Wind speeds are based on a Weibull k value of 2.0

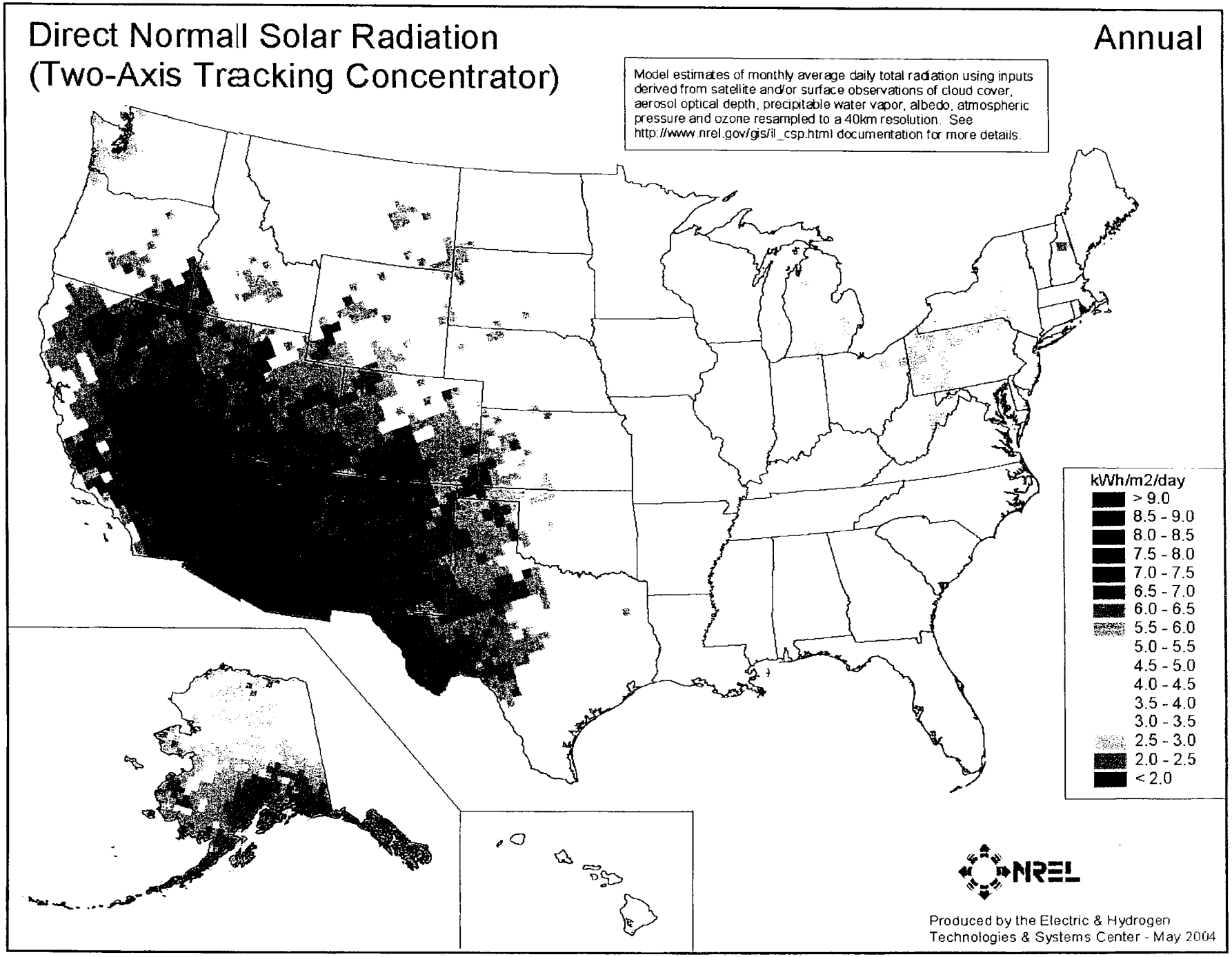
U.S. Department of Energy
National Renewable Energy Laboratory

NREL

20-MAR-2000 11:15

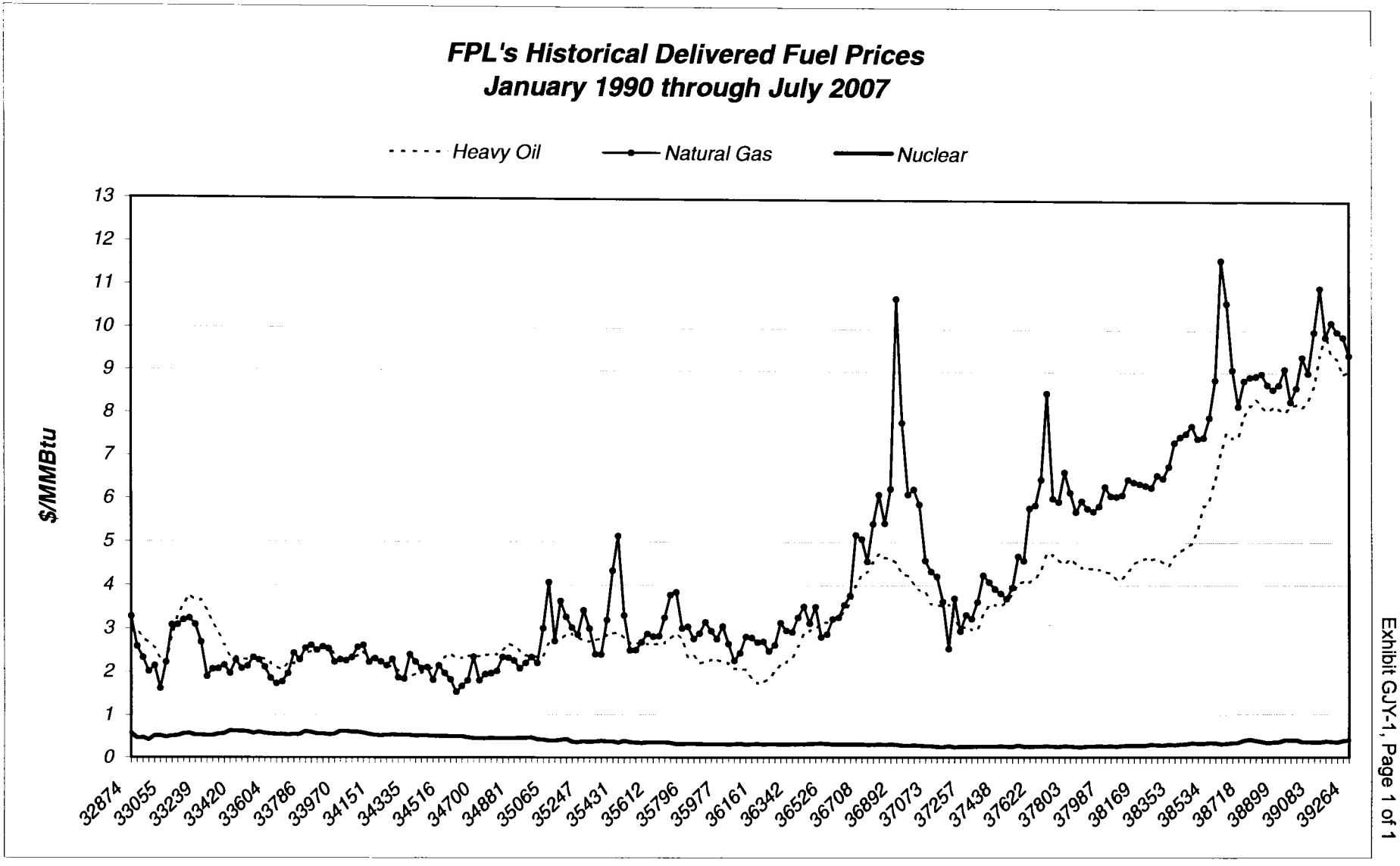
Docket No. 07____-EI
NREL United States Classes of Wind Power Density Map
Exhibit HGM-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 57
COMPANY Florida Power & Light (Direct)
WITNESS Henrietta G. McBee (HGM-4)
DATE 01/30 - 02/01/08



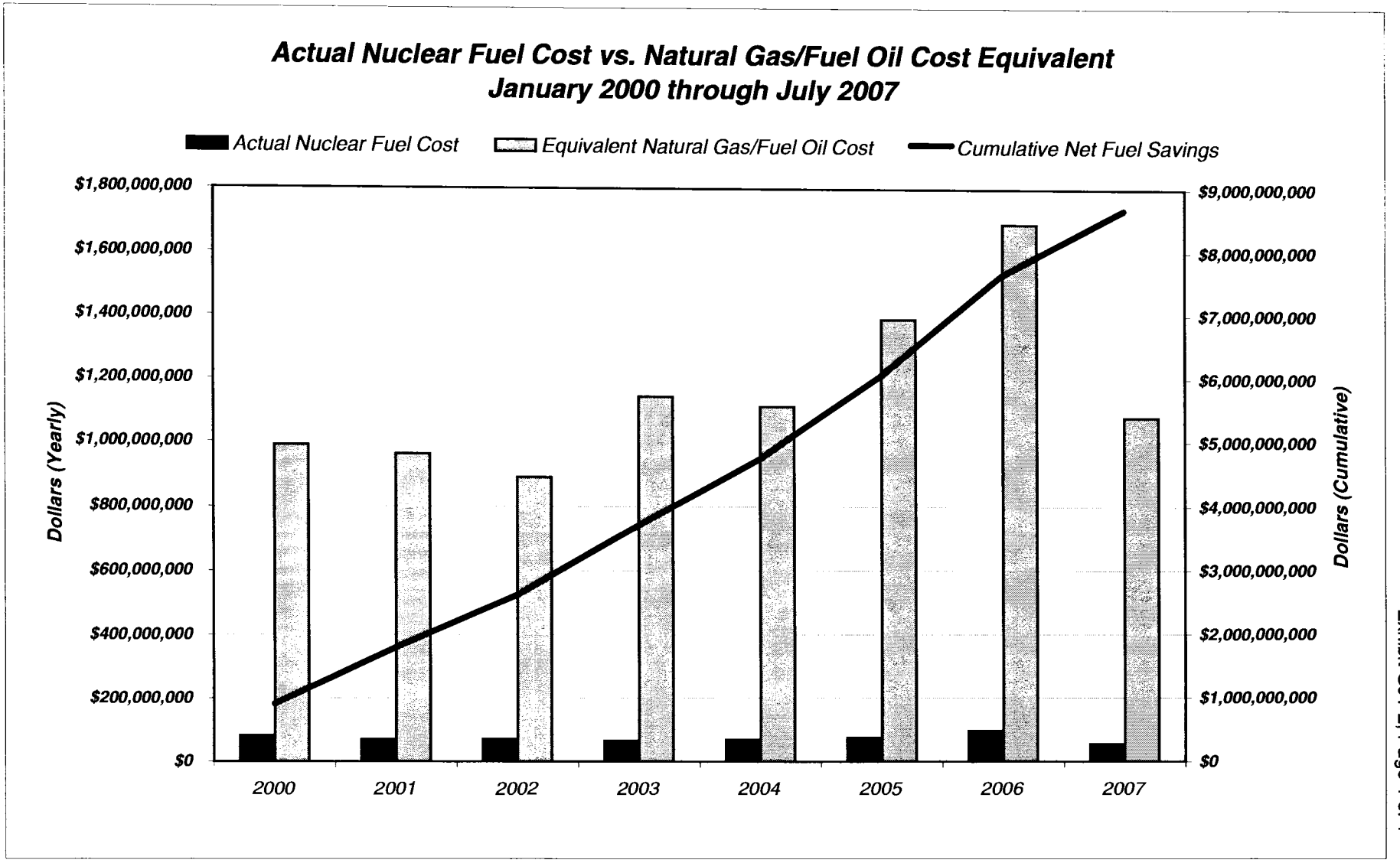
Docket No. 07____-EI
NREL United States Solar Energy Potential Map
Exhibit HGM-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. D70650-EI EXHIBIT 58
COMPANY Florida Power & Light (Direct)
WITNESS Gerard J. Yupp (GJY-1)
DATE 01/30 - 02/01/08

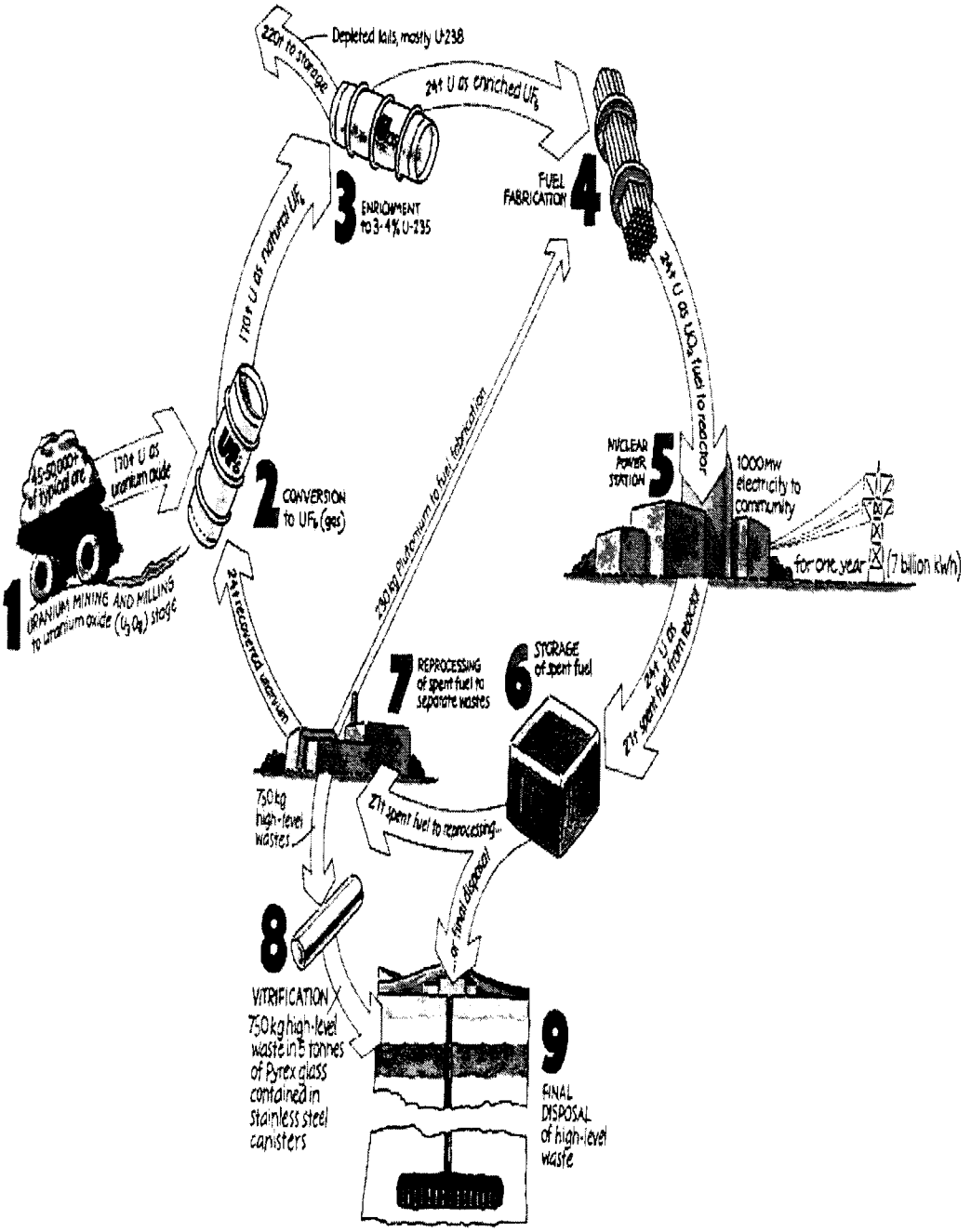


Docket No. 07_____-EI
Historical Fuel Prices
Exhibit GJY-1, Page 1 of 1

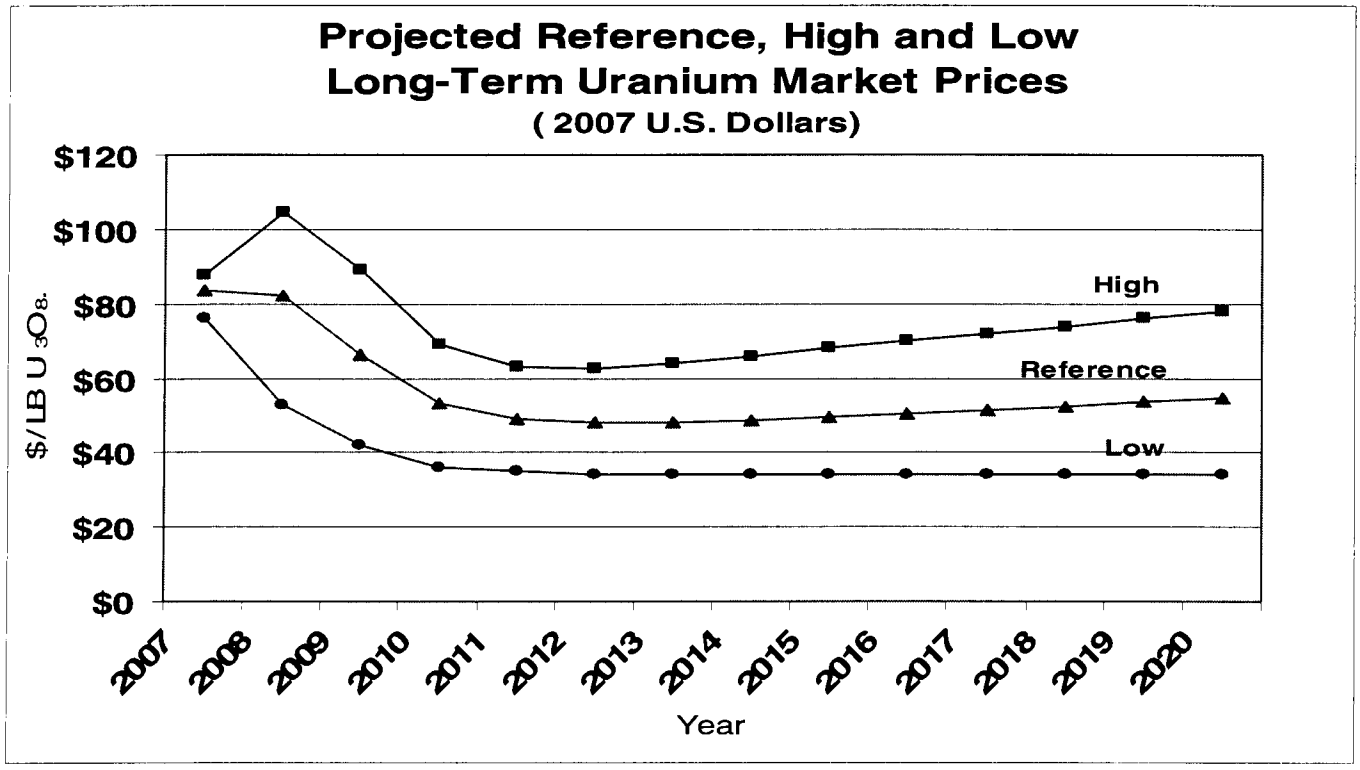
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 59
COMPANY Florida Power & Light (Direct)
WITNESS Gerard J. Yupp (GJY-2)
DATE 01/30 - 02/01/08



Docket No. 07_____-EI
Nuclear Fuel Savings
Exhibit GJY-2, Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 60
COMPANY Florida Power & Light (Direct)
WITNESS Claude A. Villard (CAV-1)
DATE 01/30 - 02/01/08



Source: FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 61
COMPANY Florida Power & Light (Direct)
WITNESS Claude A. Villard (CAV-2)
DATE 01/30 - 02/01/08

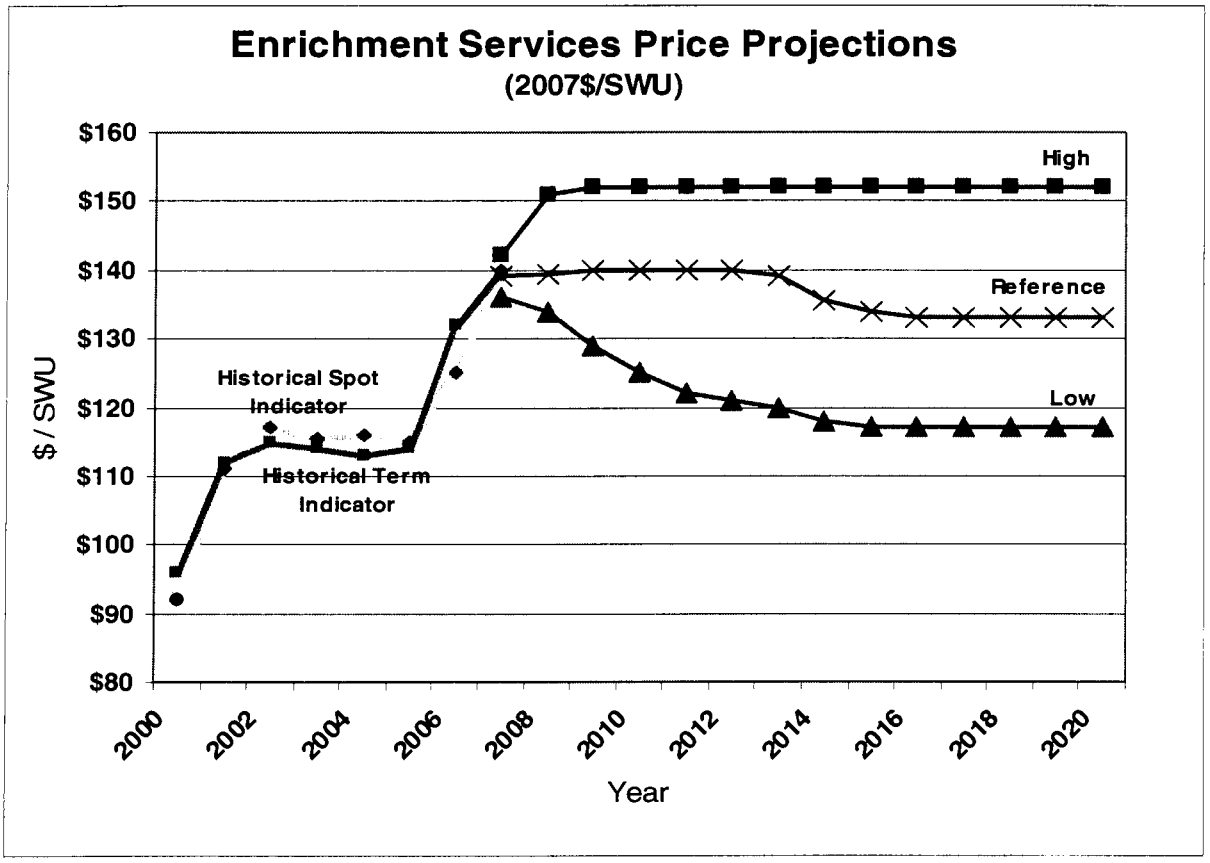
Docket No. 07 _____ - EI
Conversion Services Projected
Prices, Dollars per kgU as UF_6
Exhibit CAV-3, Page 1 of 1

Year	Base Price of 2007 U.S. Dollars			U.S. GDP IPD Escalated Price		
	Low	*Reference*	*High*	*Low*	*Reference*	*High*
2007	11.00	12.25	13.50	11.00	12.25	13.50
2008	10.50	12.00	13.50	10.76	12.30	13.84
2009	10.25	11.75	13.75	10.77	12.34	14.45
2010	10.00	11.75	14.00	10.77	12.65	15.08
2011	10.00	12.00	14.25	11.04	13.25	15.73
2012	10.00	12.25	14.50	11.31	13.86	16.41
2013	10.25	12.50	14.75	11.89	14.50	17.11
2014	10.50	13.00	15.00	12.48	15.45	17.83
2015	10.75	13.25	15.25	13.10	16.14	18.58
2016	11.00	13.50	15.50	13.74	16.86	19.36
2017	11.25	13.75	15.50	14.40	17.60	19.84
2018	11.50	14.00	15.75	15.09	18.37	20.67
2019	11.50	14.00	15.75	15.47	18.83	21.18
2020	11.50	14.00	16.00	15.85	19.30	22.06

Source: FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 62
COMPANY Florida Power & Light (Direct)
WITNESS Claude A Villard (CAV-3)
DATE 01/30 - 02/01/08

Docket No. 07 _____ - EI
Enrichment Services Projected Prices
Exhibit CAV-4, Page 1 of 1



Source: FPL

SWU: Separative work units, units of services needed to increase the % of U235 from 0.711 w/o in natural uranium to the level needed for civilian reactors (up to 5 w/o).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 63
COMPANY Florida Power & Light (Direct)
WITNESS Claude A. Vilhard (CAV-4)
DATE 01/30 - 02/01/08

Docket No. 07_____ - EI
Fabrication Services Projected Prices,
Dollars Per kgU
Exhibit CAV-5, Page 1 of 1

Year	PWR		BWR	
	Base Price (2007 Dollars)	*Escalated Price (Current Dollars)*	*Base Price (2007 Dollars)*	*Escalated Price (Current Dollars)*
2007	207	207	276	276
2008	207	212	276	282
2009	207	216	276	289
2010	207	221	276	295
2011	207	226	276	302
2012	207	231	276	308
2013	207	237	276	315
2014	207	242	276	323
2015	207	247	276	330
2016	207	253	276	337
2017	207	259	276	345
2018	207	264	276	353
2019	207	270	276	360
2020	207	276	276	369

Source: FPL

PWR = Pressurized Water Reactor
BWR = Boiling Water Reactor

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 64
COMPANY Florida Power & Light (Direct)
WITNESS Claude A. Villard (CAV-5)
DATE 01/30 - 02/01/08

NEW PLANT DETERMINATION
Annual Nuclear Fuel Expense Projection
(includes spent fuel disposal)

REFERENCE PRICE

	UNIT 1		UNIT 2	
	cents/ MBTU	mills/ KwHe	cents/ MBTU	mills/ KwHe
2018	87.19	9.10	0.00	0.00
2019	86.72	9.05	0.00	0.00
2020	95.65	9.98	87.19	9.10
2021	104.09	10.86	86.72	9.05
2022	103.62	10.81	95.65	9.98
2023	98.24	10.25	104.09	10.86
2024	100.69	10.51	103.62	10.81
2025	103.21	10.77	98.24	10.25
2026	105.79	11.04	100.69	10.51
2027	108.43	11.32	103.21	10.77
2028	111.15	11.60	105.79	11.04
2029	113.92	11.89	108.43	11.32
2030	116.77	12.19	111.15	11.60
2031	119.69	12.49	113.92	11.89
2032	122.68	12.80	116.77	12.19
2033	125.75	13.12	119.69	12.49
2034	128.89	13.45	122.68	12.80
2035	132.12	13.79	125.75	13.12
2036	135.42	14.13	128.89	13.45
2037	138.81	14.49	132.12	13.79
2038	142.28	14.85	135.42	14.13
2039	145.83	15.22	138.81	14.49
2040	149.48	15.60	142.28	14.85
2041	153.22	15.99	145.83	15.22
2042	157.05	16.39	149.48	15.60
2043	160.97	16.80	153.22	15.99
2044	165.00	17.22	157.05	16.39
2045	169.12	17.65	160.97	16.80
2046	173.35	18.09	165.00	17.22
2047	177.68	18.54	169.12	17.65
2048	182.12	19.01	173.35	18.09
2049	186.68	19.48	177.68	18.54
2050	191.34	19.97	182.12	19.01
2051	196.13	20.47	186.68	19.48
2052	201.03	20.98	191.34	19.97
2053	206.06	21.51	196.13	20.47
2054	211.21	22.04	201.03	20.98
2055	216.49	22.59	206.06	21.51
2056	221.90	23.16	211.21	22.04
2057	227.45	23.74	216.49	22.59
2058	233.14	24.33	221.90	23.16
2059	238.96	24.94	227.45	23.74
2060	244.94	25.56	233.14	24.33

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 65
COMPANY Florida Power & Light (Direct)
WITNESS Claude A. Villard (CAV-6)
DATE 01/30 - 02/01/08

Kennard F. Kosky, M.S., P.E.

Education

M.S., Environmental Engineering, University of Central Florida, 1976
B.S.E., Ocean Engineering, Florida Atlantic University, 1970
Completed coursework (1.5 years) for Ph.D. in Environmental Engineering, University of Florida, 1982

Affiliations

Registered Professional Engineer, State of Florida, No. 14996
Air and Waste Management Association, National and Florida

Experience

1996 to Date — **Golder Associates** — **Gainesville, FL**
Principal
Principal Engineer, Project Director, and Project Manager for Permitting and Environmental Impact Assessments. Specializes in power plants, industrial facilities, and agricultural activities involving air quality. Provides oversight on permitting and licensing activities including emissions estimates and impact analyses. Provides expert testimony on pollution control quality issues and noise for a variety of electrical power, industrial, and mining activities. Note: KBN merged with Golder Associates in 1996.

1985 - 1996 — **KBN Engineering and Applied Sciences (KBN)** — **Gainesville, FL**
President and Principal Engineer
Responsible for administration of a 100-person environmental consulting firm generating about $8 million per year in revenues. Principal Engineer, Project Director, and Project Manager for Permitting and Environmental Impact Assessments for electric power and industrial facilities. Provided expert testimony on pollution control and quality issues for a variety of industrial activities.

1980 - 1985 — **Environmental Science and Engineering, Inc. (ESE), Energy and Power Programs, Project Operations Department** — **Gainesville, FL**
Vice President/Director
Directed Power Programs group that included a wide diversity of services to the power industry. Project Manager of the $3 million Florida Acid Deposition Study. Project Director and Manager for a variety of permitting and licensing projects. Provided expert testimony on a variety of projects.

1978 - 1980 — **ESE** — **Gainesville, FL**
Director, Air Science Division
Responsible for all corporate air resource activities including stack testing, permitting dispersion modeling, ambient monitoring, noise monitoring, and industrial hygiene. Staff consisted of 25 professionals in three groups: Source Testing, Ambient Monitoring, and Permitting. Project Manager for multidisciplinary power projects.

1974 - 1978 — **ESE** — **Gainesville, FL**
Group Leader, Air Quality Management, Air Sciences Division
Responsible for staff involved with ambient air monitoring, dispersion modeling, and air permitting. Project Manager for multidisciplinary power projects.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 66
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-1)
DATE 01/30 - 02/01/08

Kennard F. Kosky, M.S., P.E.

1970 - 1974 **Florida Dept. of Pollution Control** **Tallahassee/Orlando, FL**

Air Pollutant Engineer

Lead engineer in air operations involved in implementing State Implementation Plan (SIP) and air pollution regulations. Performed air permitting for over 200 facilities. Coauthor of the first Florida SIP including conducting emission inventory, ambient monitoring analysis, regulatory analysis, and regulation development.

1970 **Schlumberger Well Services** **Morgan City, LA**

Well Logging Engineer

Performed geological logging of exploratory wells for oil and/or gas production in the Gulf of Mexico.

Kennard F. Kosky, M.S., P.E.

PROJECT RELATED EXPERIENCE

Mr. Kosky has performed over 200 projects focusing on a variety of industrial activities. These projects have involved control technology evaluations, regulatory interpretation, monitoring, permitting, impact analyses, and expert testimony. The following overview and project descriptions are examples of Mr. Kosky's experience.

Major Project Experience — Multiple Sites

Type of Industrial Activities
Power Plants – 68
Landfills – 4
Chemical Plants – 7
Rubber Manufacturing – 2
Metal Coil Coating – 3
Mining – 4
Pulp & Paper – 7
Resource Recovery/Incinerator – 9
Steel Mills – 4
Printing/Coating – 4
Food/Agricultural Facilities – 15
Petroleum Exploration and Refining – 9
Aerospace – 2
Fiberglass Boat Manufacturing – 4
Superfund – 5

Type of Projects
Permitting – 92
Air Pollution Emission Estimates – 67
Air Impact Analyses – 63
Air Pollution Control – 75
Policy and Regulations – 6
Air Monitoring – 26

Domestic Experience — Multiple Sites

Mr. Kosky has directed and performed projects related to his expertise in the following states:

- Southeastern US: Florida, Georgia, South Carolina, North Carolina, Alabama, Mississippi, Tennessee, Kentucky, Louisiana, and Arkansas
- Mid-Atlantic: Maryland, Virginia, West Virginia, District of Columbia, and New Jersey
- Northeast: Connecticut and New York
- Mid-West: Illinois, Indiana, Missouri, and Iowa
- West: Texas, Nevada, California, Montana, Arizona, Alaska, and Hawaii

International Project Experience

Mr. Kosky has performed a wide variety of international projects—many associated with the Multi-Lateral (e.g., World Bank) and Bi-Lateral (e.g., USAID) organizations. Projects located in the following continents and countries:

- Asia: China, Pakistan, India, Russia, Taiwan, Thailand, and Indonesia
- Africa: Egypt and Mauritius
- Latin America and Caribbean: Guatemala, Honduras, Jamaica, Dominican Republic, Mexico, and Panama
- South America: Brazil and Argentina
- Europe: Italy, Poland, Hungary and Bulgaria, and the Czech Republic
- Middle East: Saudi Arabia

Kennard F. Kosky, M.S., P.E.

PROJECT RELATED EXPERIENCE – DOMESTIC

Dickerson, Chalk Point, and
Morgantown Generating Plants **Montgomery, Prince Georges,**
Mirant Corporation **and Charles Counties, MD**

Project Director of the preparation of the environmental analysis for the Certificate of Public Convenience and Necessity (CPCN) Application for the installation of flue gas desulfurization (FGD) systems on seven existing coal-fired units. Project involved assessment of New Source Review (NSR) for each plant and an analysis of emissions from material handling. An evaluation of air quality impacts performed for new stacks at each plant site. Expert testimony provided before a Public Service Commission (PSC) Hearing Examiner at public hearings.

McIntosh Power Plant
Lakeland Electric **Lakeland, FL**

Project Manager and engineer-of-record for preparing an air permit application to obtain approval from the regulatory agencies to install low-nitrogen oxides (NO_x) burners and selective catalytic reduction (SCR) for existing 360-megawatt (MW) Unit 3. Co-lateral increase in sulfuric acid mist required the installation of sorbent injection to limit emission below prevention of significant deterioration (PSD) thresholds. Permit application and supporting material prepared. Permit issued for Low-NO_x Burners.

St. Johns River Power Park
Jacksonville Electric Authority **Jacksonville, FL**

Project Manager and engineer-of-record for preparing air permit application to obtain approval from the regulatory agencies to install SCR for two nominal 700-MW units. Co-lateral increase in sulfuric acid mist required the installation of ammonia injection to limit emission below PSD thresholds. Permit application and supporting material prepared. Permit issued.

FPL Glades Power Park
Florida Power & Light Company (FPL) **Glades County, FL**

Project Manager for the preparation of licensing documents for the two nominal 980-MW ultra supercritical pulverized coal fired units and associated facilities located on a 4,900 acre site in Glades County, Florida. These units are being licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the Site Certification Application (SCA), Federal Aviation Administration (FAA) obstruction to navigation application, U.S. Army Corps of Engineers (USACE) dredge and fill permit application, and air permit application [including PSD application]. The SCA was submitted in December 2006.

Petroleum Coke Co-Firing
St. Johns River Power Park **Jacksonville, FL**

Project Manager and engineer-of-record for the FDEP authorization allowing up to 30 percent petroleum coke to be co-fired with coal. The authorization allowed co-firing with petroleum coke from 20 percent to 30 percent.

West County Energy Center
Florida Power & Light Company **Palm Beach County, FL**

Project Manager for the preparation of licensing documents for the 2,450-MW West County Energy Center, Palm Beach County, Florida. This project involved the licensing of two 3-on-1 combined-cycle units using three MHI 501G 250-MW combustion turbines (CTs) with associated heat recovery steam generators

Kennard F. Kosky, M.S., P.E.

(HRSGs), and a 440-MW steam turbine. These units are licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the SCA, FAA obstruction to navigation application, USACE dredge and fill permit application, and air permit application (including PSD application). Full Governor/Cabinet approval was obtained in December 2006.

Application for Certificate of Public Convenience and Necessity, Brandon Shores Units 4 and 5, Constellation Power Source **Ann Arundel County, MD**

Project Manager for the preparation of the CPCN Application for installation of air pollution control systems and associated facilities on the two nominal 670 MW Brandon Shores Units 1 and 2. This project involves the installation of FGD systems, fabric filters, new dual flue stack, and material handling facilities for coal, limestone and FGD byproducts. These units are licensed under Maryland's PSC. Environmental documents prepared include the CPCN and air permit application (including PSD application).

Site Certification Application and Licensing For Seminole Generating Station Unit 3
Seminole Electric Cooperative **Putnam County, FL**

Technical direction and review for the Site Certification Application and Air Construction/PSD Permit Application for SGS Unit 3, a nominal 750 MW (net) supercritical pulverized coal-fired unit. Provided expert testimony for the local land use hearing and prepared expert testimony for the Site Certification Hearing.

Kenai Blue Sky Coal Gasification Project
Environmental Permitting Feasibility Analysis for Coal-Gasification and Pulverized Coal-Fired Power Plant
Agrium U.S., Inc. **Kenai, AK**

Project Manager for the preparation of environmental permitting feasibility of coal-gasification and 400-200 MW pulverized coal fired power plant to be located at an existing ammonia/urea production facility. The project would involve the installation of coal gasification to product hydrogen and carbon dioxide as feedstock for the ammonia/urea production facilities. The coal-fired power plant would supply steam and energy for the gasification process and ammonia/urea production facilities, as well as supplying some power to the local grid. The coal gasification process and power plant would utilize Alaskan sub-bituminous coal.

Southwest St. Lucie Power Project
Florida Power & Light Company **St. Lucie County, FL**

Project Manager for the preparation of licensing documents for the 1,700-MW Southwest St. Lucie Power Project to be located in St. Lucie County, Florida. The project involved two nominal 850 MW supercritical pulverized coal fired units and associated facilities. Portions of the SCA was completed but not submitted.

Application for Certificate of Public Convenience and Necessity, Crane Generating Station, Constellation Power Source **Baltimore County, MD**

Project Manager for the preparation of the CPCN Application for installation of coal barge unloading facility for the Crane Generating Station. This project involved the refurbishment of an existing oil unloading dock and coal handling equipment. These units are licensed under Maryland's PSC. Environmental documents prepared include the CPCN and air permit application.

Kennard F. Kosky, M.S., P.E.

Site Certification Application and Licensing of the Turkey Point Expansion Project for Florida Power & Light Company — **Miami-Dade County, FL**

Project Manager for the preparation of licensing documents for the 1,150-megawatt (MW) Turkey Point Expansion Project, Miami-Dade County, Florida. This project involved the licensing of 4-on-1 combined-cycle units using four GE Frame 7FA 170-MW CTs with associated HRSGs, and a 440-MW steam turbine. These units are licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the SCA, FAA obstruction to navigation application, USACE dredge and fill permit application, and air permit application (including PSD application). Full Governor/Cabinet approval was obtained in February 2005.

Burner Replacement for Gerdau-Ameristeel — **Baldwin, FL**

Obtained a non-PSD determination from the Florida Department of Environmental Protection (FDEP) for a burner replacement project associated with an electric arc furnace. Project involved site visit, technical support, and discussions with FDEP.

Petroleum Coke Co-Firing at the Cedar Bay Cogeneration Project — **Jacksonville, FL**

Project Manager and engineer-of-record for the FDEP authorization allowing up to 35 percent petroleum coke to be co-fired with coal. The Cedar Bay facility consists of three 75-MW circulating fluidized bed (CFB) boilers fired with coal and located in Jacksonville, Florida. The authorization allowed co-firing with petroleum coke.

Hines Energy Center Power Block 3 for Progress Energy (formerly Florida Power Corporation) — **Polk County, FL**

Project Manager and engineer-of-record for the air construction and PSD permit application for a 530-MW combined-cycle power project located in Polk County, Florida. Directed preparation of SCA sections related to air emission, best available control technology (BACT), air impacts, and noise impacts. Testified on all air quality and noise aspects at the SCA Hearing.

Air Construction Permits for Tropicana Products, Inc. — **Bradenton, FL**

Project Manager and engineer-of-record for various projects at Tropicana's Bradenton Citrus Processing Plant. The projects involved replacing the GE LM5000 aero-derivative gas turbine with the larger GE LM6000 turbine, like-kind replacement of the duct burner system on the cogeneration facility, and the installation of a stand-by boiler.

Air Construction Permit for Hydro Aluminum of North America — **St. Augustine, FL**

Project Manager for the preparation of two air construction permits for secondary aluminum foundry. Project involved physical changes to the melting furnace and increasing production limits. Project was able to net out of PSD review.

Site Certification Application and Licensing of Expansion Projects for Florida Power & Light Company — **Martin and Manatee Counties, FL**

Project Manager of the preparation of licensing documents for two 1,150-MW Expansion Projects. These projects involved the licensing of 4-on-1 combined-cycle units using four GE Frame 7FA 170-MW CTs

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with associated HRSGs, and a 440-MW steam turbine. These units were licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the SCA, FAA obstruction to navigation application, and air permit application (including PSD application).

Application for Certificate of Public Convenience and Necessity, Dickerson Units 4 and 5, Mirant Corporation — Montgomery County, MD

Project Manager for the preparation of the Certificate of Public Convenience and Necessity (CPCN) Application for the 1,100-MW Units 4 and 5 Project. This project involved the licensing of two 2-on-1 combined-cycle units using two existing GE Frame 7F 160-MW CTs and adding two GE Frame 7FA 170 MW CTs, four associated HRSGs, and two 220-MW steam turbines. These units are licensed under Maryland's PSC. Environmental documents prepared include the CPCN, FAA obstruction to navigation application, USACE dredge and fill permit application, and air permit application (including PSD application).

Application for Certificate of Public Convenience and Necessity, Chalk Point Units CT7 through CT10, Mirant Corporation — Charles County, MD

Project Manager of the preparation of the CPCN Application for the 320-MW CT Project. This project involved the licensing of four GE Frame 7EA 80-MW simple-cycle units. These units are licensed under Maryland's PSC. Environmental documents prepared include the CPCN, FAA obstruction to navigation application, and air permit application (including PSD application).

Greenhouse Gas Life-Cycle Analysis for Bitor America Corporation — Boca Raton, FL

Project Manager for the preparation of a life-cycle analysis of greenhouse gas (GHG) emissions from various fossil fuels and technologies. The life-cycle analysis compared GHG emissions from the use of coal, natural gas, LNG, oil, and Orimulsion. The technologies evaluated included conventional steam generation, Integrated Gasification Combined-Cycle (IGCC), and combined-cycle.

Odor Evaluations for Sea Ray Boats, Inc. — Palm Coast, FL

Project Manager for the evaluation of odor impacts from styrene emissions associated with an existing fiberglass boat manufacturing facility in Flagler County, Florida. Project involved meteorological monitoring, styrene monitoring using SUMA canisters, air dispersion modeling and conceptual design of exhaust stack. Involved in negotiations with regulatory agency on consent order requirements and made public presentations to citizens group.

Odor Evaluations for Sea Ray Boats, Inc. — Merritt Island, FL

Project Manager for the evaluation of odor impacts from styrene emissions associated with three co-located fiberglass boat manufacturing plants located in Brevard County, Florida. Project involved air dispersion modeling and conceptual design of exhaust stacks for two facilities. Involved in negotiations with regulatory agency and made public presentations to citizens group.

Lone Oak Energy Center for Calpine Eastern Corporation — Lowndes County, MS

Project engineer for the air construction and PSD permit application for an 800-MW combined-cycle power project.

Calhoun County Peaker Project for FPL Energy — Calhoun County, AL

Project Manager for the air construction and PSD permit applications and environmental permits for a 680-MW simple-cycle power project.

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Hillabee Energy Center for Calpine Eastern Corporation **Tallapoosa County, AL**
Project engineer for the air construction and PSD permit applications for a 700-MW combined-cycle power project.

Auburndale Peaker Project for Calpine Eastern Corporation **Polk County, FL**
Project Manager and engineer-of-record for the air construction and PSD permit applications for a 130-MW simple-cycle power project.

Hines Energy Center Power Block 2 for Florida Power Corporation **Polk County, FL**
Project Manager and engineer-of-record for the air construction and PSD permit applications for a 530-MW combined-cycle power project.

Osprey Energy Center for Calpine Eastern Corporation **Polk County, FL**
Project Manager and engineer-of-record for the air construction and PSD permit applications for a 530-MW combined-cycle power project. Provided technical oversight for the preparation of the SCA.

Simple-Cycle Power Projects for Florida Power & Light Company **Martin and Ft. Myers, FL**
Project Manager and engineer-of-record for the air construction and PSD permit applications for two 170-MW simple-cycle units located at the existing FPL Martin and Ft. Myers Power Plant sites. Each project also required an evaluation of the noise impacts. The project at the Martin Plant required a modification of the SCA.

Shady Hills Generating Station for IPS Avon Park Corporation and El Paso Energy **Hardee County, FL**
Project Manager and engineer-of-record for the air construction and PSD permit applications for a 510-MW simple-cycle power project.

Odor and Air Quality Consulting for the Viera Company **Brevard County, FL**
Lead technical consultant in providing oversight on the air permitting of a waste scrap shredder. Project involved specifying procedures and reviewing results of source tests and impact analyses.

Installation of Citrus Fruit Extractors for Tropicana Products, Inc. **Ft. Pierce, FL**
Project manager and engineer-of-record for the air construction and PSD permit applications for the addition of fruit extractors at the Tropicana Plant. Detailed air dispersion modeling was required.

DeSoto Power Project for IPS Avon Park Corporation and Entergy Power Group **DeSoto County, FL**
Project Manager and engineer-of-record for the air construction and PSD permit applications for a 680-MW simple-cycle power project.

Air Construction Permit Preparation and Review for Solutia, Inc. **Pensacola, FL**
Preparation of air construction permits for various process additions to the Solutia nylon production plant. This included new adipic acid production intermediates. Assisted Solutia in the review and comments to

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FDEP on the Title V permit application. Prepared an air permit application for an inlet fogging system for Solutia's cogeneration facility.

Sea Ray Boats, Inc., Cape Canaveral Plant **Brevard County, FL**
Project Manager for a BACT evaluation and air modeling impact analysis for a new fiberglass boat manufacturing facility. Project involved negotiations with regulatory agency on permit conditions.

Heard County Power Project for Dynergy, Inc. **Hardee County, FL**
Project engineer for the air construction and PSD permit applications for a 510-MW simple-cycle power project.

Fogger Installation at Combustion Turbine Sites **Jacksonville, FL**
Project Manager for the preparation of air permit applications for the installation of inlet cooling "foggers" on simple-cycle CTs at Jacksonville Electric Authority's (JEA) Northside and Kennedy Plant sites. Project involved developing strategy for "netting out" of PSD.

Palmetto Power Project for Dynegy, Inc. **Hardee County, FL**
Project Director and engineer-of-record for the air construction and PSD permit applications for a 510-MW simple-cycle power project.

Vandolah Power Project for IPS Avon Park Corporation and El Paso Energy **Hardee County, FL**
Project Manager and engineer-of-record for the air construction and PSD permit applications for a 680-MW simple-cycle power project.

Fogger Installation at Combustion Turbine Sites for Florida Power & Light Company **Multiple Sites, FL**
Project Manager for the preparation of air permit applications for the installation of inlet cooling "foggers" at the Ft. Myers, Putnam, and Martin Plant sites. Project involved developing strategy for "netting out" of PSD.

Independent Power Projects for Tenaska, Inc. **Multiple Sites**
Project Director and engineer-of-record for the preparation of PSD and air permit applications the following projects: Heard County, Georgia – 850-MW simple-cycle; Autauga County, Alabama, Two Projects – an 800-MW combined-cycle and an 8870-MW combined-cycle project located on adjacent sites; Lakefield, Minnesota – 480-MW simple-cycle (BACT); Coosa County, Alabama Project – 540-MW simple-cycle project.

Oleander Power Project for Constellation Energy **Brevard County, FL**
Project Manager for the preparation of PSD and Air Permit Applications for the Oleander Power Project. Project consisted of 5 General Electric Frame 7FA simple-cycle CTs (nominal 850 MW). Project involved providing expert testimony.

Repowering Project for Florida Power & Light Company **Sanford, FL**
Project Manager for the preparation of air permit applications for conversion of two existing steam electric units (Units 4 and 5) at the FPL Sanford Plant to combined cycle using 8 General Electric Frame 7FA CTs. The repowering would produce a nominal 2,200 MW of gas-fired combined-cycle generation. The project involved the preparation of the PSD and Air Permit Applications, noise evaluation, and FAA Notifications.

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Generation Project for Thermal EcoTek, Corporation **Lake Worth, FL**
Project Manager for the preparation of the PSD and Air Permit Applications for the Lake Worth Generation Project. Project consisted of the repowering of 2 existing steam units with a nominal capacity of 74 MW using a General Electric Frame 7FA CT (170 MW).

Repowering Project Licensing for Florida Power & Light Company **Ft. Myers, FL**
Project Manager for environmental licensing documents for the conversion of the existing steam electric units (Units 1 and 2) at the FPL Ft. Myers Plant to combined cycle using 6 General Electric Frame 7FA CTs. The repowering would produce a nominal 1,500 MW of gas-fired combined-cycle generation. The project involved the preparation of the PSD and Air Permit Applications, Environmental Resource Permit (ERP) Application, Wastewater Discharge Permit Application (i.e., the SPDES), FAA Notifications, and county applications.

Lakeland Electric (City of Lakeland) McIntosh Unit 5 **Lakeland, FL**
Project Manager for the preparation of the PSD and air permit applications for the McIntosh Unit 5 simple-cycle project. Included preparation of the Modification Request to Site Certification for McIntosh Unit 3. Project consisted of the first Westinghouse 501G CT with a nominal capacity of 250 MW.

Title V Permit Applications for Eagle-Picher Corporation **Multiple Sites**
Project Director for the preparation of Title V Permit applications or Federally Enforceable Synthetic Minor Operating Permit applications for 9 facilities in 6 states. The facilities include activities associated with metal coil coating, rubber part manufacturing, and printing. The states where the facilities are located include Connecticut, Florida, Michigan, New Jersey, Pennsylvania, and New York.

Odor and Noise Monitoring for North and South Broward Resource Recovery Facilities **Broward County, FL**
Project director for noise and odor studies at two large municipal waste combustors. The studies were based on ASTM methods to demonstrate conformance with requirements of regulatory approvals.

Destin Dome Natural Gas Development Project for Chevron U.S.A. Production Company **Pensacola, FL**
Project Manager for the OCS air permit application submitted to the U.S. Environmental Protection Agency (EPA) to develop the natural gas reserves in a 33-square-mile area offshore of Pensacola. The projects involved preparation of permit applications including emission estimates of well drilling and production facilities. Air emission sources included two drilling rigs, one central production facility, and 16 satellite production facilities. The project included PSD evaluations to determine BACT and air impact analysis using the OCD air dispersion model.

Title V Permit Applications for Potomac Electric Power Company **Multiple Sites**
Project Manager for the preparation of Title V Permit applications or Federally Enforceable Synthetic Minor Operating (FESOP) Permit applications for 7 facilities in 2 states and 1 jurisdiction. The Title V facilities consist of 6 power plants with coal and oil fossil fuel-fired steam generating units, CTs, and diesel units. The FESOP is for a service facility. The facilities are located in Maryland (3 plants and the service facility), Virginia (1 plant) and the District of Columbia (2 plants).

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Air Permitting for Destin Dome Blocks 57 and 96, Chevron U.S.A. Production Company Outer Continental Shelf **Pensacola, FL**

Project Manager for the Outer Continental Shelf (OCS) air permits issued by the EPA to conduct well drilling within the U.S. boundary, offshore of Florida. The projects involved preparation of permit applications including emission estimates of well drilling activities. The applications were the first in the Eastern U.S. under 40 Code of Federal Regulation (CFR), Part 55. These regulations were promulgated as a result of the 1990 Amendments of the CAA Amendments. Presented information on the emissions and impacts of the activity at an EPA sponsored public hearing.

Kaiser Aluminum-Gramercy and Baton Rouge Cogeneration Plants **Baton Rouge, LA**

Project Manager for obtaining air permits on two cogeneration facilities. The facilities were required to obtain PSD approval and meet NSPS requirements.

PSD Approval for Cogeneration Facility at Borden Chemical **Baton Rouge, LA**

Project Director for an 80-MW cogeneration facility constructed for Borden Chemical. The project involved obtaining PSD approval from the state agency.

Site Certification Application for Orimulsion Conversion **Manatee County, FL**

Project Director for the licensing of Orimulsion firing at FPL's Manatee Power Plant. The plant consists of two nominal 800-MW units. Technical activities focused on the preparation of BACT evaluation and air pollution control aspects of the project.

Petroleum Coke and Title V Application for City of Lakeland Department of Electric and Water Utilities **Lakeland, FL**

Project Manager and engineer-of-record for providing technical assistance to obtain approval for co-firing petroleum coke (20 percent) and coal (80 percent) at McIntosh Power Plant, Unit 3. McIntosh Unit 3 is a 364-MW coal-fired facility. Project Manager and engineer-of-record for preparation of Title V applications.

Coal and Petroleum Coke Co-firing Permit for St. Johns River Power Plant **St. Johns County, FL**

Project Manager and engineer-of-record for obtaining approval from the regulatory agencies to co-fire up to 20 percent of petroleum coke by weight with coal in two nominal 700-MW units. Permit application and supporting material prepared. Performed emissions estimates and impact analyses of potentially toxic air emissions (metals). Provided support and presentations to local chapter of Sierra Club who intervened in the permit proceeding. Performed post-test analyses to demonstrate compliance with settlement agreement.

Title V Economic Evaluation for Florida Electric Power Coordinating Group **Tampa, FL**

Performed an economic evaluation for Florida Electric Power Coordinating Group (FCG) on the cost to prepare Title V permits as initially proposed by FDEP and presented the results of the evaluation at the FDEP Title V Workshop. The presentation assisted in modifying the FDEP requirements to more closely follow EPA requirements.

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Electric Utility Regulatory Requirements for
Florida Electric Power Coordinating Group **Tampa, FL**

Lead the effort to prepare a comprehensive list of regulatory requirements specific for the electric utility industry. The list, which includes all applicable and non-applicable requirements, forms the basis for compliance statements required of the responsible official.

Title V Permit Recommendations for
Florida Electric Power Coordinating Group **Tampa, FL**

Providing recommendations for preparation of Title V permits for the FCG. This includes interfacing with FDEP and providing comments on insignificant activities and application form submittal. Also provided FDEP comments on data input requirements and suggestions that will make the application form easier to develop.

Florida Power Corporation Title V Applications **Multiple Sites**

Project Director and engineer-of-record for Title V applications for 11 facilities. The facilities include coal-, oil-, and gas-fired fossil fuel steam generator units, simple-cycle CT units, combined-cycle unit, and diesel generators. Project involved regulatory requirements, emissions inventories, trivial activity lists and application preparation.

Title V Permits for Florida Power & Light Company Facilities **Multiple Sites**

Assisting FPL in the preparation of Title V permit applications for all facilities. This includes 11 power plants and several minor facilities. Engineer-of-record for the applications, and responsible for overseeing the applications' preparation. Also providing input on regulatory requirements and emissions. Currently, one permit application has been completed in draft form.

Title V Permit Implementation Plan for Tennessee Valley Authority **Multiple Sites**

Assisted Tennessee Valley Authority (TVA) in developing a comprehensive list of applicable requirements in three states (Tennessee, Kentucky, and Alabama) for 10 facilities. Also performed site visits for four major plants (7,550-MW coal-fired with CTs) to develop a list of major sources and insignificant activities. The result was a comprehensive Title V plan, which is currently being implemented by TVA. Performed reviews of Title V applications for three power facilities.

Gulf Power Company Title V Applications **Multiple Sites**

Project Manager and engineer-of-record for Title V applications for three coal-fired facilities. Performed site visits for each facility and developed listing of regulatory requirements.

Title V Database for Various Clients **Multiple Sites**

Developed a Title V database built around the FDEP Title V permit application form. The database is designed to manage the data and print out a form identical to the FDEP form. The database will provide a format suitable for electronic submittal to FDEP.

Emissions Inventory and Title V Applications for
Potomac Electric Power Company (PEPCO) **Multiple Sites in Maryland**

Project Manager for the development of a comprehensive emissions inventory and preparation of Title V applications for all of PEPCO facilities. This includes 6 power plants (4 coal-fired plants, 1 oil/gas plant, and 1 CT plant) located in three regulatory jurisdictions. The inventory will involve the development of an emission inventory management system that will manage the data.

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Site Certification Application at Hardee Power Station,
Seminole Electric Cooperative Incorporated **Hardee County, FL**

Project Director for SCA and environmental assessment (EA) for a 660-MW combined-cycle electric-generating plant. Responsible for the technical, budgetary, and scheduling aspects of the project. The permitting documents prepared were designed to fulfill requirements of the PSC and the U.S. Department of Agriculture (USDA) Rural Electrification Administration (REA). Provided expert testimony for the project.

Transmission Line Corridor Siting at Hardee Power Station for
Seminole Electric Cooperative Incorporated **Hardee County, FL**

Project Director for siting and licensing of three 230-kilovolt (kV) transmission lines (total of 78 miles) to connect the Hardee Power Station to the Florida transmission grid. Siting of the transmission line corridors was accomplished using the PC ARC/INFO® geographic information system (GIS). Developed all required information and impact analyses for the Florida SCA to be presented to the Florida Department of Environmental Regulation (FDER) and PSC.

Site Certification Application and Licensing of the
Lauderdale Repowering Project for
Florida Power & Light Company **Ft. Lauderdale, FL**

Project Manager for the preparation of licensing documents for the Lauderdale Repowering Project, Broward County, Florida. This project involved replacing two existing steam generators with advanced CTs and HRSGs. The repowered units were designed to have a capacity of approximately 960 MW, approximately 640 MW resulting from the addition of the advanced CTs. Environmental documents prepared include the SCA, National Pollutant Discharge Elimination System (NPDES) application, FAA obstruction to navigation application, USACE dredge and fill permit application, and air permit application (including PSD application).

Test Burn of Orimulsion Fuel for
Florida Power & Light Company **Sanford, FL**

Project Manager for a test burn to discover if Orimulsion fuel had the potential to displace No. 6 fuel oil in steam electric power plants at Sanford Unit 4. Project provided the opportunity to evaluate the technical and operational features associated with burning Orimulsion fuel under utility operating conditions.

Air Construction Permit Application for TransPac, Inc. **Santa Rosa County, FL**

Project Manager for project requiring permit to construct an air pollutant source. Developed report supplementing the application to construct a minor-source waste storage and treatment facility. The objective of this report was to evaluate the impact of the facility based on a comparison of the proposed facility's impacts to the FDER's proposed toxic air pollutant guidelines.

Air Quality Impacts of Siting 1,050-MW CTs for
Florida Power Corporation **Multiple Sites**

Project Manager of air quality impact analyses performed to evaluate locating CTs at six potential sites in Florida: Intercession City, DeBary, Avon Park, Turner, Bartow, and Anclote. The analyses were undertaken to determine compliance with ambient air quality standards (AAQS) and PSD increments for the maximum proposed plant size (i.e., 1,050 MW).

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Particulate Matter Air Quality Assessment of Helper Cooling Towers for Florida Power Corporation — **Citrus, FL**

Project Manager of project to determine the impacts of the proposed cooling towers on ambient particulate matter (PM) levels, considering all PM emissions associated with the CT units, cooling towers, helper cooling towers, and coal- and ash-handlers already existing onsite. Impacts were addressed in regard to allowable PSD increments for PM [as total suspended PM, i.e., PM(TSP)] and AAQS for PM [as particulate with an aerodynamic diameter less than 10 micrometers (μm), i.e., PM_{10}].

Site Evaluation of 1,000-MW CT Project for Florida Power Corporation — **Multiple Sites in FL**

Project Manager responsible for evaluating the availability of water-supply sources, raw water treatment requirements, and wastewater disposal options at six facilities for the 1,000-MW CT siting project. Water supply sources were evaluated to determine their feasibility for use and included existing permitted groundwater and surface water withdrawals, new groundwater sources, new surface water withdrawals, and secondary effluent from nearby municipal wastewater treatment facilities.

CT Site Evaluation and Chalk Point Environmental Assessment for Potomac Electric Power Company — **Chalk Point, MD**

Project Manager of project to provide alternative site and environmental information required under the Maryland PSC rules for receiving a CPCN for a new generation facility. The two primary objectives of the report were to identify and evaluate suitable sites for accommodating approximately four CTs and to evaluate the environmental baseline information and potential impacts of locating the CTs at the preferred site.

Gator Power Cogeneration Facility PSD Review for Florida Power Corporation — **Gainesville, FL**

Project Manager for PSD review for a cogeneration facility consisting of a CT and HRSG. The report addressed the new source review (NSR) requirements contained in air quality regulations on both the state and federal levels.

Fog Visibility Study for Parsons, Brinkerhoff, Quade, and Douglas, Inc. — **Charleston, SC**

Project Manager responsible for study designed to obtain meteorological and fog/visibility data on the I-526 Cooper River Crossing in North Charleston. Objectives of the program were to document the frequency and duration of fog and the meteorological conditions during which it occurs; to identify and differentiate the fog plume created by the cooling towers from that of other sources; and to correlate the data collected with data observed at the National Weather Service (NWS) station in Charleston.

Site-Specific Environmental Evaluation for Potomac Electric Power Company — **Multiple Sites in Maryland**

Project Manager responsible for presenting the methodology and results of a site-specific environmental evaluation. The objective of the site environmental evaluation was to determine the environmental suitability of CT units with projected early 1990s in-service dates. The candidate site environmental evaluation consisted of analyzing candidate sites based on six environmental factors.

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PSD Permit Application for Environmental Incineration Systems, Inc. **Duval County, FL**

Project Manager of permitting activities for proposed municipal solid waste recycling/volume reduction facility. The facility was designed to reduce the amount of solid waste input to landfills in Duval County by up to 175,200 tons per year (TPY). The proposed facility was classified as a "major" source under federal and state air pollution control regulations and was subject to the PSD provisions of the regulations.

PSD Permit Application for Cogeneration Project for Tropicana Products, Inc. **Bradenton, FL**

Project Manager responsible for permitting a cogeneration facility consisting of a CT, a HRSG, and an associated auxiliary steam generator. The report addressed the NSR requirements contained in the state and federal regulations.

Crystal River PSD Analysis for Florida Power Corporation **Crystal River, FL**

Project Manager of air dispersion modeling analyses performed to determine the TSP impacts of PM emissions from the cooling towers at FPC's Crystal River facility. A modeling protocol was prepared by KBN and reviewed and commented upon by the EPA.

EMSoft II®, Permit Manager for Manatee County Public Health Unit **Manatee County, FL**

Designed and developed the EMSoft II®, a software package for micro-computers designed to assist end users in managing environmental permits and requirements through a relational database capable of generating a series of specific reports.

Agrico Chemical Company Mine **Hillsborough County, FL**

Project Manager for the EA for a phosphate mine located in eastern Hillsborough County, Florida. The project involved the development of baseline conditions including monitoring of air, water, and ecological conditions. Impact analyses involving various environmental disciplines were conducted using approved regulatory techniques.

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PROJECT RELATED EXPERIENCE – INTERNATIONAL

Best Available Control Technology Assessment and Toxic Air Emission Evaluation for Coleson Cove Refurbishment Project, New Brunswick Power Corporation — **New Brunswick, Canada**

Senior consulting engineer for developing a best available control technology (BACT) assessment and toxic air emission inventory for the conversion of the 1,050-MW Coleson Cove plant from residual oil to Orimulsion. Project involved a detailed assessment of control equipment for sulfur dioxide (SO_2), PM, nitrogen oxides (NO_x) and sulfuric acid mist (SAM). Develop a toxic air emissions inventory. Provided presentations at multi-agency meetings and public hearings.

Combined-Cycle Projects for Southern Energy, Inc. — **Multiple Sites in Italy**

Provided technical review and assistance for two 370-MW combined-cycle projects to be located in east central Italy. Reviewed the designs and impact methodologies to provide senior oversight of projects.

Environmental Due Diligence — **Campeche, Mexico**

Project Director for the environmental due diligence for the Cantarell Nitrogen Project located near Campeche, Mexico. Project is the largest nitrogen plant in the world with an associated 400-MW power complex to provide power for the nitrogen plant. Review licensing reports and documents for conformance with Mexican regulations and "world norms". Review being conducted for international financial institutions.

Environmental Benchmarking of Power Facilities, Worldwide, Confidential Client — **Multiple Sites**

Project Manager assisting an international energy company in the evaluation of their environmental conformance with international accepted norms of all of their facilities worldwide. This involved evaluating over 10,000 MWs at approximately 12 different power facilities including hydro. These plants were located in Asia, South America, North America, and Europe. Evaluation was to assist with the development of an environmental management system for all of the company's facilities.

Shanghai Municipal Electric Power Company Waigaoqiao Environmental Assessment — **Shanghai, China**

Project Manager for World Bank EA of the addition of two 1,000-MW coal-fired super-critical units to the Waigaoqiao Power Plant site. This was referred to as Phase II, while Phase I, the existing plant, consists of four 300-MW units. The EA also considered the addition of a Phase III which would be identical to Phase II (i.e., another two 1,000-MW units). The EA was prepared to meet World Bank guidelines and involved developing information and performing analyses for Phases I, II, and III.

Baley Gold Mine Project — **Western Russia**

Task Manager for the environmental assessments relating to the potential air and noise impacts from a gold mine project located in Eastern Russia. The task involved developing emissions and impact estimates for mining 25 million tonnes of material from an open pit mine. Impacts were determined using EPA dispersion models. Noise impacts from mine activities were determined using the NOISECALC model.

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Nickel and Cobalt Mine Project **Cupey, Cuba**
Working through Golder's Mississauga Office provided air impact analyses for a nickel and cobalt mine located in Cupey, Cuba. The major emissions from the project were from the ore processing, which contained PM and SO_2. The EPA dispersion model ISC3ST was used to estimate impacts using a 1-year meteorological data base. Impacts were compared to the World Bank ambient guidelines.

Ambient Air Monitoring Laboratories and Training Program for the Electricity Generating Authority of Thailand **Bangkok, Thailand**
Project Director responsible for designing and constructing two mobile laboratories as well as providing air quality and meteorological equipment. Equipment will be installed in specialty-designed cubicles, and mounted on a Nino truck chassis. The intensive training program will consist of 2 months training in the United States for three EGAT engineers.

Air Resources Studies, Mae Moh Power Plant and Lignite Mine for the Electric Generating Authority of Thailand **Mae Moh Valley, Thailand**
General Consultant for Air Quality/Project Manager managing activities within an environmental program for proposed plant and mine development in Mae Moh Valley, Northern Thailand.

Environmental Licensing Studies for the Electricity Generating Authority of Thailand **Bangkok, Thailand**
Air Resources, Subproject Manager, responsible for studies of coal-fired power plant. Managed air resources investigations as part of overall environmental studies of proposed coal-fired power plant to be located on the Gulf of Thailand, 70 kilometers (km) southeast of Bangkok.

Ambient Monitoring Network for the Electricity Generating Authority of Thailand **Gulf of Thailand**
Project Director/Air Resources, Subproject Manager, performing environmental licensing studies for a 2400-MW, coal-fired plant.

Environmental Assessment of Gas Turbine Electrical Generating Facility, World Bank **Hunts Bay, Jamaica**
Air Engineer responsible for developing mitigation and monitoring measures based on the results of air modeling to reduce the impacts from SO_2 and NO_x in the Hunts Bay area.

Development of Air Quality Standards for the Government of Mauritius for the World Bank **Mauritius**
Project Manager tasked with assisting the government of Mauritius in developing air quality standards and designing appropriate monitoring programs required for regulatory enforcement.

Environmental Assessment for 60-MW Diesel-Powered Facility **Rockfort, Jamaica**
Air Engineer responsible for developing mitigation and monitoring measures based on the results of air modeling to reduce the impacts from sulfur dioxide and nitrogen oxides in the Rockfort project area.

Environmental Assessment of the Gas/Coal Electrical Generating Facility in Mauritius for the World Bank **St. Aubin, Mauritius**
Project Director responsible for conducting all field work for the environmental assessment of a coal- and gas-fired electrical generating facility at St. Aubin in air quality, water quality, and ecology.

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Environmental Screening of Four Proposed Power Plant Sites for the World Bank — **Kingston, Jamaica**

Air Engineer responsible for conducting the air quality components of an environmental screening of four potential sites for a 60-MW diesel electrical generating facility.

Technical Cooperation Mission for the World Bank — **Multiple Sites in Bulgaria**

Team Member on the World Bank Mission to determine the major environmental problems in Bulgaria and to identify potential areas for World Bank funding. Responsible for portions of the mission involving toxic/hazardous waste and air pollution. Contributed to the mission's Aide Memoire and directed the preparation of an overall report summarizing the state of the environment in Bulgaria.

Environmental Strategy Study of Air Quality, World Bank — **Multiple Sites in Hungary**

Team Member on mission providing an overview of key air quality problems in Hungary; a description and assessment of regulatory institutions, regulations, and policy; and identification of initial approaches and investment opportunities for improving air quality. During the mission, discussions were held with relevant governmental organizations, various industries, and environmental interest groups (non-governmental organizations) throughout Hungary. Project focused on preparation of an Aide Memoire and summary report dealing with industrial pollution.

Environmental Project for World Bank — **Katewice/Krakow, Poland**

Team Member of the World Bank Mission that recommended and defined an environmental project for the Katewice/Krakow area. Interviewed various governmental personnel to determine needs and developed a comprehensive program for a $7-million loan. Developed request for quotations for various components of the recommended study. The focus of the study was air quality.

Multidisciplinary Electric Power Plant Projects for the U.S. Agency for International Development(USAID) — **Multiple Sites, Pakistan**

Project Manager for several multidisciplinary projects involving the development of electrical power plants in Pakistan. The projects included the Lakhra Mine and Power Plant EA, the Jamshoro Oil-Fired Power Plant EA, the Guddu Combined-Cycle Expansion Project, the Kalifia Point Private Sector Power Project, and the Environmental Guidelines for Electric Power Development in Pakistan.

Private Sector Power Project for USAID — **Multiple Sites, Pakistan**

Project Manager responsible for performance of an air quality impact evaluation to investigate a large coal-fired power plant planned by the Government of Pakistan and a 1,200-MW oil-fired power plant proposed by a group of private firms. Determined the air quality effects of each plant, as well as the cumulative effects of both plants, on the area's ambient air quality. Prepared guidelines providing the private sector proposer a framework for preparing an EA from which significant environmental impacts and alternative designs to mitigate them can be determined. Project also included the establishment of a framework for future assessments of the respective plants, a preliminary evaluation of cooling water requirements, and a determination of potential water quality and ecological impacts.

Guddu Environmental and Social Soundness Assessment for Gibbs & Hill, Inc. — **Guddu, Pakistan**

Project Manager of an Environmental and Social Soundness Assessment (ESSA) associated with the construction and operation of a proposed 300-MW addition to a 600-MW combined-cycle power plant in Guddu, Pakistan. The ESSA, designed to provide decision makers with a full discussion of significant

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environmental effects associated with the power plant expansion, included an evaluation of alternatives or mitigating measures.

Duri Field EA for Caltex Pacific **Duri Field, Indonesia**

Project Manager of the air quality assessment of the Duri Field steam-flood project. This project was the largest steam-flood project in the world and involved an assessment of over 300 steam generators using Duri Crude. Directed all activities and presented the results of the study to the newly formed Ministry of Environment.

EAs of Electrical Generating Facilities for Electricity Generating Authority of Thailand (EGAT) **Multiple Sites, Thailand**

Project Manager for 8 years of numerous multidisciplinary projects involving EAs of electrical generating facilities in Thailand. The projects included an assessment of a 600-MW coal-fired power plant in Ao Pai; an assessment of constructing 600 MW of additional generation at the Mae Moh site; an assessment of a combined-cycle power plant at Khanom; and a mine and power plant mitigation assessment for the Mae Moh facility.

Kennard F. Kosky, M.S., P.E.

EXPERT/EXPERT WITNESS TESTIMONY EXPERIENCE

Mr. Kosky has provided expert testimony in over 50 Cases. He has testified in the following types of proceedings:

- Hearing Officers and Administrative Law Judges (ALJs);
- Public Service Commissions;
- Circuit Court;
- Federal District Court;
- Governor of Florida;
- State and County Environmental Commissions;
- Environmental review Boards;
- County Commissions;
- Land Use Commissions; and
- EPA.

Mr. Kosky has been accepted as an expert in the following areas:

- Air Quality Impact Analyses;
- Air Pollution Control Technology (Design and Engineering);
- Best Available Control Technology;
- Air Pollution Emission Estimates;
- Air Regulation and Compliance; and
- Noise Evaluation and Impact Analyses.

Mr. Kosky has been accepted as an expert in proceeding held in the following states:

- Florida,
- Maryland,
- Georgia,
- South Carolina,
- Hawaii,
- California, and
- Louisiana.

Agrico Chemical Company **Bartow, FL**

Florida Department of Environmental Regulation Administrative Hearing. Provided assistance to attorneys at hearing for cross examination of opposing witnesses. Case involved permits for prilled sulfur terminal. 1979.

Fugitive Emissions Expertise **Alachua County, Florida**

Circuit Court. Provided expert testimony on the impacts of fugitive dust related to highway construction.

AstraZeneca **Tarpon Springs, FL**

EPA ASTDR. Provided technical support for Stauffer Chemical Company Superfund Site. Technical expertise provided in air monitoring and air impact analyses. 2001 to present.

Baltimore Gas and Electric Company **Baltimore, MD**

Provided expert testimony for the following:

- Presentation for Maryland PSC staff and hearing examiners on the technical issues related to BACT. 1992.

Kennard F. Kosky, M.S., P.E.

- Hearing Examiner. Provided direct and supplemental written expert testimony for 800-MW combined-cycle Perryman Project. Testimony required for the PSC CPNC. Testimony focused on air emissions and BACT for the project. 1990 to 1991.

Broward County Resource Recovery Office **Broward County, FL**

Hearing Examiner. Preparation and presentation of testimony for the North and South Broward County Resource Recovery projects on BACT. Testimony was part of a power plant site certification project. 1985 to 1986.

Calpine Eastern Corporation **Auburndale, FL**

Administrative Law Judge. Provided expert testimony on a 500-MW combined-cycle unit located at the Osprey Energy Center in Auburndale, Polk County, Florida. Testimony focused on air emissions, BACT, and noise. 2001.

Chevron, Inc. **Pensacola, FL**

Presentation before an EPA Region IV panel regarding the air emissions and impacts of drilling rig as part of Outer Continental Shelf Air Permit (40 CFR 55). The project was located in Destin Dome, which is located about 30 miles offshore from Pensacola. Permit was granted.

City of Jacksonville **Jacksonville, FL**

Circuit Court. Provided technical support for a class certification involving the air quality impacts of incinerators operating from about 1950 to 1970. Provided technical analysis and presented opinions at a deposition. 2004.

City of Lakeland Utilities **Lakeland, FL**

Provided expertise for the following:

- Administrative Law Judge. Presented expert testimony on the addition of the steam cycle for McIntosh Unit 5. As Project Manager for the project, the testimony covered all environmental disciplines including air emissions, BACT, and general environmental impacts.
- Hearing Examiner. Presented technical information and the results of modeling during hearings on site certification for a new electrical generating plant.

Constellation Energy **Ann Arundel County, MD**

Public Service Commission Hearing Officer. Provided expert testimony for an application for a Certificate of Public Necessity and Convenience (CPCN) for the installation of air pollution control systems and boiler/turbine upgrades for the Brandon Shores Generating Station. Testified on air quality including BACT, noise and visual aspect of the application.

Constellation Energy **Brevard County, FL**

Administrative Law Judge. Provided expert testimony for the air pollution controls and BACT for an 850-MW simple-cycle power plant to be located in Brevard County.

Confidential Clients

Provided expertise for the following (only partially listed):

- Provided technical expertise in anticipation of litigation for dioxin contamination from a refinery. Performed air impact analysis and assessment.
- Provided expert technical expertise for cases filed against facilities by Justice Department related to EPA's New Source Review regulations. 1998 to present.

Kennard F. Kosky, M.S., P.E.

Del Monte Fresh Produce, Inc. Power & Light Company **Oahu. HI**

Jury Trial. Provided testimony in the United States District Court, District of Hawaii, related to air emission and impacts from pesticides. 2004.

Delmarva Power & Light Company **Dorchester, MD**

Hearing Examiner. Provided direct and supplemental written and oral testimony for nominal 300-MW coal-fired power plant located in Dorchester, Maryland. Case was part of the CPCN before the Maryland PSC. Testimony was related to the air pollution control technology, Lowest Achievable Emission Rate (LAER) and BACT. 1994.

Florida Department of Environmental Regulation **Multiple Sites, FL**

Provided expertise for the following:

- Hearing Examiner. FDER. Provided expert testimony regarding NO_x emission limits for fossil fuel steam generators. Three hearings involved and ultimately lead to the NO_x task force. 1973.
- Hearing Examiner. Florida Environmental Regulation Commission (FERC). Administrative Hearing. Testified on impacts of rule change on phosphate rock dryers. Testimony related to air quality impacts and control technology. 1973.
- Hearing Examiner. FDER Administrative Hearing. Prepared testimony on air quality impacts of control strategy for pulp mill. Testimony involved dispersion modeling and control techniques. 1973.
- FERC. Testimony on emergency action plans and compliance schedules for the State Implementation Plan. Testimony given at six locations throughout Florida. 1973.

Florida Electric Power Coordinating Group **Multiple Site, FL**

Provided expertise for the following:

- FERC and Honorable Bob Graham, Governor of Florida. Two Hearings. Prepared technical information that allowed suspension of emissions for 120 days due to energy emergency. Approval given by all parties. 1979.
- FERC. Prepared report and testimony and presented support of a rule change for three southeast Florida counties. Rule change involved elevating ambient air quality standards. The rules were changed to be consistent with the rest of the state. 1975.
- FERC. Prepared report and testimony presented in support of a rule change that would allow the use of fuel with a higher sulfur content. Project involved approximately 10,000 MW of fossil-fueled steam generators. The rule was changed. 1975.

Florida Power Corporation (Progress Energy) **Multiple Sites, FL**

Provided expertise for the following:

- Administrative Law Judge. Provided expert testimony on a gas and distillate oil-fired 500-MW combined-cycle unit located at the Hines Energy Center in Polk County, Florida. Testimony focused on air emissions, BACT, air impacts, and noise. Certification issued by Governor and Cabinet. 2001.
- Administrative Law Judge. Provided expert testimony for the use of petroleum coke with coal in two units at the Crystal River Power Plant. Focus of testimony was regulatory applicability of PSD rules to the use of petroleum coke. 1997.
- Hearing Examiner. FDER Administrative Hearing. Presented testimony on environmental impacts of Crystal River Units 4 and 5 (1,400-MW, coal-fired power plant). Permit approved. 1978.

Kennard F. Kosky, M.S., P.E.

Florida Power & Light Company **Multiple Sites, FL**

Expert testimony provided for the following:

- Florida Public Service Commission. Provided expert testimony on the environmental impacts and future environmental costs (CAIR, CAMR, and potential greenhouse gas legislation) in the need case for the FPL Glades Power Project. 2007.
- Administrative Law Judge. Provided expert testimony for the West County Energy Center, a 2,450-MW Power Plant located in Palm Beach County, Florida. Testimony included air emissions (toxics), air quality impacts, and noise. 2006.
- St. Lucie County Board of County Commissioners. Provided expert testimony at the land use hearing before the St. Lucie County Commission of the emissions and air quality impacts of the 1,700 MW Southwest St. Lucie Power Project.
- Administrative Law Judge. Provided expert testimony for Turkey Point Expansion Project, an 1,100-MW Power Plant located in Miami-Dade County, Florida. Testimony included air emissions (toxics), air quality impacts, and noise. 2004.
- Administrative Law Judge. Provided expert testimony for Manatee Expansion Project, an 1,100-MW Power Plant located in Manatee County, Florida. Testimony included air emissions (toxics), air quality impacts, and noise. 2003.
- Administrative Law Judge. Provided expert testimony for Martin Expansion Project a 1,100-MW Power Plant located in Martin County, Florida. Testimony included air emissions (toxics), air quality impacts, and noise. 2003.
- Manatee County Planning Commission and Manatee County Board of County Commission. Provided testimony on environmental issues related to land use for the Manatee Combined-Cycle Project. 2002.
- PSC for South Carolina. Provided expert testimony for the Cherokee Falls simple-cycle power project. Testimony covered all environmental matters related to the project. 2002.
- Administrative Law Judge. Provided expert testimony for Manatee Orimulsion Conversion Project. Focus of testimony was BACT and air emissions (including toxics). 1998.
- Administrative Law Judge. Provided expert testimony for Manatee Orimulsion Conversion Project. Focus of testimony was BACT and air emissions (including toxics). 1995.
- Hearing Examiner. Provided expert testimony for the Martin combined-cycle project (1,600-MW combined-cycle coal gasification facility). Provided testimony on air emissions and BACT for Site Certification issued by Governor and Cabinet. 1990.
- Hearing Examiner. Expert testimony provided for the Lauderdale Repowering Project (800-MW combined-cycle facility). Testimony provided on air emissions, BACT, and noise. 1990.
- FDER Official. Expert testimony provided for SIP revision, various PSD aspects of test firing Orimulsion in a 400-MW gas-/oil-fired power plant. Air emissions and impacts presented. 1990.
- Hearing Examiner. Presented expert testimony for FPL to assess impacts from atmospheric downwash at 225-MW oil/natural gas-fired power plant. 1984.
- Broward County Commission. Prepared and presented testimony concerning the air quality impacts of using 2.5-percent sulfur fuel in FPL's 1,200-MW Port Everglades Plant. 1982.
- Dade County Environmental Resource Management Board. Prepared and presented testimony concerning the air quality impact of using 2.5-percent sulfur fuel in FPL's 800-MW Turkey Point Plant. Two hearings were held. The impacts to a PSD Class I area were at issue. 1982.
- Manatee County Commission. Prepared and presented testimony on the air quality impact of using 2.5-percent sulfur fuel in FPL's 1,600-MW Manatee Plant. Two hearings were involved. 1981.
- FDER. Presented testimony related to air quality impacts for particulate variance for FPL's Sanford, Ft. Myers, and Canaveral power plants. Variance extended. 1981.

Kennard F. Kosky, M.S., P.E.

- FERC. Testified before the FERC concerning the impacts of Sanford Unit 4 firing with coal-oil mixture (COM). FPL's request was for a temporary variance in particulate emissions so that full scale testing of COM could be performed. 1980.
- Dade County Commission. Prepared testimony and presented the results of modeling and technical information in support of a rule change on ambient air quality standards. 1977.
- FERC. Prepared testimony and presented the results of atmospheric dispersion modeling and other technical data at two separate hearings before the FERC in support of the contention that FPL's Manatee Plant was an existing source and thus could burn higher sulfur fuel. Approval given by both state and EPA. 1976.

Florida Sugar Cane League **Multiple Sites, FL**

Expertise provided for the following:

- Palm Beach County Commission. Testified in opposition to proposed special emission limits on the sugar cane industry in Palm Beach County. 1976.
- Florida Congressional Representative Paul Rogers. Presented technical information pertaining to CAA Amendments. Presentation in support of the League's position with respect to a proposed rule governing the significant deterioration of air quality. 1976.
- FERC. Presented testimony on the results of modeling and other technical information in support of the SO_2 rule change for three Florida counties. 1975.

Gold Kist **Live Oak, FL**

Local district court. Prepared reports, testimony, and interrogatories on case involving air pollution impacts on local car dealer. 1975 to 1979.

Lake Worth Utilities **Lake Worth, FL**

Hearing Examiner. Presented technical information and the results of modeling during hearings on site certification for a new electrical generating plant. 1977.

Maxwell House Division, General Foods Corporation **Jacksonville, FL**

District Administrator of the Occupational Safety and Health Administration (OSHA). Testified in support of the noise reduction program at the Maxwell House can plant. 1975.

McGowan Working Partners **Jefferson Parrish, LA**

Judge for the Second Parish Court. Provided expert testimony related to the air emissions and dispersion of a short-term spill of 31% hydrochloric acid from a tank.

Metropolitan Dade County **Dade County, FL**

Provided expert testimony in the following:

- PSC. Provided direct written and oral testimony for an addition to the Metropolitan Dade County Resource Recovery Facility, Florida. Case was part of the Site Certification under Florida's Power Plant Siting Act and ruled before the Governor and Cabinet acting as the Siting Board. In these proceedings, the PSC certifies the need for the project. Testimony was related to the purpose and need for the addition to the facility. This included compliance with state rules and legislative intent related to the project. 1993.
- Hearing Examiner. Presented expert testimony on the environmental impacts of Dade County Resource Recovery Facility consisting of four steam generators and associated turbines generating 77 MW by firing refuse-derived fuel. Permit granted. 1977.

Kennard F. Kosky, M.S., P.E.

Mirant Corporation **Multiple Sites, MD**

Provided expert testimony for the following:

- PSC Hearing Officer. Provided testimony on air quality aspects of the installation of FGD systems for the Morgantown Generating Plant Units 1 and 2. 2007
- PSC Hearing Officer. Provided testimony on air quality aspects of the installation of FGD systems for the Chalk Point Generating Plant Units 1 and 2. 2007.
- PSC Hearing Officer. Provided testimony on all air-related analyses for the installation of FGD systems on Dickerson Generating Station Units 1 through 3. 2007.
- PSC Hearing Officer. Provided testimony on all air-related analyses for the Chalk Point Simple-Cycle Project.
- PSC Hearing Officer. Provided testimony on all air related analyses for the Dickerson Combined-Cycle Project. 2001 and 2002.

Montenay Power Corporation **Miami-Dade County, FL**

Miami-Dade County Community Zoning Appeals Board. Provided expert testimony on the potential impacts of an existing resource recovery facility on a parcel of land being re-zoned from industrial to residential. Testimony included air quality impacts from fugitive dusts and odors as well as noise.

O.K.C. Cement **Sumter County, FL**

FDER Administrative Hearing. Testified about the results of atmospheric dispersion modeling and air quality analysis during hearings about significant deterioration. 1977.

Potomac Electric Power Company — Provided expert testimony for the following:

- Hearing Examiner. Provided expert testimony for Chalk Point CTs (two 100-MW and two 80-MW). Testimony focused on siting and overall environmental impacts. 1988 to 1989.
- Hearing Examiner. Preparation and presentation of direct and rebuttal testimony on the environmental aspects of siting a coal gasification combined-cycle power plant. Case involved the Maryland Public Service Commission. 1987 to 1988.

Seminole Electric Cooperative Incorporated

Provided expert testimony for the following:

- Hearing Examiner. Provided direct written and oral testimony for 440-MW combined-cycle power plant located in Hardee County, Florida. Case was part of the Site Certification under Florida's Power Plant Siting Act and ruled before the Governor and Cabinet acting as the Siting Board. Testimony was related to the air pollution control technology, BACT, and noise impacts. 1995.
- Hearing Examiner. Provided expert testimony on air emissions, noise, and BACT for the Hardee Power Station, a 600-MW combined-cycle facility in central Florida. 1990.

Tampa Electric Company (TECO) **Tampa, FL**

Provided expertise for the following:

- FERC. Prepared testimony based on the results of modeling and other technical data in support of the contention that TECO's Big Bend Unit 3 was an existing source and thus could burn higher sulfur fuel. 1976.
- Fifth Circuit Court of Appeals. Assisted in the preparation of legal briefs for litigation of the EPA's ruling concerning SIP revision. Case involved atmospheric dispersion modeling. 1976.
- Hillsborough County Environmental Regulatory Commission. Prepared reports and testimony on air quality standards and significant deterioration. 1976.

Kennard F. Kosky, M.S., P.E.

- FDER Administrative Hearing. Prepared testimony in support of TECO's proposed use of high sulfur fuel. Technical information and the results of atmospheric dispersion modeling were presented during hearings on significant deterioration of air quality. 1976.
- EPA Region IV Administrator. Testified in opposition to the Administrator's ruling regarding TECO's proposed use of high sulfur fuel. 1975.

TexasGulf, Inc. **NC**

Assisted senior counsel in responding to a Notice of Violation from the State of North Carolina. Provided technical expertise and reports for submittal to court. 1981.

The Viera Company **Brevard County, FL**

Assisted senior counsel in the mediation involving odors and air quality impacts of a revised air pollution permit. Provided technical expertise and review of reports. 1999.

Woodward Hall & Primm **Houston, TX**

Assisted senior counsel in the toxic tort suit involving the Motco Superfund Site. Technical expert for air monitoring and air quality impacts. Provided technical expertise, review of plaintiff's reports, and provided independent reports.

Kennard F. Kosky, M.S., P.E.

PUBLICATIONS

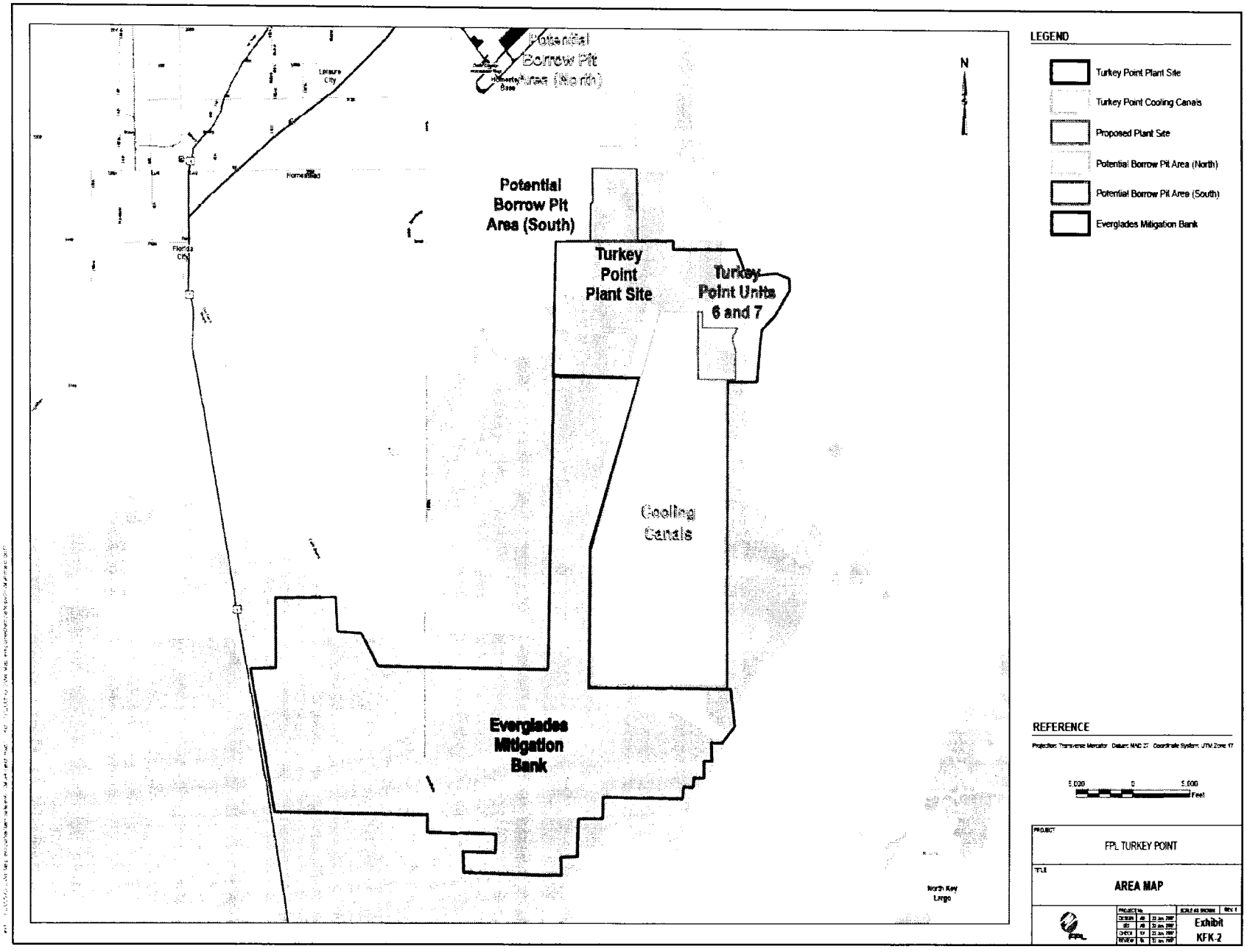
Mr. Kosky has authored and coauthored hundreds of reports and permits submitted to regulatory agencies. He has authored and coauthored over a dozen articles related to air pollution topics (i.e., emission estimates, air impacts, and permitting) and licensing power generation facilities.

LANGUAGES

English (Native Speaker)
Spanish (Read)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 67
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-2)
DATE 01/30 - 02/01/08

Docket No. 07____-EI
Graphical Representation of Turkey Point Site
Exhibit KFK-2, Page 1 of 1



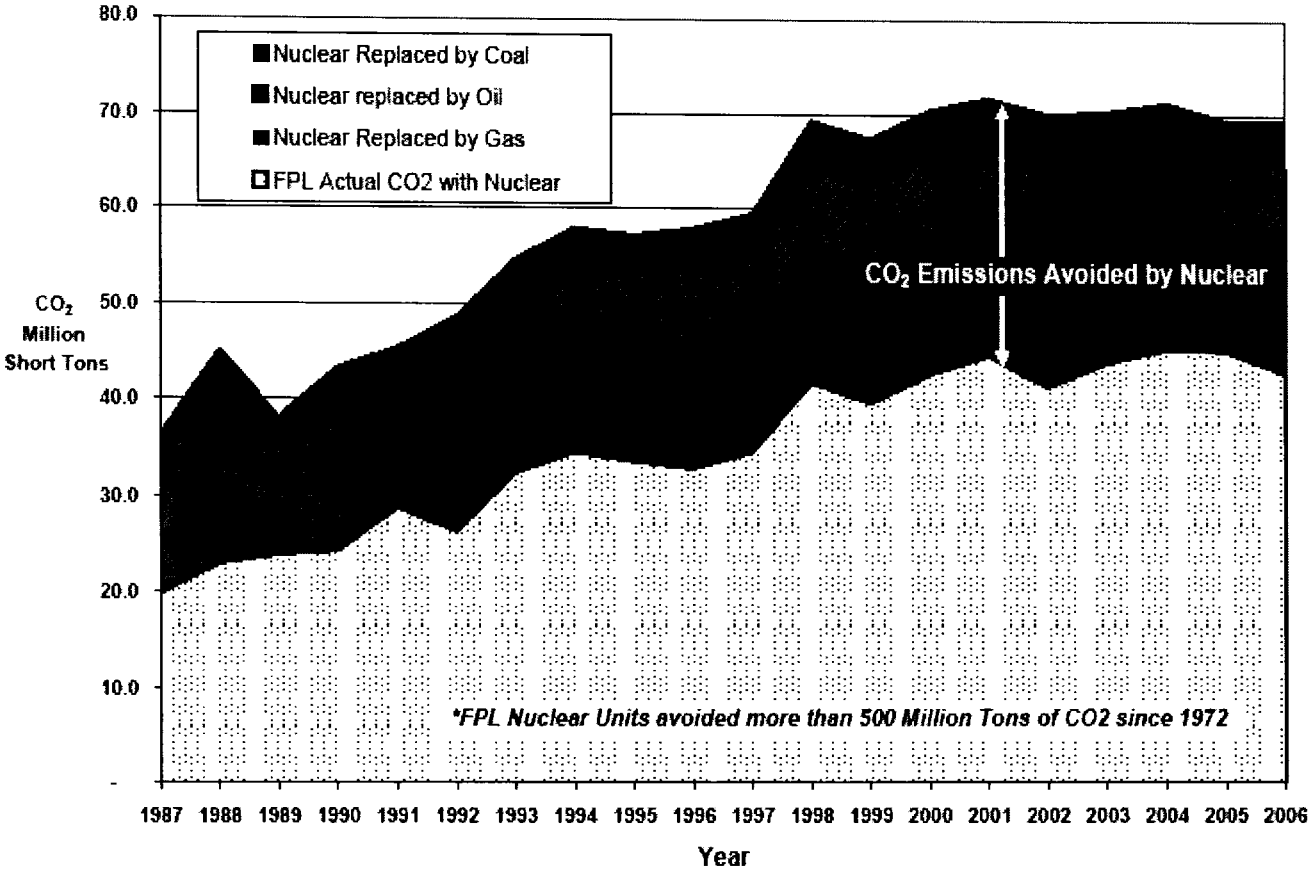
Fossil-Fuel and Air Emissions Displaced by FPL's Nuclear Units Since Initial Operation as of 2006

Type of Generation	Displaced Fossil Fuel		Air Emission (tons) SO_2	Air Emission (tons) NO_x	Air Emission (tons) CO_2
800 MW Class Oil-Fired Unit	1,059,866,309	barrels	2,591,098	817,341	542,692,203
Mid-1970's Vintage Gas-Fired Combined Cycle Unit	6,472,387	million cubic feet	3,964	1,100,218	356,821,733
Late-1970's Vintage Coal-Fired Unit	279,052,285	tons of coal	1,382,132	1,554,697	666,471,118

Docket No. 07____-EI
Fossil Fuel and Air Emissions Displaced by FPL's Nuclear Units Since Initial Operation as of 2006
Exhibit KFK-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 68
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-3)
DATE 01/30 - 02/01/08

Florida CO_2 Emissions Avoided By FPL Nuclear Units

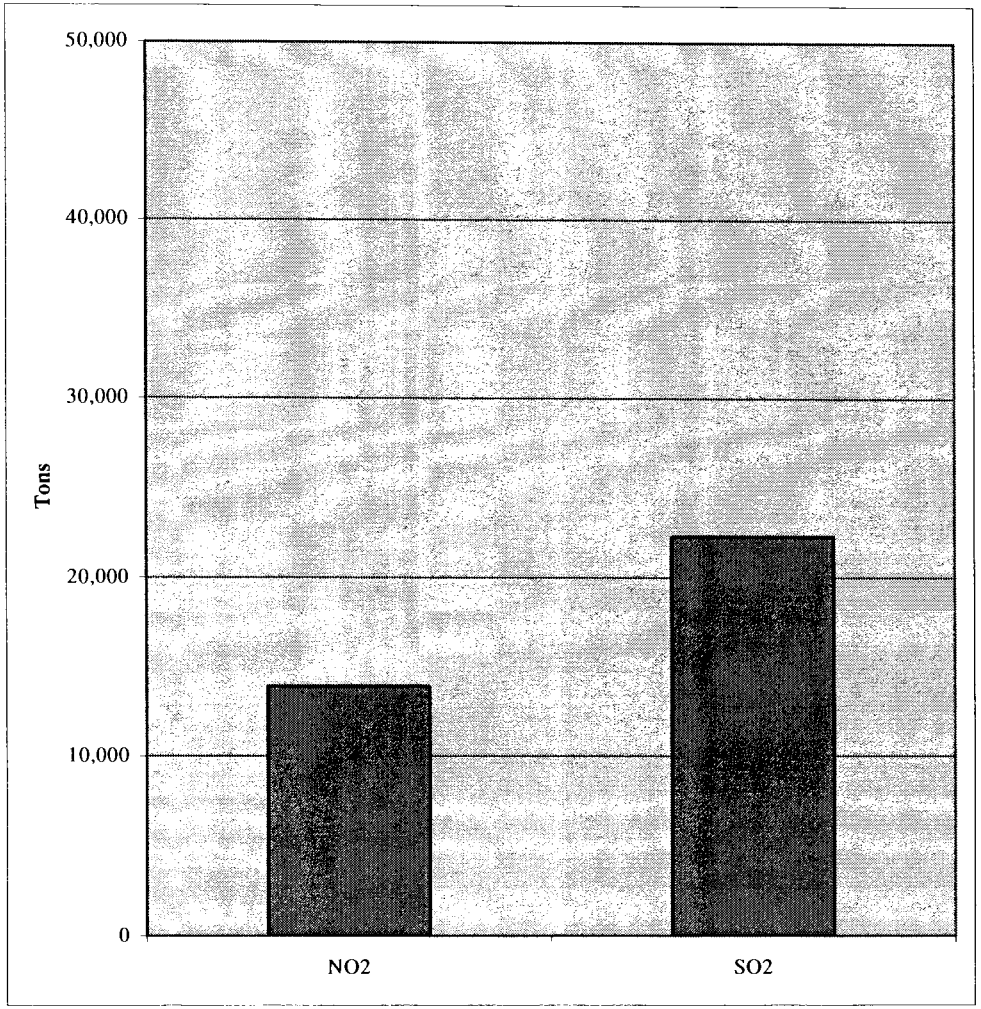


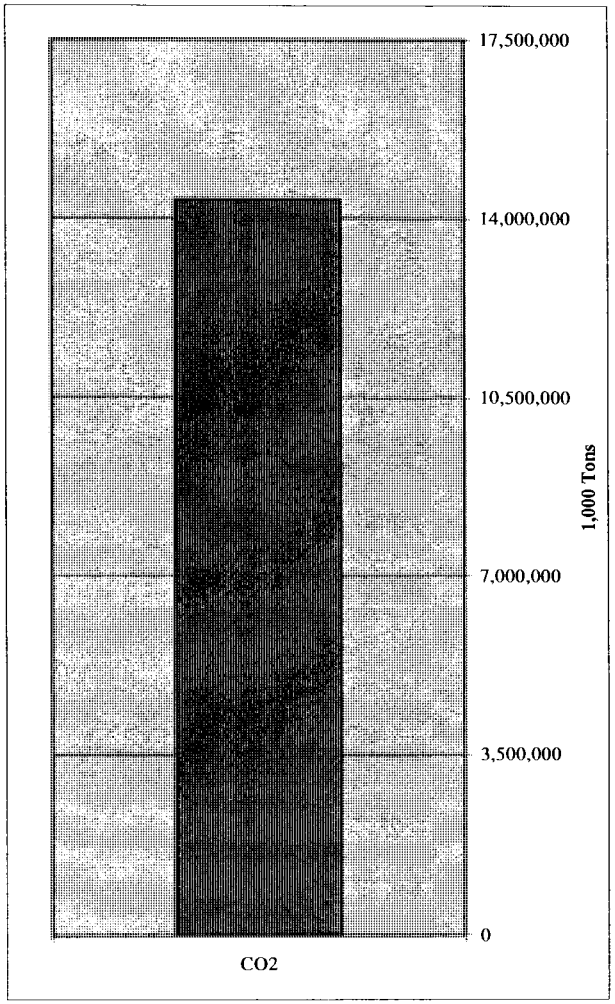
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 69
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-4)
DATE 01/30 - 02/01/08

Docket No. 07____-EI
Florida CO_2 Emissions Avoided by FPL Nuclear Units
Exhibit KFK-4, Page 1 of 1

AVOIDED AIR EMISSIONS FROM FPL'S NUCLEAR GENERATION IN 2006

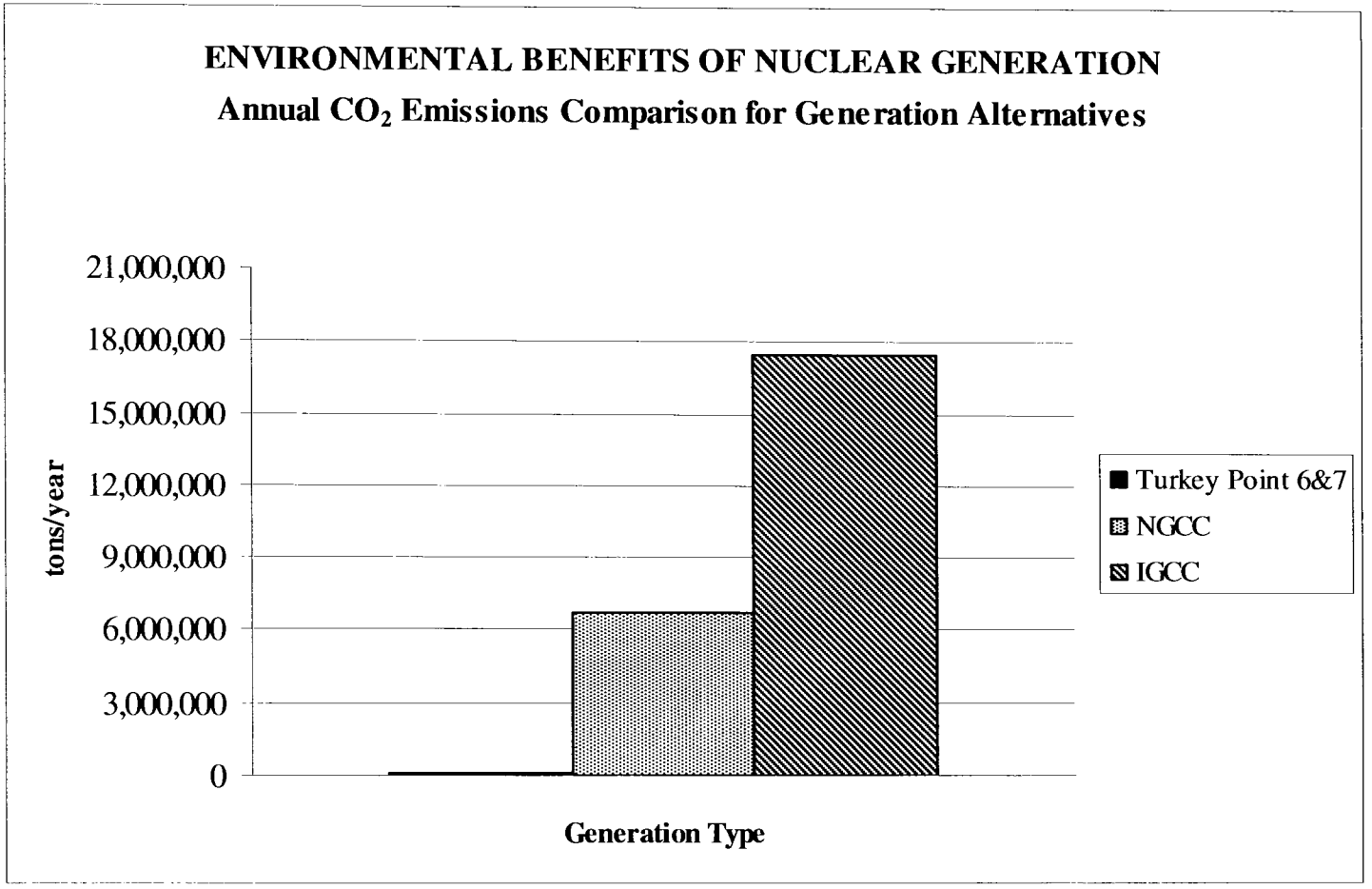
ENVIRONMENTAL BENEFITS





FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 70
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-5)
DATE 01/30 - 02/01/08

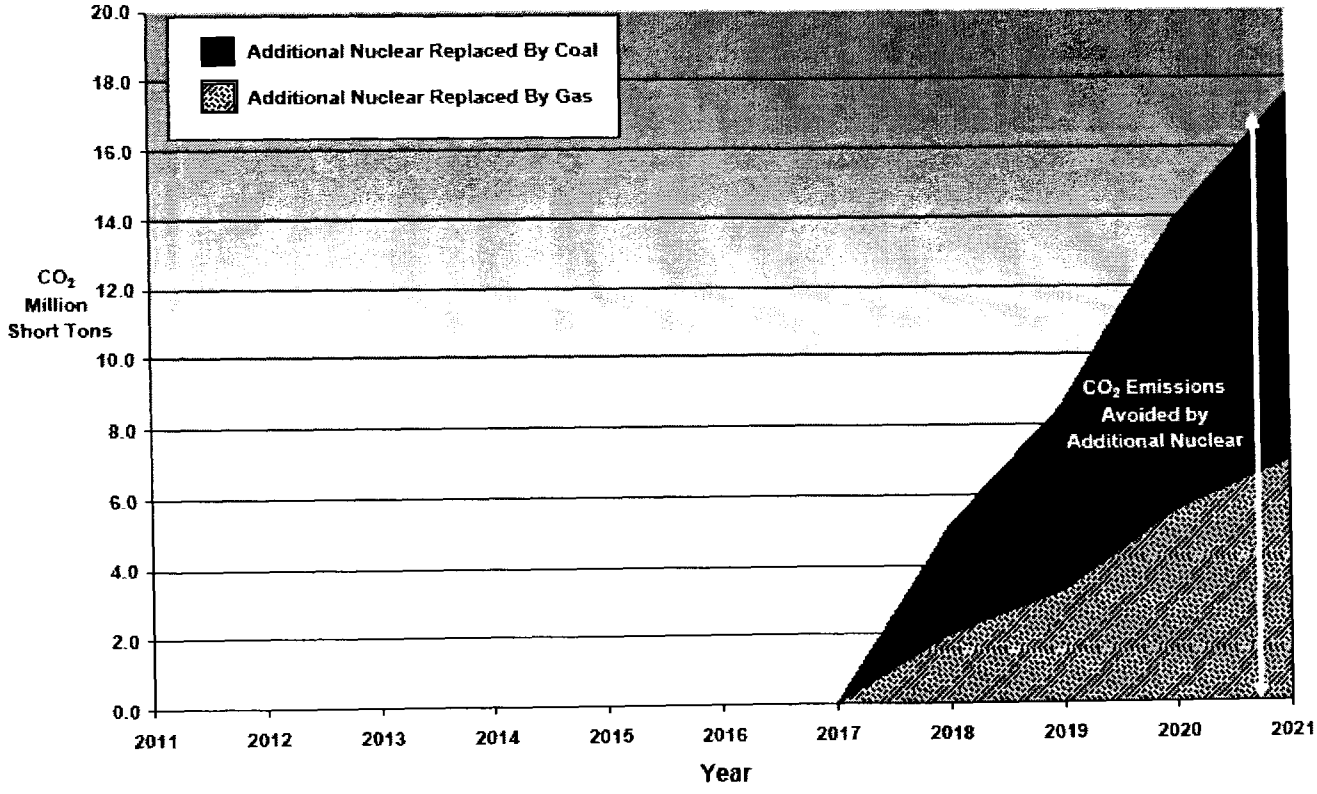
Docket No. 07____-EI
Avoided Air Emissions from FPL's Nuclear Generation in 2006
Exhibit KFK-5, Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 71
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-6)
DATE 01/30 - 02/01/08

Docket No. 07____-EI
Environmental Benefits of Nuclear Generation
Exhibit KFK-6, Page 1 of 1

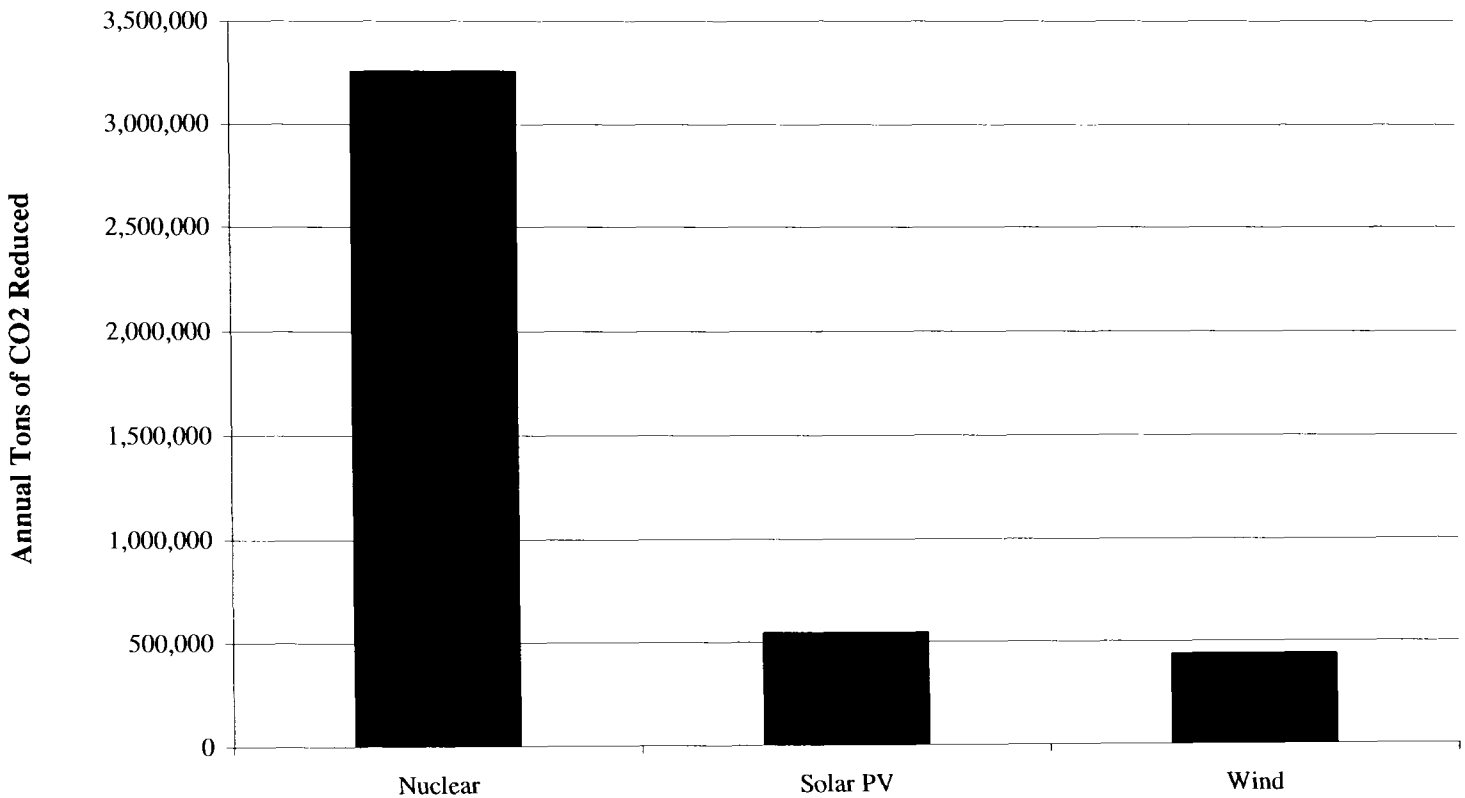
Future Annual CO_2 Emissions Avoided By FPL New Nuclear Generation



Docket No. 07____-EI
Future Annual CO_2 Emissions Avoided by FPL New Nuclear Generation
Exhibit KFK-7, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 72
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-7)
DATE 01/30 - 02/01/08

Reduction in Annual CO_2 Emissions Achieved by Adding 1000 MW of Non-Emitting CO_2 Generation Alternatives in Florida



Notes:

1. Annual CO2 reduction value for Solar PV does not account for the annual degradation of Solar PV (typically, 1% per year).
2. Assumes all options reduce operation of gas-fired capacity with an average heat rate of 7,500 BTU/kwh and a CO2 emission rate of 110 lbs/mmBTU and that annual capacity factors are 90% for nuclear, 15% for Solar PV and 12% for wind.

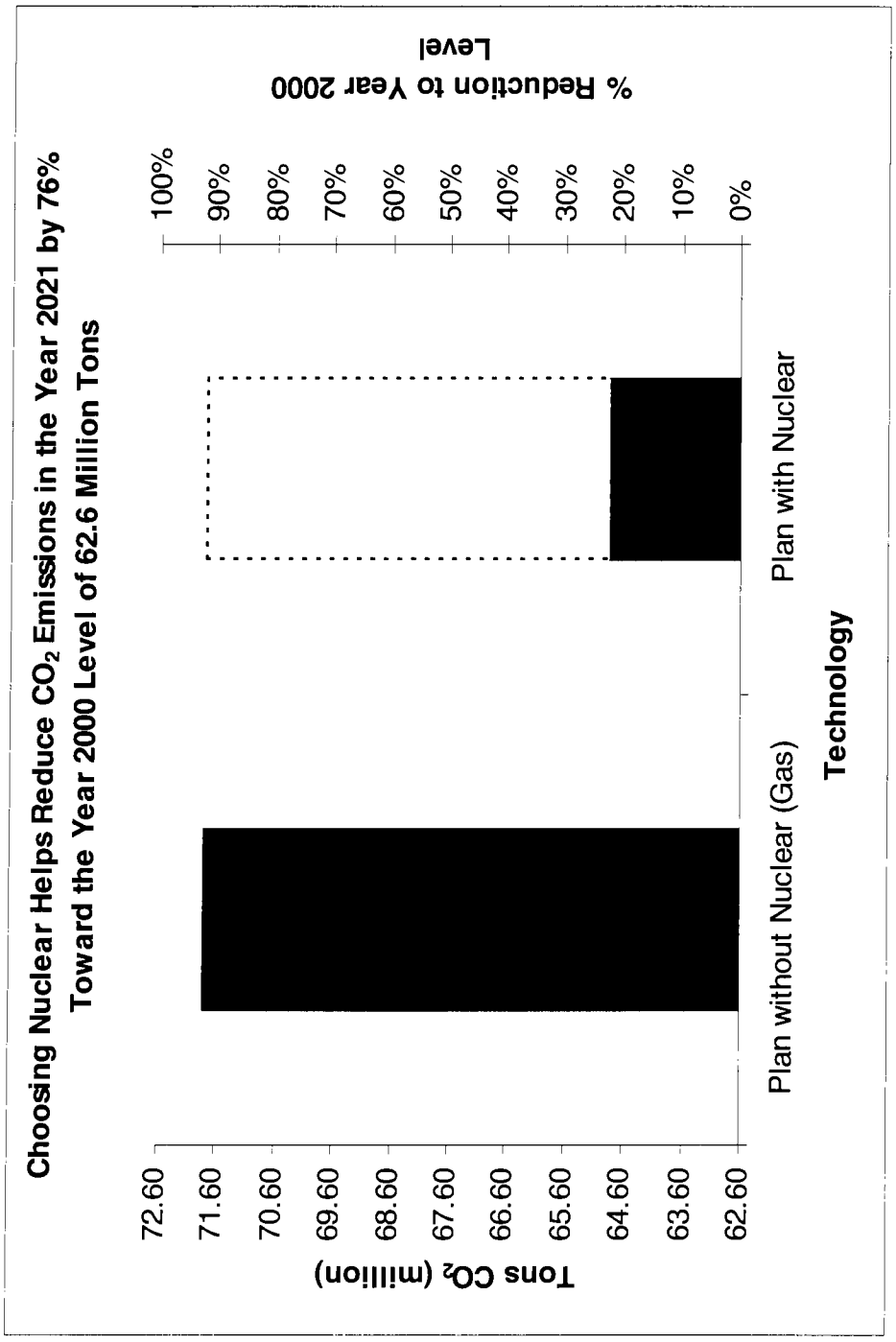
Docket No. 07____-EI
Reduction in Annual CO_2 Emissions Achieved by Adding 1000 MW of Non-Emitting CO_2 Generation Alternatives in Florida
Exhibit KFK-8, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 73
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-8)
DATE 01/30 - 02/01/08

Docket No. 07____-EI

Choosing Nuclear Helps Reduce CO_2 Emissions in the Year 2021 by 76% Toward the Year 2000 Level of 62.6 Million Tons

Exhibit KFK-9, Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 74
COMPANY Florida Power & Light (Direct)
WITNESS Kennard F. Kosky (KFK-9)
DATE 01/30 - 02/01/08

Summary of Required Facilities for Turkey Point 6 & 7

Base Facilities required for two 1,100 MW net units.

Transmission Facility Item #	Voltage (kV)	Description
TF-1	500	The connection of Turkey Point # 6 Generator Step Up (GSU) transformer to the new Turkey Point switchyard, and attendant bus equipment.
TF-2	500	The connection of Turkey Point # 7 Generator Step Up (GSU) transformer to the new Turkey Point switchyard, and attendant bus equipment.
TF-3	500	The new Turkey Point 500/230 kV switchyard.
TF-4	500	The two 500 kV transmission lines from the new Turkey Point switchyard to Levee Substation. (Approximately 42 miles each)
TF-5	230	The 230 kV transmission line from the Levee Substation to the Gratigny Substation. (Approximately 13 miles)
TF-6	230	Rebuild and rerouting of the existing Turkey Point-Davis #1 230 kV line to the new Turkey Point 230 kVswitchyard.
TF-7	230	Replace the line removed from the existing Turkey Point switchyard with a new line from the existing Turkey Point switchyard to Levee 230 kV. (Approximately 42 miles)
TF-8	230	Upgrade Killian-Turkey Point 230 kV line
TF-9	230	Upgrade Turkey Point-Galloway Tap 230 kV line
TF-10	138	Upgrade Davis-Montgomery 138 kV line
TF-11	138	Upgrade Dadeland Tap-Snapper Creek 138 kV line
TF-12	230	Two 5-Ohm Reactors installed on the 230 kV side of the autotransformers at Levee Substation (one per auto)
TF-13	230	Two 5-Ohm Reactors installed on the 230 kV side of the autotransformers at Andytown Substation (one per auto)
TF-14	230	Two 5-Ohm Reactors installed on the 230 kV buses at the existing Turkey Point 230 kV switchyard.

Additional Facilities required for two 1,520 MW net units.

TF-15	230	Upgrade Killian-Miller 230 kV line
TF-16	138	Upgrade Mitchell-Court 138 kV line
TF-17	138	Upgrade Kendall-Suniland 138 kV line
TF-18	138	Upgrade Marion-Village Green 138 kV line
TF-19	138	Upgrade Marion-Montgomery 138 kV line

Note: These facilities do not include other potential facilities that may be required to mitigate the effect of the largest unit in the FRCC being larger than 1,200 MW gross output.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 75
COMPANY FL Power & Light (Direct)
WITNESS Hector J. Sanchez (HJS-1)
DATE 01/30 - 02/01/08

Projection of FPL's 2007 - 2020 Capacity Needs
(without New Capacity Additions)

Summer

August of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Summer DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Summer Reserves (MW)	(8)=(7)/(6) Forecast of Summer Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) MW Needed to Meet 20% Reserve Margin (MW)
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	23,370	2,562	25,932	23,435	2,034	21,401	4,531	21.2%	(251)
2010	24,589	2,205	26,794	24,003	2,146	21,857	4,937	22.6%	(566)
2011	24,589	2,255	26,844	24,612	2,264	22,348	4,496	20.1%	(26)
2012	24,899	2,193	27,092	25,115	2,388	22,727	4,365	19.2%	**180**
2013	25,003	2,193	27,196	25,590	2,516	23,074	4,122	17.9%	**493**
2014	25,003	2,193	27,196	26,100	2,651	23,449	3,747	16.0%	**943**
2015	25,003	2,193	27,196	26,772	2,790	23,982	3,214	13.4%	**1,582**
2016	25,003	882	25,885	27,410	2,910	24,500	1,385	5.7%	**3,515**
2017	25,003	882	25,885	28,079	3,030	25,049	836	3.3%	**4,174**
2018	25,003	882	25,885	28,737	3,150	25,587	298	1.2%	**4,819**
2019	25,003	882	25,885	29,391	3,270	26,121	(236)	-0.9%	**5,460**
2020	25,003	882	25,885	30,091	3,390	26,701	(816)	-3.1%	**6,156**

Winter

January of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Winter DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Winter Reserves (MW)	(8)=(7)/(6) Forecast of Winter Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) MW Needed to Meet 20% Reserve Margin (MW)
2007	22,294	3,862	26,156	22,247	1,555	20,692	5,464	26.4%	(1,326)
2008	23,503	3,026	26,529	22,627	1,649	20,978	5,551	26.5%	(1,355)
2009	23,531	2,700	26,231	23,115	1,750	21,365	4,866	22.8%	(593)
2010	24,866	2,239	27,105	23,587	1,814	21,773	5,332	24.5%	(977)
2011	26,201	2,238	28,439	24,047	1,883	22,164	6,275	28.3%	(1,842)
2012	26,305	2,382	28,687	24,498	1,954	22,544	6,143	27.2%	(1,634)
2013	26,615	2,202	28,817	24,952	2,028	22,924	5,893	25.7%	(1,308)
2014	26,615	2,202	28,817	25,416	2,106	23,310	5,507	23.6%	(845)
2015	26,615	2,202	28,817	26,048	2,188	23,860	4,957	20.8%	(185)
2016	26,615	882	27,497	26,692	2,264	24,428	3,069	12.6%	**1,817**
2017	26,615	882	27,497	27,342	2,334	25,008	2,489	10.0%	**2,513**
2018	26,615	882	27,497	27,994	2,404	25,590	1,907	7.5%	**3,211**
2019	26,615	882	27,497	28,649	2,474	26,175	1,322	5.1%	**3,913**
2020	26,615	882	27,497	29,308	2,544	26,764	733	2.7%	**4,620**

* No new FPL generating unit additions after WCEC 1 in 2009 and WCEC 2 in 2010 are assumed to be added. 287 MW of renewable energy firm capacity purchases starting in the 2009 - 2012 time frame are assumed to be added. 414 MW of the proposed nuclear uprates is assumed. Approximately 104 MW are added in December 2011, 103 MW in May 2012, 103 MW in June 2012, and 104 MW by December 2012.

** DSM values shown represent cumulative load management and incremental conservation capability.

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Projection of FPL's 2007 - 2020 Capacity Needs
Exhibit SRS-1, Page 1 of 1

Projected Incremental FPL DSM: 2006 - 2020

Year	DSM Projected by FPL (Summer MW at Generator) (1)
2006	1,491
2007	1,768
2008	1,908
2009	2,034
2010	2,146
2011	2,264
2012	2,388
2013	2,516
2014	2,651
2015	2,790
2016	2,910
2017	3,030
2018	3,150
2019	3,270
2020	3,390
Incremental DSM MW from 2006 through 2020 =	1,899

Notes: (1) The DSM Summer MW shown are from column (5) in Exhibit SRS -1 and reflect projected DSM signups from 8/2006 through 8/2020. These values reflect FPL's DSM Goals through 2014 plus additional DSM through 2014 identified as cost-effective after the DSM Goals were established and for which Commission approval has been obtained. These values also include a projected continuation of DSM signups for 2015 - 2020.

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Projection of FPL's 2007 - 2020 Capacity Needs: With Turkey Point 6 and 7

Summer

August of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Summer DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Summer Reserves (MW)	(8)=(7)/(6) Forecast of Summer Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) MW Needed to Meet 20% Reserve Margin (MW)
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	23,370	2,562	25,932	23,435	2,034	21,401	4,531	21.2%	(251)
2010	24,589	2,205	26,794	24,003	2,146	21,857	4,937	22.6%	(566)
2011	24,589	2,255	26,844	24,612	2,264	22,348	4,496	20.1%	(26)
2012	24,899	2,193	27,092	25,115	2,388	22,727	4,365	19.2%	**180**
2013	25,003	2,193	27,196	25,590	2,516	23,074	4,122	17.9%	**493**
2014	25,003	2,193	27,196	26,100	2,651	23,449	3,747	16.0%	**943**
2015	25,003	2,193	27,196	26,772	2,790	23,982	3,214	13.4%	**1,582**
2016	25,003	882	25,885	27,410	2,910	24,500	1,385	5.7%	**3,515**
2017	25,003	882	25,885	28,079	3,030	25,049	836	3.3%	**4,174**
2018	26,103	882	26,985	28,737	3,150	25,587	1,398	5.5%	**3,719**
2019	26,103	882	26,985	29,391	3,270	26,121	864	3.3%	**4,360**
2020	27,203	882	28,085	30,091	3,390	26,701	1,384	5.2%	**3,956**

Winter

January of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Winter DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Winter Reserves (MW)	(8)=(7)/(6) Forecast of Winter Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) MW Needed to Meet 20% Reserve Margin (MW)
2007	22,294	3,862	26,156	22,247	1,555	20,692	5,464	26.4%	(1,326)
2008	23,503	3,026	26,529	22,627	1,649	20,978	5,551	26.5%	(1,355)
2009	23,531	2,700	26,231	23,115	1,750	21,365	4,866	22.8%	(593)
2010	24,866	2,239	27,105	23,587	1,814	21,773	5,332	24.5%	(977)
2011	26,201	2,238	28,439	24,047	1,883	22,164	6,275	28.3%	(1,842)
2012	26,304	2,382	28,686	24,498	1,954	22,544	6,142	27.2%	(1,633)
2013	26,615	2,202	28,817	24,952	2,028	22,924	5,893	25.7%	(1,308)
2014	26,615	2,202	28,817	25,416	2,106	23,310	5,507	23.6%	(845)
2015	26,615	2,202	28,817	26,048	2,188	23,860	4,957	20.8%	(185)
2016	26,615	882	27,497	26,692	2,264	24,428	3,069	12.6%	**1,817**
2017	26,615	882	27,497	27,342	2,334	25,008	2,489	10.0%	**2,513**
2018	26,615	882	27,497	27,994	2,404	25,590	1,907	7.5%	**3,211**
2019	27,715	882	28,597	28,649	2,474	26,175	2,422	9.3%	**2,813**
2020	27,715	882	28,597	29,308	2,544	26,764	1,833	6.8%	**3,520**

* This exhibit is identical to Exhibit SRS-1 except that 1,100 MW from Turkey Point 6 are assumed to be added in June 2018 and 1,100 MW from Turkey Point 7 are assumed to be added in June 2020.

** DSM values shown represent cumulative load management and incremental conservation capability.

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Projection of FPL's 2007 - 2020
Capacity Needs: with Turkey
Point 6 and 7
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The Three Resource Plans Utilized in the Analyses

Plan with Nuclear	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 - 2040
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	Turkey Point 6	(none)	Turkey Point 7	38 - 2x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,100	0	1,100	21,014
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	5,983	5,983	7,083	28,097
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	22.9%	20.4%	21.9%	(all meet criteria)

Plan without Nuclear - CC	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 - 2040
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	3x1 CC	(none)	3x1 CC	38 - 2x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,219	0	1,219	21,014
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,102	6,102	7,321	28,335
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.4%	20.9%	22.8%	(all meet criteria)

Plan without Nuclear - IGCC	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 - 2040
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	2 - IGCC	(none)	2 - IGCC	38 - 2x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,200	0	1,200	21,014
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,083	6,083	7,283	28,297
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.3%	20.8%	22.7%	(all meet criteria)

Notes: - assumes extension of DSM implementation through 2020 at currently planned implementation rates for 2012 - 2014 time frame
- assumes extension of three expiring waste-to-energy purchases and addition of three renewable energy capacity purchases totaling 287 MW
- assumes no peak load or annual energy growth after 2040

* One of the four nuclear uprates is scheduled to occur in Dec 2011, one in May 2012, one in June 2012, and one in Dec 2012. Because the 2011 uprate will occur after the Summer of 2011, for reserve margin calculation purposes the first three uprates are accounted for starting with the 2012 Summer reserve margin calculation. The fourth uprate is accounted for starting with the 2013 Summer reserve margin calculat

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The Three Resource Plans
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COMPANY Florida Power & Light (Direct)
WITNESS Dr. Steven R. Sim (SRS-4)
DATE 01/30 - 02/01/08

Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario:

(millions, CPVRR, 2007$, 2007 - 2060)

Fuel Cost Forecast = High Gas Cost

Environmental Compliance Cost Forecast = Env I

Resource Plan	(1) System Costs: Fixed Costs *	(2) System Costs: Variable Costs **	(3) = (1) + (2) System Costs: Total Costs	(4) Difference from Lowest Cost Plan
Plan with Nuclear	22,676	198,228	220,904	0
Plan without Nuclear - CC	23,684	209,368	233,052	12,148
Plan without Nuclear - IGCC	30,171	204,002	234,173	13,269

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation. (Note that nuclear generation and transmission capital costs are assumed to be zero in this analysis.)

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

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Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario
Exhibit SRS-5, Page 1 of 1

Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

(millions, CPVRR, 2007$, 2007 - 2060)

(1)	(2)	(3)	(4)	(5)	(6) = (3) - (4)	(7) = (3) - (5)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans			Total Cost Difference Plan with Nuclear - Plan without Nuclear - CC	Total Cost Difference Plan with Nuclear - Plan without Nuclear - IGCC
		Plan with Nuclear	Plan without Nuclear - CC	Plan without Nuclear - IGCC		
High Gas Cost	Env I	220,904	233,052	234,173	(12,148)	(13,269)
High Gas Cost	Env II	233,322	246,544	249,099	(13,222)	(15,777)
High Gas Cost	Env III	242,937	256,648	259,966	(13,711)	(17,029)
High Gas Cost	Env IV	252,296	266,663	270,943	(14,367)	(18,647)
Medium Gas Cost	Env I	170,391	179,356	182,648	(8,965)	(12,257)
Medium Gas Cost	Env II	182,700	192,694	197,474	(9,994)	(14,774)
Medium Gas Cost	Env III	192,190	202,702	208,218	(10,512)	(16,028)
Medium Gas Cost	Env IV	201,428	212,635	219,099	(11,207)	(17,671)
Low Gas Cost	Env I	129,850	136,175	141,533	(6,325)	(11,683)

Note: A negative value in Columns (6) and/or (7) indicates that the Plan with Nuclear is less expensive than the comparative Plan without Nuclear (CC or IGCC). Conversely, a positive value in Columns (6) and/or (7) indicates that the Plan with Nuclear is more expensive than the comparative Plan without Nuclear (CC or IGCC).

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Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios
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Economic Analysis Results: Matrix of Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

Plan with Nuclear - Plan without Nuclear-CC

Total Cost Differentials
(millions, CPVRR, 2007$, 2007 - 2060)

		Fuel Cost Forecasts		
		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental Compliance Cost Forecasts	Env I	(12,148)	(8,965)	(6,325)
	Env II	(13,222)	(9,994)	
	Env III	(13,711)	(10,512)	
	Env IV	(14,367)	(11,207)	

Plan with Nuclear - Plan without Nuclear-IGCC

Total Cost Differentials
(millions, CPVRR, 2007$, 2007 - 2060)

		Fuel Cost Forecasts		
		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental Compliance Cost Forecasts	Env I	(13,269)	(12,257)	(11,683)
	Env II	(15,777)	(14,774)	
	Env III	(17,029)	(16,028)	
	Env IV	(18,647)	(17,671)	

Note: A negative value indicates that the Plan with Nuclear is less expensive than the comparative Plan without Nuclear (CC or IGCC). Conversely, a positive value indicates that the Plan with Nuclear is more expensive than the comparative Plan without Nuclear (CC or IGCC).

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Economic Analysis Results: Matrix of Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios
Exhibit SRS-7, Page 1 of 1

Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios

Plan with Nuclear vs. Plan without Nuclear-CC

Breakeven Nuclear Capital Costs ($/kw in 2007$)

		Fuel Cost Forecasts		
		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental Compliance Cost Forecasts	Env I	6,157	4,543	3,206
	Env II	6,701	5,065	
	Env III	6,949	5,327	
	Env IV	7,281	5,680	

Plan with Nuclear vs. Plan without Nuclear-IGCC

Breakeven Nuclear Capital Costs ($/kw in 2007$)

		Fuel Cost Forecasts		
		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental Compliance Cost Forecasts	Env I	6,725	6,212	5,921
	Env II	7,996	7,487	
	Env III	8,630	8,123	
	Env IV	9,450	8,956	

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Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios
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Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7: 2009 - 2021

Scenario: Medium Gas Cost Env II

Year	(1) Plan with Nuclear Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan without Nuclear - CC Annual Total Revenue Requirements ($millions, Nominal $)	(3) = (1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000) Differential in System Average Electric Rates (cents/kwh)	(6) = ((5)x1,000) / 100 Differential in Customer Bill of 1,000 kwh ($)
2009	6,278	6,160	118	116,870	$0.10	$1.01
2010	6,289	6,184	105	120,715	$0.09	$0.87
2011	6,364	6,253	111	124,562	$0.09	$0.89
2012	6,433	6,378	56	128,243	$0.04	$0.43
2013	6,922	6,763	159	131,170	$0.12	$1.21
2014	7,646	7,352	294	134,617	$0.22	$2.18
2015	8,733	8,270	463	138,217	$0.33	$3.35
2016	9,944	9,281	663	142,209	$0.47	$4.66
2017	10,768	9,924	843	145,542	$0.58	$5.80
2018	11,611	10,870	742	149,218	$0.50	$4.97
2019	12,489	11,898	591	152,896	$0.39	$3.86
2020	13,077	12,907	170	157,170	$0.11	$1.08
2021	13,872	13,931	-59	161,572	-$0.04	-$0.36

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.
(3) For purposes of this analysis, a capital cost of $3800/kW (2007$) is assumed for both nuclear units.

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Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7: 2009 - 2021
Exhibit SRS-9, Page 1 of 1

Non-Economic Analysis Results: FPL System Fuel Mix Projections by Plan

Scenario: High Gas Cost Env III

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2018	7.3%	69.6%	2.0%	20.8%	0.3%	7.3%	73.3%	1.8%	17.3%	0.3%	10.6%	69.7%	2.2%	17.3%	0.2%
2019	7.1%	67.6%	2.6%	22.3%	0.4%	7.1%	73.4%	2.4%	16.9%	0.2%	12.7%	67.4%	2.8%	16.9%	0.2%
2020	7.0%	65.2%	1.9%	25.7%	0.2%	7.0%	74.5%	1.5%	16.7%	0.3%	15.4%	65.4%	2.2%	16.7%	0.3%
2021	6.6%	64.7%	1.9%	26.5%	0.3%	6.6%	74.9%	2.1%	16.1%	0.3%	17.2%	63.6%	2.9%	16.1%	0.2%

Scenario: Low Gas Cost Env I

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2018	6.6%	70.4%	1.9%	20.8%	0.3%	6.6%	74.1%	1.7%	17.3%	0.3%	9.9%	70.8%	1.8%	17.3%	0.2%
2019	6.5%	68.4%	2.5%	22.3%	0.3%	6.6%	74.1%	2.2%	16.9%	0.2%	12.0%	68.5%	2.3%	16.9%	0.3%
2020	6.4%	65.9%	1.7%	25.7%	0.3%	6.5%	75.2%	1.3%	16.7%	0.3%	14.9%	66.4%	1.7%	16.7%	0.3%
2021	6.2%	65.3%	1.7%	26.5%	0.3%	6.2%	75.5%	1.9%	16.1%	0.3%	16.7%	64.6%	2.4%	16.1%	0.2%

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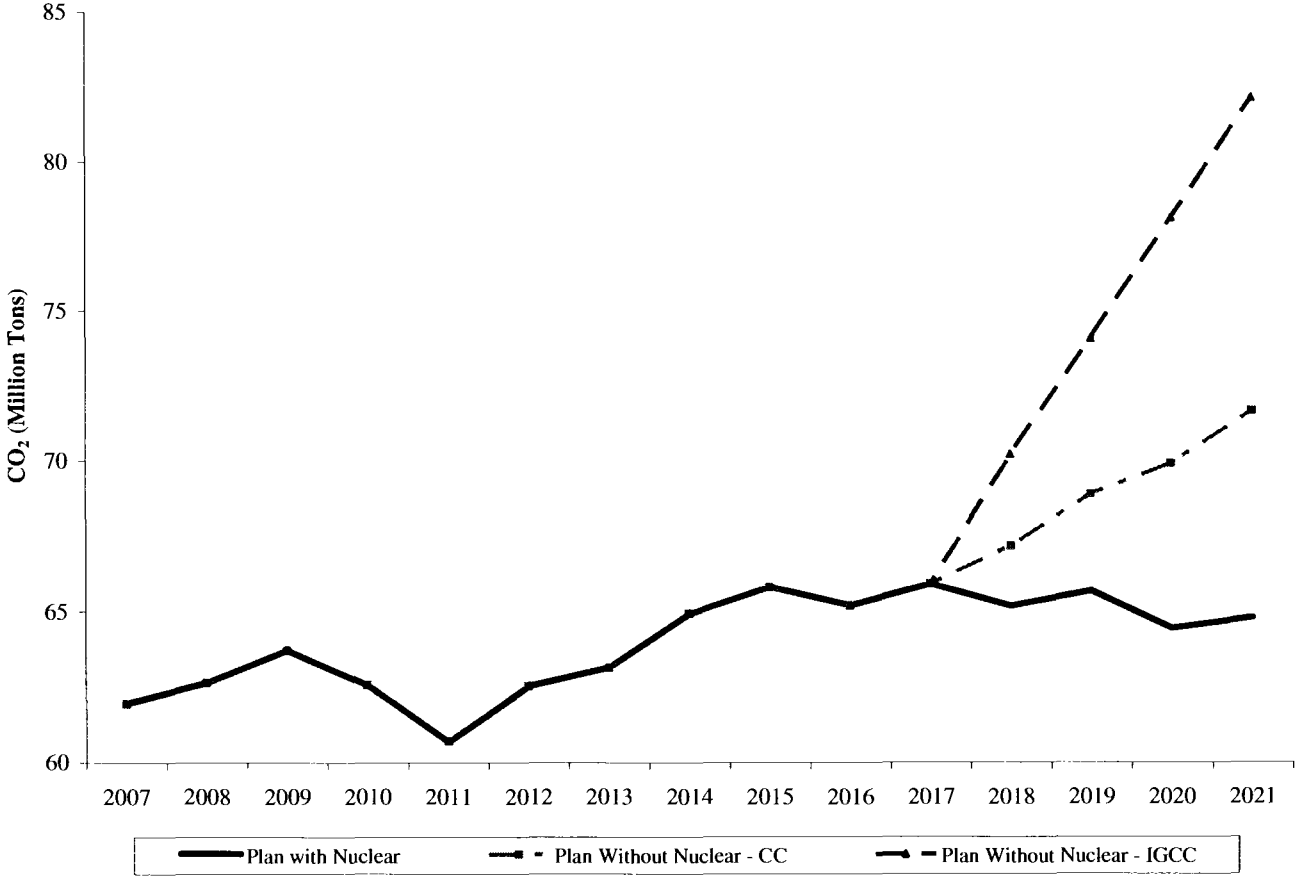
Non-Economic Analysis Results
System Fuel Mix Projections by Plan
Exhibit SRS-10, Page 1 of 1

Non-Economic Analysis Results:
FPL System CO_2 Emissions Projection by Plan



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WITNESS Dr. Steven R. Sim (SRS-11)
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Non-Economic Analysis results: FPL
FPL System CO2 Emissions
Exhibit SRS-11, Page 1 of 1

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 25 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 125 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join CEA as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 20 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 87
COMPANY Florida Power + Light (Direct)
WITNESS John J. Reed (JJR-1)
DATE 01/30 - 02/01/08

Litigation Support and Expert Testimony

Provided expert testimony on more than 125 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)

Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

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BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

REGULATORY AGENCIES

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Colorado Public Utilities Commission				
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
Conn. Department of Public Utilities Control				
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline
District Of Columbia PSC				
Potomac Electric Power Company	3/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Direct)
Potomac Electric Power Company	5/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Supplemental Direct)
Potomac Electric Power Company	7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Rebuttal)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 88
COMPANY Florida Power + Light (Direct)
WITNESS John J. Reed (JJR-2)
DATE 01/30 - 02/01/08

Docket No. 07_____-EI
Expert Testimony of John J. Reed
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EXPERT TESTIMONY OF JOHN J. REED 1997-2007

Federal Energy Regulatory Commission				
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Cause No. 41746	Standby Charge

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Docket No. 99-0207	Direct Testimony, Valuation of Electric Generating Facilities
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Public Benefits
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Public Benefits
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Public Benefits
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Public Benefits
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Public Benefits
Maryland Public Service Commission				
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection (Direct)

Mass. Department of Public Utilities				
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Regulatory Issues
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	3/06	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
National Energy Board of Canada				
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Segmented Service
Brunswick Pipeline	9/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	3/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

New York Public Service Commission				
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Evaluate their use of storage
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage

Rhode Island Public Utilities Commission				
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Vermont Public Service Board				
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Tariff Filing
Green Mountain Power	7/98	Green Mountain Power	Docket No. 6107	Direct Testimony
Green Mountain Power	9/00	Green Mountain Power	Docket No. 6107	Rebuttal Testimony
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant

COURTS AND ARBITRATION

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices
State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

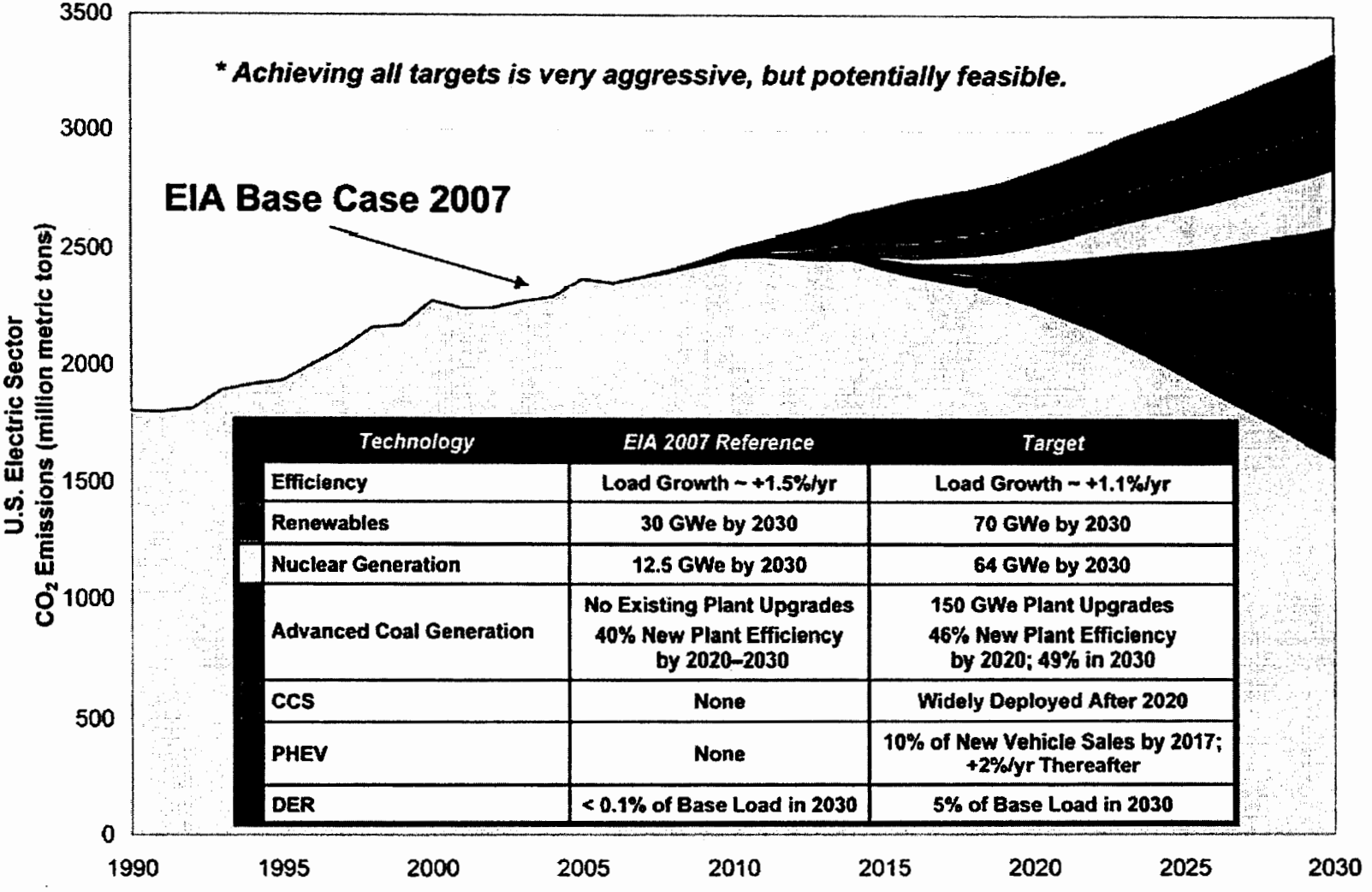
U. S. Court of Federal Claims				
Boston Edison Company	7/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way

EXPERT TESTIMONY OF JOHN J. REED 1997-2007

U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Expert Report, Shortnose Sturgeon Case
Central Hudson Gas & Electric	8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Revised Expert Report, Shortnose Sturgeon Case
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
District of Columbia Court City Council				
PEPCo	7/99		Bill 13-284	

Docket No. 07_____-EI
Expert Testimony of John J. Reed
Exhibit JJR-2, Page 11 of 11

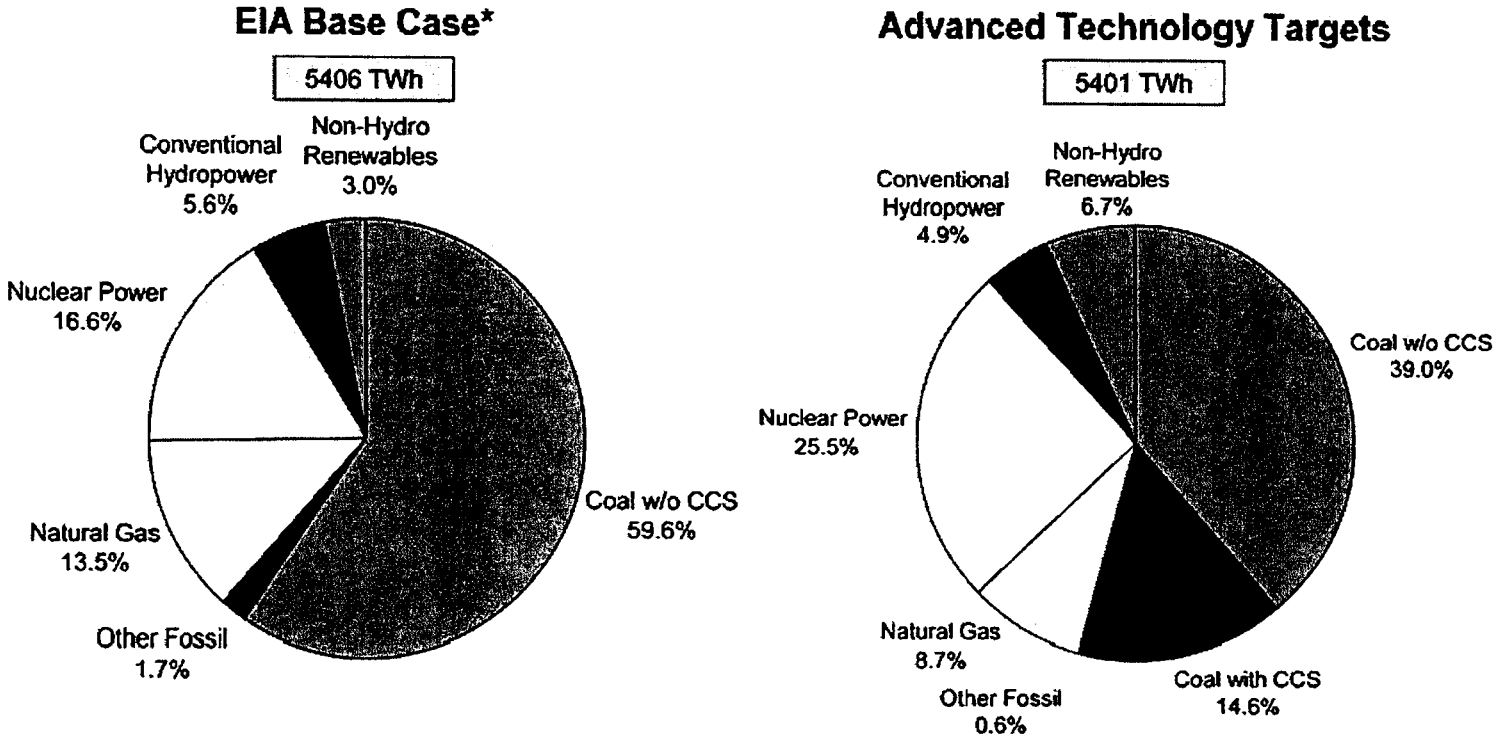
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 89
COMPANY Florida Power & Light (Direct)
WITNESS John J. Reed (JJR-3)
DATE 01/30 - 02/01/08



Technology	EIA 2007 Reference	Target
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr
Renewables	30 GWe by 2030	70 GWe by 2030
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

Source: "The Power to Reduce CO2 Emissions, The Full Portfolio", Electric Power Research Institute Energy Technology Assessment Center, August, 2007

Docket No.07_____-EI
CO_2 Reductions by Technology Type
Exhibit JJR-3, Page 1 of 1



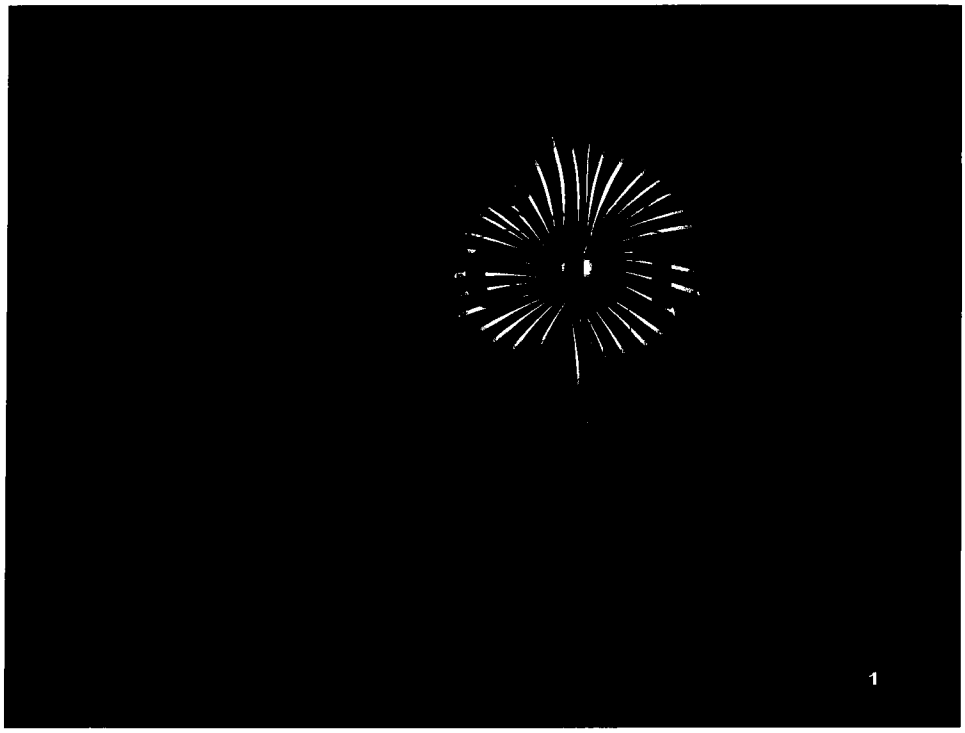
Base case from EIA "Annual Energy Outlook 2007"

Source: "The Power to Reduce CO2 Emissions, The Full Portfolio", Electric Power Research Institute Energy Technology Assessment Center, August, 2007.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 90
COMPANY Florida Power & Light (Direct)
WITNESS John J. Reed (JJR-4)
DATE 01/30 - 02/01/08

Docket No. 07____-EI
2007 US Electricity by Technology Sector vs. 2030 US Electricity by Technology Sector Including Advanced Technologies
Exhibit JJR-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 91
COMPANY
WITNESS Gordon Hansen Documents
DATE 01/30 - 02/01/08



1

NATIONAL SOLAR HOT WATER HEATING PROGRAM WILL....

- Save homeowners $72 billion /yr ($600 in electric bill /yr /customer)
- Save 600 billion lbs CO2 pollution /yr
- Reduce consumption by 980 billion kWh /yr
- Eliminate need for 112 power plants of 1,000 mega watts each
- Save mining 1,100 billion lbs coal /yr

2

Ex. 91

THE PLAN

BRIEFLY REVIEW SUN POWER
SOLAR ELECTRIC vs SOLAR HOT WATER
WHY UTILITIES DON'T FAVOR SOLAR
NUCLEAR POWER vs SOLAR HOT WATER
SOLAR HOT WATER ACHIEVABLE ALTERNATIVE
OTHER ENERGY SAVINGS
SUMMARY

SUN POWER

100 Watts PER SQUARE FOOT

Road 300 miles, 30 billion watts

10 times one NUCLEAR PLANT

SOLAR ELECTRIC vs SOLAR THERMAL PANELS

Solar ELECTRIC PANELS COST 28 X solar HOT WATER PANELS

Solar HOT WATER PANELS EFFICIENCY 7 X solar ELECTRIC PANELS

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SOLAR ELECTRIC vs SOLAR HOT WATER SYSTEMS

Solar ELECT COST 6 X HOT WATER

Solar ELECT 8 X INCENTIVE $

Solar HOT WATER 1/6 INCENTIVE $

Solar ELECT INCENTIVE $ CAN BUY 6 solar HOT WATER SYSTEMS

6

UTILITIES DON'T APPEAR TO FAVOR SOLAR

- Don't MESS with MY GRIDS
- Solar ELECT does not reduce CAPACITY.....Except for A/C
- Solar HOT WATER does reduce CAPACITY.....Lose $600 /yr /cust
- With solar HOT WATER no need for additional POWER PLANTS
- Utilities conflicting positions

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SOLAR HOT WATER offsets NUCLEAR POWER PLANT

If 1/3 of FPL's 4.2 million customers had Solar HOT WATER of 2800W = 1.4 M x 2800 W x 8 hr = 31,360 MWh/day

NUCLEAR SYSTEM

1,100 MW x 24 hr = 26,400 MWh/day

2.8 M customers offset 2 NUCLEAR

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NUCLEAR POWER vs SOLAR HOT WATER

System cost	$12 - $15 B ?	$14 B
Gov incentives	$?	$5.6 B
Benefit foreign country	$?	$0
Save customer /yr	$0	$600
Save customers /yr	$0	$1.7 B
Disbursed power	None	7,840 Mw
Vulnerability terrorist	Great ?	None
Vulnerability meltdown	Small ?	None
Vulnerability radiation	Moderate?	None

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NUCLEAR POWER vs SOLAR HOT WATER cont'd

CO_2 saved on site	12 B lbs/yr	14 B lbs/yr
Fuel mining	$?	$0
Fuel cost	$?	$0
Spent fuel storage	$?	$0
Infrastructure	$?	$0
Environment damage	$?	$0
Factories created	None	10s ?
Permanent jobs	700	1000s ?
Benefit US worker	Short term	Long term

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SOLAR HOT WATER ACHIEVABLE STATEWIDE

- Pass law/code require solar hot water

NEW HOMES

- New home cost $1K to $2k more
- Buyer $600 less electric bill /yr forever

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SOLAR HOT WATER ACHIEVABLE STATEWIDE

EXISTING HOMES - 10YR PERIOD

- No up-front money
- Homeowner calls for installation
- Contractor completes job and bills gov
- Gov pays contractor direct
- Gov gives interest-free loan to homeowner after rebate deducted
- Pay back is ½ electric savings - $300 /yr until paid off
- Customer gets $600 /yr savings forever

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OTHER ENERGY SAVINGS

HEAT HOMES BY SOLAR

PHASE OUT INCANDESCENT BULBS

REINTRODUCE INDUCTION STOVES

BUILD SOLAR-PUMPED HYDRO POWER PLANTS

CONVERT EXISTING PLANTS TO HYBRID USING TRACKING MIRRORS.....LIKE "SOLAR ONE"

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SUMMARY

SOLAR WATER HEATERS ARE ONLY ONE LOW TECH SOLUTION FOR FLORIDA

THEY ALONE OFFSET 2 NUCLEAR PLANTS

NATIONALLY IT WOULD BE 112 PLANTS

DON'T RUSH TO NUCLEAR

SOLAR IS GREATEST ENERGY SOURCE

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PRESENTATION-SOLAR ENERGY vs ELECTRIC UTILITIES 1/29/08

GORDON HANSEN, Home owner, Retired Naval Research Laboratory

1209 ENDERBY CT.

CHULUOTA, FL. 32766

H 407-971-2350 C 407-620-3342 gordojean@msn.com

THANK YOU FOR THIS OPPORTUNITY. IT SHOULD TAKE ABOUT 15 MINUTES.

A SUMMARY AND DETAILED DESCRIPTION OF MY TALK HAS BEEN PROVIDED TO THE COMISSIONERS AND RECORDING CLERK.

NATIONAL SOLAR HOT WATER HEATING PROGRAM WILL....

- SAVE HOMEOWNERS $72 BILLION /yr

  ($600 IN ELECTRIC BILL /YR /CUSTOMER)

- SAVE 600 BILLION lbs CO2 POLLUTION /yr
- REDUCE COMSUMPTION BY 980 BILLION Kwh /yr
- ELIMINATE THE NEED FOR 112 POWER PLANTS OF 1,000 MEGA WATTS EACH
- SAVE MINING 1,100 BILLION lbs COAL /yr

PLAN IS TO:

- BRIEFLY REVIEW THE POWER OF THE SUN
- COMPARE SOLAR PHOTOVOLTAIC AGAINST SOLAR HOT WATER
- SHOW WHY THE UTILITIES DO NOT FAVOR SOLAR
- COMPARE NUCLEAR POWER AGAINST SOLAR HOT WATER

- SHOW SOLAR AS AN ACHIEVABLE ALTERNATIVE TO NUCLEAR POWER
- BRIEFLY TOUCH ON OTHER ENERGY AND CONSERVATION METHODS
- SUMMARY

POWER OF THE SUN

AS A SIMPLE REMINDER, THE ENERGY OF THE UNREFLECTED SUN SHINING DOWN ON EARTH IS ABOUT 1000 WATTS PER 1 SQUARE METER OR ABOUT 100 WATTS PER SQUARE FOOT.

TODAY, WE DROVE OVER 30 BILLION WATTS TO GET HERE. THAT IS THE AMOUNT OF SOLAR ENERGY SHINING DOWN ON THE 300 MILE LONG, 200 FOOT WIDE, ROADWAY WE TRAVELED.

30 BILLION WATTS, ON AN 8 HOUR BASIS, WOULD EQUATE TO THE ENERGY OF 10 BILLION WATTS ON A 24 HOUR BASIS. 10 BILLION WATTS IS ABOUT 10 TIMES THE POWER OF ONE OF THOSE NUCLEAR POWER PLANTS.

COMPARE SOLAR PHOTOVOLTAIC AGAINST SOLAR HOT WATER

Note: Solar photovoltaic will be referred as "solar electric" from here forward.

COMPARING TWO TYPICAL 40 SQUARE FOOT SOLAR PANELS:

ATTRIBUTE	SOLAR ELECTRIC PANEL	SOLAR HOT WATER PANEL
Sun power	4000 watts	4000 watts
Efficiency	10%	70%
Useable power	400 watts	2800 watts
8 hour output	3.2 kWh	22.4 kWh
Cost per panel	$2000	$500
Cost per watt	$5.00	$0.18

CONCLUSION:

SOLAR ELECTRIC PANELS COST 28 TIMES THAT OF SOLAR HOT WATER PANELS, YET SOLAR HOT WATER PANELS SAVE 7 TIMES THE POLLUTION.

COMPARING A GRID TIED SOLAR ELECTRIC SYSTEM AGAINST A SOLAR HOT WATER SYSTEM OF EQUAL POWER

ATTRIBUTE	SOLAR ELECTRIC SYSTEM	SOLAR HOT WATER SYSTEM
Useable power	2800 watts	2800 watts
CO2 pollution saved	5,000 lbs/yr	5,000 lbs/yr
# of 40 sq ft panels	7 (280 sq ft)	1 (40 sq ft)
System cost	$30,000	$5,000
Incentives Fed Gov	$2,000	$1,500
Incentives State Gov	$11,200	$500
Incentives utilities	$4,200 *	$200 **
Total incentives	$17,400	$2,200
Owner cost	$12,600	$2,800
Savings on $150 elec bill	$20	$50
Benefit per month to utility	$30	$0

*limited time

**if utility controls backup

CONCLUSION:

- THERE IS 8 TIMES THE INCENTIVE MONEY GIVEN TO THE SYSTEM THAT PROVIDES THE UTILITY $30 PER MONTH.

- SOLAR ELECTRIC INCENTIVE MONEY WOULD PAY FOR 6 COMPLETE SOLAR HOT WATER SYSTEMS.
- THE SOLAR HOT WATER SYSTEM PROVIDES THE CUSTOMER $50 PER MONTH SAVING FOREVER.

SHOW WHY THE UTILITIES DO NOT FAVOR SOLAR

Most of this is my opinion based on participation in the net metering workshops and documents I have read. My comments.....are added.

#1 The utilities don't want their customers messing with their grid.

#2 Grid tied solar electric has no storage and therefore does not reduce capacity requirement of the utility.....This is true, except solar produces energy when the sun shines while air conditioning demands are higher.

#3 Solar hot water heating does reduce the utilities capacity requirement because the insulated water storage tank can store the energy for several days. This represents a 1/3 revenue loss ($600 /yr) for the utility, per solar customer..... No need to expand generation capacity.

#4 Losing the load benefit of electric hot water heating to solar hot water heating, means the utilities may have to shut down some power plants, in the wee hours of the night, because there is little draw on the grid.....The utilities love the electric hot water heater. It is a pure resistive load that they can control turning on & off. Remember General Electric and others make electric generating equipment and also make hot water heaters. It is a complementary mix for them - sell more power and run their system more efficiently.

#5 Utilities have to walk a thin line. They must appear that they are pro-solar and at the same time, try to justify expansion of their capacity.....This is evident from their conflicting positions of, promoting their Sunshine Energy program and temporarily giving rebates to encourage solar photovoltaic, while at the same time, they are doing everything they can to destroy the net metering

program, which is based mostly on solar photovoltaic. Four of the investor-owned utilities; FPL, Gulf Power, PEF and Tampa Electric, banded together, in their latest official act, before the 5 pm deadline on the net metering docket, to reiterate all their objections in comments. These comments, if agreed to by the PSC, would completely kill the net metering program and solar electric in Florida. This is exactly the kind of interference that killed solar electric for the past 20 years.

COMPARE NUCLEAR POWER AGAINST SOLAR HOT WATER

FPL has over 4.2 million customers. What would be the effect if 1/3 of FPL's average residential customers installed a domestic solar hot water heater?

1.4 million customers x 2800 watts = 3,920 mega watts for an 8 hour period.
3,920 mega watts x 8 hours = 31,360 mega watt hours of power capacity per day.

A nuclear power plant of 1,100 mega watts x 24 hours = 26,400 mega watt hours of power capacity per day. The solar hot water systems exceed this by 5,000 mega watt hours.

COMPARING A NUCLEAR POWER PLANT AGAINST SOLAR THERMAL HOT WATER SYSTEMS OF EQUAL POWER

ATTRIBUTE	NUCLEAR POWER	SOLAR HOT WATER
Size of system	1,100 Mw	2,800 w
Number of systems required	2	2.8 million
Total wattage	2,200 Mw	7,840 Mw
Total capacity per day	52,800 Mwh	62,720 Mwh
CO2 pollution saved @ site	12 billion lbs/yr	14 billion lbs/yr
System cost	$12 - $24 billion ?	$14 billion
Incentives Fed Gov	$????	$4.2 billion

Incentives State Gov	$????	$1.4 billion
Total incentives	$????	$5.6 billion
Total cost	$ 12- $24 billion ?	$8.4 billion

continuing

ATTRIBUTE	NUCLEAR POWER	SOLAR HOT WATER
Save customer /yr	$ neg ??	$600
Save customers /yr	$ neg ??	$1.7 billion
Mining fuel & pollution	$????	$ 0 forever
Infrastructure cost & pollution	$????	$ 0 forever
Fuel cost	$????	$ 0 forever
Spent fuel storage/pollution	$????	$ 0 forever
Damage to environment	$????	$ 0 forever
Disbursed power	None	7,840 Mw
Vulnerability to terrorist	Great ?	None
Vulnerability to meltdown	Small ?	None
Vulnerability to radiation release	Moderate ?	None
Benefit to USA worker	Short term	Long term
Benefit to foreign country	$ 4-6 billion ?	$ 0
Factories created	0	10s ?
Permanent jobs created	700	1000s ?

CONCLUSION:

- LESS THAN 2.8 MILLION RESIDENTIAL CUSTOMERS THAT INSTALL A SOLAR HOT WATER HEATER WOULD OFFSET TWO NUCLEAR POWER PLANTS OF 1,100 MEGA WATTS EACH.
- COMPARED TO NUCLEAR, THE SOLAR OPTION COSTS LESS, HAS NO SAFETY ISSUES, REDUCES ENERGY CAPACITY, BOOSTS THE ECONOMY FOR EVERYONE, HAS NO NEGATIVE IMPACT ON THE ENVIRONMENT AND SAVES HOMEOWNERS $1.7 BILLION PER YEAR – FOREVER!

SOLAR IS AN ACHIEVABLE ALTERNATIVE TO NUCLEAR POWER

Here is how a statewide solar hot water heating program might take place:

Pass law/code requiring new homes to have a domestic solar hot water heater

- New home cost $1k to $2k more
- Buyer enjoys $600 less electric bill per year forever

Pass law/code requiring existing homes have solar hot water heater within 10 yrs

- No up-front money required
- Homeowner calls for installation and selects contractor
- Contractor completes paper work, installation and calls for inspection
- Contractor bills government after satisfactory inspection
- Government pays contractor direct
- Government subtracts any incentive money and records remainder in homeowner's tax record
- Government treats remainder as a non-interest loan

- Homeowner pays off loan at rate equal to ½ year electric bill savings ($300 per year)

There are many options that must be considered. The decision to do these things is, of course, a political one. Education and promotion, done correctly, are key factors to get a program like this off the ground.

Governor Crist and the rest of our legislators must be well informed to see the value to Florida environment and its citizens. Governor Crist's tax package, agree or disagree, is an example of how fast the government can move if motivated. A solar hot water program could be implemented in a year or two.

OTHER ENERGY AND CONSERVATION METHODS

- Use solar hot water to heat our homes.
- Phase out incandescent light bulbs. 500 watts total x 4 million customers = 2,000 mega watts. Less air conditioning needed.
- Reintroduce the electric induction stove. Twice the efficiency and again less air conditioning required.
- Build solar-pumped hydro power plants
- Convert conventional steam power plants to hybrid, using solar tracking mirrors and elevated receiver....like "Solar One". The generating and distribution infrastructure is already in place.

SUMMARY

Please remember, a state domestic solar hot water heating program is only one of several low tech solar options to reduce pollution and save energy. In this case, it alone will offset two nuclear power plants. Just think what can be done on the national level. Let Florida be the first.

Please don't be rushed to go nuclear. Solar is our greatest source of energy.

Respectfully submitted, Gordon L. Hansen

SOLAR ENERGY vs ELECTRIC UTILITIES

January, 2008

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-Save the homeowner $600 in electric bills each year.
-Save the nation's combined homeowners $72 billion.
-Save 600 billion pounds CO2 pollution each year.
-Reduce power consumed by 980 billion Kwh each year.
-Eliminate 112 power plants of 1 billion watts each.

All this through pollution free existing technology and a national SOLAR THERMO hot water heating program.

And.....The Energy is Free Forever

Solar Energy vs Electric Utilities
(Save $72 billion and 600 billion pounds pollution each year)

Be part of the single most important act to conserve energy since we started using electricity over 200 years ago. Read this article to the end and enjoy your newly found power!

This article describes, as priority one, the details and benefits of a national solar hot water heating program. It proves, beyond any doubt, that solar energy is the most cost-effective, efficient, naturally clean, low-tech solution for heating household water. Solar photovoltaic, a direct source of electricity, is also discussed but mainly as a comparison topic.

Benefits for the homeowner:

- Save $600 in electric bills each year
- Save 5000 pounds pollution each year
- No up front money required
- Pays for itself in 3 to 5 years

Benefits for the United States:

- Save the nation's combined homeowners $72 billion each year
- Save 600 billion pounds CO2 pollution each year
- Save 112 coal-fired or nuke plants of 1 billion watts each from being built
- Reduce power consumption by 980 billion kilowatt hours each year
- Save 1,100 billion pounds of coal from being mined each year
- Save mother earth from some "mountain top removal" coal mining

The electric utility companies seem to be backing away from coal, the dirtiest fuel of all, for their next round of power plants and are now trying for nuclear. Plants, by the way, that would not be needed if the thrust of this article were implemented. As this article will show, a national solar hot water heating program will offset 112 coal-fired or nuclear power plants of 1 billion watts each, which may be about the number of plants planned for the future.

Florida, with the most to gain because of its abundant sunshine, has one of the worst records of any state on using the sun to help reduce power consumption and global warming. I use the Florida situation in this article to provide revealing examples.

Most of the articles I have read on global warming and energy have been in general terms like "improve gas mileage" or "reduce consumption." This, I believe, leaves the public and our politicians in the dark about what can be done to help solve the problem. There is too much emphasis on high tech and the exotic which, by design, tends to fool the public into thinking there must be some technological breakthrough before anything significant can be accomplished. And there seems to be a quest by the electric power utilities to forge relationships with our politicians to make regulations that keep "the power" with the utilities, not with the people.

For clarity and in keeping with not dealing in generalities, I use "balance your checkbook" type math and "rounded values" to describe the quantities under discussion. The information presented can be verified by searching the web. What unfolds is eye-opening.

First, I believe you need an understanding in layman terms of the fundamental energy of the sun as it shines down on our earth. It will give you a perspective of how powerful our sun really is and provides the basic premise for this article.

The question is, "how much energy does the non-reflected overhead sun produce on a one square foot (12 inch x 12 inch) area on earth?" The answer in terms of power is approximately 100 watts. You know how hot a 100 watt incandescent light bulb gets!

The fact that the sun can produce about 100 watts per square foot is amazing, but when you apply that energy to larger areas, the amount of power becomes almost inconceivable. Here are a few examples:

AREA of	SUN POWER	ENERGY of
4 ft x 10 ft (typical solar panel)	4000 (4 kilowatts)	1 hot water heater
40 ft x 50 ft (2000 sq ft home)	200,000 (200 kilowatts)	4 homes
208 ft x 208 ft (1 acre lot)	4,300,000 (4.3 megawatts)	90 homes
5280 ft x 5280 ft (1 sq mile)	2,800,000,000 (2.8 billion w)	3 coal fired power plants
100 mi x 100 mi (10,000 sq miles)	(28 trillion watts)	46 times all US power plants

Efficiency and exposure time per day are two major factors that reduce this power to practical amounts. This is where "watts output" and "kilowatt hours" come into play. Here are examples of the sun shining down on two solar collecting panels:

#1 panel 4 ft x 10 ft 4000 watts x 10% efficiency = 400 watts output
400 watts x 8 hours = 3.2 kilowatt hours

#2 panel 4 ft x 10 ft 4000 watts x 70% efficiency = 2800 watts output
2800 watts x 8 hours = 22.4 kilowatt hours

Which panel would you buy for your solar project? Well, #2 panel of course. It has much higher output, seven (7) times as much as #1 panel.

Now if #1 costs $2,000 and #2 costs $500, which one would you choose? Again you would choose #2 panel. It has much higher output and costs one-fourth as much. Anyone can see a good deal when it is this obvious.

In terms of cost per watt, the two panels compare like this:

#1 panel ($2000 / 400w) = $5.00 per watt

#2 panel ($500 / 2800w) = $0.18 per watt

This means that on a per watt basis, #1 panel costs about 28 times #2 panel.

($5.00 / $0.18) = 28

What is being compared here is a solar photovoltaic electric panel against a solar hot water heating panel. The photovoltaic electric panel costs 28 times more than the hot water panel; yet the hot water panel saves 7 times the pollutant because it is 7 times more efficient. This is incredible to say the least.

Let's make one more comparison. Solar systems require more than just solar panels. In brief, a solar hot water heating system for the average home may consist of an 80 gallon tank, a 40 square foot 2800 watt solar heat panel, a pump, an anti-freeze feature, control circuit and would cost about $5,000 installed. A 2800 watt solar photovoltaic electric system that hooks into the electric grid would require seven (7) solar panels for a total of 280 square feet, a current source inverter, control circuits, safety circuits and costs about $30,000 installed.

Both systems run on free sunshine forever and save about 5,000 pounds CO2 pollution per year. The pollution value used here is an average from two states. Florida Power & Light Sunshine Energy program claims a 250 kW solar system saves 680,000 pounds of CO2 each year which extrapolates to 7,000 pounds for a 2800 watt system. The state of Vermont claims a similar system will save about 3,400 pounds per year. The average is about 5,000 pounds.

System cost would normally scare off most consumers but there are incentives that make ownership much easier. These incentives are not applied equally, as you will soon learn.

Incentives for a $5,000 solar hot water system as described above are:

No sales taxes
$1,500 (30 %) off the original price from the federal government
$500 rebate from State of Florida
$200 possible from the electric utility if they can control backup power

Under present Florida regulation and federal law a $5,000 solar hot water heating system would cost about $2,800 and have these attributes:

Reduce electric bill by 33% according to federal government (impressive)
Total system payback - 3 to 5 years (very impressive)

Incentives for a $30,000 solar photovoltaic system as described above are:

No sales taxes
$2,000 from the federal government
$11,200 from State of Florida ($4.00 per watt off the solar panels $4 x 2800 w)
$0.0 from the electric utility company

Under present Florida regulation and federal law a $30,000 solar photovoltaic electric system would cost about $16,800 and have these attributes:

Reduce electric bill by 13% based on utility dual metering payback scheme now being used (this will be explained later)

Total system payback - probably never (interest on $16.8k is more profitable)

System cost comparison when using a consumer monthly electric bill of $150:

	Solar Hot Water	Solar Photovoltaic
Initial cost	$5,000	$30,000
Incentives	$2,200	$13,200
Owner cost	$2,800	$16,800
Monthly electric savings	$50	$20
Benefit to elect utility per mo	$0	$30

Looking at the above comparisons, you might conclude there is 6 times the incentive money given to the system that provides the utility $30 per month. Photovoltaic incentive money could purchase five (5) complete solar hot water systems. Let's not stop here... there is more.

A few years ago the federal government was urged to help solve our energy problem. They wisely recognized the best solution was to have some distributed electrical power sources instead of all centrally located ones. Solar photovoltaic and wind power were the two main sources that offered the perfect nonpolluting answer. In other words, instead of having larger and more polluting power plants supplying all the electricity, the public could now help supply our country's electrical needs from nonpolluting sources. This idea led to a law that gave residential homeowners and others the right to hook to the electric utility grid so they could put electric power into the grid as well as draw from it. This action would reduce the drain on the grid, reduce household electrical costs, reduce pollution, and eliminate the need for building more polluting power plants. It also allowed the development of homegrown power sources without the use of large, messy, and expensive storage batteries. It would be a boom to the solar power producing industry in every respect.

To implement the grid connection solution, the process had to be safe and have a simple method to keep track of the power consumed and produced by the homeowner. The connection and safety issues were quickly solved by what is known as a current source inverter with sophisticated sensing and control circuits. Keeping track of power consumed or produced was also quickly solved, by allowing the utility meter to turn forwards when using power from the grid and turning backwards when supplying power into the grid.

Reversing the meter was termed "net metering." It was supposed to work like this: During periods of sunshine and/or wind, power would be produced at the residential site. If the power consumed by the resident was greater than that produced, the electric utility would supply the difference as indicated by the meter turning forward. If the power produced by the resident was greater than that consumed as indicated by the meter turning backwards, the excess would be used by the utility to help feed other customers or to reduce its generation output. True net metering meant the consumer would be "selling back" the excess electricity at the same price as he/she would buy it from the utility company and would either pay for electricity consumed or be paid for excess produced at some monthly or yearly interval. This was a great solution to help reduce global warming and reduce the customer's electric bill. It was the spirit and true intent of the law.

Who does not like this true "net metering" idea? You guessed it - most of the electric utility companies. Somehow they had the political power through state governments to completely destroy the essence of the federal program. It appears they do not want the consumer using the utility grid infrastructure to spread pollution-free solar electricity all over the country without collecting an unreasonable fee, even though we have been paying for that utility grid for over 100 years. My utility bill shows a "customer monthly fee" of $5.34. Part of that could surely pay for grid usage. Co-op owned utilities like true "net metering" because they are owned by the people and anything they can do to reduce consumer cost and help control pollution is great with them. We should try to convert more utilities to Co-op!

Louisiana has one of the best "net metering" regulations for the consumer. Florida has about the worst program for the consumer and the best program for the electric utility companies of any other state. It is as if the power utility company wrote the regulations. It all seems to benefit the utility and circumvent everything the federal government tried to accomplish for the people a few years ago. Here is how it plays out for someone wanting to hook to the grid with Florida Power and Light (FPL) for example:

Once all the forms are filled out and approved and inspections completed, FPL still will not let you hook to the grid until they remove your old meter and install a dual functioning meter that separately measures incoming and outgoing power. They then charge retail rate for power they supply and credit you at about 40% of that rate for power you feed into the grid. Remember, you may be at work not using much energy during most of your sunshine power generation period. This payback scheme is the most effective killer of the distributed solar energy program than any other. It effectively reduces the efficiency of a solar photovoltaic panel from 10% to 4% and reduces the effectiveness of any other system including wind by 60% also. The program killer does not stop there. If you produce more electricity than you use over a one-year period, they wipe the account clean at the end of the cycle year and you have to start over from zero to accumulate credit for the next year. This is completely devastating for everyone but especially for snowbirds who would otherwise be great candidates for a solar system. FPL has stated they will not pay out money for any excess. Under these conditions, a photovoltaic system would never be effective or pay for itself. The utility companies have successfully killed the program in Florida as they have in most other states. But wait, how about FPL's Sunshine Energy program?

The FPL Sunshine Energy program has been offered the past few months to customers through a flyer enclosed in their monthly electric bill. It is great to demonstrate that FPL is willing to use solar energy when it is to their advantage and under their control. They really want you to feel good about what they are doing. I'd like to quote one sentence from the flyer "Sunshine Energy is American-made and generated from wind, bioenergy and the sun". It sounds a bit like propaganda to me.

Here is how I understand the Sunshine Energy program works: You send in $9.75 per month to join the 35,000 other participating customers, giving FPL $340,000 per month or $4,100,000 per year. FPL uses that money to advertise, administer the program, and build renewable energy facilities or purchase renewable energy so you are ensured that 1,000 kwh per month come from renewable sources somewhere. This prevents 10,000 pounds of carbon dioxide

from entering the atmosphere per year somewhere in the US. The electricity the customer uses comes from exactly the same sources it always has, just like a non-participating neighbor. The customer continues to pay his full electric bill as usual like everyone else along with the extra $9.75 per month and has a good feeling about the whole thing.

FPL does not mention that if the customer would use the money to install a solar hot water system, he would cut his electric bill by one-third and save 5,000 pounds of pollution locally.

FPL further does not mention that if only half of their 4 million residential customers would install a solar hot water heating system, there would be no need for those two 1 billion watt nuclear power plants they plan to build which impact the environment in other negative ways.

With global warming awareness, there is a rush nationwide by the utilities to build over 100 coal-fired power plants before stiffer pollution safeguards are imposed by congress. According to the Tennessee Valley Authority, their 1 billion watt coal-fired Kingston power plant burns 14,000 tons (28 million pounds) of coal per day, an amount that would fill 140 railroads cars. On a yearly basis 100 plants would burn over 1000 billion pounds, most of which could come from "mountain top removal" mining methods. This is another environment disaster!

There are 120 million households in the US according to government 2001 census. If each household had a 2800 watt solar hot water heater, they would save $600 in electric bills and 5,000 pounds of pollution each year. Nationally, the yearly benefits would save $72 billion in electric bills and reduce greenhouse gases by 600 billion pounds. 120 million households at 2800 watts equal 336 billion watts on an 8 hour basis. Compared to power plants which operate on a 24 hour basis, the equivalent power would be 112 billion watts. This would offset 112 power plants of 1 billion watts each.

On average, if only two existing homes installed a solar hot water system for every new home built with a solar hot water system, the electrical impact on the utilities would be zero!

The single biggest complaint of the utilities, with respect to solar photovoltaic grid connected electric systems is, they do not reduce energy capacity requirements because when the sun does not shine, solar electric power is gone. This ignores the fact that air conditioners use most electricity when the sun shines most. A solar hot water system, by design, has a huge storage device called a water tank and they truly do reduce energy capacity requirements.

The evidence to support a national solar hot water heating agenda is so overwhelming, it must be priority one! These systems need to become as common as toilets and refrigerators in the household. The idea is that, with no up-front money and assurance the system will pay for itself, the homeowner simply calls a 1-800 number to schedule installation. The process must be simple. The following is how the deal might take place.

<u>As priority one</u>, our government would need to pass a law requiring all new and existing homes be equipped with a solar hot water heating system. Once the law is enacted, building

codes would mandate a solar hot water heating system for new homes. Starting now and over the next 10 years, existing homes would be required to have a system installed.

New home costs would be only $1 k to $2 k higher because the system would be part of the original design and the builder would be operating at a wholesale level. The builder has to install a water heater anyway, so why not solar? The buyer would immediately enjoy 1/3 less electric bills. This keeps the new home process simple and does not involve the government.

Existing homeowners would call a 1-800 number or go online to be scheduled for their solar system. In due time, three certified and licensed contractors would visit the home and submit their bid to the homeowner. The homeowner would then choose the one he/she likes and informs the contractor. The contractor applies for the building permit, completes the work, and calls for county inspection. Once inspection passes, the contractor sends in the paperwork to the federal government for payment. The federal government pays the contractor direct. The government then subtracts any incentive money and records the remaining amount in the homeowner's tax record. It will be treated as a no-interest loan that gets paid off at a rate that equals ½ the electric bill savings. This would amount to about $300 per year assessment until paid off for the average family, while they enjoy $600 per year savings in electric bills forever.

How about solar photovoltaic electric systems? Well, you might get the feeling I am totally against these systems. I am not and plan to install one, hopefully, within a year. The savings are not even addressed in this article and could be more than solar hot water savings for the individual. Remember those air conditioners run more during hot, daylight hours when solar systems produce the most. They, in a sense, compliment each other. To make it anywhere near feasible, however, the "net metering" regulations must be fixed.

As priority two, our lawmakers must pass a no-nonsense true "net metering" law. Photovoltaic electric systems would then become practical for homeowners so that they can help supply our nation's power if they choose to do so. Customers must get the same price selling back to the utilities as the utilities charge them. Simple reverse metering will do it as was the original intent. If the customer can create an excess at the end of a cycle year, he/she should get full retail price for that excess. A fixed monthly amount of about $5, as is charged now for customer fee, would pay for use of the grid. The law must be explicit so it cannot be gutted at the local level. Florida and other states are now working to correct some of the past inhibitive rules.

Remember, this article only cites the savings from homeowner participation in solar hot water heating. Participation by the commercial sector could easily exceed those savings.

We need to send this article to every lawmaker, code office, environmental and political group in the country. Spreading the word by e-mail is fast and gets many people involved quickly. Spreading the word to lawmakers is more difficult because they delete much of their e-mail if it does not come from their own constituent. If we could get someone from each state to mail a hard copy, with their own cover letter, to their representative it would be a great help.

Gordon L. Hansen Jan.17, 2008
Homeowner and long-time solar energy advocate

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 92
COMPANY
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DATE 01/30-02/01/08

WHY A FUTURE FOR THE NUCLEAR INDUSTRY

IS RISKY

BASED IN PART ON PRESENTATIONS BY

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Former Chair, Maine Public Utilities Commission,
Former Commissioner, U.S. Nuclear Regulatory Commission.

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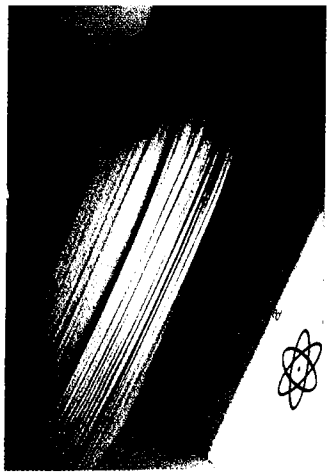

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Sponsored by a coalition of environmental, health, social investment and public interest organizations concerned about the impacts of nuclear power including:

Friends of the Earth,

Interfaith Center on Corporate Responsibility (ICCR),

North Carolina Waste Awareness and Reduction Network (NC WARN),

Nuclear Information and Resource Service (NIRS),

Public Citizen,

Southern Alliance for Clean Energy (SACE), and

U.S. Public Interest Research Group (PIRG).

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INTRODUCTION

Talk of a "nuclear renaissance" abounds. The accidents at Chernobyl and Three Mile Island are receding in public memory. Promises of improved safety and performance are coupled with billions of dollars of subsidies. However, the claims that nuclear power is a necessary energy source for displacing greenhouse gases hasn't convinced investors that new nuclear power plants will be safe and profitable investments.

New nuclear power plants will not be cost competitive with other electricity generating alternatives. Wind power and other renewable technologies, combined with energy efficiency, conservation and cogeneration can be much more cost effective and can be deployed much sooner than new nuclear power plants. Building expensive new nuclear plants will divert private and public investment from the cheaper and readily available renewable and energy efficiency options needed to protect our climate.

In competitive markets, new nuclear power plants will be bad investments. At the same time, worldwide private equity and venture capital investments in clean energy continue to grow. Worldwide investment in renewable energy capacity was almost $40 billion in 2005 and the renewable energy markets continue to grow robustly.[1]

DESPITE THE SIGNIFICANT SUBSIDIES PROVIDED IN THE ENERGY POLICY ACT OF 2005 (EPACT 2005), INVESTMENTS IN NEW NUCLEAR PLANTS REMAIN VERY RISKY

- The estimated cost of $1,500-$2,000 per KW for new nuclear plants is unlikely to be achieved and has recently been revised upward for some companies.
- The prices of recently built nuclear power plants in Japan were much higher, ranging between $1,796 and $2,827 per KW, in 2003 dollars.[2]
- The subsidies provided in EPACT 2005 are limited to a few plants and some require Congressional appropriations which are not guaranteed. Moreover, Standard & Poor's analysis of EPACT 2005 has concluded that the bill has few implications for the credit quality of nuclear developers and that the regulatory risk for new nuclear construction remains high, given the possibility that a plant for which construction has started may never actually commence operations.[3]
- None of the new nuclear power plant designs under consideration in the U.S. have actually been built. The industry's optimistic construction time and cost estimates are unproven and theoretical.
- Despite massive subsidies and R&D investments, there has not been an order for a new nuclear power plant in the U.S. for almost three decades.[4]
- Even with the subsidies in EPACT 2005, the U.S. Department of Energy has moved its target for bringing a new nuclear unit online from 2010 to 2014.[5]

1 "Renewables Global Status Report: 2006 Update," Renewable Energy Policy Network for the 21st Century, 2006, at pages 2-5, available at http://www.ren21.net/globalstatusreport/download/RE_GSR_2006_Update.pdf.

2 "Economic Future of Nuclear Power," The University of Chicago for the U.S. DOE, August 2004, at pages 2-14.

3 "Energy Policy Act 2005 has Limited Credit Implications: S&P," Nuclear Engineering International News, August 18, 2005, available at http://www.neimagazine.com/story.asp?sc=2030540&ac=7969460 and "Long-Awaited Energy Act Has Marginal Credit Implications for U.S. Utility And Oil And Gas Companies," Standard & Poor's, August 1, 2005.

4 "Nuclear Power: Economics and Climate Protection Potential," Amory Lovins, Rocky Mountain Institute, September 11, 2005, at page 9, available at http://www.rmi.org/images/other/Energy/E0508_NukePwrEcon.pdf.

5 Statement of Samuel W. Bodman, Secretary of Energy, Before the Committee on Science, U.S. House of Representatives, Concerning the Department of Energy's FY 2007 Budget, February 15, 2006. available at http://resourcescommittee.house.gov/science/hearings/full06/Feb15/bodman.pdf.

- A recent article in The Energy Journal, published by the International Association for Energy Economics, concluded that in current liberalized markets, investors have no incentives to back the construction of new nuclear power plants because of their capital intensity, "engineering difficulties" and "regulatory creep."[6]

- Nuclear construction cost estimates in the U.S. have been notoriously inaccurate. In fact, the estimated costs of some existing nuclear units were wrong by factors of two or more. The total estimated cost of 75 of today's nuclear units was $45 billion (in 1990 dollars).[7] The actual cost turned out to be $145 billion (also in 1990 dollars). This $100 billion cost overrun was more than 200 percent above initial cost estimates.

  - New billion dollar mega-projects traditionally cost much more than their original estimates. As a result, a 1988 RAND Corporation study concluded that "the data on cost growth, schedule slippage and performance shortfalls of mega-projects are certainly sobering, but the most chilling statistic is that only about one in three of these projects is meeting its profit goals."[8]

  - Standard & Poor's stated that "given that construction [of new nuclear plants] would entail using new designs and technology, cost overruns are highly probable."[9]

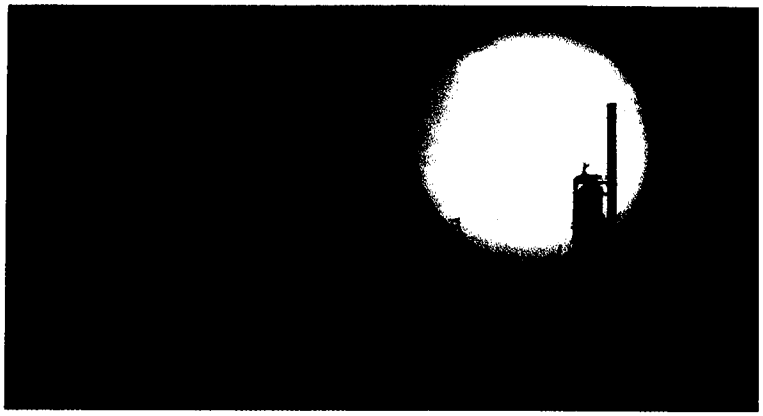
  - The DOE's Energy Information Administration has clearly and concisely stated that "new [nuclear] plants are not expected to be economical."[10]

  - A 2003 study by the Massachusetts Institute of Technology forecasted that the base case real levelized cost (present value of building and running a plant for its lifespan) of electricity from new nuclear reactors with an estimated 85 percent capacity would be $.067 per kilowatt hour over a projected forty year operating life more expensive than from pulverized coal or natural gas.[11]

  - A 2005 assessment by Synapse Energy Economics, Inc. showed that the levelized cost of electricity from a new nuclear power plant would be $.068 per kilowatt hour, which was significantly higher than obtaining the same amount of energy from a combination of wind and gas-fired capacity and energy efficiency measures.[12] Additional studies have also concluded that overnight capital costs, lead construction times and interest rate premiums are likely to place the cost of electricity from any future nuclear power plants within the range of $.06 to $.07 per kilowatt hour.[13]

- Nuclear utilities have acknowledged that there are significant economic risks associated with the operation of nuclear power plants.

  - Plant O&M and capital expenditures could increase or the nuclear plant(s) could experience outages as a result of events at other operating nuclear power plants, new rules or regulations issued by the U.S. Nuclear Regulatory Commission (NRC), or as the result of deficiencies identified by the NRC.[14]



- Restructuring of the electric utility industry brings additional uncertainty to the ownership of new nuclear power plants. Without captive customers from whom increased costs can be recovered, plant owners are exposed to the risks of higher O&M expenses, higher decommissioning costs, and the lost revenues and higher costs of extended unit outages.

  - For example, Standard & Poor's stated that "Decommissioning risk remains an important factor in determining credit quality of U.S. firms and weighs more in the analysis of competitive nuclear generators. This is the case because, again, a regulatory process cannot provide recovery for underfunding."[15]

6 "Nuclear Power: A Hedge against Uncertain Gas and Carbon," Fabien A. Roques, William J. Nuttall, David M. Newbery, Richard de Neufville, Stephen Connor, The Energy Journal, Vol. 27, n. 4., 2006.

7 Study prepared by the Energy Information Administration of the U.S. DOE, "An Analysis of Nuclear Power Plant Construction Costs," 1986.

8 "Understanding the Outcomes of Megaprojects: A Quantitative Analysis of Very Large Civilian Projects," Edward W. Merrow, RAND Corporation, March 1988.

9 "Credit Aspects of North American and European Nuclear Power," Standard & Poor's, January 9, 2006.

10 Annual Energy Outlook 2005, Energy Information Administration, available at http://www.eia.doe.gov/emeu/plugs/plfeb05.html.

11 "The Future of Nuclear Power - Summary Report," MIT, 2003, available at http://web.mit.edu/nuclearpower/pdf/nuclearpower-summary.pdf.

12 Affidavit of Bruce Biewald, Synapse Energy Economics, in U.S. NRC Docket No. 52-007-ESP, at page 23.

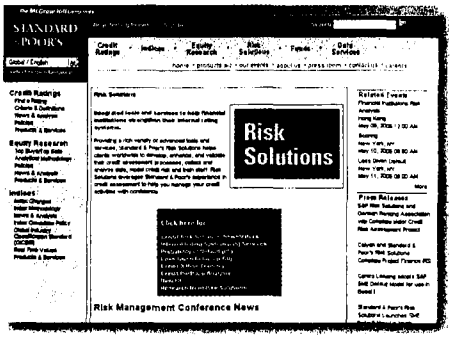
13 "Insurmountable Risks: The Dangers of Using Nuclear Power to Combat Global Climate Crisis - Summary," Brice Smith, Institute for Energy and Environmental Research, 2006, at page 6, available at http://www.ieer.org/reports/insurmountablerisks/summary.pdf.

14 For example, see the Testimony of Thomas Aller, in Iowa Utility Board Docket No. SPU-05-15, at page 15.

15 "Credit Aspects of North American and European Nuclear Power," Standard & Poor's, January 9, 2006.

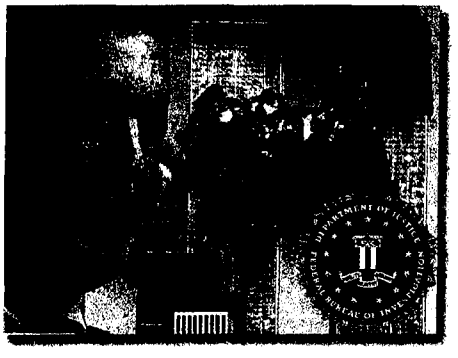
WALL STREET HAS EXPRESSED SERIOUS CONCERNS ABOUT THE CREDITWORTHINESS OF COMPANIES THAT PURSUE NEW NUCLEAR PLANTS

- Standard & Poor's Ratings Services found that "an electric utility with a nuclear exposure has weaker credit than one without and can expect to pay more on the margin for credit. Federal support of construction costs will do little to change that reality. Therefore, were a utility to embark on a new or expanded nuclear endeavor, Standard & Poor's would likely revisit its rating on the utility." [16]
- Standard & Poor's has also expressed concern that "from a credit perspective, [2005 Energy Policy Act] provisions may not be substantial enough to sustain credit quality and make [nuclear generation] a practical strategy."[17]
- The credit rating service Fitch reminds potential investors that "the overarching concern [regarding nuclear power generation] is the financial effect of an extended outage, forcing the generating company to buy potentially more expensive replacement power on the spot market to honor any existing supply commitments."[18]



NUCLEAR POWER PLANTS ARE STATED TERRORIST TARGETS: A SUCCESSFUL ATTACK COULD HALT NEW CONSTRUCTION EVEN AFTER SIGNIFICANT EXPENDITURE

In testimony before the Select Committee on Intelligence in the U.S. Senate in February 2005, FBI director Robert S. Mueller stated that, "Another area we consider vulnerable and target rich is the energy sector, particularly nuclear power plants. Al-Qa'ida planner Khalid Sheikh Mohammed had nuclear power plants as part of his target set and we have no reason to believe that Al-Qa'ida has reconsidered."[19]



- In October 2001, the Federal Aviation Administration temporarily restricted all private aircraft from flying over 86 nuclear facilities due to threats of terrorist attacks.[20]
- Over 53,000 metric tons of highly radioactive spent nuclear fuel is stored at commercial reactors in the U.S. Nearly 90% of this fuel is stored in cooling pools without adequate protection.[21] According to a recent study by the National Academy of Sciences, a terrorist attack on a spent fuel pool could lead to the release of large quantities of radioactive materials to the environment.[22] Such an event could result in thousands of cancer deaths and economic damages in the range of hundreds of billions of dollars.
- In the event of a major radioactive release from a nuclear power plant, public opinion would likely react strongly against nuclear power (as occurred after the Chernobyl and Three Mile Island accidents), resulting in the halting of construction of any new planned reactors.

16 Ibid.

17 Ibid.

18 "Fitch's Approach to Rating U.S. Wholesale Energy Companies," October 2004.

19 "Testimony of Robert S. Mueller, III, Director, Federal Bureau of Investigation Before the Senate Committee on Intelligence of the United States Senate," February 16, 2005, available at http://www.fbi.gov/congress/congress05/mueller021605.htm.

20 "FAA Restricts All Private Aircraft Flying Over Nuclear Facilities," October 30, 2001, available at http://www.faa.gov/news/press_releases/news_story.cfm?newsId=5446.

21 "Spent Nuclear Fuel Storage Locations and Inventory," Anthony Andrews, Congressional Research Service, updated 2004.

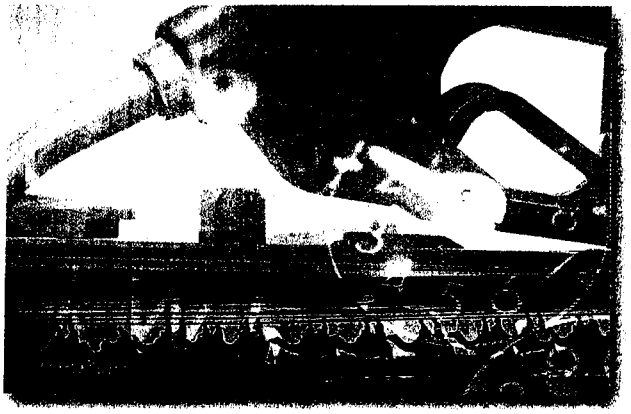
22 "Safety and Security of Commercial Spent Fuel Storage: Public Report," Committee on the Safety and Security of Commercial Spent Fuel Storage, National Research Council, 2006, available at http://newton.nap.edu/catalog/11263.html#toc.

WEAKNESSES IN NUCLEAR REGULATORY COMMISSION (NRC) OVERSIGHT OFFER TROUBLESOME INDICATIONS THAT THE NRC IS PUTTING THE NUCLEAR INDUSTRY AHEAD OF SAFETY AND PUBLIC CONFIDENCE

- In recent years, the NRC appears to have retreated into a similar pro-industry mindset that was described in the assessment of the March 1979 accident at the Three Mile Island nuclear power plant that was prepared by a Presidential Commission: "We find that the NRC is so preoccupied with the licensing of plants that it has not given primary consideration to overall safety issues. [...] With its present organization, staff and attitudes, the NRC is unable to fulfill its responsibility for providing an acceptable level of safety for nuclear power plants."[23]
- For example, shortcomings in the U.S. nuclear regulatory process were clearly implicated in the 2001 near-accident at the Davis-Besse plant in Ohio. The NRC Inspector General's report on that incident found that there was a clear connection between cost considerations and NRC laxity in the fact that the licensee sought and the NRC staff allowed the Davis-Besse plant to operate without performing important inspections, and that this situation was driven in large part by a desire to lessen the financial impact that would result from an early shutdown.[24] A loss of coolant accident at Davis-Besse might well have eliminated all discussion of a nuclear revival in the U.S.
- NRC surveys have showed that almost half of all NRC employees thought that their careers would suffer if they raised safety concerns and nearly one-third of those who had raised safety concerns felt they had suffered harassment and/or intimidation as a result. [25]
- Streamlined licensing processes for construction and operating permits eviscerate public involvement as a check on laxity in the licensing process.

NUCLEAR POWER WILL NOT REDUCE U.S. DEPENDENCE ON ENERGY SUPPLIES FROM ABROAD

- The U.S. is importing more oil each year – most of it from the world's most unstable regions – increasing our country's economical and political vulnerability and making oil dependency among the largest threats to our economy and national security.
- Increasing reliance on nuclear power will not reduce our nation's dependency on foreign sources of oil – only about 3% of the electricity produced in the U.S. is from petroleum and almost none of that petroleum comes from the Middle East.[26]
- Nuclear power's only substantial contribution to oil displacement in the U.S. comes in regions in which natural gas displaced by nuclear power can penetrate further into oil's share of the markets, such as space heating in New England. [27]
- Indeed, transportation is the sector that accounts for most of U.S. oil consumption – about two-thirds of the country's oil consumption is used by vehicles, which corresponds to roughly 13 millions barrels a day.[28] Thus, possible nuclear power development would not have any influence over these statistics.



23 "Report of the President's Commission on the Accident at Three Mile Island: The Need for Change," October 1979, pages 51, 56.

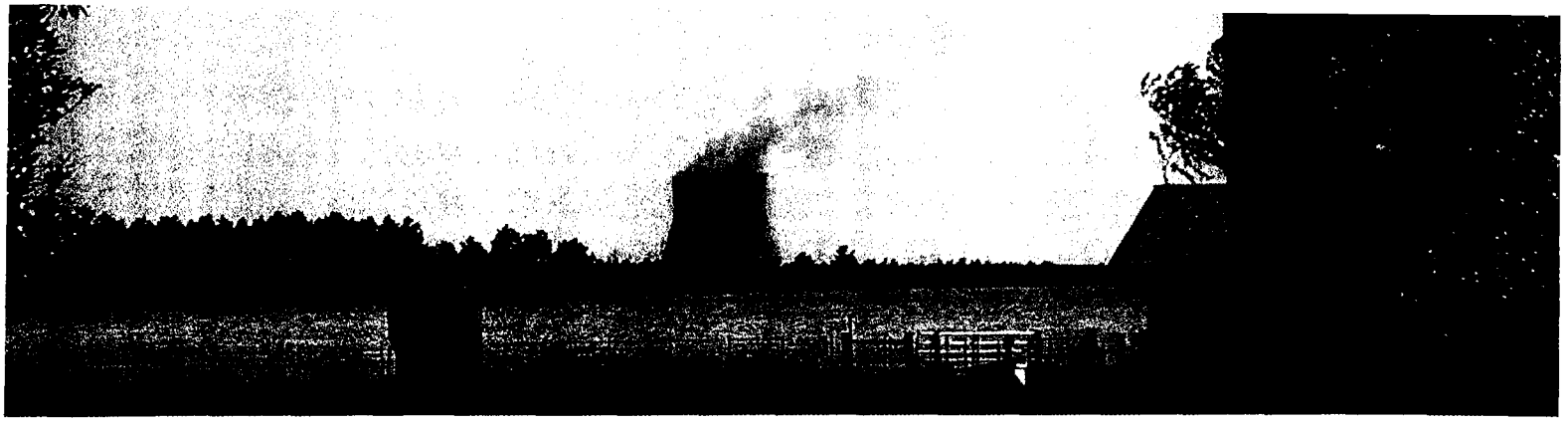
24 "NRC's Regulation of Davis Besse Regarding Damage to the Reactor Vessel Head," NRC Inspector General, Case No. 02-03S, December 30, 2002, at page 23.

25 "Special Evaluation: OIG 2002 Survey of NRC's Safety Culture and Climate," Office of the Inspector General, U.S. Nuclear Regulatory Commission, December 11, 2002, OIG-03-A-03; "Audit Report: Review of NRC'S Differing Professional View/Differing Professional Opinion Program," Office of the Inspector General, U.S. Nuclear Regulatory Commission, September 20, 2000, OIG-00-A-07.

26 U.S. Energy Information Administration, Electric Power Generation by Fuel Type (2004), available at http://www.eia.doe.gov/fuelelectric.html.

27 "Nuclear Power's Prospects in the Power Markets of the 21st Century," Peter A. Bradford, Nonproliferation Education Center, February 2005, available at: http://www.npec-web.org/Essays/Essay050131%20NPT%20Bradford%20Nuclear%20Powers%20Prospects.pdf.

28 "Peaking of World Oil: Impacts, Mitigation and Risk Management," Hirsch et al, Science Applications International Corporation, Department of Energy, February 2005, available at http://www.netl.doe.gov/publications/others/pdf/Oil_Peaking_NETL.pdf.



PERMANENT STORAGE OF SPENT NUCLEAR FUEL REMAINS UNRESOLVED

One of the riskiest elements of building new nuclear plants is that the long-term disposition of the waste is far from being resolved. The planned Yucca Mountain repository in Nevada is almost 20 years behind schedule and may never open. The projected opening date for this permanent spent fuel repository has been delayed countless times and, according to the Department of Energy, the current target date of 2017 is a "best-achievable schedule."[29]

A plan proposed by the Bush Administration, the Global Nuclear Energy Partnership (GNEP), that would allow the reprocessing of spent nuclear fuel, will face significant technical, legal, and political challenges and cannot be counted on as a realistic solution. Reprocessing results in large amounts of waste still needing disposal, and much of the technology essential to GNEP is unproven and undeveloped. Indeed, similar attempts to reprocess spent fuel in the past have been unsuccessful and the DOE does not have a lifecycle cost analysis for the program.

Interim storage of waste at Idaho National Engineering & Environmental Laboratory

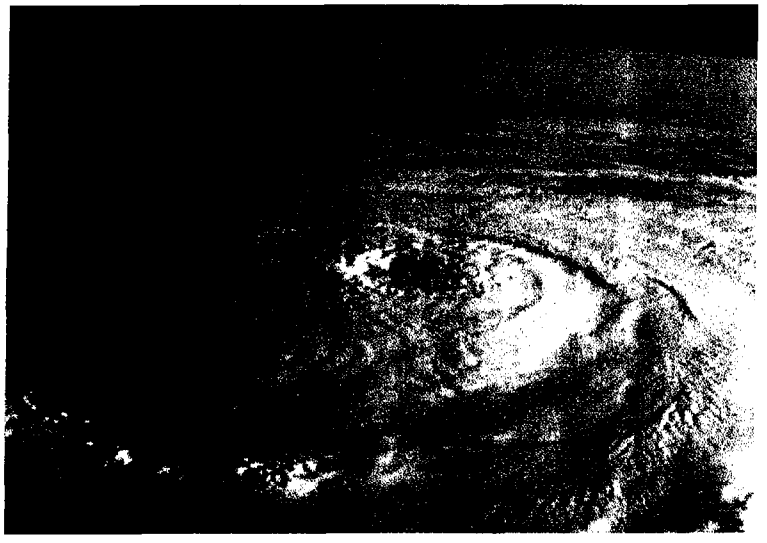
- Reprocessing would be a dangerous shift in U.S. global nonproliferation policy and would increase the likelihood that a terrorist could obtain fissile material to build a nuclear bomb. Moreover, DOE is trying to build momentum for the program before deliberations have been conducted by Congress to determine whether this path is in the best interests of U.S. national and energy security, as well as fiscally sound, even if it should eventually prove technically feasible.
- Reprocessing would increase the number of nuclear waste streams to be managed and secured and is the most polluting part of the nuclear fuel cycle. It would not alleviate the problem of used (spent) fuel storage on reactor sites or the need for a permanent waste repository.[30]
- U.S. taxpayers are still paying several billion dollars each year to clean up contamination from reprocessing programs in the 1960s and 1970s for nuclear weapons at the Hanford Site (WA) and the Savannah River Site (SC), as well as the reprocessing of naval irradiated fuel at the Idaho National Laboratory (ID) and commercial reprocessing at West Valley (NY), which all make this new reprocessing push unlikely and illogical.

29 Statement of Edward F. Sproat, III, Director for the Office of Civilian Radioactive Waste Management, U.S. Department of Energy, Before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, U.S. House of Representatives. September 13, 2006, available at http://www.ocrwm.doe.gov/info_library/program_docs/testimonies/SPROAT9-13Testimony_FINAL.pdf.

30 Spent fuel rods must remain in on-site cooling pools for at least five years until they have cooled sufficiently to be transported. Reprocessing waste does not eliminate long-lived radioactive elements that necessitate secure storage for hundreds of thousands of years. GNEP proposes to transmute much of the nuclear waste, but this technology as yet to be proven.

WHAT ABOUT GLOBAL GLOBAL WARMING? BETTER SOLUTIONS EXIST

- Climate change is one of the most pressing threats of our time and it is imperative that we take swift and decisive action to avert its most severe impacts. However, building more nuclear power plants is not the answer.
- The claim that "we need all energy options" to face growing energy needs is disingenuous. On the contrary, we cannot afford all energy options. Further investment in nuclear power would squander the limited financial resources that are available to implement meaningful climate change mitigation policies.
- Nuclear power's role in mitigating climate change (and in reducing oil dependence) is constrained because its impact is limited to the electric sector.



Wind power and other renewables, such as solar and bioenergy, coupled with energy efficiency, conservation and cogeneration are much more cost effective and can be deployed much faster. Building new nuclear power plants will divert private and public investment from the cheaper, readily available options needed to protect our climate. Each dollar invested in electric efficiency in the U.S. displaces nearly seven times as much carbon dioxide as a dollar invested in nuclear power, and nuclear power saves as little as half as much carbon per dollar as wind power and cogeneration.[31]

- Recent studies analyzing the potential of nuclear power to combat global warming have concluded that between 1,000 and 2,000 new nuclear reactors would have to be built around the globe in the next decades to achieve a meaningful impact on CO_2 emissions.[32] These projections point to a clearly infeasible schedule, as new reactors would have to come online every few weeks.
- A 2005 study by Synapse Energy Economics, Inc. showed that the U.S. can substantially reduce global warming pollution through efficiency improvements in power generation. In fact, the report concludes that modest investments in efficiency and renewable energy would reduce global warming pollutants from the electricity sector by 47% by 2025.[33]

IMPACTS OF GLOBAL WARMING INCREASE RISKS OF OPERATING NUCLEAR POWER PLANTS

- Heat waves in the summer of 2006 forced U.S. and European utilities to shut down some reactors and reduce operations at others. Some companies in Europe also had to secure exemptions from regulations in order to discharge overheated water into the environment and others were forced to buy electricity on the spot market.[34]
- Rise in frequency and intensity of catastrophic weather events pose additional risks to nuclear plants' safety because reactors are particularly vulnerable to the effects of flooding, hurricanes, and tornados, as severe storms can disable the on and off-site power systems necessary to operate the plants' safety mechanisms.

31 "Return of the Nuclear Salesmen: Global Warming Gives Them a New Sales Pitch," Dave Reed, Rocky Mountain Institute Newsletter, Vol. XVI, #1, Spring 2000, pages 25 and 15, available at http://www.rmi.org/images/other/Newsletter/NLRMIspring20.pdf.

32 "The Future of Nuclear Power - Summary Report," MIT, 2003 and "Insurmountable Risks: The Dangers of Using Nuclear Power to Combat Global Climate Crisis - Summary," Brice Smith, Institute for Energy and Environmental Research, 2006, at page 6, available at http://www.ieer.org/reports/insurmountablerisks/summary.pdf.

33 "A Responsible Electricity Future: An Efficient, Cleaner and Balanced Scenario for the US Electricity System," Bruce Biewald et al. Synapse Energy Economics, Inc. and National Association of State PIRGS, May 2005, available at http://www.uspirg.org/uploads/w7/0S/w70S27rKo2G0k0LMyQqBNg/AResponsibleElectrictyFuture.pdf .

34 "Nuclear Power's Green Promise Dulled by Rising Temps," Susan Sachs, The Christian Science Monitor, August 10, 2006, available at http://www.csmonitor.com/2006/0810/p04s01-woeu.html; and "U.S. Heat Wave Heads to Northeast, May Break Records," update to Bloomberg News, July 31 2006, available at http://www.bloomberg.com/apps/news?pid=20601087&sid=aNtzVaLCaNc8&refer=home.

RENEWABLE ENERGY INVESTMENTS ARE BOOMING WHILE PRICES FOR CONSUMERS KEEP DROPPING

- Worldwide investment in renewable energy capacity was almost $40 billion in 2005. In the U.S., renewable power capacity expanded to 23 GW.[35]
- In 2005, wind energy in the U.S. grew by almost 2,500 MW of installed capacity – a 35% increase in just one year.[36] Total wind-generating capacity in the United States now stands at over 9,000 MW, enough to power more than 2.3 million average American homes.[37]
- Venture capital investment in U.S. based solar companies totaled more than $150 million in 2005 – double the investment from the previous year.[38]
- The International Energy Agency predicts a cost reduction up to 25% for wind power and 50% for solar photovoltaics from 2001 to 2020.[40]
- In the global marketplace, nuclear power is already losing to its faster, cheaper, less financially risky competitors that are NOT centralized power stations.
  - In 2005, micropower (low-carbon fossil-fueled cogeneration, 2/3 of it gas-fired, plus decentralized renewables) added 4 times as much output and 8 times as much capacity as nuclear power.
  - These alternatives have eclipsed nuclear power in both capacity (in 2002) and output (in 2006) .
  - In 2005, micropower provided 32% of the additional global electrical output and was mostly financed by private risk capitol. Thus, investors focusing on actual market behavior must conclude that nuclear power is not preferred.[39]

HOW THE EVOLUTION OF POWER SUPPLY MARKETS AFFECTS NUCLEAR POWER

Assessing the future of nuclear power begins by understanding the past. Nuclear power is a technology force fed into an unsophisticated power supply selection process at a pace too fast for the nuclear industry to assimilate the lessons of operating experience. Moreover, the evolution occurred in ways that concealed or understated the real costs and problems, assuring a series of unpleasant surprises, deepening public mistrust, and, ultimately, reform of the power supply selection processes under which nuclear power had momentarily thrived.

- A real nuclear revival will not exist until private capital is available to build plants, which will require market prices that assure competitive success and profitability. However, even with their ability to compete on the basis of operating costs, the most recent sales of nuclear units have not been at prices that would support the building of a new plant.[41]
- In short, nuclear power's asserted comeback rests not on a newfound competitiveness in power plant construction, but on an old formula: massive government subsidies and licensing shortcuts, and perhaps, guaranteed purchases with risks borne by customers. Climate change has replaced oil dependence as the bogeyman from which supposedly only nuclear power can save us.

35 "Renewables Global Status Report: 2006 Update," Renewable Energy Policy Network for the 21st Century, 2006, at pages 2-5, available at http://www.ren21.net/globalstatusreport/download/RE_GSR_2006_Update.pdf.

36 "U.S. Wind Industry Ends Most Productive Year, Sustained Growth Expected for At Least Next Two Years," American Wind Energy Association, January 24, 2006, available at http://www.awea.org/news/US_Wind_Industry_Ends_Most_Productive_Year_012406.html.

37 "Global Wind 2005 Report," Global Wind Energy Council, 2005, available at http://www.gwec.net/fileadmin/documents/Publications/Global_WindPower_05_Report.pdf.

38 Ibid, page 4.

39 "The Rise of Micropower" Armory Lovins, Rocky Mountain Institute, Updated July 2006, available at www.rmi.org/sitepages/pid171.php#E05-04.

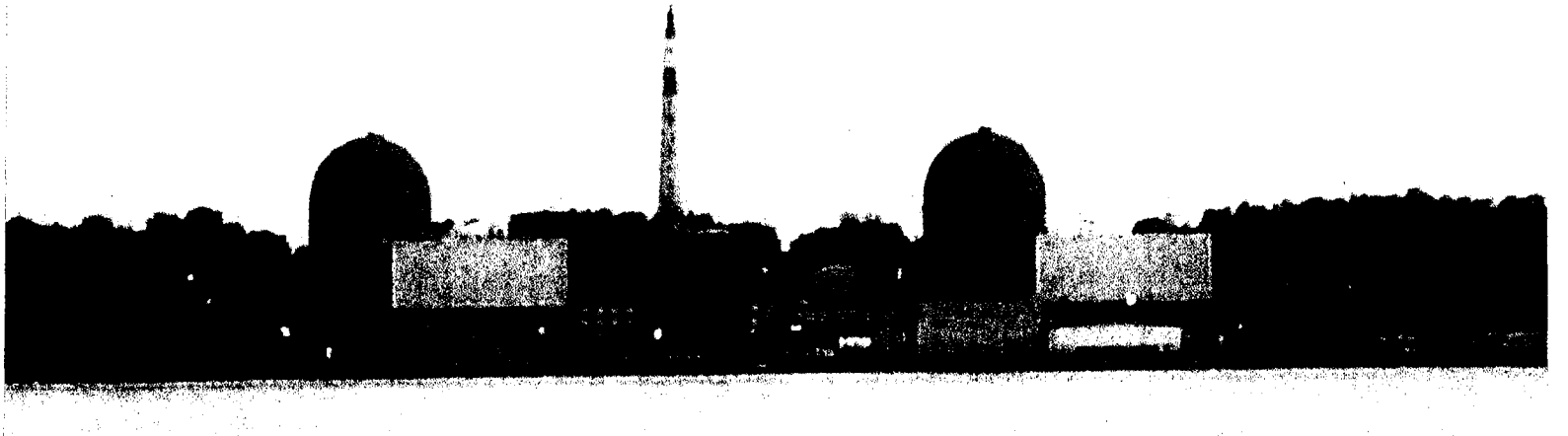
40 "Renewable Energy," International Energy Agency, available at http://www.iea.org/textbase/papers/2002/renewable.pdf.

41 The MIT study, in discussing the 2002 sale of 88% of the Seabrook station, notes that the price "implies that the market value of a fully licensed and operational nuclear power plant with a good performance record is less than half of the most optimistic cost estimates for building a new nuclear power plant....Comparable analyses of other nuclear power plant sales come to very similar conclusions. The market value of nuclear plants is far below their replacement cost, a result that is inconsistent with merchant investment in new nuclear plants." ("The Future of Nuclear Power," Appendix 5, p. 140.)

CONCLUSION

The genesis of nuclear power was the "Atoms for Peace Program" which was intended to make the public more comfortable with the horrifying destruction of the nuclear bomb. Originally, the promise was that the technology would provide energy that would be "too cheap to meter." However, in the last 50 years, nuclear energy subsidies have totaled close to $145 billion and amount to more taxpayer dollars for R&D than for all other energy sectors combined. In fact, nuclear power became the energy that is "too expensive to matter."

A nuclear revival is financially risky. The likelihood of large numbers of new nuclear units being built on the basis of favorable economics is very unlikely. Nuclear power is not competitive today and for nuclear power to succeed it must achieve major cost cuts, avoid even one serious accident, resolve the nuclear waste storage and disposal issue in an enduring way, sever its links to proliferation of nuclear weapons, and get the benefit of its status as a lower carbon-emitting power source. However, even if all of these things occur over the next decade, success will not be guaranteed. Nuclear power may still be more expensive and offset much fewer greenhouse gas emissions than a portfolio of renewable and energy efficiency options.



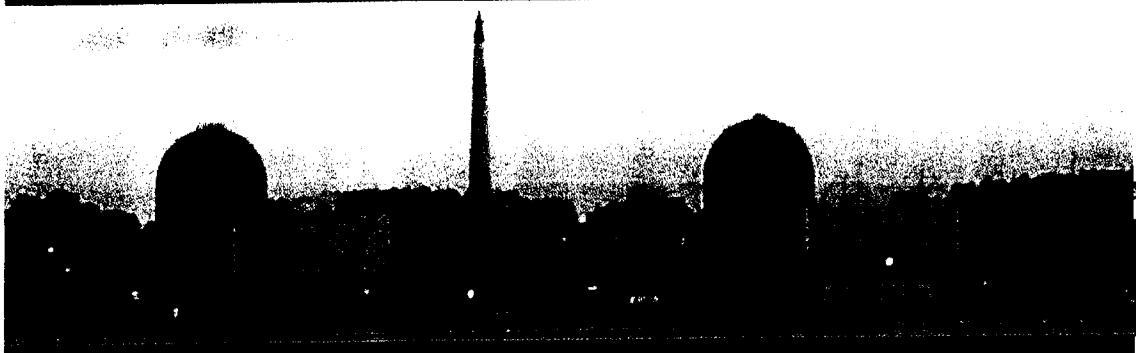
PHOTOGRAPHY

Front Cover, Saturn x-ray device, Credit: U.S. Department of Energy.

Back Cover, Environmental workers at Fernald, Credit: U.S. Department of Energy.

P6, Interim storage of solid transuranic waste at Idaho National Engineering & Environmental Laboratory, Credit: U.S. Department of Energy.

P9, Indian Point power plant, on the Hudson River, 24 miles north of New York City, Credit: Elena Pousada.



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Arthur R. Marshall Foundation
Audubon of Florida
Audubon Society of the Everglades
Broward County Audubon Society
Clean Water Action
Clean Water Network
Collier County Audubon Society
The Conservancy of Southwest Florida
Defenders of Wildlife
Earthjustice
Everglades Law Center
The Environmental Coalition
Everglades Coordinating Council
Environment Florida
Florida Defenders of the Environment
Florida Division of the Izaak WaltonLeague of America
Florida Keys Chapter of the Izaak Walton League of America
Florida Keys Environmental Fund
Florida Native Plant Society
Florida Oceanographic Society
Florida Sierra Club
Florida Wildlife Federation
Friends of the Everglades
Izaak Walton League of America
Last Stand
League of Woman Voters of Florida
Loxahatchee River Coalition
Mangrove Chapter of the Izaak Walton League of America
Martin County Conservation Alliance
National Audubon Society
National Parks Conservation Association
National Wildlife Federation
Natural Resources Defense Council
The Ocean Conservancy
The Pegasus Foundation
Sanibel-Captiva Conservation Foundation
Save It Now, Glades!
Sierra Club
Sierra Club Broward Group
Sierra Club Loxahatchee Group
Sierra Club Miami Group
Tropical Audubon Society
The Urban Environment League
World Wildlife Fund

Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

January 29, 2008

VIA FACSIMILE: 850-431-7118

Re: Docket Number 070650

The Everglades Coalition, an alliance of 47 local, state and national organizations, urges you to deny approval of Florida Power and Light's (FPL) need determination.

It is incumbent upon the Public Service Commission to make informed decisions. FPL has failed to provide critical information necessary to understand the effects of the proposed nuclear power plant expansion on South Florida's aquifers, endangered species, and America's Everglades.

The water needs of this project and how they will be met are undetermined at this time. FPL has refused to identify a water source during the Miami-Dade County Commission land use hearings on December 20, 2007, in its application to the PSC dated October 16, 2007 and during initial PSC testimony on January 9, 2008. If critical information is unknown or withheld, it is egregious for the PSC to approve this application.

Given this lack of information, it is impossible for the PSC to project reasonability of direct and indirect costs of water supply to FPL ratepayers as mandated by Florida Statute 403.519. As such, PSC and Florida's ratepayers also cannot be assured that this is the most cost-effective energy alternative. FPL is examining options which include the installation of 26 miles of pipe to procure reclaimed water from the Virginia Key plant which could cost an estimated $700 million dollars and additional unknown water treatment costs.

Florida's water shortages have severe implications regarding the safety and reliability of nuclear power as outlined by the Associated Press in their January 23, 2008 article "Drought could close nuclear power plants". Safe and dependable operation of the proposed units at Turkey point is reliant on the availability of an abundant, dedicated supply of water. Until this source can be identified the PSC cannot evaluate "reliability and integrity of power generation" in accordance with F.S. 403.519.

Ex. 93

Further, the Everglades Coalition supports energy conservation methods and renewable energy sources.

Accordingly, to preserve the integrity of the PSC process we ask that you deny this need determination until adequate information is provided by FPL.

Sincerely,

Mark D. Perry
Co-Chair

Drew Martin
Co-Chair

www.evergladescoalition.org
Ph: 561-746-8078 ♦ Fax: 561-745-8936 ♦ P.O. Box 1902, Jupiter, FL 33468

Environmental Statement on Nuclear Energy and Global Warming

June 2005

As national and local environmental, consumer, and safe energy organizations, we have serious and substantive concerns about nuclear energy. While we are committed to tackling the challenge of global warming, we flatly reject the argument that increased investment in nuclear capacity is an acceptable or necessary solution. Instead we can significantly reduce global warming pollution and save consumers money by increasing energy efficiency and shifting to clean, renewable sources of energy.

For at least 30 years, the public, policymakers, and private investors have viewed nuclear power as uneconomical, unsafe, and unnecessary. As a result, no new reactors have been ordered in this country. With respect to these serious concerns, nothing has changed. While we urgently need to reduce our global warming emissions, nuclear power still remains the least attractive, least economic, and least safe avenue to pursue.

Nuclear Power Is Unnecessary

We can meet our future electricity needs and reduce global warming pollution without increasing our reliance on nuclear energy. For example, a 2004 study by Synapse Energy Economics found that the U.S. could reduce carbon dioxide emissions from electricity generation by more than 47 percent by 2025 compared to business as usual and meet projected electricity demand, while saving consumers $36 billion annually. In fact, we can do this while cutting our reliance on nuclear power by nearly half.

The states are moving forward with clean energy solutions. Nineteen states have passed renewable electricity standards requiring an increasing percentage of energy to be generated by renewable energy sources. Replicating this effort nationally would increase our ability to reduce global warming emissions, while benefiting public health, consumers and the environment. Several states are working to increase efficiency standards for appliances, while many are working to reduce global warming pollution from cars. The states are demonstrating that there is an effective arsenal of clean energy solutions that can significantly curb our global warming emissions; it is these ideas that we need to draw upon.

Nuclear Power Is Too Expensive

The economics of nuclear power remain so unattractive that without additional federal subsidies, no new plants will be built. Despite 50 years and more than $150 billion in federal support, the nuclear power industry is still seemingly incapable of building a new plant on its own. In fact, the U.S. DOE's Energy Information Administration stated in its 2005 Annual Energy Outlook that "new [nuclear] plants are not expected to be economical."

Dominion CEO & Chairman Thomas Capps has stated that:

> "If you announced you were going to build a new nuclear plant, Moody's and Standard & Poor's would assuredly drop your bonds to junk status, hedge funds would be bumping into each other trying to short your stock."

Not surprisingly, private investors have shown such disinterest in supporting new nuclear power plants that the industry is, yet again, at the mercy of federal handouts. In 2003, Senator Domenici included extensive federal incentives in his original energy bill, including loan guarantees and power purchase agreements covering up to half the cost of building a new plant, as well as clean air credits and federal lines of credit. Despite this, Standard & Poor's concluded:

> "Standard & Poor's Ratings Services has found that an electric utility with a nuclear exposure has weaker credit than one without and can expect to pay more on the margin for credit. Federal support of construction costs will do little to change that reality. Therefore, were a utility to embark on a new or expanded nuclear endeavor, Standard & Poor's would likely revisit its rating on the utility."

Due to the lack of private investment, it is the inevitable that any new nuclear construction will result in significant public cost to taxpayers. Between 1950 and 1998, the federal government spent 56 percent of the energy supply research and development on nuclear energy, while only 11 percent was invested in all renewable technologies. If the federal government is going to spend any money on energy, those dollars should be focused on clean and safe technologies.

Nuclear Energy Is Too Dangerous

Nuclear energy has never been safe, but post 9-11 nuclear power plants and radioactive waste storage facilities have become terrorist targets as well. Al-Qaeda operatives were surveying nuclear power plants as potential terrorist targets; in the post 9-11 world these risks are only elevated. The National Academy of Sciences has raised serious concerns about the safety of irradiated nuclear fuel storage facilities from terrorist attacks in its report entitled "Safety and Security of Spent Nuclear Fuel Storage." Furthermore, protecting the fuel from terrorists as it is moved to longer term storage facilities, if they are ever built, will be nearly impossible.

The fact that reactors in the U.S. are also deteriorating with age and inadequate oversight by the Nuclear Regulatory Commission provides further reason for concern. Just three years ago, for example, a nuclear reactor in Ohio came within one-fifth of an inch of stainless steel from a rupture that would have vented radioactive steam into the reactor's containment building and could have led to a meltdown.

Nuclear Power Is Too Polluting

Beyond operating concerns remains the unsolved and disturbing issue of waste disposal. Some 95 percent of the radioactivity ever generated in the U.S. is contained in the

nation's civilian high-level atomic waste. Despite almost two decades of pushing to make Yucca Mountain in Nevada the nation's high-level waste repository, it has not been shown scientifically to be suitable to safely store the waste. The Yucca Mountain project is further thrown into doubt by the recent revelations of the falsification of scientific data by USGS scientists, as well as the court ruling that found EPA's public health standards for the site to be illegal. No country in the world has solved its nuclear waste problem. It makes little sense to begin building new reactors when we don't know what to do with the lethal waste from the ones we have.

Using Nuclear Power to Address Global Warming Would Exacerbate the Problems

Major studies, such as those by MIT, agree that using nuclear power to have any significant effect on global warming would require building at least 1,000 new reactors worldwide. This would exacerbate all of the problems of the technology: more terrorist targets, more cost (potentially trillions of dollars), less safety, need for a new Yucca Mountain-sized waste site every four or five years, more proliferation of nuclear materials and technologies, dozens of new uranium enrichment plants, and, even then, a severe shortage of uranium even within this century, while displacing the resources needed to ensure a real solution to the global warming issue.

Conclusion

We believe that the financial and safety risks associated with nuclear power are so grave that nuclear power should not be a part of any solution to address global warming. There is no need to jeopardize our health, safety, and economy with increased nuclear power when we have cleaner, cheaper solutions to reduce global warming pollution.

Signatories (313):

National Groups

Center for Health, Environment, and Justice
Clean Water Action
Environmental Working Group
Friends of the Earth
Global Resource Action Center for the Environment (GRACE)
Greenpeace
Indigenous Environmental Network
Nuclear Age Peace Foundation
Nuclear Information and Resource Service
Nuclear Policy Research Institute
Progressive Democrats of America
Public Citizen
Sierra Club
Sustainable Energy and Economy Network
U.S. Public Interest Research Group (U.S. PIRG)

Regional Groups

Blue Ridge Environmental Defense League
New England Coalition
Northwest Energy Coalition
Southern Alliance for Clean Energy

State Groups

Alabama
Alabama Environmental Council

Alaska
Alaska PIRG

Arizona
Arizona PIRG
Arizona Safe Energy Coalition
Democratic Processes Center, Inc.
Pray for Peace Foundation
The Nuclear Resister
Women's International League for Peace and Freedom

California
Alliance for Nuclear Responsibility
Bay Area Hunters Point Community Advocates
Bay Area Nuclear Waste Coalition
Better World Group
Blue Water Network - A Division of Friends of the Earth
California Communities Against Toxics
California Environmental Rights Alliance
Clean Water Action (CA Chapter)
Committee to Bridge the Gap
Earth Action Network
Environment California
Global Community Monitor
Grandmothers for Peace
Greenaction for Health and Environmental Justice
HOME: Healing Ourselves & Mother Earth
Lightupthedarkness.org
Occidental Arts and Ecology Center
Peace & Justice Network of San Joaquin County
Planners for Social Responsibility
Planning and Conservation League
Public Citizen – California
Redwood Alliance
Richard Norgaard, Professor of Energy and Resources, University of California at Berkeley
San Luis Obispo Mothers for Peace
SLO GREEN Party Committee on Nuclear Waste
The Atomic Mirror
The Law Office of Maria E. Hall
Tri-Valley Communities Against A Radioactive Environment

Colorado
Boulder Renewable Energy & Efficiency Working Group
Center for Resource Conservation
Colorado Environmental Coalition
Colorado Renewable Energy Society
Colorado Solar Energy Industries Association
CoPIRG
Environment Colorado
ProgressNow.org
Rocky Mountain Peace And Justice
Western Colorado Congress
Western Slope Environmental Resource Council
Women in Sustainable Energy

Connecticut
Center for Resource Solutions
Citizens Awareness Network (CT Chapter)
Clean Water Action (CT Chapter)
Connecticut Coalition Against Millstone
ConnPIRG
Energy Solutions

Delaware
Green Delaware

Florida
Clean Water Action (FL Chapter)
Florida PIRG
Legal Environmental Assistance Foundation
Pegasus Foundation
Safe Earth Alliance

Georgia
Action for a Clean Environment
Center for a Sustainable Coast
Food Not Bombs
GANE - Georgians Against Nuclear Energy
Savannah Riverkeeper
Georgia PIRG
Women's Action for New Directions

Hawaii
Ahahui Malama i ka Lokahi (Hawaiians for the Conservation of Native Ecosystems)

Idaho
Snake River Alliance

Illinois
ASC Justice and Peace Office

Cancer Prevention Coalition
Illinois PIRG
Inside Out Art Studio
New Community Project
No New Nukes
Nuclear Energy Information Service

Indiana
Citizens Action Coalition
INPIRG
Valley Watch, Inc.

Iowa
Iowa PIRG

Kansas
Enviro-Health Concerns

Kentucky
Kentucky Environmental Foundation

Louisiana
Advocates for Environmental Human Rights
Alliance for Affordable Energy
Louisiana Environmental Action Network

Maine
American Lung Association of Maine
Environment Maine
Friends of the Coast
Maine Public Health Association
Natural Resources Council of Maine

Maryland
Audobon Naturalist Society
Chesapeake Climate Action Network
Clean Energy Partnership
Clean Water Action (Chesapeake Chapter)
Cleanup Coalition
Maryland United for Peace and Justice
MaryPIRG
Peace & Justice Coalition
Sun Day Campaign

Massachusetts
C-10 Research and Education Foundation
Citizens Awareness Network (MA Chapter)
Clean Water Action Alliance (MA Chapter)
Del Amo Action Committee
FlybyNews.com

Green Futures from Fall River
Lawrence Environmental Action Group, Inc.
Lawrence Environmental Justice Advisory Committee
Massachusetts Citizens for Clean Energy
MASSPIRG
Pilgrim Watch
Solar Design Associates, Inc.
Toxics Action Center
Women's Community Cancer Project

Michigan
Citizens' Resistance at Fermi Two
Clean Water Action (MI Chapter)
Coalition for a Nuclear-Free Great Lakes
Don't Waste Michigan
Ecology Center
Michigan Environmental Council
PIRGIM
Radiological Evaluation Acton Project, Great Lakes (REAP-GL)
Sisters of Mercy, Regional Community of Detroit
West Michigan Environmental Action Council

Minnesota
Clean Water Action (MN Chapter)
Friends for a Non-Violent World
Honor the Earth
Mankato Area Environmentalists
School Sisters of Notre Dame

Missouri
MoPIRG

Montana
Clark Fork Coalition
Montana Environmental Information Center
MontPIRG
Oasis Montana Inc.
Women's Voices for the Earth

Nebraska
Nebraskans for Peace
Western Nebraska Resources Council

Nevada
Citizen Alert
Nevada Conservation League/Education Fund
Nevada Environmental Coalition, Inc.
Nevada Nuclear Waste Task Force
The Organization for the Protection of Nevada's Resident Tortoises Inc.

New Hampshire
Clean Water Action (NH)
New Hampshire PIRG

New Jersey
Coalition for Peace and Justice in New Jersey
Grandmothers, Mothers and More for Energy Safety
Jersey Shore Nuclear Watch
N.J. Hiroshima/Nagasaki Remembrance Committee
New Jersey Audubon Society
New Jersey Environmental Federation
New Jersey PIRG
SJG Design
Unplug Salem

New Mexico
Citizen Action New Mexico
Los Alamos Study Group
New Mexico Environmental Law Center
New Mexico Physicians for Social Responsibility
New Mexico PIRG
Nuclear Watch of New Mexico
Southwest Climate Council
Southwest Research and Information Center
Street Solidarity

New York
Beacon Sloop Club
Cheektowaga Citizens' Coalition, Inc.
Citizens Awareness Network (NY Chapter)
Citizens' Environmental Coalition
Code Pink New York
Community Health and Environmental Coalition
Council On Intelligent Energy & Conservation Policy (CIECP)
Dominican Sisters of Hope
Environmental Advocates of New York
Long Island Neighborhood Network
Nuclear Free New York
Nuclear Weapons Education and Action Project
NYPIRG
People's Environmental Network of New York
Radiation and Public Health Project
Renewable Energy Long Island
Rockland (FUSE)
Saint Peter Damian Fraternity, Secular Franciscan Order at Saint Joseph Church
Toxic Waste/Lupus Coalition
Ursuline Sisters of Tildonk-U.S. Province

North Carolina
Appalachian Voices

Blue Ridge Environmental Defense League
Canary Coalition
Conservation Council of North Carolina
North Carolina Citizens Research Group
North Carolina PIRG
North Carolina Waste Awareness and Reduction Network (NCWARN)
Protect All Children's Environment
Western North Carolina Alliance

North Dakota
Clean Water Action (ND Chapter)

Ohio
Community Organizing Center
Earth Day Coalition
Independent Environmental Conservation & Activism Network
Ohio PIRG
Portsmouth/Piketon Residents for Environmental Safety and Security

Oklahoma
Citizens' Action for Safe Energy, Inc.

Oregon
Erik Sten - Portland City Commissioner
Oregon Citizen Utility Board
Oregon Natural Resources Council
Oregon State PIRG
Trout Unlimited - Oregon Council

Pennsylvania
ActionPA
Citizen Power
Clean Water Action (PA Chapter)
Energy Justice Network
International Development Alternatives Consortium (IDAC)
Jefferson Action Group
Lafayette Environmental Awareness and Protection (LEAP)
PennEnvironment
Philadelphia Physicians for Social Responsibility
Three Mile Island Alert, Inc.

Rhode Island
Allen & Pavlides, Architect
American Friends Service Committee Southeastern New England
Apeiron Institute for Environmental Living
Brown University Environment Action Network (BEAN)
Clean Water Action (RI Chapter)
Environment Committee of the Episcopal Diocese of Rhode Island
Ocean State Action
People's Power and Light

Rhode Island Peace Action
Rhode Island PIRG
SolarWrights

South Carolina
Charleston Peace
ThinkingPeople
York County Greens

South Dakota
Clean Water Action (SD Chapter)

Tennessee
Cumberland Green Bioregional Council

Texas
Clean Water Action (TX Chapter)
Galveston Houston Association for Smog Prevention
Greater Edwards Aquifer Alliance
Hudspeth Directive for Conservation
Peace Action (Texas Chapter)
Public Citizen (TX Chapter)
Sustainable Energy and Economic Development Coalition (SEED)
Texas Center for Policy Studies
Texas Environmental Democrats
Texas Radiation Online
TexPIRG

Utah
HEAL Utah

Vermont
Fairwind Vermont
Vermont Energy Investment Corp.
Vermont Green Building Network
Vermonters for a Clean Environment
VPIRG

Virginia
CLEAN (Citizens of Lee Environmental Action Network)
Clinch Coalition
Coalition for Jobs and the Environment
Devil's Fork Trail Club
Patrick Environmental Awareness Group (PEAG)
People's Alliance for Clean Energy (PACE)
Virginia Forest Watch

Washington
Community Coalition for Environmental Justice
Solar Washington

The Backbone Campaign
WashPIRG
Waste Action Project

Washington, D.C.
Proposition One Committee
Stella Group, Ltd.
Voices Opposed to Environmental Racism

West Virginia
WV Citizen Action Group

Wisconsin
Citizen Power, Inc.
Clean Water Action (WI Chapter)
Clean Wisconsin
Community Awareness Forum
Peace and Justice Center
Sunny Solutions Energy Company
Wisconsin Citizens' Utility Board
WISPIRG

International Groups

Australia
Friends of the Earth (Australia)

Austria
ATOMSTOPP International - WISE Austria
Center for Encounter and Active Non-Violence
GLOBAL 2000
PLAGE - Überparteiliche Plattform gegen Atomgefahren

Belgium
KWIA

Bulgaria
Bulgarian NGOs National Coalition "NO Belene NPP!"
CEIE/CEE Bankwatch Network

Canada
Citizens for Renewable Energy
David Suzuki Foundation
Sierra Club of Canada

Czech Republic
South Bohemian Mothers

Finland
No More Nuclear Power Movement
Women Against Nuclear Power

Women For Peace

Germany
Nuclear-Free Future Award

Hungary
The ZHABA Collective

India
People's Movement Against Nuclear Energy

Netherlands
Global Anti-Nuclear Alliance
World Information Service on Energy

Russia
Russian Green Party "Green Russia"

Sweden
Swedish Antinuclear Movement (Folkkampanjen mot kaernkraft-kaernvapen)

Uganda
New Horizons, Women's Education Centre

Ukraine
Ecoclub
NIRS/WISE Ukraine

Special Comment

Moody's Corporate Finance

October 2007

New Nuclear Generation in the United States:

Keeping Options Open vs Addressing An Inevitable Necessity

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Summary

The US electric utility sector is in the early stages of a massive new construction period to address its future base-load capacity needs. Given the practical realities associated with electric supplies, environmental trends and national energy security, we believe the sector will focus a considerable amount of attention on building new nuclear generation.

According to the Nuclear Regulatory Commission (NRC), there are approximately 12 companies developing 17 Construction and Operating License (COL) applications for 31 new reactors. Other sources, such as the Nuclear Energy Institute (NEI), count approximately 17 companies developing 21 COL applications for up to 31 new reactors. While we do not incorporate a view that all 31 reactors will be built, we observe that many companies have already begun to pre-condition their selected sites, and several have entered into arrangements with vendors to procure long-lead time items. While these companies range the spectrum from vertically integrated regulated electric utilities to wholesale merchant energy suppliers, we believe the regulated utilities will be in a more advantageous position to commence construction over the intermediate-term horizon.

From a credit perspective, business and operating risk profiles will increase for companies that pursue new nuclear generation. This increase in risk is attributable to the size and complexity of the project, the long-term nature of the construction cycle, the uncertainties associated with all-in costs, regulatory oversight and the ultimate rate impact to end-use consumers and the ability for a utility to recover costs and earn an appropriate return. We observe that most of the risks that will be discussed in this report also apply to advanced coal-fired generation, which also include uncertainties associated with carbon capture and sequestration.

The increase in business and operating risks will be gradual as companies transition from the evaluation stage, to the permitting stage to meaningful construction. Moody's does not believe the sector will bring more than one or two new nuclear plants on line by 2015 – a date cited by a majority of the companies currently highlighting their nuclear ambitions. The complexity associated with the permitting process as well as the execution risks associated with construction projects of this nature should not be underestimated.

There are other equally important issues associated with nuclear generation that should not be underestimated, the most important of which include the political realities concerning global warming (regardless of whether or not it is scientifically a reality) and the longer-term issues surrounding national energy security. These issues – carbon controls and energy security – could further stimulate interest in new nuclear investment.

In addition, because companies that build new nuclear generation will increase their over-all business and operating risk profiles, there will be a need to establish financial policies over the near-term aimed at producing very strong financial credit ratios in order to maintain a given rating. While a constructive regulatory relationship will help mitigate near-term credit pressures, Moody's will remain concerned over the prospects of construction delays, cost over-runs, the implications for rate-shock and future disallowances. Moody's observes that given the long-term time horizon associated with construction projects of this nature, there can be no assurances that tomorrow's regulatory, political, or fuel environments will continue to be as supportive to nuclear power as they are currently.

In this Special Comment, we describe our views around the prospects for new nuclear generation and the likely implications for credit.

Rating Rationale

In general, Moody's maintains a relatively favorable bias towards nuclear generation. In our opinion, nuclear generation represents a critical component of the nation's electric supply base. Nuclear units tend to be well run, maintain very high average annual capacity factors; are extremely economic from a marginal cost perspective; and, they do not emit any of the air pollutants that are emerging as a major political issue.

From a credit perspective, Moody's believes that one of the biggest risks associated with nuclear generation is an unanticipated extended outage. While the ownership of nuclear generating facilities brings a higher level of complexity associated with operating and maintaining the units; ownership also comes with additional regulatory oversight, primarily with respect to the NRC, which we view as a credit positive. We also incorporate a view that most companies will fare reasonably well in taking appropriate measures to mitigate nuclear-related risks and the average credit rating for the regulated nuclear peer group is well positioned within the investment grade **Baa** rating category.

Amount of electricity generated by a 1,000-MWe reactor at 90% capacity factor in one year:

7.9 billion KWh—enough to supply electricity for 740,000 households.
If generated by other fuel sources, it would require:

- Oil: 13.7 million barrels – 1 barrel yields 576 KWh
- Coal: 3.4 million short tons – 1 ton yields 2,297 KWh
- Natural Gas: 65.8 billion cubic feet – 100 cubic feet yields 12 KWh

(based on average conversion rates from the Energy Information Administration)

Source: NEI

Extended Outages

While the high costs associated with the ownership and operation of nuclear plants are offset by the robust earnings and cash flow they generate, an extended outage can significantly stress an owner's liquidity and over-all financial profile. We believe the best way to mitigate this risk is through diversity, operational excellence and predictive maintenance practices. We note that the vast majority of nuclear operators continue to amass large portfolios of units in different transmission and geographical regions. From a downside scenario planning perspective, Moody's continues to assess outage risk in relation to the experience of First Energy during the Davis Besse outage, which lasted approximately 26 months (from February 2002 until March 2004).

Quantity and Quality of Skilled Labor

While the actual production of electricity does not differ between a nuclear, coal or gas-fired generating plant, there is greater complexity associated with nuclear generation, as evidenced by the more advanced degrees and skilled labor required to operate a nuclear plant. The nuclear labor force includes both degreed-engineers (to design, build, and operate the plant) as well as skilled craftsmen, both of which are in short supply. Separately, Moody's views the continuous training requirements for the nuclear labor force favorably. Most operators maintain regular training and simulation training exercises for employees and the NRC is constantly re-qualifying the employee base.

Environmental concerns are a political reality

The single greatest benefit that nuclear generation can offer over coal is the clean air effects associated with emissions. Whereas coal-fired facilities produce a significant amount of nitrogen oxide (NOx), sulfur dioxide (SO2), mercury and carbon emissions, nuclear facilities only produce steam as a by-product. On the other

hand, there is a trade off with respect to the fuel waste, which will be addressed later in this report. Coal-fired waste, namely ash, can be recycled into cement or used as landfill; nuclear waste, namely radio-active ceramic pellet assemblies need to be stored in a pool of water for at least 5 years before they are transferred into above ground dry storage (steel or concrete casks) for as long as 100 years and ultimately either recycled or entombed in an underground disposal facility for approximately 10,000 years. Taken as a whole, however, Moody's observes that there has been a subtle shift in the stance of several environmental groups as the carbon-free nature of nuclear generation is increasingly recognized as a societal benefit. However, we observe that environmental opposition remains a concern as their primary motivational agenda appears to be aimed at reduced consumption.

Nuclear is a Critical Component of National Supply Mix

In our opinion, nuclear generation is a critical component of the US energy supply mix. According to the Nuclear Energy Institute (NEI), there are 104 licensed nuclear generating stations in the US, which account for roughly 19.4% or 787.2 billion kilowatt-hours (bkWh) of the total electrical production in the US. These facilities typically operate around the clock, and are an integral component of the base-load supply needs of the country. As can be seen in the table below, the nuclear component of the total US electric supply base has been reasonably steady over the past several decades.o

Year	Total Electricity Generation (MWh)	Nuclear Generation (MWh)	Nuclear Share (percent)	Capacity Factor (Percent)
1975	1,920,754,569	172,505,075	9.0	55.9
1985	2,473,002,122	383,690,727	15.5	58.0
1995	3,353,487,362	673,402,123	20.1	77.4
2005	4,055,422,744	781,986,365	19.3	89.3
2006*	4,052,967,852	787,218,636	19.4	89.8

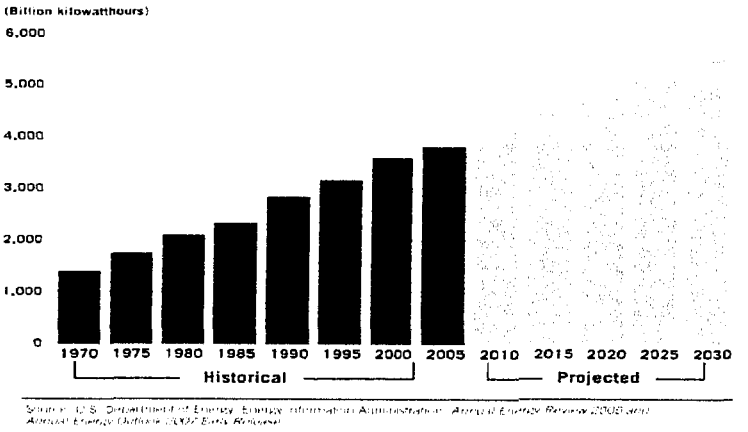
**Preliminary*

Source: Global Energy Decisions / Energy Information Administration

Nuclear operators should continue to produce power at an average capacity factor of approximately 90%. We do not believe the US nuclear sector can achieve average capacity factors much-higher than 90% on a sustainable basis or that the sector can meaningfully increase its electricity production from recent levels. This view is primarily based on our assumption that the vast majority of up-rates and performance improvements have been realized.

Supply / Demand fundamentals are favorable for new nuclear generation

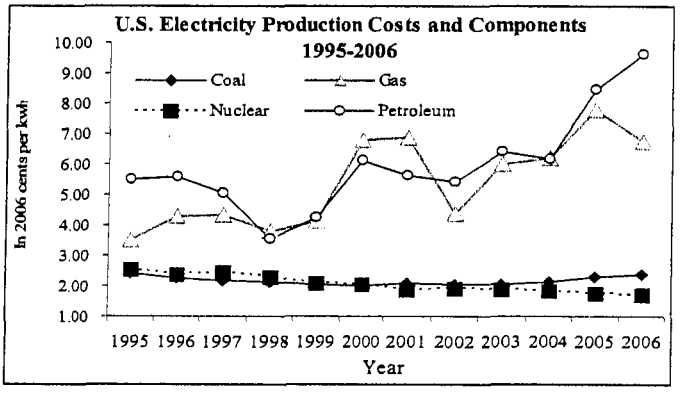
According to the Energy Information Administration (EIA), there is a need for approximately 258 gigawatts of new electric generation capacity in the US by 2030 at a cost of approximately $412 billion (in 2005 dollars) for an average cost of approximately $1,600 per kw-capacity. This need for capacity is partly a function of organic demand growth and includes some expectations that older generation facilities will be retired and / or otherwise taken out of service. Existing nuclear units are, on average, approximately 20 years old and most of the base-load coal-fired fleet is approximately 35 years old. It is reasonable to assume that many of the oldest plants will eventually reach the end of their useful lives over the next ten to fifteen years, but many of the larger and older units continue to be refurbished to extend their life beyond the original design specifications. For example, there are two coal-fired facilities associated with the Ohio Valley Electric Corporation (OVEC) that are 1950's vintage plants that have recently been undergoing a massive refurbishment (and environmental upgrade) plan to extend their lives for another 20 years.



Assuming there is a real need to build new base-load generation, there are really only two fuel options that can readily meet that need: coal and nuclear. While we remain favorably biased to renewable sources of generation, such as wind, solar and bio-mass, ensuring reliability of power generation from renewable sources continues to be a matter of concern. Also, additions to hydro power generation appear to be limited by geographical considerations and environmental opposition.

Nuclear enjoys a very competitive operating cost structure

The existing nuclear generation fleet tends to be a very strong producer of earnings and cash flow. The average cost for fuel (including nuclear fuel) tends to hover around $5 - $6 per MWh (megawatt hour). Operating and maintenance costs tend to average around $12 - $13 per MWh and additional "to-go" costs (comprised of incremental capital costs, administrative and general costs, insurance costs and other fees) average around $5 - $6 per MWh, for a total dispatch cost of approximately $22 - $25 per MWh. Assuming the average wholesale price of power for the nation is approximately $50 - $55 MWh, these units tend to produce power with an approximately $25 - $30 MWh margin.



Source: Global Energy Decisions

Nuclear Fraternity Helps Ensure Safe, Reliable and Economical Operations

One of the more unique features of being a nuclear operator is that it provides access to the nuclear operator "fraternity" on both a national and international scale. For example, in the US, nuclear operators meet regularly and share an enormous amount of operational and safety-related data. This fraternity atmosphere is a large part of the success of the industry, and the industry recognizes that it is only as good as its weakest link. Through organizations such as the Institute of Nuclear Power Operations (INPO) and the World Association of Nuclear Operators (WANO), nuclear operators assess each other on both standards of excellence (operational) as well as standards of compliance (regulation). In our opinion, the nuclear fraternity has been an important component of the more recent operational successes experienced by these facilities.

Nuclear operating performance has been impressive

The nation's fleet of nuclear units has experienced a tremendous improvement from an operational perspective. As recently as the early 1980's, the US nuclear fleet was operating with average capacity factors in the mid to high 70% range, but has, over the past 20 – 25 years, dramatically improved the averages. From a credit perspective, Moody's incorporates a view that the 90% average capacity factor will be maintained over the near to intermediate term horizon, and that the current fleet is, essentially, maxed-out from an operating efficiency stand point. It bears noting that the original design specifications of the existing fleet incorporated a view that these plants would indeed operate at a 90% range capacity factor.

We believe these performance improvements can be attributed to the following:

- Outage management – The most significant factor contributing to the improved operating performance, in our opinion, is related to outage management. In the past, it was not unusual for an outage to last 90 – 100 days. Today, it would be unusual for an outage to last more than 30 days.
- Advancements with diagnostics – The analytical and diagnostic ability to monitor equipment and components has advanced tremendously over the past 10 years. These technologies provide an operator with an unprecedented ability to monitor system components. In addition, the industry maintains extensive industry wide data bases on equipment performance, which guides the scheduling of preventative and predictive maintenance. As a result, an operator can address potential issues before a component fails, thereby lowering the "mean time between failure" and improving operating performance.
- Risk Assessment Analytics – Similar to the diagnostic technology advancements noted above, these tools provide an operator with system performance probabilities that allow an operator to calculate when it is acceptable to conduct maintenance without taking a unit off-line and without compromising safety. This reduces the amount of maintenance work that must be performed during an outage, and thus reduces outage duration. An example would be repairing a feed water train.
- Personnel – There is now better management of facilities and skill sets of personnel enhanced through superior training and educational programs.

Nuclear Regulatory Commission Provides Additional Layer of Oversight

In general, Moody's views the oversight provided by the NRC as a credit positive as the NRC primarily regulates the safety of the operating fleet in the US; at the moment, approximately 100 plants.

One risk is that a fundamental problem or equipment failure at one plant could create significant strass for the entire industry, should the NRC decide that every operating license needs to be reassessed in some fashion. As a result, nuclear operators can only operate their plants with the blessing of the NRC, they are only as good as their weakest colleague. To mitigate this risk, the nuclear industry has engaged in a "best practices" effort for many years, and regularly cross-trains and shares operational and technical data. While this fraternity approach helps the over-all sector, Moody's can not ignore the potential for contagion risk. This risk was

recently exhibited with the Davis Besse reactor vessel head problem that occurred a few years ago; although we acknowledge that the industry addressed that issue in a timely manner without experiencing undue financial or operational stress at any other units.

Regulatory Approval Process Still a Constraint...

Although we acknowledge the NRC licensing process is more enhanced today than it was in the 1970's and 1980's, we still believe that the regulatory approval process associated with pursuing a new nuclear facility will emerge as a potential constraint. The combination of the construction and operating process appears to be biased towards risk mitigation, and therefore is viewed as a credit positive. However, this new regulatory process remains untested and therefore deserves careful attention.

...But NRC is Experienced

The NRC is very experienced with license approvals. We observe that over the past several years the NRC has been active with four broad categories of license review and approvals with respect to: License Renewals; Power Up-Rates; Early Site Permits and Fuel Facilities. However, we can not ignore the fact that there are many countries that are equally as active with pursuing new nuclear generation and that the regulatory approval process is either non-existent or substantially less burdensome.

First COL filing expected to be litigated

We believe the first COL filing will be litigated, which could create lengthy delays for the rest of the sector. We note that while many in the industry believe this risk has largely been removed from the regulatory filing process, many are also reluctant to move forward without US governmental guarantees or other backstops to protect them from lengthy litigation or extended regulatory delays. Moody's will carefully monitor the potential for litigation related to NRG Energy's recent COL filing.

Other Agencies Need to Provide Approvals

Separately, there are still important state regulators and local governmental agencies that need to be convinced that new nuclear generation is an appropriate alternative. These include numerous permits from state agencies (i.e., air and water permits and certificates of public convenience and necessity from state public regulatory authorities), the US Army Corps of Engineers and other local authorities (i.e., construction permits) before meaningful construction can commence.

The NRC Review Team

The NRC has significantly increased its labor force in anticipation of many new COL filings. As a result, there are now essentially two different divisions at the NRC: one team to monitor the existing fleet of operating units (Nuclear Reactor Regulation) and another to review the license filings and inspect the new sites (New Reactor Office). The New Reactor Office is comprised of technical experts that will be divided up according to the technology selected by the licensee, that is, GE, Westinghouse or Areva. The teams (by technology) will then be broken down into expertise on civil / structural engineering, piping, environmental impact, security, emergency plans etc. These sub-teams will share their assessments and evaluations between technologies.

The COL permit

The NRC is committing to complete its review of the applications within a 42 month period (30 months for the application review and 12 months for hearings). Moody's notes, however, that the NRC clock does not start ticking when the COL is first filed but starts when the filing is docketed by the regulator. As a result, some companies that make their COL filing may get the filing sent back if the NRC feels it is deficient in some respect.

Once the filing is docketed, the NRC's staff will divide the filing into teams. The teams are formed by technology and sub-teams will be formed to review the various components of the filing. Although Moody's believes that the first filing may become mired in contentious litigation, we also believe the NRC will strive to

meet its commitment to complete its review within the allotted 42 month timeframe and not be viewed as a major bottleneck organization. Instead, potential delays in the process may come from hearings before various licensing boards. We expect the industry and the NRC will gain from its experience with the first several COL filings and we expect the process to become shorter over time – especially with respect to the 12 months of hearings that are incorporated into the approval process.

Moody's believes there may be as many as three to five filings made in 2007. In our opinion, most of the filings will be pushed back into the late 2008 timeframe, due to the need to resolve several of the important open issues that will be highlighted in this report, the most important of which are the implications of investment recovery and the effect on consumer rates.

COL has a long-term shelf life

The COL permit does not have an "expiration date" for the construction portion. Once the COL is granted, a company can hold that license as long as no new significant information comes to light. Once a plant actually goes commercial, the operating license portion of the COL is good for 40 years, with the possibility of renewal for an additional 20 years. The Early Site Permit, which does not allow reactor-related construction, has a 20-year shelf life and can be renewed for an additional 20 years. This will provide a substantial amount of lead-time for companies to continue their evaluation and cost studies before commencing construction of a plant.

Nuclear New Build Economics

The prospects for building new nuclear generation in the US are very good. A significant number of large, well capitalized companies are publicly discussing their plans to build new nuclear generating facilities and a number of these companies are expected to make the necessary license filings with the NRC starting in October 2007.

Notwithstanding the favorable fundamentals associated with the need to add new nuclear generation into the nation's capacity supply, Moody's believes that many of the current expectations regarding new nuclear generation are overly ambitious. In fact, the timing associated with commencing construction and making the next nuclear unit commercially available could be well beyond 2015 and the costs associated with the next generation of nuclear build could be significantly higher than the approximately $3,500/kw estimates cited by many industry participants.

Short-Comings of Cost Estimates

All-in fact-based assessments require some basis for an overnight capital cost estimate, and the shortcomings of simply asserting that capital costs could be "significantly higher than $3,500/kw" should be supported by some analysis. That said, Moody's can not confirm (and all of our research supports our conclusion) definitive estimates for new nuclear costs at this time. Moody's can assert with confidence that there is considerable uncertainty with respect to the capital cost of new nuclear and coal-fired generating technologies, and that companies may decide not to proceed with financing and construction unless and until they have satisfied themselves (and, where necessary, their boards and regulators) that the investment is justified and that the plant can produce electricity and recover costs at a price that will not be overly burdensome to consumers.

Massive Construction Projects Are Complex

The over-all risks associated with building a new nuclear facility are essentially the same as the execution risks associated with most major construction projects, such as chemical plants or refineries. These construction projects are massive in scale and scope, require a tremendous amount of planning (and execution) and take years to complete. As a result, companies that pursue these kinds of projects take on a much higher level of business and operating risk, since there are no practical ways to mitigate away the gremlins that live in large, complex construction projects. There are ways to mitigate the risks associated with large construction projects, including highly skilled construction management, the terms and conditions of EPC contracts, completion of design work before construction starts, a disciplined licensing and permitting process completed before major capital outlays, liquidated damages provisions, etc.

We observe that the nuclear construction sector has made significant strides with modular construction design, which can meaningfully cut down on the construction schedule, particularly when coupled with the significant improvements in construction techniques since the last nuclear construction cycle in the 1970's and 1980's. As evidence, it has been reported that a recently completed nuclear facility in Japan was constructed in approximately 40 months (from first concrete pour to fuel load).

Increased Risks Associated with Escalation Assumptions

Dramatic increases in commodity prices over the recent past, exacerbated by a skilled labor shortage, have led to significant increases in the over-all cost estimates for major construction projects around the world. In the case of new nuclear, the very detailed specifications for forgings and other critical components for the construction process can add a new element of complexity and uncertainty. As noted previously, labor is in short supply and commodity costs have been extremely volatile. Most importantly, the commodities and world wide supply chain network associated with new nuclear projects are also being called upon to build other generation facilities, including coal as well as nuclear, nationally and internationally. Nuclear operators are also competing with major oil, petrochemical and steel companies for access to these resources, and thus represent a challenge to all major construction projects.

Significant Bottlenecks to Construction Add to Execution Risk

There are significant bottlenecks to construction that have not yet been resolved. In our opinion, there are five key bottlenecks that should not be assumed away from a planning perspective. Moody's notes that some of these constraints are widely recognized and being factored into some of the planning and construction schedules. In the case of nuclear engineers, for example, enrollment in nuclear engineering programs at many universities have been increasing across the country over the last several years, which suggests that the market is responding to perceived increased demand.

- Ultra Heavy / Ultra Large Forgings - There are numerous long-lead time items that need to be ordered (or reserved) now in order to meet a construction timetable for any project of this magnitude. These items include the ultra-heavy steel forgings required for a generating station (regardless of whether its coal or nuke) and include the reactor vessel, the steam generator shell and the bottom head (which is welded to the shell). At the moment, the only ultra heavy forgery in the world is located in Japan, at a Japan Steel Works facility. There may also be capacity developing in France (Creusot Forge) and possibly South Korea, but we have not independently verified those claims. Moody's observes that each generating facility may require a number of ultra heavy forgings, in some cases between 6 and 12 forgings per plant; and that Japan Steel Works can only produce a limited number of forgings of this size per year. As a result, it is questionable whether the 2015 timeframe is realistic, since Japan Steel Works is also taking orders from other industry sectors (like petrochemicals) and other countries that have already committed to building new nuclear plants (China, India and several countries in Europe).
- Large Manufactured Components – these items include the steam turbines and reactor pressure vessels.
- Engineering Resources – this is part of the skilled labor shortage issue noted previously. Nuclear engineers are required for the detailed design work for a new nuclear facility.
- Logistics – As with any major construction project, there are massive logistical issues that need to be managed, including the procurement of cranes and ships (to transport the ultra heavy forgings). Properly managing the logistical aspects of a major construction project will be critical to delivering a plant on time and within budget.
- Site Labor – Another component to the skilled labor shortage issue. Site labor includes the construction force, welders and other trained professionals. Moody's observes that if the federal government is proactive with carbon emission legislation and the desire to build new nuclear units becomes more compelling over the near to intermediate-term horizon, this issue could become a major obstacle for the industry.

Costs Associated with New Nuclear Build are Early Best Estimates

Throughout our due diligence process, Moody's has not been able to make a finite determination of the range for the all-in cost associated with new nuclear. As a result, we believe the ultimate costs associated with building new nuclear generation do not exist today – and that the current cost estimates represent best estimates, which are subject to change.

There is empirical data that suggests a possible range for new nuclear plant costs based on experience overseas, but firm cost estimates are not available at this time in the US (including both new nuclear and new coal technologies). We believe that in order to support corporate decisions on whether or not to proceed with new nuclear projects, the industry will work with all possible speed to complete the detailed design and engineering work that will permit firm cost estimates based on a substantially complete design and that many regulatory authorities may require this information as part of their approval process. Therefore, it is reasonable to assume that companies will not move forward with new nuclear construction projects until and unless they have a high degree of confidence in the capital cost, a solid EPC wrap, and with construction and other risks adequately hedged or otherwise mitigated. Similar uncertainty attends virtually all other base load generating technologies, although the sources of the uncertainty may vary from technology to technology.

Many companies planning to build new nuclear generation freely acknowledge considerable uncertainty regarding new nuclear plant costs. More firm cost estimates will not be available until the vendors / suppliers have secured their own cost estimates, which will require a detailed review of the world wide supply network, the availability of commodities and labor supplies.

There are some figures available in the marketplace that claim new nuclear generation can be procured at approximately $2,500/kw - $3,500/kw, but it remains unclear as to what was included in the estimate, and more importantly, what was left out. This concept, creating an "apples-to-apples" cost comparison, could become an important determinant for various state regulatory authorities as they attempt to assess the ultimate impact on rates for end-use consumers.

Potential Owner's Costs Associated with New Nuclear Units:

Transmission upgrades / refurbishments

Access to transmission right-of-ways (ROW's)

Site Specific Costs

- Security
- Cooling Towers
- Roads / Other infrastructure
- Underground utilities

Administrative

- Dormitories
- Training Facilities
- General Administrative Buildings

From a credit perspective, Moody's is indifferent as to what the "overnight" cost of the actual nuclear generating plant might be – as overnight costs often exclude owner's costs and price escalation. Instead, we are concerned with the total all-in costs of the nuclear generating facility. An analogy would be the purchase price of a house (the over-night cost), which excludes the costs of appliances, furnishings, and landscaping (the all-in cost). Capitalized interest, other owner's costs (which include site preparation, administrative buildings and other administrative costs) and transmission upgrades / refurbishments could add several hundred more dollars per kw-capacity.

The potential costs associated with transmission upgrades / refurbishments appears to be getting very little attention at this time – possibly due to Federal Energy Regulatory Commission (FERC) rules and regulations which make management teams leery of engaging in public discourse too early.

Moody's believes the all-in cost of a nuclear generating facility could come in at between $5,000 - $6,000/kw. While we acknowledge that our estimate is only marginally better than a guess; it is a more conservative estimate than current market estimates and represent a substantial premium to the current estimates for new IGCC coal-fired generation. For example, AEP's filing in West Virginia for an IGCC plant is estimated to cost approximately $3,500 kw capacity. As noted previously with respect to these estimates, it is unclear as to whether or not capitalized financing costs and other owner's costs are included in the estimate.

Estimated Valuations for Generation

	$ / kw capacity	
	Low	High
Nuclear		
Existing fleet	$2,700	$3,500
New build - market estimates	$3,000	$4,000
New build - Moody's estimates	**$5,000**	**$6,000**
Coal		
Existing fleet	$1,700	$2,200
New build - Traditional	$2,500	$2,900
New build - IGCC	$3,300	$3,700
Natural Gas		
Combined Cycle (non-city)	$700	$900
Peakers	$600	$800

State regulatory arrangements

Moody's observes that many state legislatures and regulatory authorities continue to work in a constructive manner with their electric utilities to address the need for new base load plant. In addition, many states appear to be favorably disposed to new nuclear generation – especially if it can be located within their state.

We believe the first new nuclear unit is likely to become commercially available in the southeast region. In our opinion, the states in the southeast (Florida, Virginia, North Carolina, South Carolina, Georgia) have been most supportive of designing cost recovery mechanisms that encourage new nuclear investment, and this supportiveness may also be a function of the limited renewable resources available in the southeastern region.

The implications for end-use rate payers / customers

From a credit perspective, Moody's remains concerned about the prospects of steadily rising rates for end use customers, regardless of whether new nuclear generation is built or not. It is clear to us, however, that the need to recover the construction costs associated with a new nuclear unit (or coal-fired unit) over the construction period could help to mitigate rate shock that would otherwise occur when the plant is finally brought on-line. These plants are likely to add approximately $5 to $10 billion to rate base, in some cases

doubling the existing rate base, and there will be a need to recover both the operating expenses as well as the high capital costs through new base rates. Eventually, end use customers may find it very difficult to balance their family budgets if the average electric bill continues to go up by roughly 10% a year over the next 5 years, which could raise the level of potential regulatory / political intervention risk.

Who Will Build the Next New Nuclear Facility?

The majority of the companies looking at building new nuclear generation are regulated utilities such as Duke Energy, Dominion, Entergy and Southern Company. There are several merchant energy companies looking at new nuclear as well, such as Constellation Energy, Public Service Enterprise, Exelon and NRG Energy, but the majority of merchants appear to be waiting for the second wave.

New Nuclear Plants Under Consideration[1]

Company	Site	Design	Number of Reactors	Date for Filing COL[2] Application
Alternate Energy Holdings	Bruneau, ID	TBD	TBD	TBD
Amarillo Power	Amarillo, TX vicinity	EPR	1	FY[3] 2008
Ameren UE	Callaway, MO	EPR	1	FY 2008
Detroit Edison	Fermi, MI	TBD	TBD	FY 2009
Dominion[4]	North Anna, VA	ESBWR	1	FY 2008
Duke Energy	William States Lee Cherokee County, SC	AP1000	2	FY 2008
Entergy	River Bend, LA	ESBWR	1	FY 2008
Entergy (NuStart Energy[5])	Grand Gulf, MS	ESBWR	1	FY 2008
Exelon	Clinton, IL	TBD	TBD	TBD
Exelon	Texas	TBD	1	FY 2009
Florida Power & Light	TBD	TBD	TBD	FY 2009
NRG Energy/STPNOC	Bay City, TX	ABWR	2	FY 2008
PPL	Susquehanna, Pa	TBD	1	TBD
Progress Energy	Harris, NC;	AP1000	2	FY 2008
Progress Energy	Levy Co., FL	AP1000	2	FY 2008
South Carolina Electric & Gas	Jenkinsville, SC	AP1000	2	FY 2008
Southern Company	Vogtle, GA	AP1000	2	FY 2008
TVA (NuStart Energy[5])	Bellefonte, AL	AP1000	2	FY 2008
TXU	Comanche Peak, TX	APWR	2	FY 2008
UniStar Nuclear[6]	Calvert Cliffs, MD plus 2 additional sites	EPR	3	First Submittal - FY 2008

[1] *This compendium is based on public announcements as of July 2007.*

[2] *Construction/Operating License*

[3] *Fiscal Year*

[4] *This consortium includes Dominion, General Electric, Bechtel.*

[5] *NuStart Energy includes Constellation, Duke, EDF International North America, Entergy, Exelon, FPL Group, General Electric, Progress, SCANA, Southern, Tennessee Valley Authority, Westinghouse.*

[6] *UniStar Nuclear is a joint venture of Constellation Energy and Areva.*

SOURCE: NEI

In our opinion, it makes more sense for regulated utilities to pursue new nuclear generation in the first wave of applications. This is largely premised on the traditional Integrated Resource Plans (IRP) that many utilities file (and review) with their respective state regulators. As a result, value can be ascribed to fuel diversity and environmental benefits that may not be as transparent in a merchant market. More importantly, the risks associated with construction can be mitigated through creative cost recovery designs that would not be available to a merchant operator. However, merchant companies may be able to achieve a lower risk profile (but usually not approaching a regulated utility) by using project finance structures, supported by Federal guarantees of the debt, vendor financing and, in some cases, guarantees from foreign export credit agencies, and/or robust off-take agreements. Some utilities may also seek many of these kinds of financing provisions.

From a credit perspective, there are still significant regulatory risks associated with building a nuclear plant in rate base. These risks will become exacerbated if there are lengthy construction delays or cost escalation. In addition, there are no accurate methods to assess what the political, environmental and fuel-commodity environments will look like in five to seven years time. If, at the end of construction, fuel is cheap, environmental concerns have abated and the political mood becomes contentious (for example, over the steady rate increases experienced over the previous five to seven years), utilities could be at risk with their regulatory / political constituents. Moody's is unable to assess the magnitude of this risk at this time, but we will continue to recognize its potential existence into our longer-term assessments. In addition, we also recognize that these factors may break in favor of nuclear development which can further stimulate new build.

Two Critical Near-Term Decision Points

There are two critical near-term decision points that companies need to make after they have decided that pursuing new nuclear generation is an option / alternative that they wish to explore: selecting an appropriate site and selecting a technology. Once these two decisions have been made, a company can commence developing its COL application for the NRC.

Site selection

The location of a site for a new nuclear facility will be one of the most important near-term decisions that a company has to make before committing to a major construction project (and the filing of its COL). In our opinion, the selection of a site where an existing nuclear facility is already operating (a brown field site) will be a lower risk decision than a pure green-field site.

Brown field sites, in general, have a clear advantage over green field sites due to their existing infrastructure which includes water supplies, transmission connections and administrative facilities. The current nuclear operators also have emergency and security plans in place and a local population more receptive to an additional unit at a pre-existing facility.

Brown field site advantages:

During the last nuclear construction cycle, in the 1970's and 1980's, many companies applied for construction permits to build multiple generating units at a given site. However, because of the events that unfolded during this period, namely Three Mile Island, inflation and regulatory reviews and disallowances, a number of the second or third units were never built. As a result, for those companies looking to build new nuclear units in the next construction cycle, there could be many advantages associated with the next new plant being sited at an existing facility. These sites, commonly referred to as "brown-field" sites, could provide an operator with the following benefits:

- An existing comfort level with the local community
- An existing transmission infrastructure with access to ROW's
- An existing supply of water / water rights
- Existing security and emergency management plans
- Existing on-site spent-fuel storage facilities
- The availability of historical environmental data
- An existing labor force

Technology Selection

The selection of a technology is also a major decision. At this time, only GE's Advanced Boiling Water Reactor (ABWR) and Westinghouse's AP1000 technology have been fully certified as a nuclear plant by the NRC. NRG plans to use the ABWR technology. However, the certification does not apply to GE's most advanced next generation passive design technology. We observe that GE is still working through data discovery with the NRC on its newer ESBWR technology. Areva's current design has not yet been certified either. Westinghouse's AP1000 technology has been certified by the NRC from a design perspective, but it still needs to fully certify its total plant design. While the technologies still need certification work, most utility and merchant generation companies are willing to pursue their strategies of filing COLs' under the assumption that the selected technology will be certified within their over-all construction timeframes.

As an aside, Moody's observes that the GE's ESBWR and Westinghouse's AP1000 designs are passive in nature from a safety perspective (ie, relying on gravity) as opposed to Areva (ie., relying on redundancy). As a result, it is our understanding that the GE and Westinghouse designs will require a smaller footprint for the facility and use less cement, steel and other commodities to build.

Design	Supplier	*Background and Current Status*
Advanced Boiling Water Reactor	General Electric	This large (1,350 MW) boiling water reactor is an evolutionary improvement on the boiling water reactors that make up approximately one-third of the U.S. nuclear power plant fleet. The first models of this design were deployed commercially by Tokyo Electric Power Co. at its Kashiwazaki-Kariwa generating station in Japan. TEPCO and other Japanese utilities continue to build ABWRs. This design was certified by the NRC in 1997.
AP1000	Westinghouse	The AP1000 is a 1,150-MW reactor, the first approved by the NRC to employ so-called "passive" safety features. The passive designs substitute natural forces like gravity to deliver cooling water to the reactor. The improved design eliminates a number of the pumps, valves, piping and other components that increase the complexity and the capital cost of today's nuclear plants. The AP1000 received its final design approval from the NRC in late 2004, and the final certification rule became effective in January 2006.
ESBWR	General Electric	The ESBWR is GE's new 1,500-MW design incorporating "passive" safety features. By simplifying the design of the ESBWR compared to the ABWR, GE expects to reduce the capital cost of the plant by approximately 20 percent. GE filed its application for design certification with the NRC in August 2005. The application has been accepted and the Final Design Approval (FDA) is scheduled for late 2008, with certification to follow in 2009.
EPR	Areva (in the U.S. market: UniStar, a joint venture of Areva and Constellation)	The EPR is a large (1,600 MW) design developed by Areva, the reactor supplier formed by Framatome (France) and Siemens (Germany). Areva has formed a joint venture with Constellation Energy Group called UniStar Nuclear to deploy the EPR technology in the United States. The first EPR is now being built in Finland, and it will be the next generation of nuclear plants built in France by Electricité de France. The EPR is an advanced light water reactor. The EPR design includes additional safety features not in today's light water reactors, including four safety trains instead of two, bunkered safety systems, double containments, and additional severe accident management features. Areva plans to make a design certification submittal to the NRC for the EPR in 2007.
ESBWR	General Electric	The ESBWR is GE's new 1,500-MW design incorporating "passive" safety features. By simplifying the design of the ESBWR compared to the ABWR, GE expects to reduce the capital cost of the plant by approximately 20 percent. GE filed its application for design certification with the NRC in August 2005. The application has been accepted and the Final Design Approval (FDA) is scheduled for late 2008, with certification to follow in 2009.

Source: NEI

International Markets Appear More Active

While the US continues to evaluate and assess the longer-term benefits and risks associated with building new nuclear generating facilities, in many other parts of the world, companies and / or governments are much more active with their nuclear new build plans. This is most obvious in Asia, where China is pursuing four new nuclear units (Westinghouse technology), and where Japan and Taiwan have also been active. China, in particular, may be interested in building over a dozen new nuclear plants over the near to intermediate term horizon and may use multiple technology designs (as opposed to the US's strategy of using a "standardized" design). In Europe, there has been activity in France, Finland and several Eastern European countries (Romania, Bulgaria and Russia).

In addition, Moody's observes that there are several Middle-Eastern countries that would like to build new nuclear facilities. For many of these countries, nuclear facilities are viewed as a great source of energy for water desalination, and they clearly have the capital to make the necessary investments. From a construction and operating risk perspective, these countries face the same set of issues that would be faced in the US, including the need to procure long lead time items over the very near-term horizon.

Nuclear Units under Construction Worldwide

Country	Total MWe
Argentina (1)	692
Bulgaria (2)	1,906
China (5)	3,220
China, Taiwan (2)	2,600
Finland (1)	1,600
India (6)	2,910
Iran (1)	915
Japan (1)	866
Pakistan (1)	300
Russia (7)	4,585
South Korea (2)	1,920
Ukraine (2)	1,900
Total (31)	23,414

Source: International Atomic Energy Agency PRIS database

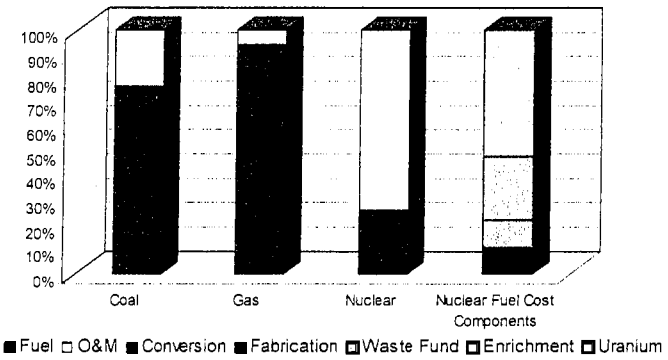
Fuel Fundamentals

Uranium is the primary fuel source for nuclear generation. It is located primarily in Canada, Australia, Africa, Russia and some of the Central Asian Republics that were formerly part of the Soviet Union. It is our understanding that the fuel conversion cycle has four primary components:

- Mining – uranium is contained in rock, which needs to be mined primarily in underground mines.
- Milling – the uranium ore (U235) is separated from the rock at a mill, similar to how copper and iron are milled, resulting in a powder, which is commonly referred to as "yellowcake".
- Conversion – the yellowcake is converted into a gas (uranium hexafluoride, or UF6).
- Fabrication – the uranium hexafluoride gas is a feedstock for an enrichment plant, where the uranium is enriched 3% - 5% and converted onto solid ceramic pellets. The enrichment process is a critical component of the nuclear fuel cycle. Many companies (including two in the US), and governments, are either building new enrichment capacity or are actively looking at ways to enhance enrichment capacity, but it may be several years before additional capacity becomes available (i.e., 2012).
- The pellets are assembled into tubes and the tubes are bundled into assemblies and shipped to the nuclear generating facility.

Once the fuel assemblies arrive at the nuclear plant, they are put into the reactor. During a refueling, operators will typically withdraw the oldest one-third of the fuel assemblies and rearrange the remainder and blended with the new assemblies. This is not unlike rearranging batteries in a large flashlight. Approximately 90% of the energy remains in fuel rods that are removed from the fuel assemblies and classified as "spent" fuel.

Fuel as a Percentage of Electric Power Production Costs 2006



Source: Global Energy Decisions

On September 11th, 2007, Duke Energy held an analyst meeting in New York where they presented the picture below. It was stated that the ceramic pellet has an equivalent amount of energy as one ton of coal.

Source: Duke Energy

Storage and Disposal

The storage and ultimate disposal of spent nuclear fuel continues to represent a major issue in the United States. There is roughly 50,000 metric tons of spent nuclear fuel in the US, but the industry does not view the issue as a critical path item. At the moment, spent fuel is primarily stored in large pools of water, usually for at least 5 years, then placed into dry cement or steel casks and stored on site. While this creates some local issues and emergency planning obstacles, Moody's incorporates a view that most sites are well equipped to manage the safe storage of spent nuclear fuel.

Some countries recycle their spent nuclear fuel, including France, Japan, Russia and the United Kingdom. Other countries bury their spent nuclear fuel, such as Sweden and Finland. Regardless of which path the US decides to pursue, it appears that many within the industry are confident that a solution can be found. Currently, the industry is working with the Global Nuclear Energy Partnership (GNEP) to design solutions for the 50,000 metric tons that exists throughout the country.

Federal Initiatives

One of the biggest near-term challenges associated with new nuclear generation construction in the US involves financing, including whether or not the Federal government will provide loan guarantees and / or otherwise encourage investment, much of which was encompassed in the Energy Policy Act (EPA) of 2005. Several large companies – both regulated as well as merchant have very clearly stated that they would not pursue their new nuclear plans if the Federal government did not provide an appropriate investment stimulus and investment protection. Moody's observes that the EPA provided four key incentives for the nuclear industry:

- Extension of Price-Anderson Act by 20 years
- Risk insurance / Stand-by support for risks beyond the control of management (delays due to licensing or litigation) of approximately $2.0 billion in total – up to $500 million for the first 2 new plants and up to $250 million for the next 4 plants.
- Production Tax Credits (PTC's) – in the amount of 1.8 cents per kwh for the first 6GW's of new nuclear capacity. However, in order to be eligible, an operator must submit the COL application and start construction by specific dates (end of 2008 and beginning of 2014, respectively).
- Loan Guarantees – Federal loan guarantees are authorized but the current rulemaking associated with how big of a guarantee and how much of a guarantee is still under debate. In addition, the calculation regarding how the government's subsidy costs has not yet been determined. This appears to be a particularly important issue for the merchant operators.

While it is understandable why the Federal loan guarantees are of particular interest to the merchant companies given the high level of risks associated with nuclear construction, it is debatable whether the Federal government should be involved in enhancing the profitability of the merchant market by socializing the up-front costs. However, the merchant generator would be responsible for paying the cost for the loan guarantee – the formula for which has not yet been determined. Moody's notes that some of the regulated electric utilities may also seek these Federal guarantees to help them facilitate their construction needs.

Moody's would view Federal loan guarantees positively from a construction perspective, but we observe that these guarantees, by themselves, will not be enough to completely mitigate the increased business and operating risk profile of a company seeking to build new nuclear generation. These guarantees are currently proposed to be made available to a specific number of companies considering new nuclear generation on a first-come-first-serve basis. From a potential off-balance sheet credit perspective, we question how serious a problem will need to be before a company decides to abandon its project and how these Federal guarantees will be structured from a risk sharing perspective. Notwithstanding these issues, we believe Federal loan guarantees could be very helpful in keeping the all-in costs down for a new nuclear project, which should help end-use consumers with rate shock.

Moody's also observes that the Federal loan guarantees are intended (according to the statute) to offset the technical, financial and market risks associated with building new, cleaner energy production facilities, including new nuclear power plants). The theory is that once the capital markets become more familiar with new nuclear construction, the market will be able to assess and price risk accordingly. Moody's does not fully subscribe to this philosophy. First, we believe the capital markets are capable of assessing the risk of new nuclear construction. To the extent that the capital markets price nuclear construction risk at extremely high levels, companies might consider injecting a larger component of equity into the project or find partners to share the risk. Secondly, there are several regulated utilities that are not basing their plans on the availability of these guarantees. Instead, the decision to pursue new nuclear generation was a result of their long-term resource plans, and in some cases, was made well before the Energy Policy Act even contemplated authorizing Federal guarantees.

September 25, 2007 - **Department of Energy Releases Conditional Agreement for New Nuclear Power Plants** - *Marks initial step for sponsors of new nuclear plants to qualify for up to $2 billion in federal risk insurance*

WASHINGTON, DC– The U.S. Department of Energy (DOE) Secretary Samuel W. Bodman today released a **Conditional Agreement** for companies building new nuclear power plants in the United States to qualify for a portion of $2 billion in federal risk insurance. Risk insurance covers costs associated with certain regulatory or litigation-related delays - which are no fault of the company - that stall the start-up of these plants. Authorized by the Energy Policy Act of 2005 (EPAct), risk insurance provides incentive and stability in spurring construction of new nuclear power plants and meeting our energy needs in a clean, safe, economical manner. Secretary Bodman made today's announcement while in Chicago speaking to the World Association of Nuclear Operators and United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry.

"To meet the world's growing demand for electricity and confront climate change, safe and emissions-free nuclear energy must play an integral role in our energy mix," Secretary Bodman said. "Conditional Agreements pave the way for risk insurance contracts that will provide the first project sponsors constructing new nuclear power plants with assistance if they face delays in expanding the use of nuclear energy across the nation."

Providing risk insurance is part of President Bush's bold energy agenda and allows the first of several sponsors of new nuclear power plants to be backed by the U.S. government should a sponsor undergo lengthy and unnecessary delays preventing operation.

EPAct authorizes DOE to enter into contracts with the first six sponsors that begin construction of new nuclear facilities and meet all other contractual conditions to provide risk insurance for certain regulatory and litigation delays in the full power operation of their facility. Up to $500 million in coverage is available for the initial two plants for which construction is started and up to $250 million is available for the next four plants. The Conditional Agreement, the first step in the process toward a risk insurance contract, is available to sponsors of advanced nuclear facilities once its application for a Construction and Operating License (COL) is docketed by the Nuclear Regulatory Commission (NRC). Companies can enter into a Conditional Agreement with DOE, however, only the first six that are issued a COL and begin construction are eligible for the risk insurance contract with DOE.

The Conditional Agreement announced today details the rights and responsibilities of potential sponsors to become eligible for risk insurance contracts. Events that would be covered by the risk insurance contract include delays associated with the NRC's reviews of inspections, tests, analyses and acceptance criteria, as well as certain delays associated with a pre-operational hearing or litigation in federal, state or tribal courts. Insurance coverage is not available for normal business risks such as employment strikes and weather delays. In August 2006, DOE issued a final rule that outlines a two-step process to apply for risk insurance coverage, which requires entering into a Conditional Agreement first and, if eligible, then a risk insurance contract.

Today's announcement closely follows previous progress through the Department's Nuclear Power 2010 program, which is a joint government/industry cost-shared effort to identify sites for new nuclear power plants, develop and bring to market advanced nuclear plant technologies, evaluate the business case for building new nuclear power

plants, and demonstrate untested regulatory processes. In March of this year the first two Early Site Permits were issued by the NRC. These permits were funded through a 50-50 cost share by DOE and industry. Through the Nuclear Power 2010 program, DOE is partnering with industry to promote the expansion of nuclear power in the United States and work toward the submission of COL applications for new nuclear plants to the NRC.

Financial Metrics / Valuation

The key financial credit metrics for the power sector are strong given the average Baa-rating. These metrics, which include cash flow to adjusted total debt ratios in the mid to high-teen's are expected to remain in this range over the near to intermediate term horizon, and is incorporated into our stable rating outlook for the industry.

Prospectively, there is a concern developing over the industry's current expectations for significantly increased capital investment and how the financing of that investment will be executed (primarily with debt). With respect to new nuclear generation, Moody's incorporates a view that companies will approach the financing plans associated with new nuclear generation as conservatively as they are approaching the site and technology assessments. Specifically, we believe new nuclear facilities that are included in a utility's rate base are likely to be financed on an approximately 50% debt / 50% equity basis – reasonably consistent with its existing rate base.

To the extent that a company develops a financing plan that overly relies on debt financing, which effectively reduces the consolidated key financial credit ratio's, regardless of the regulatory support associated with current cost recovery mechanisms, there is a reasonably high likelihood that credit ratings will also decline.

It has been noted in this report that the companies that are actively considering new nuclear generation have been evaluating the option for several years. While we acknowledge that it will be several more years to finalize all of the necessary regulatory approvals to commence and complete construction, in order to maintain current ratings, these companies may decide to commence an ***aggressive balance sheet strengthening program*** going into the construction period. The most effective method to protect current credit ratings for a company entering into a nuclear construction phase is the issuance of common equity at the front end of the construction cycle or, at a minimum, limiting the amount of shareholder dividends or other shareholder return alternatives. Given the numerous regulatory overhang and construction execution risks identified in this report, Moody's will be less inclined to hold a given rating over the course of a long-term construction cycle (such as that associated with a new nuclear generation facility) if a company as been active with aggressive shareholder return strategies.

The importance of partnerships

Many companies claim that the Federal loan guarantees are necessary because the companies, by themselves, are not large enough to handle the construction of a multi-billion project on a stand-alone basis. This raises a very obvious question: Why not pursue a program with multiple partners to share the risk? From a credit perspective, if a board feels that their company is too small to handle a project like a new nuclear facility, Moody's would be very concerned if the company attempted to pursue the program without adequately allocating risk within the constraints of their balance sheet.

Is there a role for Securitization Bonds?

Given some of the industry's desire for Federal loan guarantees, the need to spread risk and the size of many of the companies considering building new nuclear generation, securitization might represent a reasonable alternative to assist with the financing of the next new nuclear facilities. We observe that securitization has been successfully used within the sector to finance conservation investments, environmental mandates, stranded costs and storm recoveries. A product structured for nuclear generation could emerge as another viable financing tool.

5 Year Average Metrics

Regulated Nuke Parent Company	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
FFO = CFO-W/C						
RCF = CFO-W/C-Dividends						
FPL Group, Inc.	A2	5.2	22.7%	17.4%	107.4%	46.5%
SCANA Corporation	A3	4.0	17.7%	13.2%	94.9%	52.9%
Southern Company	A3	5.2	21.2%	14.4%	87.1%	49.4%
Ameren Corporation	Baa2	4.9	21.5%	13.7%	92.2%	44.6%
American Electric Power Company	Baa2	3.8	16.3%	12.2%	89.5%	55.3%
Dominion Resources Inc.	Baa2	4.0	17.5%	12.8%	74.5%	53.5%
DTE Energy Company	Baa2	3.5	14.9%	11.2%	105.9%	60.7%
Duke Energy Corporation	Baa2	4.1	19.9%	10.0%	65.8%	41.3%
Progress Energy, Inc.	Baa2	3.6	15.5%	10.3%	89.2%	57.5%
Entergy Corporation	Baa3	5.0	24.3%	20.3%	120.0%	44.1%
PG&E Corporation	Baa3	3.7	29.1%	27.7%	126.8%	54.3%
Pinnacle West Capital Corporation	Baa3	4.2	18.4%	14.4%	81.2%	50.5%
	Average	**4.3**	**19.9%**	**14.8%**	**94.5%**	**50.9%**

Non-Regulated Nuke Parent Company	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
FPL Group, Inc.	A2	5.2	22.7%	17.4%	107.4%	46.5%
Constellation Energy Group, Inc.	Baa1	4.3	19.6%	16.4%	126.3%	51.8%
Exelon Corporation	Baa1	5.2	25.1%	20.1%	159.0%	57.0%
Dominion Resources Inc.	Baa2	4.0	17.5%	12.8%	74.5%	53.5%
PPL Corporation	Baa2	3.6	15.9%	12.4%	125.2%	59.7%
Public Service Enterprise Group	Baa2	2.9	13.0%	9.2%	109.7%	60.6%
Entergy Corporation	Baa3	5.0	24.3%	20.3%	120.0%	44.1%
FirstEnergy Corp.	Baa3	3.6	16.0%	12.5%	144.4%	57.7%
TXU Corp.	Ba1	4.0	18.2%	15.1%	173.6%	71.4%
NRG Energy, Inc.	B1	1.7	5.9%	5.8%	203.1%	70.2%
	Average	**3.9**	**17.8%**	**14.2%**	**134.3%**	**57.2%**

Non-Nuclear Regulated Parent Company	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
OGE Energy Corp.	Baa1	4.9	25.0%	18.5%	109.7%	46.3%
IDACORP, Inc.	Baa2	4.4	19.1%	14.3%	102.9%	43.8%
Cleco Corporation	Baa3	4.7	22.1%	16.4%	149.0%	47.6%
Allegheny Energy, Inc.	Ba1	2.3	10.0%	9.5%	128.6%	67.3%
Puget Energy, Inc.	Ba1	3.3	16.0%	12.8%	93.8%	53.0%
TECO Energy, Inc.	Ba1	2.4	8.8%	4.6%	34.7%	70.4%
Sierra Pacific Resources	B1	2.0	7.8%	7.6%	50.7%	66.0%
	Average	**3.4**	**15.6%**	**12.0%**	**95.6%**	**56.3%**

Regulated Nuke Utility Company	Unsecured /Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
Florida Power & Light Company	A1	9.5	43.4%	28.4%	74.6%	32.5%
Alabama Power Company	A2	5.6	23.5%	13.9%	84.6%	44.4%
Georgia Power Company	A2	5.6	23.0%	12.6%	77.6%	42.5%
South Carolina Electric & Gas Co	A2	4.4	21.5%	14.9%	84.3%	44.6%
Duke Energy Carolinas, LLC	A3	6.1	22.6%	14.8%	97.3%	47.6%
Progress Energy Carolinas, Inc.	A3	6.0	28.4%	17.0%	99.0%	48.3%
Progress Energy Florida, Inc.	A3	6.0	24.6%	17.1%	75.5%	48.5%
Southern California Edison	A3	7.0	41.2%	33.9%	159.4%	46.9%
Detroit Edison Company	Baa1	4.3	18.6%	13.3%	102.6%	57.8%
Pacific Gas & Electric Company	Baa1	3.8	28.7%	26.9%	114.5%	49.9%
Virginia Electric and Power	Baa1	5.0	21.8%	13.9%	92.4%	46.2%
Arizona Public Service Company	Baa2	4.2	18.4%	13.5%	82.3%	49.6%
	Average	**5.6**	**26.3%**	**18.4%**	**95.3%**	**46.6%**

Merchant Nuke Generator	Unsecured /Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
Exelon Generation Company, LLC	A3	11.4	53.1%	38.8%	134.1%	50.8%
PSEG Power L.L.C.	Baa1	4.3	18.7%	18.7%	129.5%	60.4%
PPL Energy Supply, LLC	Baa2	4.6	19.0%	6.2%	50.8%	51.3%
Texas Competitive Electric Hlds.	Baa2	5.9	40.1%	22.6%	244.0%	40.7%
NRG Energy, Inc.	B1	1.7	5.9%	5.8%	203.1%	70.2%
	Average	**5.6**	**27.4%**	**18.4%**	**152.3%**	**54.7%**

Cross Industry	Unsecured / Issuer Rating	FFO / Int (x)	FFO / Debt	RCF / Debt	RCF / Capex	Debt / Cap
Exxon Mobil Corporation	Aaa	17.1	98.8%	80.1%	209.8%	19.8%
BP plc	Aa1	19.1	76.8%	57.7%	148.7%	27.4%
Royal Dutch Shell Plc	Aa1	18.1	104.4%	77.2%	135.5%	23.4%
Chevron Corporation	(P)Aa2	14.4	62.2%	49.7%	149.3%	27.7%
European Aeronautic Defence	A1	5.1	38.7%	32.9%	92.9%	28.5%
Nucor Corporation	A1	42.6	149.7%	116.3%	356.4%	20.3%
Boeing Company (The)	A2	7.7	39.8%	32.6%	432.0%	112.8%
E.I. du Pont de Nemours	A2	7.6	33.0%	22.4%	190.8%	61.8%
Praxair, Inc.	A2	7.5	33.2%	28.4%	154.2%	52.0%
Dow Chemical Company (The)	A3	5.0	23.1%	15.9%	160.1%	62.6%
Weyerhaeuser Company	Baa2	3.5	17.9%	14.2%	189.9%	49.6%
International Paper Company	Baa3	3.5	15.9%	12.5%	145.5%	60.6%
United States Steel Corporation	Baa3	6.3	46.2%	43.7%	165.0%	61.1%
Temple-Inland Inc.	Ba1	5.4	25.8%	22.3%	250.0%	58.1%
	Average	**11.6**	**54.7%**	**43.3%**	**198.6%**	**47.6%**

Moody's Related Research

Special Comments:

- Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector, August 2007 (103941)
- Credit Risks and Benefits of Public Power Utility Participation in Nuclear Power Generation, June 2007(103522)
- Moody's Comments on the Credit Implications Associated with North American Utility Consolidation, December 2006 (101392)
- Moody's Comments on the Back to Basics Strategy for the North American Electric Utility Sector, November 2006 (100660)
- U.S. Nuclear Assets Remain Attractive Acquisition Targets; With Potentially Favorable Credit Implications for Efficient Operators, September 2004 (89008)
- Nuclear Power Trends in the United States, February 2004 (81342)
- Standardized Designs for Nuclear Plants Beneficial for U.S. Power Industry But Waster Disposal Is an Unresolved problem, December 2003 (80790)
- Nuclear Update: A Buyer's market for nuclear Plants, June 1999 (39917)
- Moody's Assesses Nuclear Power Risk in a More Competitive Market, April 1997(20929)

Rating Methodology

- Rating Methodology: Global Regulated Electric Utilities, March 2005 (91730)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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MSNBC.com

Drought could close nuclear power plants

Southeast water shortage a factor in huge cooling requirements

The Associated Press

updated 2:54 p.m. ET, Wed., Jan. 23, 2008

LAKE NORMAN, N.C. - Nuclear reactors across the Southeast could be forced to throttle back or temporarily shut down later this year because drought is drying up the rivers and lakes that supply power plants with the awesome amounts of cooling water they need to operate.

Utility officials say such shutdowns probably wouldn't result in blackouts. But they could lead to shockingly higher electric bills for millions of Southerners, because the region's utilities could be forced to buy expensive replacement power from other energy companies.

Already, there has been one brief, drought-related shutdown, at a reactor in Alabama over the summer.

"Water is the nuclear industry's Achilles' heel," said Jim Warren, executive director of N.C. Waste Awareness and Reduction Network, an environmental group critical of nuclear power. "You need a lot of water to operate nuclear plants." He added: "This is becoming a crisis."

An Associated Press analysis of the nation's 104 nuclear reactors found that 24 are in areas experiencing the most severe levels of drought. All but two are built on the shores of lakes and rivers and rely on submerged intake pipes to draw billions of gallons of water for use in cooling and condensing steam after it has turned the plants' turbines.

Because of the yearlong dry spell gripping the region, the water levels on those lakes and rivers are getting close to the minimums set by the Nuclear Regulatory Commission. Over the next several months, the water could drop below the intake pipes altogether. Or the shallow water could become too hot under the sun to use as coolant.

"If water levels get to a certain point, we'll have to power it down or go off line," said Robert Yanity, a spokesman for South Carolina Electric & Gas Co., which operates the Summer nuclear plant outside Columbia, S.C.

Limits on intake pipes

Extending or lowering the intake pipes is not as simple at it sounds and wouldn't necessarily solve the problem. The pipes are usually made of concrete, can be up to 18 feet in diameter and can extend up to a mile. Modifications to the pipes and pump systems, and their required backups, can cost millions and take several months. If the changes are extensive, they require an NRC review that itself can take months or longer.

Even if a quick extension were possible, the pipes can only go so low. It they are put too close to the bottom of a drought-shrunken lake or river, they can suck up sediment, fish and other debris that could clog the system.

An estimated 3 million customers of the four commercial utilities with reactors in the drought zone get their power from nuclear energy. Also, the quasi-governmental Tennessee Valley Authority, which sells electricity to 8.7 million people in seven states through a network of distributors, generates 30 percent of its power at nuclear plants.

While rain and some snow fell recently, water levels across the region are still well below normal. Most of the severely affected area would need more than a foot of rain in the next three months — an unusually large amount — to ease the drought and relieve pressure on the nuclear plants. And the long-term forecast calls for more dry weather.

Lakes nearing their minimums

At Progress Energy Inc., which operates four reactors in the drought zone, officials warned in November that the drought could force it to shut down its Harris reactor near Raleigh, according to documents obtained by the AP. The water in Harris Lake stands at 218.5 feet — just 3½ feet above the limit set in the plant's license.

Lake Norman near Charlotte is down to 93.7 feet — less than a foot above the minimum needed for a backup system at Duke Energy Corp.'s McGuire nuclear plant. The lake was at 98.2 feet just a year ago.

"We don't know what's going to happen in the future. We know we haven't gotten enough rain, so we can't rule anything out," said Duke spokeswoman Rita Sipe. "But based on what we know now, we don't believe we'll have to shut down the plants."

During Europe's brutal 2006 heat wave, French, Spanish and German utilities were forced to shut down some of their nuclear plants and reduce power at others because of low water levels — some for as much as a week.

If a prolonged shutdown like that were to happen in the Southeast, utilities in the region might have to buy electricity on the wholesale market, and the high costs could be passed on to customers.

"Currently, nuclear power costs between $5 to $7 to produce a megawatt hour," said Daniele Seitz, an energy analyst with New York-based Dahlman Rose & Co. "It would cost 10 times that amount that if you had to buy replacement power — especially during the summer."

At a nuclear plant, water is also used to cool the reactor core and to create the steam that drives the electricity-generating turbines. But those are comparatively small amounts of water, circulating in what are known as closed systems — that is, the water is constantly reused. Water for those two purposes is not threatened by the drought.

Instead, the drought could choke off the billions of gallons of water that pass through the region's reactors every day to cool used steam. Water sucked from lakes and rivers passes through pipes, which act as a condenser, turning the steam back into water. The outside water never comes into direct contact with the steam or any nuclear material.

At some plants — those with tall, Three Mile Island-style cooling towers — a lot of the water travels up the tower and is lost to evaporation. At other plants, almost all of the water is returned to the lake or river, though significantly hotter because of the heat absorbed from the steam.

Progress spokeswoman Julie Hahn said the Harris reactor, for example, sucks up 33 million gallons a day, with 17 million gallons lost to evaporation via its big cooling towers. Duke's McGuire plant draws in more than 1 billion gallons a day, but most of it is pumped back to its source.

Nuclear plants are subject to restrictions on the temperature of the discharged coolant, because hot water can kill fish or plants or otherwise disrupt the environment. Those restrictions, coupled with the drought, led to the one-day shutdown Aug. 16 of a TVA reactor at Browns Ferry in Alabama.

The water was low on the Tennessee River and had become warmer than usual under the hot sun. By the time it had been pumped through the Browns Ferry plant, it had become hotter still — too hot to release back into the river, according to the TVA. So the utility shut down a reactor.

David Lochbaum, nuclear project safety director for the Union of Concerned Scientists, warned that nuclear plants are not designed to take the wear and tear of repeatedly stopping and restarting.

"Nuclear plants are best when they flatline — when they stay up and running or shut down for long periods to refuel," Lochbaum said. "It wears out piping, valves, motors."

Both the industry and NRC spokesman Scott Burnell said plants can shut down and restart without problems.

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Exh. 94

FPL's PROPOSED STIPULATION TO RESOLVE
ISSUE 7 (CO-OWNERSHIP DISCUSSIONS)

403.519(4)(a)(5), F.S., and

Issue 7: Does Florida Power & Light Company's nuclear power plant petition contain a summary of any discussions with other electric utilities regarding ownership of a portion of the plant by such utilities, consistent with the requirements of Rule 25-22.081, F.A.C.?

Position: Yes. FPL has had initial discussions with FMEA, FMPA, and OUC regarding any mutual benefits that may accrue from joint participation in Turkey Point Units 6 & 7. No later than July 1, 2009, FPL will continue its good faith discussions with FMEA, FMPA and OUC, and will also commence good faith discussions of joint participation in Turkey Point Units 6 & 7 with JEA and Seminole. FPL will report on the status of such ongoing status discussions to the FPSC every quarter thereafter. The results of these ongoing status discussions shall be reported to the FPSC as part of a docket which will be opened by the FPSC pursuant to its authority under the Grid Bill as codified in the Florida Statutes, in order to provide the parties with such rights and remedies as may exist to the extent of the FPSC's jurisdiction thereunder. FPL, FMPA, FMEA, JEA, OUC and Seminole each agree that such docket to be opened by the Commission pursuant to its Grid Bill authority is the sole forum for raising issues concerning joint participation in Turkey Point 6 & 7. FMPA, FMEA, JEA, OUC and Seminole each agree not to intervene or otherwise participate directly or indirectly in section 366.93, Florida Statutes, cost recovery proceedings for the purpose of addressing joint participation in Turkey Point 6 & 7. Nothing in this stipulation is intended to imply that ongoing status discussions necessarily will lead to an agreement among any of the parties for joint participation in Turkey Point 6 & 7 or that any party is obligated to enter into any such agreement.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 94
COMPANY FL Power + Light
WITNESS Stipulation to Issue 7
DATE 01/30/08 - 02/01/08

The Miami Herald el Nuevo Herald

www.herald.com www.elherald.com

PUBLISHED DAILY

MIAMI, FLORIDA

STATE OF FLORIDA
COUNTY OF DADE

Before the undersigned authority personally appeared:

Sofia Espinosa

who on oath says that she is

Advertising Sales Representative

of The Miami Herald, a daily newspaper published at Miami in Dade County, Florida; that the advertisement for **FPL** appeared in said newspaper in the issues of:

Miami Herald, December 18, 2007
El Nuevo Herald, December 18, 2007

Affiant further says that the said Miami Herald is a newspaper published at Miami, in the said Dade County, Florida and that the said newspaper has heretofore been continuously published in said Dade County, Florida, each day and has been entered as second class mail matter at the post office in Miami, in said Dade County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement.

Sofia Espinosa

Sworn to and subscribed before me

This 18th day of December 2007

NOTARY PUBLIC-STATE OF FLORI
Majella Shedden
Commission # DD739144
Expires: DEC. 04, 2011
BONDED THRU ATLANTIC BONDING CO., INC.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 95
COMPANY FL Power & Light
WITNESS Notice/Proof of Publication
DATE 01/30 - 02/01/08

NOTICE OF SERVICE HEARING

TO FLORIDA POWER & LIGHT COMPANY AND ALL OTHER INTERESTED PERSONS - DOCKET NO. 070650-EI
PETITION TO DETERMINE NEED FOR TURKEY POINT NUCLEAR UNITS 6 AND 7 ELECTRICAL POWER PLANT, BY FLORIDA POWER & LIGHT COMPANY.

ISSUED: December 4, 2007

NOTICE is hereby given that the Florida Public Service Commission will hold a service hearing in the above docket on FPL's Petition to Determine Need for Turkey Point Nuclear Units 6 and 7 Electrical Power Plant. The service hearing will commence at the time and location shown below and will continue until all interested have been heard. Customers who wish to present testimony are urged to appear promptly at the scheduled hearing time since the hearing may be adjourned early if no witnesses are present to testify.

Wednesday, January 9, 2008, 4:00 p.m. - Miami Dade College - Wolfson Campus - Building 1000, Room 1261 (Auditorium) - 300 NE 2nd Avenue - Miami, FL 33132

PURPOSE AND PROCEDURE

The purpose of this service hearing is to permit members of the public who are not parties to the need determination proceeding an opportunity to present testimony regarding the need for the proposed plants. The procedure of these hearings shall be as follows: The Company will present a brief summary of its case and then members of the public may present testimony. Members of the public who wish to present testimony are urged to appear promptly at each scheduled hearing time since the hearing may be adjourned early if no witnesses are present to testify. By providing public testimony, a person does not become a party in the proceeding. To become an official party of record, you must file a Petition for Intervention at least five days before the final hearing, pursuant to the requirements enumerated in Rule 25-22.039, Florida Administrative Code. All witnesses shall be subject to cross examination at the conclusion of their testimony.

EMERGENCY CANCELLATION OF SERVICE HEARING

If a named storm or other disaster requires cancellation of the meeting, Commission staff will attempt to give timely direct notice to the parties. Notice of cancellation of the meeting will also be provided on the Commission's website (http://www.psc.state.fl.us) under the Hot Topics link found on the home page. Cancellation can also be confirmed by calling the Office of the General Counsel at (850) 413-6199.

JURISDICTION

The Commission is vested with jurisdiction over the subject matter of this proceeding by Section 403.519, Florida Statutes. Any person requiring some accommodation at this hearing because of a physical impairment should call the Office of Commission Clerk at (850) 413-6770, at least 48 hours prior to the hearing. Any person who is hearing or speech impaired should contact the Florida Public Service Commission by using the Florida Relay Service, which can be reached at 1-800-955-8771 (TDD). By DIRECTION of the Florida Public Service Commission this 4th day of December, 2007.

NOTICE OF COMMISSION HEARING AND PREHEARING

TO FLORIDA POWER & LIGHT COMPANY AND ALL OTHER INTERESTED PERSONS - DOCKET NO. 070650-EI
PETITION TO DETERMINE NEED FOR TURKEY POINT NUCLEAR UNITS 6 AND 7 ELECTRICAL POWER PLANT, BY FLORIDA POWER & LIGHT COMPANY.

ISSUED: December 4, 2007

NOTICE IS HEREBY GIVEN that a hearing will be held before the Florida Public Service Commission in the above docket regarding the petition of Florida Power & Light Company (FPL) for determination of need for electrical power plants, at the following time and place:

Wednesday – Friday, January 30 – February 1, 2008, 9:30 a.m. - Betty Easley Conference Center, Room 148 - 4075 Esplanade Way - Tallahassee, Florida

PURPOSE AND PROCEDURE

The purpose of this hearing will be for the Commission to take final action to determine the need, pursuant to Section 403.519, Florida Statutes, for FPL's proposed electrical power plants in Dade County, Florida. This proceeding shall: (1) allow FPL to present evidence and testimony in support of its petition for a determination of need for its proposed nuclear power plant; (2) permit any intervenors to present testimony and exhibits concerning this matter; (3) permit members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and (4) allow for such other persons as the Commission may deem appropriate. The proceedings will be governed by the provisions of Chapter 120, Florida Statutes, Section 403.519, Florida Statutes, and Chapters 25-22 and 25-106, Florida Administrative Code. Under Section 403.519, Florida Statutes, the Commission is the sole forum for the determination of need for the proposed electrical power plants. In making its determination, the Commission must take into account the need for electric system reliability and integrity, the need for fuel diversity, the need for base-load generating capacity, the need for adequate electricity at a reasonable cost, and whether the proposed plants will provide the most cost-effective source of power. In addition, the Commission must expressly consider any renewable energy sources and technologies or conservation measures taken by or reasonably available to FPL which might mitigate the need for the plants. The Commission may consider other matters within its jurisdiction which it deems relevant. The Commission's determination of need for the proposed plants shall include a concise order of public need and necessity and shall serve as the Commission's report required by subsection 403.507(2)(a)2, Florida Statutes. An order entered by the Commission pursuant to this hearing shall constitute final agency action. Only issues relating to the need for the proposed electrical power plants will be heard at this hearing. Separate public hearings will be held before the Division of Administrative Hearings, at a later date, to consider environmental and other impacts of the proposed plants and associated facilities. Members of the public who are not parties to the need determination proceeding will have an opportunity to present testimony regarding the need for the proposed plants. All members of the public who wish to offer testimony should be present at the beginning of the hearing, 9:30 a.m., Wednesday, January 30, 2008. All witnesses will be sworn in and will be subject to cross-examination at the conclusion of their testimony. By providing public testimony, a person does not become a party to the proceeding. Anyone wishing to become a party in this need determination proceeding should file an appropriate petition pursuant to Rule 25-22.039, Florida Administrative Code, with the Office of the Commission Clerk at the address listed below. Copies of the petition should be sent by mail to all parties. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be a qualified representative pursuant to Chapter 120, Florida Statutes, and Rule 28-106.106, Florida Administrative Code. Petitions for leave to intervene must be filed at least five (5) days before the final hearing, and conform with Rule 28-106.201(2), Florida Administrative Code, and must include allegations sufficient to demonstrate that the intervenor is entitled to participate in the proceeding as a matter of constitutional or statutory right or pursuant to Commission rule, or that the substantial interests of the intervenor are subject to determination or will be affected through the hearing. Written comments regarding the need for the expansion of the proposed plants and associated facilities may be sent to the Commission at the following address:

Office of Commission Clerk - Florida Public Service Commission – 2540 Shumard Oak Boulevard - Tallahassee, Florida 32399-0850 - Re: Docket No. 070650-EI

GENERAL LOCATION AND PROJECT DESCRIPTION

FPL's proposed consists of two nuclear generating units, which will contribute between 2,200 and 3,040 MW of new generation. FPL proposes the construction of two nuclear facilities located adjacent to FPL's current Turkey Point complex. The proposed in-service dates for the proposed units are 2018 and 2020.

PREHEARING CONFERENCE

A prehearing conference will be held at the following time and place:

Monday, January 14, 2008, at 1:30 p.m. - Room 148, Betty Easley Conference Center – 4075 Esplanade Way - Tallahassee, Florida

The purpose of this prehearing conference is: (1) to define and limit, if possible, the number of issues; (2) to determine the parties' positions on the issues; (3) to determine what facts, if any, may be stipulated; (4) to dispose of any motions or other matters that may be pending; and (5) to consider any other matters that may aid in the disposition of this case.

EMERGENCY CANCELLATION OF HEARING

If settlement of the case or a named storm or other disaster requires cancellation of the hearing, Commission staff will attempt to give timely direct notice to the parties. Notice of cancellation of the hearing will also be provided on the Commission's website (http://www.psc.state.fl.us/) under the Hot Topics link found on the home page. Cancellation can also be confirmed by calling the Office of the General Counsel at 850-413-6199.

JURISDICTION

This Commission is vested with jurisdiction over the subject matter of this proceeding by Section 403.519, Florida Statutes. A copy of FPL's petition for determination of need and supporting exhibits is available for public inspection during normal business hours at the following location:

Florida Public Service Commission - Office of Commission Clerk – Room 110 - Betty Easley Conference Center - 4075 Esplanade Way - Tallahassee, Florida

Any person requiring some accommodation at this hearing because of a physical impairment should call the Office of Commission Clerk at (850) 413-6770, at least 48 hours prior to the hearing. Any person who is hearing or speech impaired should contact the Florida Public Service Commission by calling the Florida Relay Service, which can be reached at 1-800-955-8771 (TDD). By DIRECTION of the Florida Public Service Commission this 4th day of December, 2007.

FPL
an FPL Group company

AVISO DE AUDIENCIA

A LA FLORIDA POWER & LIGHT COMPANY Y A TODAS LAS PERSONAS INTERESADAS - EXPEDIENTE NO. 070650-EI

PETICIÓN PARA DETERMINAR LA NECESIDAD DE LAS UNIDADES NUCLEARES 6 Y 7 EN LA PLANTA ELÉCTRICA TURKEY POINT, POR FLORIDA POWER & LIGHT COMPANY.

PUBLICADO: 4 de diciembre de 2007

Por la presente se NOTIFICA que la Comisión de Servicio Público de la Florida llevará a cabo una audiencia sobre el expediente arriba mencionado por la Petición de Florida Power & Light Company para Determinar la Necesidad de las Unidades Nucleares 6 Y 7 en la Planta Eléctrica Turkey Point. La audiencia iniciará a la hora y en el lugar que se muestra abajo y continuará hasta que todos los testigos hayan sido escuchados. A los clientes que deseen presentar su testimonio, se les exhorta presentarse puntualmente en la audiencia programada, ya que la audiencia puede ser aplazada si no se presenta ningún testigo.

Miércoles, 9 de enero de 2008, 4:00 p.m. - Miami Dade College - Wolfson Campus - Building 1000, Room 1261 (Auditorium) - 300 NE 2nd Avenue - Miami, FL 33132.

PROPÓSITO Y PROCEDIMIENTO

El propósito de esta audiencia es permitirle a miembros del público que no sean parte de los grupos en este procedimiento, la oportunidad de presentar testimonio oral referente a la necesidad de las plantas propuestas. El procedimiento en estas audiencias será como sigue: La Compañía presentará su examen de este caso y luego los miembros del público podrán presentar testimonio. A los miembros del público que deseen presentar su testimonio, se les exhorta presentarse puntualmente en la audiencia programada, ya que la audiencia puede ser aplazada si no se presenta ningún testigo. Al proporcionar testimonio público, una persona no se convierte en parte del procedimiento. Para convertirse en parte oficial, usted debe presentar una Petición para Intervención por lo menos cinco días antes de la audiencia final, según los requerimientos contenidos en la Regla 25-22.039, Código Administrativo de Florida. Todos los testigos deberán estar sujetos a interrogatorio a la conclusión de su testimonio.

CANCELACIÓN DE EMERGENCIA DE LA AUDIENCIA

Si una tormenta u otro desastre requiere la cancelación de la audiencia, el personal de la Comisión intentará dar aviso directo con Internet a los grupos. El aviso de cancelación de la audiencia también será proporcionado en la página Web de la Comisión (http://www.psc.state.fl.us/) bajo el enlace "Hot Topics" que se encuentra en la página principal. La cancelación también puede ser confirmada llamando a la Oficina del Abogado General al (850) 413-6199.

JURISDICCIÓN

La Comisión está investida con la jurisdicción sobre este proceso por la Sección 403.519, Estatutos de la Florida. Cualquier persona que requiera servicios especiales para participar en esta audiencia debe llamar a la Oficina del Secretario de la Comisión al (850) 413-6770, por lo menos 48 horas antes de la audiencia. Cualquier persona con deficiencias auditivas o del habla debe comunicarse con la Comisión de Servicio Público de la Florida usando el Servicio de Retransmisión de Florida, marcando 1-800-955-8771 (TDD).

Por DIRECCIÓN de la Comisión de Servicio Público de la Florida este 4 de diciembre de 2007.

AVISO DE AUDIENCIA Y CONFERENCIA PREVIA A LA AUDIENCIA

A LA FLORIDA POWER & LIGHT COMPANY Y A TODAS LAS PERSONAS INTERESADAS - EXPEDIENTE NO. 070650-EI

PETICIÓN PARA DETERMINAR LA NECESIDAD DE LAS UNIDADES NUCLEARES 6 Y 7 EN LA PLANTA ELÉCTRICA TURKEY POINT, POR FLORIDA POWER & LIGHT COMPANY.

PUBLICADO: 4 de diciembre de 2007

POR LA PRESENTE SE NOTIFICA que la Comisión de Servicio Público de la Florida llevará a cabo una audiencia -y la hora y en el lugar a continuación señalados- sobre el expediente arriba mencionado por la petición de Florida Power & Light Company (FPL), para determinar la necesidad de plantas eléctricas: Miércoles - viernes, 30 de enero - 1 de febrero de 2008, 9:30 a.m. - Betty Easley Conference Center, Room 148 - 4075 Esplanade Way - Tallahassee, Florida.

PROPÓSITO Y PROCEDIMIENTO

El propósito de esta audiencia será que la Comisión tome acción final para determinar la necesidad, de acuerdo con la Sección 403.519, Estatutos de la Florida, para las plantas eléctricas propuestas por FPL en el Condado Dade, Florida. Este proceso deberá: (1) permitir a FPL presentar evidencia y testimonio como apoyo a su petición para una determinación de la necesidad de su planta eléctrica propuesta; (2) permitirle a cualquier interesado una perspectiva justificada y pruebas instrumentales sobre esta acción; (3) permitirle al público que no sea parte de los grupos la oportunidad de presentar testimonio referente a esta acción; y (4) permitir otros procedimientos como la Comisión lo considere apropiado. Los procedimientos serán gobernados por las disposiciones del Capítulo 120, Estatutos de la Florida, Sección 403.519, Estatutos de la Florida, y Capítulos 25-22 y 25-106, Código Administrativo de la Florida. Bajo Sección 403.519, Estatutos de la Florida, la Comisión es el único foro para la determinación de la necesidad de las plantas eléctricas propuestas. Para tomar su decisión, la Comisión debe tomar en cuenta la necesidad de un sistema eléctrico confiable, la necesidad de diversidad en combustibles, la necesidad de capacidad generadora con bajo nivel de carga, la necesidad de electricidad adecuada a un costo razonable, y si las plantas propuestas proporcionarán la fuente de energía más confiable. Además, la Comisión debe considerar representativamente cualquier tecnología de energía renovable y tecnologías o medidas de conservación tomadas por o razonablemente disponibles para FPL, las cuales puedan mitigar la necesidad de las plantas. La Comisión puede considerar otros aspectos dentro de las inquietudes que sean relevantes. La decisión de la Comisión de la necesidad de las plantas propuestas deberá crear una suposición de necesidad pública y deberá servir como soporte de la Comisión requerido por el artículo 403.507(2)(a), Estatutos de la Florida, una orden preparada por la Comisión de acuerdo con esta sentencia constituirá acción Final de la agencia. Sólo aquellos relacionados a la necesidad de las plantas eléctricas propuestas serán escuchados en esta audiencia. De llevarse a cabo audiencias públicas por separado sobre la División de Audiencias Administrativas en una fecha futura para considerar los impactos ambientales y otros impactos de las plantas propuestas o instalaciones asociadas. Los miembros del público que no sean parte en el procedimiento tendrán una oportunidad de presentar testimonio respecto a la necesidad de las plantas propuestas. Todos los miembros del público que deseen ofrecer su testimonio deberán estar presentes el lunes de la audiencia, 9:30 a.m., asimismo, 30 de enero de 2008, todos los testigos deberán estar sujetos a interrogatorio a la conclusión de su testimonio. Al proporcionar testimonio público, una persona no se convierte en parte del procedimiento. Para convertirse en parte oficial, usted debe presentar una Petición para Intervención, según los requerimientos contenidos en la Regla 25-22.039, Código Administrativo de Florida, con la Oficina del Secretario de la Comisión a la dirección de abajo. Copias de la petición deben enviarse por correo a todas las partes/grupos. Aquellos que cumplen satisfactoriamente con estos procedimientos, a menos que se presenten en nombre propio, deberán estar representados por un abogado u otra persona que pueda ser representante calificado de acuerdo con el Capítulo 120, Estatutos de la Florida y Regla 28-106.106, Código Administrativo de la Florida. La petición para intervenir debe presentarse por lo menos cinco (5) días antes de la audiencia final, conforme a la Regla 28-106.205(2), Código Administrativo de la Florida, y debe incluir todos los hechos específicos para demostrar que el interventor tiene derecho a participar en el procedimiento por derecho constitucional o estatutario o según la regla de la Comisión, o que intereses sustancialmente del interventor estén sujetos a determinación o a verse afectados por medio de la audiencia. Los comentarios por escrito respecto a la necesidad de expansión de las plantas propuestas e instalaciones asociadas pueden enviarse a la Comisión a la dirección siguiente: Office of Commission Clerk - Florida Public Service Commission - 2540 Shumard Oak Boulevard - Tallahassee, Florida 32399-0850 - Re: Docket No. 070650-EI.

UBICACIÓN GENERAL Y DESCRIPCIÓN DEL PROYECTO

La propuesta de FPL consiste de dos generadores nucleares, los cuales contribuirán con cerca 2,200 y 3,000 MW de generación nueva. FPL propone la construcción de dos torres nucleares ubicadas a un lado del actual complejo Turkey Point de FPL. Las fechas de servicio propuestas para las unidades son 2013 y 2020.

CONFERENCIA PREVIA A LA AUDIENCIA

Una conferencia previa a la audiencia se llevará a cabo a la siguiente hora y en el siguiente lugar: Lunes, 14 de enero de 2008, a las 1:30 p.m. - Room 148, Betty Easley Conference Center - 4075 Esplanade Way - Tallahassee, Florida.

El propósito de esta conferencia es: (1) definir y facilitar, si es posible, el número de temas; (2) establecer los parámetros de los temas sobre los temas; (3) determinar qué hechos, si los hay, pueden ser estipulados; (4) despachar cualquier otra moción o asunto que esté pendiente; y (5) considerar otros asuntos que puedan ayudar en la disposición de la acción.

CANCELACIÓN DE EMERGENCIA DE LA AUDIENCIA

Si un acuerdo extrajudicial del caso o una tormenta u otro desastre requiere la cancelación de la audiencia, personal de la Comisión intentará dar aviso directo con Internet a los grupos. El aviso de cancelación de la audiencia también será proporcionado en la página Web de la Comisión (http://www.psc.state.fl.us/) bajo el enlace "Hot Topics" que se encuentra en la página principal. La cancelación también puede ser confirmada llamando a la Oficina del Abogado General al (850) 413-6199.

JURISDICCIÓN

La Comisión está investida con la jurisdicción sobre este proceso por la Sección 403.519, Estatutos de la Florida. Una copia de la petición de FPL para determinación de la necesidad y pruebas instrumentales está disponible para inspección pública en formato informal en la siguiente dirección: Florida Public Service Commission - Office of Commission Clerk - Room 110 - Betty Easley Conference Center - 4075 Esplanade Way - Tallahassee, Florida.

Cualquier persona que requiera servicios especiales para participar en esta audiencia debe llamar a la Oficina del Secretario de la Comisión al (850) 413-6770, por lo menos 48 horas antes de la audiencia. Cualquier persona con deficiencias auditivas o del habla debe comunicarse con la Comisión de Servicio Público de la Florida usando el Servicio de Retransmisión de Florida, marcando 1-800-955-8771 (TDD). Por DIRECCIÓN de la Comisión de Servicio Público de la Florida este 4 de diciembre de 2007.

FPL

an FPL Group company

Need Study for Electrical Power

FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 96
COMPANY Florida Power & Light (Direct)
WITNESS Need Study + Appendices
DATE 01-02/01/08

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TABLE OF ABBREVIATIONS

ABWR	Advanced Boiling Water Reactor
ACOE	U.S. Army Corps of Engineers
AEC	Atomic Energy Commission
AFUDC	Allowance for Funds Used for Construction
BACT	Best Available Control Technology
BTU	British Thermal Unit
BWR	Boiling Water Reactor
CAAP	Central Appalachian Coal
CC	Combined Cycle
CCC	Carrying Charges of Construction
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
COL	Combined Construction and Operating License
COLA	Combined Construction and Operating License Application
CPVRR	Cumulative Present Value of Revenue Requirements
D.C.	District of Columbia
DOE	Department of Energy
DSM	Demand Side Management
EPAct2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ESBWR	Economic Simplified Boiling Water Reactor
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGT	Florida Gas Transmission
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GPPRP	Green Power Pricing Research Project
GSU	Generator Step Up
GWh	Gigawatt Hour
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Planning
ITAAC	Inspections, Tests, Analysis and Acceptance Criteria
JEA	Jackson Electric Authority
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LNG	Liquefied Natural Gas
LOLP	Loss-of-Load-Probability
MW	Megawatt
MWh	Megawatt Hour
MMBTU	Millions of British Thermal Units

NEL	Net Energy for Load
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corp
NRC	Nuclear Regulatory Commission
NOAA	National Oceanographic and Atmospheric Association
NO_x	Nitrogen Oxide
OPEC	Organization of Petroleum Exporting Countries
PC	Sub-critical Pulverized Coal
PPSA	Florida Electrical Power Plant Siting Act
PSD	Prevention of Significant Deterioration
PV	Photovoltaic
PWR	Pressurized Water Reactor
RFI	Request for Information
RFP	Request for Proposals
SCA	Site Certification Application
SERC	Southeast Electric Reliability Council
SFWMD	South Florida Water Management District
SO_2	Sulfur Dioxide
TIGER	Tie-Line Assistance and Generation Reliability Model
TMI	Three Mile Island
TREC	Tradeable Renewable Energy Credits
TVA	Tennessee Valley Authority
U308	Uranium
U-235	Uranium Atomic Mass of 235
U-238	Uranium Atomic Mass of 238
UF6	Uranium Hexafluoride
UIC	Underground Injection Control
UO_2	Uranium Oxide
U.S.	United States
WCEC	West County Energy Center

I. EXECUTIVE SUMMARY

Florida Power & Light Company (FPL or the Company) is requesting the Commission for approval in its determination of need for the construction of two additional nuclear-fueled generating units at FPL's existing Turkey Point electrical power plant site, together with the associated facilities, including transmission line and substation facilities, needed to integrate, interconnect and transmit energy from the Turkey Point site to FPL's transmission network for delivery to customers. The units and associated facilities are referred to as "Turkey Point 6 & 7" or the "Project".

As one of the most populous states in the nation, Florida continues to be one of the fastest growing. FPL is projecting an annual average increase of approximately 85,000 new customers for the next fourteen years. In addition, with the increase in the number of electricity-consuming devices, even as end-use efficiency has significantly improved, electric usage per FPL customer has increased by approximately 30 % over the past 20 years. Accordingly, FPL must continue to make significant investments in new infrastructure to keep pace with the increasing demand for adequate, reliable power associated with such growth. While FPL continues to advance reduced electricity usage through industry-leading conservation efforts and demand side management (DSM) programs, and actively cultivate the development of additional renewable generating capacity within the state, by themselves these efforts are insufficient to mitigate the need for additional generating capacity. FPL must also at times construct large, baseload capacity additions if the Company is to continue providing electricity to its customers. The proposed Project is intended to help meet FPL's growing need for additional

baseload capacity, which is the essential foundation of any utility's supply portfolio, because these plants run year-round to provide the continuous supply of electricity that customers require. The Project also will enhance the reliability of FPL's system by reducing reliance on fossil fuels and diversifying the resource mix.

In its 2007 integrated resource planning (IRP) process, Florida Power & Light Company (FPL) determined that beginning in 2011 and growing through 2020 it needs to add a total of 8,350 MW of firm resources (supply and demand-side) to continue to meet its reserve margin planning criterion approved by the Florida Public Service Commission (Commission), which FPL believes is necessary to meet in order to provide reliable service. This need for additional resources is due in part to the expiration of more than 1,600 MW of power purchases, but is primarily due to the continuing increase in the number of electricity customers in FPL's service territory, which is projected to grow at about 85,000 new customers per year over the next fourteen years. In addition to meeting the growing resource need and maintaining a 20% reserve margin in a cost effective manner, FPL's 2007 IRP process directly addressed two other very important objectives: (1) how best to maintain a balanced fuel mix in FPL's generation portfolio to achieve fuel cost stability and maintain system reliability, and (2) how best to reduce system emissions of Greenhouse Gases (GHG), including carbon dioxide (CO_2).

Maintaining fuel diversity on FPL's system is important for several reasons. Lack of fuel diversity would result in vulnerability to potential supply disruptions in one type of fuel (such as could occur in the event of a major hurricane disrupting the flow of natural gas into Florida or interruption in the pipeline delivery systems), and exposure to price volatility in natural gas.

With the issue of fuel diversity in mind, the Florida Legislature recently enacted the 2006 Florida Energy Act that encouraged fuel diversity by directing the Commission to consider fuel diversity as a key criterion when reviewing Ten-Year Site Plans submitted annually by electric utilities. The 2006 Florida Energy Act further encourages fuel diversity by facilitating the process of developing nuclear generation alternatives, as well as providing for alternative cost-recovery mechanisms for new nuclear power projects. In addition, the Commission has specifically included fuel diversity and reduced dependence on fossil fuels among the goals to be considered in need determination proceedings for new power plants.

FPL will continue to promote DSM measures and renewable resources as potential contributors to satisfying electric demand and improving fuel diversity. However, there will not be sufficient additional cost-effective DSM or renewable resource capacity to meet FPL's resource needs through 2020 even after the addition of Turkey Point 6 & 7. Therefore, FPL must look to new coal and/or nuclear generation to maintain fuel diversity on FPL's system while meeting FPL's customers' needs.

Regarding coal generation, FPL's petition to the Commission for a determination of need to build an advanced technology coal plant in 2013 and 2014 was not granted. Furthermore, because of the need to reduce GHG emissions it is clear that currently available coal-fueled generation technology without carbon sequestration is not an acceptable alternative. Therefore, new nuclear generation must be included in FPL's resource plan and actively pursued in order to maintain system fuel diversity in the future. Because the process required to obtain all necessary permits, design and construct a new nuclear plant unit will take at least eleven years, it is essential that FPL and the

Commission initiate that process now in order to preserve for FPL's customers the option of placing in service two nuclear units in 2018 and 2020, respectively.

Adding new nuclear generating baseload units requires a determination of need by the Commission, as well as a site certification under the Florida Electrical Power Plant Siting Act (PPSA). FPL has elected to place the two new nuclear generating units, Turkey Point 6 & 7, at its existing Turkey Point Plant site in Miami-Dade county.

FPL has conducted comparative economic, fuel diversity, and GHG emission evaluations of three resource plans. The first resource plan includes Turkey Point 6 & 7 in 2018 and 2020, respectively. The first of the two alternate resource plans reflects the addition of gas-fueled combined cycle generation in 2018 and 2020 in place of Turkey Point 6 & 7. The second alternate plan reflects the addition of coal-fueled Integrated Gasification Combined Cycle (IGCC) generation in 2018 and 2020 in place of Turkey Point 6 & 7.

In order to address uncertainty with respect to future costs, the economic analysis initially utilized three fuel cost forecasts and four environmental compliance cost forecasts combined into 9 scenarios of future fuel costs and environmental compliance costs for each of the three resource plans. Then, after considering the different scenarios, FPL removed from further consideration three scenarios comprised of a low natural gas price forecast and medium-to-high compliance costs for CO_2 based on FPL's belief that medium-to-high CO_2 compliance costs will result in upward pressure in natural gas prices. Each of the remaining 9 scenarios was then utilized separately in both the economic and non-economic analyses of the three resource plans.

The results of the economic analyses show that the nuclear breakeven cost ranges are generally higher than FPL's current non-binding capital cost estimate range for new nuclear units; i.e., a range of $3,108/kW to $4,540/kW.

In regard to the fuel diversity analysis of these three resource plans, the alternate plan with gas-fueled generation in 2018 and 2020 does not contribute to fuel diversity in FPL's system. Without new nuclear generation additions or IGCC additions, by 2021 75% of FPL's annual energy would be supplied by natural gas with less than 7% being supplied by coal and 16% by nuclear. The plan with Turkey Point 6 & 7 would result in a significantly lower 65% of FPL's annual energy for 2021 being supplied by natural gas and about 27% being supplied by nuclear generation. Therefore, proceeding with developing Turkey Point 6 & 7 is a critical first step in enhancing the balanced, diverse fuel mix in FPL's system.

The addition of new baseload nuclear generation, as a component of FPL's future fuel mix, is even more important given the high likelihood of significant GHG regulation in the near future, including the potential for either federal or state targeted or mandated reductions in GHG emissions being imposed for the relevant planning horizon. The addition of Turkey Point 6 & 7 is a critical component of any plan to reduce system GHG emissions. At present there is no commercially available means of capturing and sequestering CO_2 emissions from an IGCC plant or from a gas-fueled plant in Florida, and the current estimates regarding the cost and adverse effects on plant performance of carbon capture and sequestration make such alternatives much more costly than adding new nuclear generation because generating electricity with nuclear fuel produces no CO_2 emissions.

Based on the results of FPL's evaluations, the addition of Turkey Point 6 & 7 is FPL's best alternative to reliably serve its customer's future demand for electricity, provide adequate electricity at a reasonable cost, contribute to fuel diversity, and reduce GHG emissions.

There is not sufficient additional, cost-effective demand side management (DSM) that is reasonably available or sufficient firm cost-effective renewable resources to mitigate the need for these new nuclear baseload units. For example, FPL already assumes, as part of its resource plan, that from August 2006 through August 2020, FPL will have added sufficient new DSM to offset the need for 2,279 MW of generation capacity. Regarding renewable resources, in April 2007 FPL issued a request for proposals for renewable generation, and by August 15 had received proposals to supply less than 150 MW of new renewable capacity. FPL's resource plan already assumes that all the proposed new renewable resource capacity, as well as all capacity provided under expiring contracts with existing renewable suppliers, will be under contract to FPL by 2012. More importantly, to the extent that additional cost-effective DSM and renewable resources are available in the future, such resources can readily be utilized to provide a share of the between 3,000 MW and 4,000 MW of firm resources that, in addition to the 2,200 MW to 3,040 MW to be provided by Turkey Point 6 & 7, will be needed between 2011 and 2020 to reliably meet FPL customers' demand for electricity.

There are significant areas of uncertainty related to the capital cost, licensing and permitting requirements and schedule of adding new nuclear generation. These areas of uncertainty could affect the viability and cost-competitiveness of new nuclear generation. However, the only way to address these uncertainties is to embark on the process of

obtaining the necessary licenses and permits to build Turkey Point 6 & 7. FPL can undertake that effort only after the Commission grants an affirmative determination of need for the addition of these units.

Therefore, FPL seeks from the Commission an affirmative determination of need, consistent with the provisions of Commission Rule 25-6.0423, the Nuclear Power Plant Cost Recovery Rule, for the addition to FPL's generation portfolio of Turkey Point 6 & 7, two nuclear-fueled generating units, each nominally with a net summer capacity rating of up to approximately 1,520 MW, currently projected to be placed in service by June 1, 2018 and June 1, 2020, respectively, including the associated electric transmission facilities described herein and in other documents.

FPL believes that the earliest date that it can place the first new nuclear unit into service is in 2018, and the second unit in 2020, assuming that no unforeseen permitting, construction, or other delays occur. The remainder of this Need Study contains more detailed information, analyses, and discussion supporting FPL's requested determination of need for Turkey Point 6 & 7.

II. INTRODUCTION

A. PURPOSE AND OVERVIEW OF THIS DOCUMENT

This document supports FPL's petition to the Commission to determine the need for the proposed Turkey Point 6 and 7. The new units will be two Advanced Light Water Reactors using nuclear fuel located in Miami-Dade County at FPL's existing Turkey

Point site. Once completed, Turkey Point 6 & 7 will each supply between 1,100 to 1,520 MW, depending on the selected design, for a combined capacity of approximately 2,200 to 3,040 MW.

This document contains the information required by Rule 25-22.081, F.A.C. It provides the information that will "allow the Commission to take into account the need for electric system reliability and integrity, the need for adequate reasonable cost electricity, fuel diversity and supply reliability, and the need to determine whether the proposed plant is the most cost-effective alternative available." This document also contains information regarding how the proposed new nuclear units would address key planning issues facing the state's electric generation infrastructure today.

1. Fuel Diversity and Energy Independence

The State of Florida continues to enjoy a steadily growing economy and a high quality of life. Supporting and sustaining the economic and social fabric of Florida is a reliable, cost-effective electric generation infrastructure anticipating and meeting the needs of customers. The emergence of climate change as a major driver of developing energy policy in the U.S. and Florida has profoundly affected the view held regarding the viability of different generating alternatives. Proposed changes to economic policies at the state, regional and federal level regarding the cost of carbon are also expected to dramatically change the economic environment in which new generation can be expected to operate.

Florida requires a stable and reliable electric generation infrastructure that will meet the needs of our growing economy in a way that recognizes the need to maintain and enhance

the unique environment of Florida. Pursuing new nuclear generation through the use of a time-tested, reliable generating technology near where the energy is consumed is the best choice for FPL and its customers. Developing additional generation at an existing generating site that is emission-free and has a proven track record of safely co-existing with and enhancing a thriving ecosystem is the best choice for Florida. As a result of the proposed project, FPL and Florida would gain increased fuel diversity without incurring additional GHG emissions as well as increased reliability and energy independence for its electric generation infrastructure.

2. FPL's Proposed Approach

Action is required now to create this option for future nuclear generation. Recently passed legislation in Florida has established a careful, methodical approach to new nuclear generation. This legislation and the Commission's Nuclear Cost Recovery Rule recognize the uncertainty in the renewed nuclear deployment process in the U.S. and the need to proceed with full knowledge of that uncertainty. Once a need determination is issued, the process allows FPL to take the initial steps necessary to define fully the costs, schedule, and benefits of the project with the active involvement of the Commission through the annual Nuclear Cost Recovery Rule. Those initial actions include the following key steps:

- Developing and submitting a Combined Construction and Operating License Application (COLA) to the Nuclear Regulatory Commission (NRC);

- Developing and submitting a Site Certification Application (SCA) to the Florida Department of Environmental Protection;
- Supporting the COLA and SCA through the review and determination process;
- Taking steps to secure the commercial operation date as early as possible through procurement of long-lead equipment;
- Developing detailed engineering and construction plans; and,
- Conducting approved site preparation activities.

The steps in the initial permitting and construction process will allow FPL to pursue the option for new nuclear as quickly as is warranted, while keeping the Commission fully informed on the development of the project at all stages. This approach, consistent with the intent of the Legislature, enables FPL to pursue a generation resource that is both proven and environmentally compatible with the vision of a clean Florida.

B. DESCRIPTION OF FPL AND ITS SYSTEM

FPL is the largest investor-owned electric utility in Florida and is among the largest in the U.S. During 2006, FPL served an average of 4.4 million customer accounts in 35 counties. FPL's service area contains approximately 27,650 square miles within which the population is approximately 8.6 million. FPL is charged with providing service not only to its existing customers, but also to new customers requesting service. FPL's load forecasts predict substantial continued customer growth within its service territory.

FPL currently serves its customers from a variety of resources including: FPL-owned oil, gas, coal, and nuclear generating units, firm capacity purchases from both utility and non-

utility-owned generators, and DSM. Each type of resource is discussed in more detail later in this document.

During 2006, FPL's bulk transmission system consisted of 6,620 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system was achieved through FPL's 542 substations. FPL is interconnected directly with eight other electric utilities. A list of FPL's major interconnections with other utilities is presented in Appendix A of this Need Study.

1. FPL-Owned Generating Resources

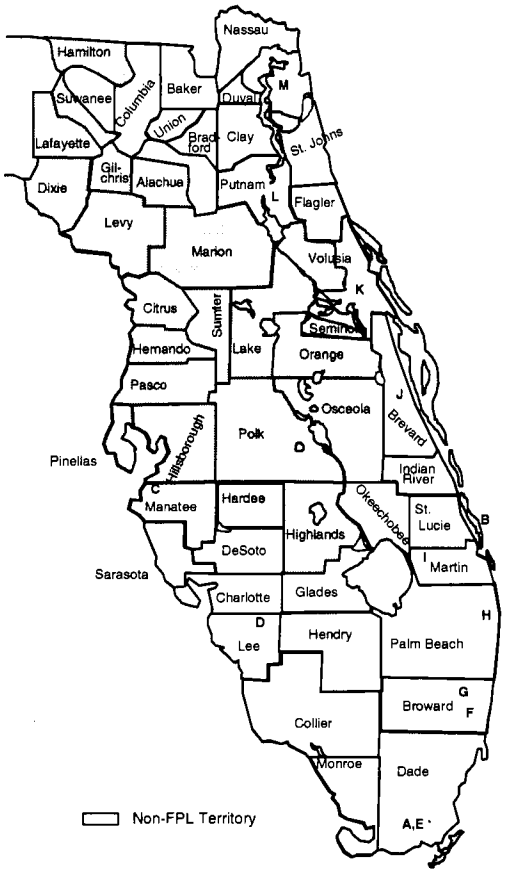
FPL's existing generating resources are located at 14 generating sites distributed geographically throughout its service territory, and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. As of the Summer of 2007, FPL's generating facilities consist of four nuclear units, three coal units, 12 combined cycle units, 17 fossil fuel steam units, 48 combustion turbines, and 5 diesel units. The location of these generating units, their fuel type and the projected summer capability for 2007 is shown on Figure II.B.1.1. More detailed information regarding FPL's existing generating resources is presented in Appendix B of this Need Study.

FPL has filed separately with the Commission a petition for need determination for capacity uprates at FPL's four existing nuclear units. The proposed capacity uprates will add about 414 MW of capacity to FPL's system in the 2011-2012 time period. In the analyses conducted for this filing, FPL includes the effects of these capacity uprates.

Figure II.B.1 1

FPL Generating Resources by Location for Summer of 2007

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	5	3,328
B	St. Lucie *	2	1,553
C	Manatee	3	2,764
D	Fort Myers	2	1,767
E	Cutler	2	170
F	Lauderdale	2	856
G	Port Everglades	4	1,226
H	Riviera	2	560
I	Martin	5	3,705
J	Cape Canaveral	2	798
K	Sanford	3	2,066
L	Putnam	2	498
M	SJRPP **	2	254
	Scherer ***	1	658
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	**90**	**22,123**



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2: St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The Scherer unit is located in Georgia and is not shown on this map.

2. Firm Capacity Purchases

FPL has contracts to purchase firm capacity and energy from five cogeneration and small power production facilities. A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one

that does not exceed 80 MW of capacity and that uses solar, wind, waste, geothermal, or other renewable resources for at least 50% of its energy.[1]

FPL also has contracts with two utilities, Southern Company (Southern) and Jacksonville Electric Authority (JEA), to purchase 931 MW and 381 MW, respectively. In addition, FPL has a number of short-term firm purchase contracts with other non-utility generators.

For purposes of the analyses conducted for this filing, FPL has included the capacity and energy contributions from six renewable energy purchases not currently under contract for the 2009 – on time period. Three of these assumed purchases are extensions of current purchases from municipal waste-to-energy facilities. The current contracts for these three purchases are scheduled to end in the time period from August 2009 to December 2010. The current total capacity under contract from these three purchases is 143 MW.

In addition, FPL has received three firm capacity proposals in response to its recent Renewable Request for Proposals (RFP). These three proposals, one from a waste-to-energy facility and two from biomass facilities, would provide a total of 144 MW of capacity starting between March 2011 and January 2012 with proposed end dates ranging from 2021 to 2036.

At the time of this filing, FPL is analyzing these three firm capacity proposals received in response to the Renewable RFP. Furthermore, no decision has been made by either FPL

[1] Certain small power production facilities are exempt from the 80 MW size limitations by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990.

or the municipal solid waste-to-energy facilities currently under contract to FPL as to whether new contractual arrangements will occur. Consequently, no decisions have yet been made in regard to any of these six renewable capacity options.

However, for purposes of the analyses conducted for this filing, FPL is assuming that all 287 MW of firm capacity will be in place. The 143 MW from the three municipal renewable waste-to-energy facilities currently under contract is assumed to continue through 2026 when other contracts for smaller capacity amounts from these facilities are scheduled to end. The 144 MW from the three renewable RFP bids are assumed to be in place through their proposed end dates.

A summary of all of FPL's firm capacity purchases, including these 287 MW of assumed new renewable purchases, is presented in Table II.B.2.1. This table presents the dates of the terms of these current contracts and the projected Summer MW purchase amounts through the year 2020.

Table II.B.2. 1

FPL's Firm Capacity Purchases: 2007 – 2020 (Summer MW)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. Broward South	4/1/1991	8/1/2009	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
2. Broward South	1/1/1993	12/31/2026	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	1/1/1997	12/31/2026	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	4/1/1992	12/31/2010	45.0	45.0	45.0	45.0	45	45	45	45	45	45	45	45	45	45
6. Broward North	1/1/1993	12/31/2026	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	1/1/1997	12/31/2026	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	1/25/1994	12/31/2024	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/1995	12/1/2025	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	4/1/1992	3/31/2010	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5
12. Florida Crushed Stone	4/1/1992	10/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13. Florida Crushed Stone	1/1/1994	10/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14. Florida Crushed Stone	1/1/1995	10/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	QF Purchases Sub Total:		**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. UPS from Southern Co.	7/20/1988	5/31/2010	931	931	931	0	0	0	0	0	0	0	0	0	0	0
2. UPS Replacement	6/1/2010	12/31/2015	0	0	0	930	930	930	930	930	930	0	0	0	0	0
3. SJRPP	4/2/1982	10/31/2015	381	381	381	381	381	381	381	381	381	0	0	0	0	0
	Utility Purchases Sub Total:		**1312**	**1312**	**1312**	**1311**	**1311**	**1311**	**1311**	**1311**	**1311**	**0**	**0**	**0**	**0**	**0**
Total of QF and Utility Purchases =			**2050**	**2050**	**2050**	**2049**	**2049**	**2049**	**2049**	**2049**	**2049**	**738**	**738**	**738**	**738**	**738**

III. Other Purchases:

	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. Oleander/Constellation 1	6/1/2002	5/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2. Progress Energy Ventures/Desoto	6/1/2002	5/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Reliant/Pasco/Shady Hills	2/28/2002	2/28/2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Reliant/Indian River	1/1/2006	12/31/2009	354	576	250	0	0	0	0	0	0	0	0	0	0	0
4a. Indian River (Additional)	5/1/2006	12/31/2009	222	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Progress Energy Ventures/Desoto (Put option)	6/1/2005	5/31/2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Oleander/Southern Co (Put option)	6/1/2005	5/31/2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6a. Oleander (Extension)	6/1/2007	5/31/2012	156	156	156	156	156	0	0	0	0	0	0	0	0	0
7. Williams	3/1/2006	12/31/2009	106	106	106	0	0	0	0	0	0	0	0	0	0	0
8. Progress Energy Ventures	4/1/2006	3/31/2009	105	105	0	0	0	0	0	0	0	0	0	0	0	0
9. Other Renewables							50	144	144	144	144	144	144	144	144	144
	Other Purchases Sub Total		**943**	**943**	**512**	**156**	**206**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**
Total "Non-QF" Purchase Sub-Total =			**943**	**943**	**512**	**156**	**206**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**
Summer Firm Capacity Purchases Total MW:			**2993**	**2993**	**2562**	**2205**	**2255**	**2193**	**2193**	**2193**	**2193**	**882**	**882**	**882**	**882**	**882**

3. Demand Side Management

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through year-end 2006 have resulted in a cumulative summer peak reduction of approximately 3,659 MW at the generator and an estimated cumulative energy saving of approximately 38,169 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts have eliminated the need to construct the equivalent of more than 11 new 400 MW generating units.

Table II.B.3.1 presents FPL's projected DSM additions from August 2006 through August 2020. This projection includes FPL's approved DSM Goals for Summer MW reduction. These DSM Goals exceed the significant levels of DSM implementation FPL achieved before the year 2005. FPL's current DSM Plan was approved by the Commission in 2004 and was designed to achieve the DSM Goals for the 2005–2014 time periods.

For purposes of the analyses conducted to support this filing, FPL is also projecting a total of 1,899 MW of additional DSM from August 2006 through August 2020, which is presented in Table II.B.3.1.

Table II.B.3.1

Projected Incremental FPL DSM: 2006 – 2020

(Summer MW)

Year	DSM Projected by FPL (Summer MW at Generator) (1)
2006	1,491
2007	1,768
2008	1,908
2009	2,034
2010	2,146
2011	2,264
2012	2,388
2013	2,516
2014	2,651
2015	2,790
2016	2,910
2017	3,030
2018	3,150
2019	3,270
2020	3,390
Incremental DSM MW from 8/2006 through 8/2020 =	1,899

4. Renewable Energy

FPL has been, and continues to be, committed to utilizing renewable energy sources from both a supply side and demand side perspective.

In regard to supply side utilization of renewable energy, FPL has firm capacity contracts with several waste-to-energy facilities as shown in Table II.B.2.1 and has as-available energy contracts with several other facilities that provide energy to FPL on a non-firm

basis. FPL is also currently seeking to site a wind energy project in Florida and is supporting Florida Atlantic University's Department of Ocean Engineering in its efforts to evaluate the feasibility of utilizing ocean energy conversion off of Florida's coasts.

On April 23, 2007 FPL issued a RFP for renewable energy-based capacity and energy. Five (5) proposals were received in response to this RFP. Three proposals offered firm capacity, one proposal offered energy only, and the remaining proposal was conceptual in nature. The three firm capacity proposals consist of two biomass and one waste-to-energy proposal. The energy-only proposal was based on ocean current and the conceptual proposal was based on photovoltaic's (PV). The total capacity offered by the three firm capacity proposals is 144 MW. At the time of this filing, FPL is evaluating all five of these proposals.

In regard to utilizing renewable energy for demand side purposes, FPL has offered a variety of DSM programs that have utilized renewable energy and is actively engaged in research projects to identify additional feasible, cost-effective ways in which renewable energy may be used in a DSM offering. A description of FPL's renewable energy DSM activities is presented in Section VIII of this document.

5. Fuel Mix

In 2006, FPL's fuel mix consisted of natural gas (50%), nuclear generation (21%), coal (18%), and fuel oil (9%). If only natural gas-fueled generation were to be added to FPL's system, the contribution of natural gas would increase to approximately 75% by 2021 of total electricity delivered to FPL's customers by 2018, while that of nuclear would

decrease to approximately (16%) in 2021 even with the proposed capacity uprates to FPL's four existing nuclear units.

However, if the two new nuclear units are added by 2018 and 2021, the contribution of nuclear would increase to approximately 27% by 2021, while the contribution of natural gas would be approximately 65% by 2021. The addition of these new nuclear units would therefore significantly improve FPL's system fuel diversity.

The primary benefits of greater fuel diversity are improved system reliability and reduced fuel price volatility. An electric system that relies on a single fuel and a single technology to generate all the electricity needed to meet its customers' demand, all else 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 wide or sudden swings in the price of one fuel, a phenomenon that has characterized the natural gas market over the last several years. In section III of this report, the various benefits associated with balancing the fuel mix are addressed in detail.

C. FPL'S PROPOSED APPROACH

1. Choices for Maintaining Fuel Diversity

FPL has previously evaluated four coal-based technologies to determine whether they could reliably contribute to the fuel diversity and capacity needs of FPL's system in the 2012 – 2015 time period. The technologies were: sub-critical pulverized coal (PC), circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), and

ultra-supercritical pulverized coal (advanced technology coal). The results of FPL's analyses of these four coal-based technologies established that the advanced technology coal option was the best solid fuel alternative for the 2012 – 2015 time period. However, because a determination of need was not granted for this advanced technology coal option, FPL has continued to consider only the IGCC alternative, along with new nuclear generation, as a potential baseload contributor to fuel diversity for the period beginning in 2018.

2. FPL's Approach: New Nuclear Generation

FPL concluded that new nuclear generation is more cost-effective than IGCC, has reliability that will be as good as, or better than, IGCC, and, unlike IGCC, can be counted on with reasonable certainty to contribute to reducing GHG emissions in the future. Based on these factors, FPL has concluded that the addition of new nuclear generation at its Turkey Point site is the best choice to contribute to fuel diversity and meet FPL's generation capacity need in the 2018 – 2020 time period.

III. FPL'S NEED FOR THE PROPOSED POWER PLANT

FPL determined in its 2006/2007 IRP work that it needs significant additional resources starting in 2012 to meet its reserve margin criterion. The reliability assessment portion of the IRP process is designed to determine both the magnitude and timing of FPL's resource needs. It is a determination of how much load reduction, new capacity, or a combination of both load reduction and new capacity is needed, and when these resources

need to be added to meet FPL's reliability criteria. Based on this analysis, FPL determined it would need a minimum of either 6,156 MW of new supply (power plant construction or power purchase), or approximately 5,130 MW of new DSM, to meet its 2012-2020 reserve margin requirements. These projections already account for all of the additional 1,899 MW of DSM projected to be added from August 2006 through August 2020, the 414 MW from the proposed capacity uprates of FPL's four existing nuclear units, and the assumed 287 MW of renewable energy purchases discussed previously.

A. Reliability Assessment

In the reliability assessment portion of its 2006/2007 IRP analysis, FPL started with updated power plant capability and reliability data, plus a load forecast prepared after the summer of 2006. This load forecast is presented in Appendix D. In addition, the reliability assessment took into account committed construction capacity additions including the proposed capacity uprates to FPL's existing nuclear units, firm capacity purchases, and DSM.

1. Committed Construction Capacity Additions

FPL included its previously committed generation construction projects in its 2006/2007 reliability assessment. These committed construction projects are the new 1,219 MW CC unit at the West County Energy Center (WCEC) that is scheduled to be placed into service in mid-2009 (WCEC Unit 1), the new 1,219 MW CC unit (WCEC Unit 2) that is scheduled to be placed into service in mid-2010, and the proposed 414 MW from the proposed capacity uprates of FPL's four existing nuclear units.

2. Firm Capacity Purchases

FPL took into account all of its current short-term and long-term firm capacity purchases from a combination of utility and non-utility generators in its 2006/2007 reliability assessment. In addition, 287 MW of renewable energy purchases are also assumed to be added for purposes of this analysis. These firm capacity purchases are discussed in Section II.B.2 and are presented in Table II.B.2.1.

3. Demand Side Management (DSM)

Since 1994, FPL's IRP process has used the amount of DSM capacity in FPL's approved DSM Goals as a basis for the system reliability analysis. The system reliability analysis conducted for this filing assumed continuation of FPL's DSM signups in 2015 through 2020 at current DSM trends. All of this DSM is presented in Table II.B.3.1, which shows the addition of 1,899 MW at the generator of cost-effective DSM during this period. The cumulative impact from all of FPL's conservation program efforts prior to 2006 is captured in the load forecast prepared after the summer of 2006 that is discussed in Section V.A.1.

B. FPL's Reliability Criteria

System reliability analyses were based on the dual planning criteria of: (1) a minimum summer and winter reserve margin of 20%, and (2) a maximum of 0.1 days per year Loss-of-Load-Probability (LOLP). The reserve margin criterion of 20% applies for reserve margin analyses addressing both summer and winter peak hours. The Commission approved this reserve margin criterion in Order No. PSC-99-2507-S-EU.

The LOLP criterion of 0.1 days per year is an electric industry standard that the Commission has accepted in numerous resource planning-related dockets.

Reserve margin analysis is a deterministic approach, while LOLP analysis is a probabilistic approach. The reserve margin analysis is essentially a calculation of excess firm capacity at the time of the summer system peak hour and at the time of the Winter system peak hour. This calculation provides a measure of the capability a generating system possesses to meet its native load during peak hours. However, a deterministic approach such as a reserve margin calculation does not take into account probabilistic elements such as the reliability of individual generating units and the total number and sizes of generating units on the system. A deterministic approach also does not fully account for the value of an interconnected system.

Therefore, FPL also utilizes a probabilistic approach, LOLP, to provide additional information on the reliability of its generating system. LOLP is an indicator of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages. LOLP is expressed in units of "number of times per year" that the system demand could not be served and requires a more complicated calculation than does reserve margin analysis. FPL calculates LOLP using the Tie-Line Assistance and Generation Reliability (TIGER) model. A listing and summary of the computer models utilized by FPL in its resource planning work, including the TIGER model, is provided in Appendix C.

In a reliability assessment, either the reserve margin criterion or the LOLP criterion will "drive" the need for additional resources. This means that, for a given future year, FPL's system will not have a reserve margin high enough to meet its 20% criterion or it will have a projected LOLP value greater than 0.1 days per year. Whichever criterion is not met first is said to drive FPL's future resource needs. For the last few years, the summer reserve margin criterion has driven FPL's future needs. This again was the case in FPL's most current reliability assessment performed as part of its 2006/2007 IRP work. The projection of capacity needs summarized above, and discussed in more detail in the next section, is based on summer reserve margin analysis.

C. FPL's 2006/2007 Reliability Assessment Results

FPL's reliability analyses showed that with no additional resources beyond its existing generating units, existing purchases, and the committed construction capacity additions (including the proposed capacity uprates to FPL's four existing nuclear units) mentioned above, FPL would not meet its summer reserve margin criterion of 20% starting in the summer of 2013 and for each summer thereafter. (A relatively small 180 MW capacity need exists in 2012 that results in FPL's projected reserve margin for 2012 being 19.7%. FPL may choose to address this relatively small 2012 need with a short-term purchase(s), enhancements to its existing generating units, and/or additional cost-effective DSM.) Assuming that the small 2012 need is met with a one-year capacity purchase, 6,156 MW of additional supply resources would be needed during the 2012 - 2020 time frame for FPL to continue to meet its summer reserve margin criterion of 20% for those years. This need is demonstrated in Table IV.C.1. This table also shows that meeting the

summer capacity needs will also easily meet the much smaller winter need that begins to appear several years after 2012.

If the 2012-2020 resource needs were to be met solely by additional new DSM resources, FPL would need to find an additional 5,130 MW of cost-effective DSM. Accounting for FPL's 20% reserve margin criterion, the 6,156 MW of generating capacity need would become 5,130 MW of DSM (6,156 MW/1.20 = 5,130 MW). There is not 5,130 MW of additional, cost-effective DSM available to meet this need. This will be further discussed in Section VII.D.

Table III.C.1

Projection of FPL's 2007 - 2020 Capacity Needs (without New Capacity Additions)

Summer

August of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Summer DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Summer Reserves (MW)	(8)=(7)/(6) Forecast of Summer Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) MW Needed to Meet 20% Reserve Margin (MW)
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	23,370	2,562	25,932	23,435	2,034	21,401	4,531	21.2%	(251)
2010	24,589	2,205	26,794	24,003	2,146	21,857	4,937	22.6%	(566)
2011	24,589	2,255	26,844	24,612	2,264	22,348	4,496	20.1%	(26)
2012	24,899	2,193	27,092	25,115	2,388	22,727	4,365	19.2%	**180**
2013	25,003	2,193	27,196	25,590	2,516	23,074	4,122	17.9%	**493**
2014	25,003	2,193	27,196	26,100	2,651	23,449	3,747	16.0%	**943**
2015	25,003	2,193	27,196	26,772	2,790	23,982	3,214	13.4%	**1,582**
2016	25,003	882	25,885	27,410	2,910	24,500	1,385	5.7%	**3,515**
2017	25,003	882	25,885	28,079	3,030	25,049	836	3.3%	**4,174**
2018	25,003	882	25,885	28,737	3,150	25,587	298	1.2%	**4,819**
2019	25,003	882	25,885	29,391	3,270	26,121	(236)	-0.9%	**5,460**
2020	25,003	882	25,885	30,091	3,390	26,701	(816)	-3.1%	**6,156**

Winter

January of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Winter DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Winter Reserves (MW)	(8)=(7)/(6) Forecast of Winter Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) MW Needed to Meet 20% Reserve Margin (MW)
2007	22,294	3,862	26,156	22,247	1,555	20,692	5,464	26.4%	(1,326)
2008	23,503	3,026	26,529	22,627	1,649	20,978	5,551	26.5%	(1,355)
2009	23,531	2,700	26,231	23,115	1,750	21,365	4,866	22.8%	(593)
2010	24,866	2,239	27,105	23,587	1,814	21,773	5,332	24.5%	(977)
2011	26,201	2,238	28,439	24,047	1,883	22,164	6,275	28.3%	(1,842)
2012	26,305	2,382	28,687	24,498	1,954	22,544	6,143	27.2%	(1,634)
2013	26,615	2,202	28,817	24,952	2,028	22,924	5,893	25.7%	(1,308)
2014	26,615	2,202	28,817	25,416	2,106	23,310	5,507	23.6%	(845)
2015	26,615	2,202	28,817	26,048	2,188	23,860	4,957	20.8%	(185)
2016	26,615	882	27,497	26,692	2,264	24,428	3,069	12.6%	**1,817**
2017	26,615	882	27,497	27,342	2,334	25,008	2,489	10.0%	**2,513**
2018	26,615	882	27,497	27,994	2,404	25,590	1,907	7.5%	**3,211**
2019	26,615	882	27,497	28,649	2,474	26,175	1,322	5.1%	**3,913**
2020	26,615	882	27,497	29,308	2,544	26,764	733	2.7%	**4,620**

* No new FPL generating unit additions after WCEC 1 in 2009 and WCEC 2 in 2010 are assumed to be added. 287 MW of renewable energy firm capacity purchases starting in the 2009 - 2012 time frame are assumed to be added. 414 MW of the proposed nuclear uprates is assumed. Approximately 104 MW are added in December 2011, 103 MW in May 2012, 103 MW in June 2012, and 104 MW by December 2012.

** DSM values shown represent cumulative load management and incremental conservation capability.

D. Consistency with Peninsular Florida Need

FPL's need for an additional 6,156 MW of supply resources (or 5,130 MW of demand side resources) is generally consistent with the Peninsular Florida need identified by the Florida Reliability Coordinating Council (FRCC) in its 2007 reliability work reported in its FRCC 2007 Regional Load and Resource Plan. The FRCC's 2007 reliability work uses FPL-specific data that was contained in FPL's 2007 Ten-Year Site Plan in conjunction with similar information from other Peninsular Florida electric utilities. FPL's 2007 Ten-Year Site Plan is consistent with the results of the reliability assessment discussed above with three exceptions. One difference between the capacity need projected in this filing and the FPL-specific data included in the Peninsular Florida need forecast is the recent inclusion of 414 MW from the proposed capacity uprates to FPL's four existing nuclear units. A second difference is the assumption of 287 MW of additional renewable energy purchases. The third difference is the assumption of a continuation of DSM signups at current trends for 2015 through 2020. The 2007 Ten-Year Site Plan and the FRCC's reliability work did not address years beyond 2016 due to their ten year focus.

E. System Fuel Diversity

1. Current

In 2006, the last full year for which data was available at the time this document was prepared, FPL's fuel mix consisted of natural gas (50%), nuclear generation (21%), coal (18%), fuel oil (9%), and other sources (about 2%).

2. Future

If only natural gas-fueled generation were to be added to FPL's system in the future, the contribution of natural gas would increase to more than 75% of total electricity delivered to FPL's customers in 2021, while that of coal would decrease to less than 7%, and that of nuclear to about 16%.

With the proposed addition of the two new baseload nuclear units at Turkey Point, the share of electricity produced by natural gas would be approximately 65% in 2021, while that of nuclear generation would be approximately 27%. These fuel mix projections, both with and without the addition of Turkey Point 6 & 7, are presented later in Section VII in Table VII.D.2.1. This table shows that the addition of Turkey Point 6 & 7 is needed to make a significant initial contribution to enhance fuel diversity in FPL's system and reduce FPL's growing dependence on natural gas.

3. Reasons to Balance the Fuel Mix

The primary benefits of fuel diversity are greater system reliability and reduced fuel price volatility. An electric system that relies on a single fuel and a single technology to generate all the electricity needed to meet its customers' demand, all else 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 large and/or sudden swings in the price of one fuel, a phenomenon that has characterized the natural gas market over the last several years.

In regard to improved system reliability, there are at least three ways in which a more fuel diverse system is more reliable than a less fuel diverse system, all other aspects being equal.

a) Fuel Diversity Enhances System Reliability

An electric system that relies exclusively on one fuel is more susceptible to events that cause delays or interruptions in the production of that fuel. For example, in 2005 a significant number of natural gas production facilities in the Gulf of Mexico were shut down as a result of hurricanes. The shutdown of these facilities, which occurred with very little advance warning, significantly reduced the quantities of natural gas available to FPL to meet electricity demand. Had FPL's system relied exclusively on natural gas to produce electricity it would have been difficult, if not impossible, to continue to meet its customers' demand for electricity until some gas production capability was restored. It is unlikely that FPL would have been able to obtain sufficient natural gas from other regions to make up for the reduced gas supply from the Gulf of Mexico, particularly at a time when other natural gas users would also be seeking natural gas supplies to replace what could not be produced in the Gulf of Mexico. However, because FPL's system is fuel-diverse, there was sufficient energy produced by generating units that use other fuels such as nuclear fuel, coal, and oil to enable FPL to offset the reduction in natural gas supply and meet customers' needs. An inventory of these other fuels is maintained on-site at FPL's generation locations to further enhance system reliability.

b) Diversity in Fuel Transportation and Delivery Methods and Routes Also Improves System Reliability.

The ability of a generating system that relies on only one fuel transportation and delivery method and route to serve its customers can be severely impaired by delays or interruptions in the transportation and delivery of that single fuel to the generating plants. Diversity in transportation methods and routes enables a utility to mitigate the effects of such interruptions and delays by fully utilizing other transportation channels that remain unaffected until transportation problems are resolved.

Because different fuels usually originate from different geographical areas and are transported and delivered via different methods and routes, having a fuel diverse generation system helps mitigate the effect of problems related to transportation and delivery as well as production.

c) Diversity, Not Just in Fuel Type, but in Generation Technology, also Improves Reliability

Occasionally, equipment design or manufacturing problems manifest themselves in the form of systematic failure of the same part in a number of generating plants that utilize the same part design, or those plants that use parts produced in the same production batch. Having diversity in generation technology also is important because any generic equipment problem will affect a smaller portion of a utility's generation portfolio, and will make it easier for the utility to mitigate the effect of that problem without adversely

affecting service to its customers. Because generating units that use different fuels usually also use different technologies, a fuel diverse system also helps mitigate the effect of equipment problems that affect one specific type of generation technology, such as gas turbines.

4. Alternatives to Balance the Fuel Mix in 2018 and beyond

FPL has previously evaluated four coal-based technologies to determine whether they could reliably contribute to the fuel diversity and capacity needs of FPL's system in the 2012 – 2015 time period to select the best among those technologies that could provide those benefits by 2015. The technologies were: PC, CFB, IGCC, and advanced technology coal. The results of FPL's analyses of these four coal-based technologies clearly established that the advanced technology coal option was the best alternative for the 2012 – 2015 period. However, because a determination of need was not granted for this advanced technology coal option, FPL has continued to consider only the IGCC alternative, along with new nuclear generation, as a potential contributor to fuel diversity for the period beginning in 2018.

5. The Alternative Selected by FPL

FPL concluded that new nuclear generation is more cost-effective than IGCC, has reliability that as good as, or better than, IGCC, and, unlike IGCC, can be relied on to reduce GHG emissions in the future. Based on these factors, FPL has concluded that the addition of new nuclear generation at its Turkey Point site is by far the best choice to contribute to fuel diversity and meet FPL's generation capacity need in the 2018 – 2020 time period.

6. Benefits of the Selected Alternative

All of the benefits described above associated with having fuel diversity in the system are applicable to the addition of Turkey Point 6 & 7. Adding up to 3,040 MW of new baseload nuclear generation to FPL's system will reduce dependence on natural gas and will enable FPL to more effectively offset decreases in natural gas supply because factors that affect gas production will not affect coal production. The nuclear fuel that would be used in Turkey Point 6 & 7 can be produced in the U.S., Canada, Australia and other areas of the world, all different from the area near the Gulf of Mexico where most of FPL's natural gas is produced, and nuclear fuel will be transported via means that are different from the pipelines used to deliver natural gas so any event that affects gas production or transportation would not affect nuclear fuel supply or transportation. The technology to be used in Turkey Point 6 & 7 will be different from that used in most of FPL's gas-fueled units, so technical problems that affect the gas units are less likely to affect Turkey Point 6 & 7.

There are additional benefits in regard to the nuclear refueling process. Nuclear generating facilities typically have sufficient fuel in the core to operate at full power for approximately eighteen months without the need for additional fuel. A natural gas-fueled facility, on the other hand, requires that natural gas be delivered via an interstate pipeline to the generating plant continuously in order to continue to operate. In addition, replacement nuclear fuel is typically delivered to the nuclear plant at least two months prior to the time the fuel is needed to conduct the refueling of each unit. Therefore, Turkey Point 6 & 7 will have, in effect, at least two months of full power "inventory" of fuel at all times. In addition, because the reserves of uranium (U3O8) in the U.S.,

Canada, Australia, and elsewhere, are so large, fuel supply that meets the specifications required by Turkey Point 6 & 7 from secure sources is assured for the entire operating life of the plant.

7. Hedge Provided by Fuel Diversity

Fuel diversity helps mitigate the effects of price volatility in one or two fuels. For example, if a utility relies solely on natural gas to produce all the electricity needed by its customers, any increase or decrease in the market price of natural gas would translate into a direct and comparable increase or decrease in the cost of electricity. Because natural gas prices are projected to be volatile in the future, the customers would be subject to significant volatility in the future cost of electricity. Recent history has demonstrated how volatile natural gas prices can be. Because the price of nuclear fuel has been and is projected to remain relatively stable, and because changes in nuclear fuel prices are not directly linked to changes in the prices of natural gas and fuel oil, having a fuel diverse portfolio that includes significant contributions from nuclear fuel helps dampen the effect of volatility in natural gas prices. For this reason the addition of Turkey Point 6 & 7 will help dampen the volatility in system fuel costs and make the cost of electricity more stable and predictable.

F. Renewable Energy

According to the U.S. Department of Energy (DOE) data released in July 2007, Florida performs well in producing energy from its renewable resources. Florida ranks second in the nation in renewable energy production when one excludes hydroelectric and

geothermal resources that the highest ranking states have, which are not abundant in Florida. FPL has been providing a portion of its customers' energy needs from renewable resources since 1980. Currently, FPL provides more than 300 MW of firm and non-firm capacity and energy from renewable resources yearly. This energy is purchased from owners of waste-to-energy, biomass and landfill gas power plants located in Florida.

During 2003, the FPSC and the FDEP issued "An Assessment of Renewable Electric Generating Technologies for Florida" (the FPSC/FDEP Renewable Assessment). The FPSC/FDEP Renewable Assessment concluded that as of 2003 Florida as a whole had approximately 680 MW of potential renewable capacity, exclusive of waste heat from sulfuric acid manufacturing operations, which the Renewable Assessment estimated as providing an additional 340 MW of potential capacity from renewable resources.

Without understating the importance of renewable energy for Florida, nor FPL's interest in utilizing and promoting the use of such resources, FPL's view is that the FPSC/FDEP Renewable Assessment's conclusions remain correct in terms of the comparatively small potential contribution of renewable energy to overall electricity production in Florida. The resources recognized as reasonably available in the FPSC/FDEP's Renewable Assessment on a commercial basis were modest.

FPL is working to extract as much energy as technically and economically possible from renewable resources and continues to explore the use of emerging technologies. For example, in July 2007, FPL concluded a renewable energy request for proposals (2007

Renewable RFP). The 2007 Renewable RFP sought proposals for new renewable energy with expected in-service dates prior to June 2015. The 2007 Renewable RFP also sought information regarding new renewable firm capacity and/or energy sources with expected in-service dates beyond 2015.

The 2007 Renewable RFP contained no restriction on price and provided maximum flexibility for potential suppliers of renewable energy in order to encourage as much participation as possible. The 2007 Renewable RFP was available to potential bidders in Florida, across the country and beyond for their consideration and response.

As a result of the 2007 Renewable RFP, FPL received proposals from five bidders totaling 144 MW of firm capacity. FPL has incorporated these potential resources into its Integrated Resource Planning (IRP) analyses. In addition, FPL received a proposal for the supply of 100 MW of non-firm capacity and energy from technology under development based on harnessing ocean current energy.

FPL will continue to promote renewable generation in Florida through RFPs and other purchase power agreements, and is exploring direct development of renewable generation projects, including solar and wind. FPL is presently in the process of considering and supporting development of wind, solar and other renewable energy sources in the State of Florida. FPL is committed to developing the maximum cost-effective amount of renewable resources to serve its customers.

FPL has been assessing the commercial wind energy potential of the state of Florida for several years. In this regard, FPL commissioned three wind studies of the state of Florida. These studies are much more detailed than information commonly available through government and general industry sources. The first study addressed the state of Florida as a whole. Two more recent studies focused on the Southwest and Northeast Florida geographical regions. The studies all had similar overall findings:

- Florida's wind resource is minimally adequate to produce some power along portions of its coast;
- The wind resources decline significantly inland; and
- Florida's wind resource is seasonal, and is more productive during winter (October through March).

From these studies, and FPL's other work assessing possible wind energy development in Florida, FPL concludes that (i) the wind energy that may be subject to development is on or near Florida's beaches (including possible offshore wind); and (ii) while wind power might offset some winter energy use, it is not meaningfully available during FPL's Summer load peak and, therefore, cannot contribute to meeting FPL's reserve margin on a reliable basis.

Since 2004, FPL has attempted to site a wind project along Florida's coast, utilizing several potential locations, but has not yet obtained site approval for a project. Concerns raised with respect to the possible siting of the project have included potential radio signal interference, avian concerns, aircraft flight paths, land availability, and other local

land use matters. In June 2007, FPL announced the St. Lucie Wind Project, a 3 to 4.5 MW project, which FPL hopes to site near its St. Lucie nuclear generating plant. FPL is pursuing the necessary permits and performing due diligence required for this project. In addition, FPL will be pursuing additional wind opportunities that would add to its renewable portfolio, which FPL will build, own and operate to provide renewable energy for customers. In contrast with a baseload generating resource, wind energy provides intermittent electric energy and is not a dependable source of electrical capacity, meaning that wind generation cannot be counted on to provide electricity upon demand when customers require it.

FPL is also supporting deployment of solar energy technologies. FPL has a solar PV project at its Martin plant site that was first energized in the 1990s. Under FPL's Sunshine Energy Program, a 250 kW PV array is being built in Sarasota, Florida that is expected to be in commercial operation around the end of 2007. Additionally, FPL recently announced a major solar energy initiative in Florida, which is expected to result in installation of up to 300 MW of solar capacity at a cost of up to an estimated $900 million. This is expected to begin with installation of about 10 MW of capacity at an existing FPL generating site. While this major new initiative is subject to regulatory, land use and other approvals as well as business due diligence, FPL is optimistic about the potential of using a new solar generating technology to provide service to customers in Florida.

FPL is commissioning a study to better evaluate the potential solar resource in FPL's service territory. Development of utility scale solar projects in Florida requires extensive

land resources, estimated to be in the range of 10 acres/MW. Distributed installations of rooftop solar PV generation is feasible but due to low capacity factor, high cost and intermittent availability is not a substitute for high capacity factor, high reliability baseload generation. Because solar power is an intermittent resource with a low capacity factor, many more MW of solar would need to be installed to equate with the energy production of reliable baseload electric generating resources.

FPL is assisting Florida universities and others with the investigation of possible electric generation using ocean currents. Florida is one of the few places in the world that has a major ocean current located near electric load centers. FPL is actively involved with Florida Atlantic University's Florida Center of Excellence in Ocean Energy Technology in developing this non-emitting renewable technology. FPL is hopeful that it may be commercially deployed to serve its customers first in experimental and ultimately in commercial amounts in the future.

In summary, FPL believes there is a role for renewable energy in FPL's resource plan. However, that role is limited in several respects. First, as projected in the FPSC/FDEP Renewable Assessment, Florida as a whole was projected to have approximately 680 MW of potential renewable capacity (exclusive of waste heat from sulfuric acid manufacturing operations). FPL serves approximately one half of the electricity customers in the state. Therefore, assuming that one half of this renewable potential was available as firm capacity to serve FPL's customers would result in 340 MW of renewable firm capacity. A 340 MW firm capacity amount equates to less than 6% of the 6,156 MW of firm capacity need projected for FPL by 2020 as presented in Table III.C.1.

Consequently, renewable resources cannot be expected to fully meet FPL's capacity needs by 2020.

Second, as discussed above, a significant amount of the renewable potential – particularly solar and wind resources – is intermittent in nature. Resources with intermittent availability cannot be reliably counted on to meet FPL's firm capacity needs during peak load hours. Therefore, an amount less than 340 MW – and perhaps significantly less than 340 MW – will actually be available to help meet FPL's firm capacity needs. Third, many renewable energy options are relatively expensive to construct or install on a dollars per installed kilowatt basis. This fact, when combined with their lower capacity factors, can result in the cost of energy on a dollars per megawatt-hour basis produced by renewable energy options being quite expensive.

For these reasons renewable energy cannot be reasonably be expected to avoid the Turkey Point 6 & 7 units. These new nuclear units can be expected to provide firm capacity reliably, to operate at very high capacity factors, and, as will be discussed later in this document, are currently projected to be economically competitive with other commercially available baseload generating technologies.

IV. NEW NUCLEAR GENERATING UNITS

A. Resumption of Nuclear Deployment in the U.S.

Nuclear power generation is an important and reliable contributor to the national energy mix, providing approximately 19.4% of the electricity in the U.S. from 104 licensed reactor facilities. This significant contribution stands in contrast to the fact that no new reactor plants have been ordered in the U.S. since the Three Mile Island (TMI) accident in 1979. The resulting hiatus in new nuclear plant design and construction was the result of the confluence of many technical, economic, and regulatory issues. Internationally, nuclear generation technology continued to grow, mature and safely serve many customers using the designs that were developed in the U.S. The following provides a brief review of how the nuclear generation industry has learned from the U.S. experience, continued to mature in the U.S. and internationally, and is now poised to resume deployment with full knowledge of the lessons learned from its own history.

1. Early Days

The commercial nuclear power generation industry began in the 1960s following the success of first generation small scale plants operated at Shippingport, Pennsylvania and Dresden, Illinois. The second generation of plants that followed was based on similar designs, but as the relatively new technology evolved during the decade, so did the designs applied to each subsequent project. Additionally, the Atomic Energy Commission (AEC) (then the agency charged with oversight of all nuclear reactors in the U.S.) was continually modifying and adapting its regulatory requirements to reflect new information regarding siting and design safety analysis. The non-standardization of design and evolving regulatory requirements began to create delays and cost overruns in the large number of projects that were under construction in the late 1960s and early

1970s. In 1974, the AEC was dissolved and replaced by the Nuclear Regulatory Commission (NRC).

As the seventies continued, reactor construction projects continued to face the problems created by non-standardization of design. Costs grew and delays were frequent. In efforts to maintain the project economics, designs were often modified during construction to incorporate increased capacity or higher efficiency components. This exacerbated the standardization issue. Probabilistic Risk Analysis, now the standard for predicting the likelihood of a severe nuclear accident, was just developing and being applied – an effort led by the NRC. This resulted in further delays.

2. Turning Point

This early period of U.S. nuclear generation history ended with the loss of coolant accident at TMI. The accident, in which no lives were lost and relatively little radiation was released offsite, triggered a Presidential Commission review (the Kemeny Commission) that called for sweeping changes in the operation and regulation of nuclear reactors. The Kemeny Commission's recommendations shaped the U.S. nuclear industry's focus on safety, training, emergency preparedness, and technical assessment for which it is known and internationally respected today.

At the time of TMI, there were over one hundred nuclear units in some form of planning or construction. Fifty of those units were completed over the next decade. Revisions to designs and construction practices required by regulation or spurred by an effort to

increase the economics of the facilities continued the trend of non-standardization in these plants.

The strong commitment of the nuclear power industry to operational safety, along with the increased focus on risk assessment, have been the foundation for the successful track record of the industry in the past two decades. The industry safety record is strong, and nuclear power today is one of the most dependable forms of energy generation (the capacity factor for all U.S. nuclear plants was 90.1% for 2006). Economically, the investment continues to pay off for the customers served by nuclear power, providing low cost, stably priced energy with no GHG emissions. Increasing the capacity of existing reactor units continues to be one of the best choices for new capacity. Since 1977, the NRC has approved up to 4,900 MW of capacity uprates at existing facilities.

3. Lessons Learned

The lessons of the absence of standardization and regulatory stability that resulted in delays and cost overruns in the second generation of nuclear units were taken seriously as the NRC and the industry began to contemplate how new nuclear licensing and construction could be made feasible in the U.S.

A key feature of the renewed deployment of nuclear generation in the U.S. is the focus and unanimous support from potential owners, designers, and regulators for design standardization. Such standardization not only reduces the cost of units using the same design, it streamlines the regulatory reviews and allows for significant operational

synergies in the future. This approach has been demonstrated as a highly successful model in France, where designs are held standard for multiple units before changes are allowed for the next fleet of units to be built.

Until 1992, the federal licensing process was a two-step process wherein a prospective owner would apply for and receives a construction license that would authorize the construction of a plant. Once built, the owner would apply for an operating permit. This two step process proved unwieldy and prone to delays. The potential of not being able to operate a facility following the investment in construction deterred potential investment. The NRC began to review and design a streamlined process to provide the regulatory framework that would allow new nuclear generation to move forward in the U.S.

B. Modifications to the Regulatory Processes

Regulatory processes at the federal and state level have been modified to accommodate the concerns of the past and address the issues that would, otherwise, present insurmountable barriers to the development of new nuclear generation in the U.S. These modifications, along with the specific supporting legislation passed in 2005 and 2006, enhance the licensing process for new nuclear generation.

1. NRC's Combined Construction and Licensing Process

The two-step nuclear licensing process, under which the second generation of nuclear units was licensed, had two distinct license review periods separated by the construction

period. The initial Construction Permit application process required approximately four years from planning to receipt of license, following NRC review and legal proceedings. The construction period for post-TMI units averaged approximately eight years. Then the owner applied for an Operating License at the NRC. This process essentially re-opened issues deliberated during the Construction Permit hearing.

The Combined Construction and Operating License (COL) process developed by the NRC in the past several years has reorganized the review process to require the careful review of all issues in a single process that occurs prior to the commencement of construction. This allows for all issues to be thoroughly heard prior to the commencement of nuclear system construction. Importantly, the new process also requires that a defined set of Inspections, Tests, Analysis and Acceptance Criteria (ITAAC) be developed and agreed upon prior to construction. In this way, the documentation of these important quality measures are developed and reviewed through the construction phase. When construction is complete, the ITAAC are presented and reviewed to ensure the facility was constructed and tested according to plan. At this stage, the owner is granted permission to load the facility with fuel and begin operations.

Standardization of design remains a critical facet to the successful deployment of new nuclear generation and success in the revised NRC review process. The first COL application for each design will be deemed the reference design. All subsequent COL applications using that design will be based on the reference design, with the exception of site-specific issues (geology, seismology, cooling water source, etc.). This common basis will allow a significant streamlining of the NRC review process and subsequent

inspections and operating procedures. Industry participants are uniformly supportive of this standardized approach, and FPL intends to leverage the approach to reduce risk and manage costs for our customers.

2. Federal Legislation Signals Support

Federal legislation enacted in 2005 signaled a validation of nuclear energy's renewed importance as a national resource and the increasing public acceptance of new nuclear generation as a credible emission-free alternative that should be pursued. The Energy Policy Act of 2005 (EPAct 2005) recognized the need to assist potential nuclear plant owners by providing incentives and tools to help manage the risks of undertaking nuclear development activities. Among other initiatives, EPAct 2005 provided three proposed programs designed to benefit up to six first wave new nuclear plants developed in the U.S. that meet specific development and construction milestones: a form of "risk insurance" designed to cover costs incurred by an owner as a result of delays created in the commercial operation of a new nuclear plant by the NRC failure to act in a timely manner; a Loan Guarantee program intended to reduce the lending costs associated with a new nuclear project; and production tax credits that would come into effect when operational. These programs are promising, but limited in their ability to materially offset deployment risks. Given the number of announced projects that would be competing for the benefits, and the uncertain value that would be obtained by any given project, FPL chose not to begin expenditures towards the preparation of a Construction and Operating License Application (COLA) in order to meet the first milestone, filing of a COLA prior to the end of 2008.

The EPAct 2005 legislation is an important signal to FPL and other utilities that there is support for new nuclear generation. The EPAct 2005 and state level initiatives have advanced the development of new nuclear generation in Florida.

3. Florida Demonstrates Clear Intention to Support New Nuclear Generation

The Florida Energy Act of 2006 provided significant legislative direction to enact rules that allow Florida utilities to actively consider and pursue new nuclear generation. Recognizing the uncertain and developing status of new nuclear development, the Florida Legislature directed the Commission to take concrete steps to modify the rules associated with Power Plant Need Determinations to allow for the initial investigative steps for new nuclear generation to be initiated without the same level of certainty that is required when a utility proposes to build most fossil-fueled facilities. Additionally, the Florida Energy Act of 2006 created a mechanism by which the Commission could oversee the progress and expenditures of the project on an annual basis and utilities can file for interim cost recovery of prudently incurred costs, a feature that lowers the overall costs customers will pay. This legislation was implemented in early 2007 with the adoption of the Commission's Nuclear Cost Recovery Rule, clearing the way for FPL to present this request for Determination of Need.

C. Considerations Related to Nuclear Technology

1. Protecting Public Safety

Safety of the public is a top priority at FPL. Nuclear operations, both for FPL and for FPL Energy-operated facilities in other states, are rigorously managed to maintain public safety. In addition, FPL's emergency preparedness programs work in close coordination with local authorities to ensure response systems are ready and personnel are trained to manage a range of potential events.

Turkey Point 3 and 4 sustained no significant damage during the Category 5 Hurricane Andrew in 1992. New designs will be even more fortified than the second generation facilities and are more robust in the face of severe weather than conventional fossil-fueled plants.

Location of new nuclear generation units at Turkey Point utilizes an existing nuclear facility with a strong established network of local public safety officials ready to support emergency preparedness plans. The significant buffer region around the existing site maintains an appropriate perimeter, while preserving the land as a valuable habitat for a range of wildlife native to the area.

2. Ensuring Plant Security

FPL's security program is designed to be able to respond to a wide range of potential threats, including terrorist attacks. The "defense-in-depth" strategy is built on layers of protection including heavily fortified buildings, expertly trained and screened personnel, and extensive physical security measures. FPL's security team works closely with local,

state, and federal agencies to continually assess threats and ensure the security program adapts to and anticipates potential threats.

Siting a new nuclear plant at Turkey Point leverages the experience of on-site and local authorities in addressing the specific concerns surrounding security of nuclear installations. The new facility would be secured by an independent security force that would complement and reinforce the existing security force at Turkey Point 3 and 4.

3. Provisions for Safe Spent Fuel Storage

Nuclear reactors are designed with safe storage facilities that can hold a significant quantity of fuel after it has been used in the electric generation process. These facilities are adjacent to the reactor and allow the fuel to cool underwater after use in the reactor. As these storage facilities begin to reach capacity in plants across the U.S., the nuclear industry has designed safe and secure methods for storing and controlling the used fuel assemblies. While the U.S. Department of Energy continues to develop a long-term national repository, many plants have begun to use a licensed and approved process called dry storage.

Dry storage allows the stabilized used fuel assemblies to be placed into cylindrical shielded casks and stored on site in protected areas. This process has been in use for over 20 years. Dry cask storage will be pursued at FPL's existing nuclear facilities, and is a safe and reliable option for disposition of used fuel from new nuclear generation until a long term national repository can be developed and made operational.

4. Decommissioning Costs

Operation of nuclear units is conducted with a full commitment to the complete lifecycle of costs associated with facility, including the eventual decommissioning of the facility when its operating life has been completed. Operating plants are required to periodically project the cost to decommission the facility and ensure that appropriate funds will be available to pay the costs of decommissioning.

The estimates being used for fixed operations and maintenance costs for the Turkey Point 6 & 7 project are based on costs in FPL/FPLE's current fleet, and include decommissioning costs.

D. Cost Control and Stepwise Decision Making

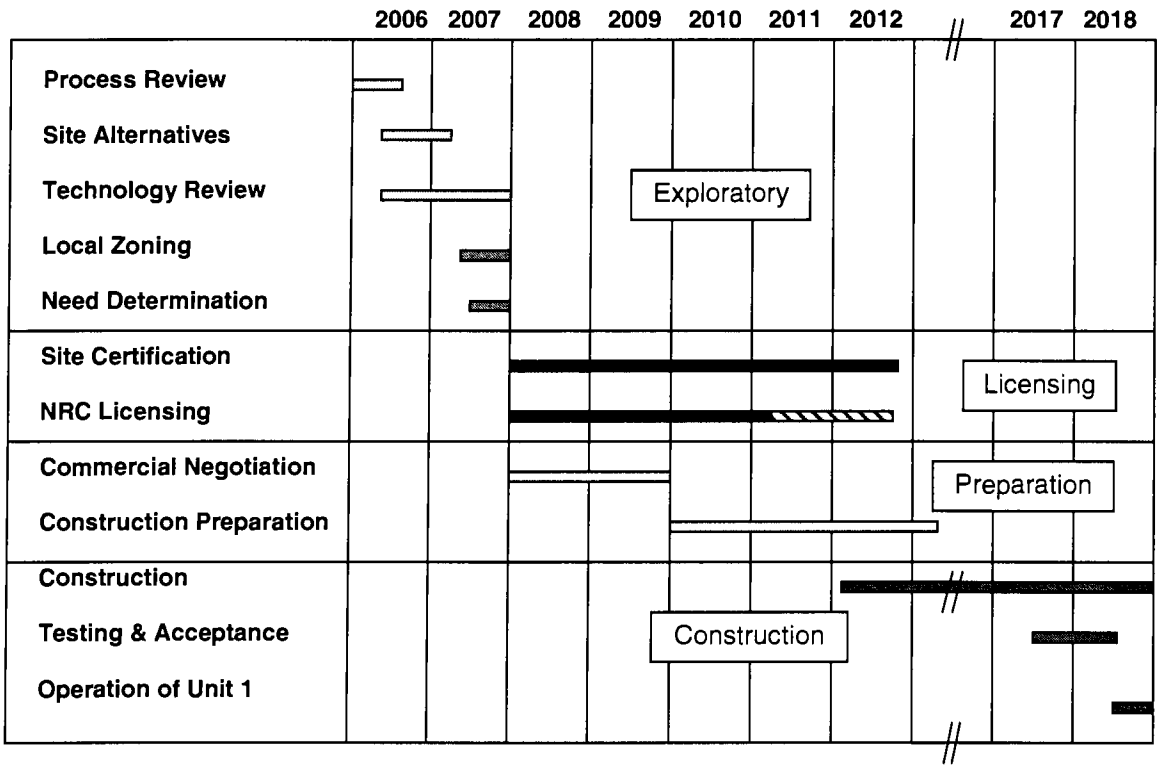
The revisions to the Need Determination Rule and the development of the Nuclear Cost Recovery Rule explicitly acknowledge the unique nature of new nuclear generation with regard to cost certainty and the need to initiate early steps in the process to create the option for new nuclear generation at the earliest possible date. Specifically, the Nuclear Cost Recovery Rule recognizes a non-binding cost estimate as the appropriate level of information to be provided at the early stages of the long and complex nuclear deployment process. Under the Nuclear Cost Recovery process, the expenditures for the project are periodically reviewed and an annual decision is made to continue the project based on the best current information.

FPL believes the framework established by the revised Need Determination Rule and the newly developed Nuclear Cost Recovery Rule will provide the joint assurance and cost control necessary to deploy new nuclear in Florida.

1. Near-Term in Sharper Focus

The deployment process for new nuclear involves four phases; the exploratory phase followed by Licensing, Preparation and Construction phases. These phases are characterized in Figure IV.D.1.

Figure IV.D.1 Phases of New Nuclear Project Deployment



The early steps of the Exploratory and Licensing phases are well understood. These steps allow FPL to project the expected cost to develop a COL Application to file with the NRC and a Site Certification Application to be filed with the Florida Department of Environmental Protection with a higher level of certainty than costs later on in the deployment process. COL applications are being completed now in a number of southeastern U.S. states. Additionally, FPL has current experience with the information necessary to satisfy the filing requirements of the state Site Certification process. The development of these applications will begin following an affirmative Need determination and will be completed and filed in 2009. The available background information and FPL's experience provide a firm basis from which to estimate costs for the development of the applications for Turkey Point 6 & 7 within this relatively short time frame.

2. Follow-up Steps Less Certain

Following application submission, several steps in the process are initiated that do not have the same level of precedent as the application development. The most notable step involves supporting and defending the applications through the review process. Other critical steps preceding construction include site preparation and long lead procurement.

The first COL applications will be submitted late in 2007 and will not complete the review process for several years. The pace and cost of that review process, including the cost of defending the applications in judicial or quasi-judicial proceedings, will be demonstrated over the next several years for the first wave of applications. FPL will be

in the second wave of applications and may or may not benefit from this position. The uncertainty, however, adds to the complexity of estimating costs at this juncture.

The Preparatory phase steps are unrelated to the licensing phase, but are critical items that must be accomplished in advance of the Construction phase. Postponing these steps will postpone the commercial operation. Investing in these steps in advance of receiving the license are prudent enabling decisions that FPL will recommend as circumstances warrant.

For example, manufacturing space for ultra-heavy forgings is a critical path item that must be secured to enable the earliest practical deployment schedule. FPL recommends that procuring an option for the necessary manufacturing space to support this schedule should be a priority activity following a Need determination. In the event the Turkey Point 6 & 7 project is not pursued, the option may have a market value for other users that can be recovered.

Additionally, in order to maintain the earliest practical deployment schedule, expenditures will be recommended as warranted to begin the detailed engineering design and site preparation activities. The costs of these steps will be able to be determined with certainty as they are recommended, allowing the Commission to fully understand the justification and reasonableness of the proposed expenditure.

V. FACTORS AFFECTING SELECTION

A. FORECASTS AND ASSUMPTIONS

The forecasts of electric load and fuel prices are developed by FPL analysts who aggregate data and perform various analyses to develop these forecasts that are used in FPL's IRP process.

1. The Electrical Load Forecast

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used during the IRP process. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

a) Forecast Assumptions

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and the price of electricity. In addition to these drivers, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanographic and Atmospheric Association (NOAA), and inputs from FPL's own customer service planning areas. Population trends by county, plus characteristics such as housing starts, housing size, and vintage of homes, are assessed in the area of demographics.

Econometric models are developed for each revenue class using the statistical tool called Metrix ND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

b) Forecast Methodology

(i) Sales

(A) Residential electric usage per customer is estimated by using a linear multiple regression model that contains the real residential price of electricity, income, Cooling and Heating Degree Days as explanatory variables, and dummy variables for hurricanes and historical periods.

(B) Commercial sales are forecast using a linear multiple regression model which contains the following explanatory variables: Gross Domestic Product, commercial real price of electricity, Cooling Degree Days, and dummy variables for hurricanes and historical periods.

(C) Industrial sales are forecast through a linear multiple regression model using Gross Domestic Product, Cooling Degree Days, and several dummy variables for outliers, hurricanes, and months.

(D) Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. Currently, there are four customers in this class: the Florida Keys Electric

Cooperative; the City Electric System of the Utility Board of the City of Key West, Florida; Metro-Dade County Solid Waste Management; and the Florida Municipal Power Authority.

Sales forecasts for these and other classes are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual NEL.

(ii) Net Energy for Load

A monthly model econometric model is also developed to produce a NEL forecast.[2] The key inputs to the model are: the real price of electricity, Heating and Cooling Degree Days, and Real Florida Personal Income. Once the NEL forecast is obtained using this methodology, the results are compared for reasonability to the separate NEL forecast generated using the revenue class sales forecasts. The revenue class sales forecasts are then adjusted to match the NEL from the monthly econometric NEL model.

(iii) System Peak Forecasts

In recent years, the absolute growth in FPL system load has been associated with a larger customer base, weather conditions, continued economic growth, changing patterns of customer behavior (including an increase in electricity-consuming appliances), and more efficient heating and cooling appliances. The Peak Forecast models were developed to capture these behavioral relationships.

[2] This calculation is independent from that used to determine NEL. It is developed by applying an expansion factor to the revenue class sales forecasts described above.

(A) Summer peak demand is developed using an econometric regression model developed on a per-customer basis. The key variables included in the summer peak model are total average customers, the real price of electricity, Florida Real Personal Income, average temperature on peak day, and a heat buildup factor consisting of the sum of the Cooling Degree hours during the peak day and three prior days.

(B) Winter peak demand is forecast using the same methodology and taking into account weather-related variables. The winter peak model is a per customer model that contains the following explanatory variables: the square of the minimum temperature on the peak day and Heating Degree hours from the prior day until 9:00 a.m. of the peak day. The model also includes an economic variable: Florida Real Personal Income.

c) Load Forecast Results

The historical and projected compound average annual growth rates in customers, energy, and demand are summarized in Table V.A.1.c.1 below.

Table V.A.1.c.1
FPL's 2006 Load Forecast Results
Compound Average Annual Growth

Years	Total Customers	Net Energy For Load	Summer Peak	Winter Peak
1997-2006	2.2%	3.1%	3.1%	2.0%
2007-2016	1.8%	3.1%	2.3%	2.0%
2017-2040	1.1%	2.2%	2.1%	2.1%

The actual forecasts of peak demands and NEL used in the IRP analyses are presented in Appendix D. These forecasts address the 2006 through 2040 time period. For purposes of the analyses, FPL assumed that the load was constant from 2041 through 2060.

2. The Fuel Price Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

a) Fuel Price Forecast Methodology

Future fuel oil and natural gas prices, and to a much lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of fuel oil, natural gas, coal, and petroleum coke. 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, in particular in China and the other Pacific Rim countries; (4) Organization of Petroleum Exporting Countries (OPEC) production and the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity; (5) non-OPEC production and expected growth in non-OPEC production; (6) the geopolitics of the Middle East, West Africa, the former Soviet Union, Venezuela, etc.; (7) the impact upon worldwide energy consumption of various factors including worldwide environmental legislation; (8) current and projected North American natural gas demand; (9) current and projected U. S., Canadian, and Mexican natural gas production; (10) the worldwide supply and demand of Liquefied Natural Gas (LNG); and (11) the growth in solid fuel generation on a U.S. and worldwide basis.

The volatility of natural gas and fuel oil prices, as compared with solid fuel and nuclear fuel prices, clearly underscored the need to develop a set of plausible fuel oil, natural gas and solid fuel price scenarios that bound the reasonable set of long-term price outcomes for economic evaluation purposes. In this light, FPL developed Low, Medium, and High Gas Cost forecasts for oil, natural gas, and solid fuel which were used in the analyses of the three resource plans.

FPL's Medium Gas Cost forecast methodology is consistent for fuel oil and natural gas. For fuel oil and natural gas commodity prices, FPL's Medium Gas Cost forecast applies the following methodology: (1) for 2007 through 2009, the methodology used the July

31, 2007 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil and Henry Hub natural gas commodity prices; (2) for the next two years (2010 and 2011), FPL used a 50/50 blend of the July 31, 2007 forward curve and annual projections from the PIRA Energy Group; (3) for the 2012 through 2020 period, FPL used the annual projections from the PIRA Energy Group; and (4) for the period beyond 2020, FPL used the rate of real (constant dollar) price changes from the Energy Information Administration (EIA). All constant dollar changes were then converted to nominal dollars using a 2.5% annual escalation rate. In addition to the development of commodity prices, price forecasts also were prepared for fuel oil and natural gas transportation costs. The addition of commodity and transportation projections resulted in delivered price forecasts.

FPL has used a consistent approach in developing the Medium Gas Cost forecast methodology for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach: (1) the price forecasts for Central Appalachian coal, South American coal, and petroleum coke were provided by JD Energy; (2) the marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy; (3) the terminal throughput fee was based on a range of offers from comparable facilities throughout the Southeast U.S.; and (4) the rail transportation rates from Central Appalachia and from the import terminal facility were based on the proposed rail transportation rates as of the second quarter of 2007. In order to achieve the maximum fuel supply diversity and delivery flexibility for FPL's customers, FPL assumed that the delivered price of solid fuel for IGCC units in FPL's

Plan without Nuclear -- IGCC would be a mix of 25% Central Appalachian coal, 25% South American coal, and 50% petroleum coke.

These delivered price forecasts for fuel oil, natural gas and solid fuel were used in the economic evaluation of Turkey Point 6 & 7 and the alternative expansion plans.

The development of FPL's Low and High Gas Cost forecasts for fuel oil, natural gas, coal, and petroleum coke prices was based upon the historical relationship of the high and low prices realized by FPL's customers for each fuel between January 2000 and April 2007, to the average fuel prices in that same time frame. For example, the January 2000 through April 2007 average natural gas price delivered to FPL's system was $6.65/MMBtu. The high price of the range was $9.09/MMBtu or 137% of the average and the low price of the range was $4.57/MMBtu or 69% of the average. These factors were multiplied by the monthly Medium Gas Cost forecast to determine the Low and High price for each commodity for the duration of the forecast period. This same process was applied to fuel 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 January 2000 to April 2007 period, thus ensuring that the analyses of the three Resource Plans will reflect a range of reasonable forecast outcomes.

FPL's long-term oil, natural gas and solid fuel price forecasts are reasonable and appropriate for the economic evaluation of Turkey Point 6 & 7 and the alternative plans.

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 January 2000 through April 2007 period, a period of time that experienced high variability among commodity prices, high price volatility on a domestic and worldwide basis, and periods of both low and high price differentials between commodities.

b.) Nuclear Fuel Price Forecast Methodologies

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. Therefore, there are four separate markets evaluated to develop nuclear fuel price projections.

During the first step, uranium is mined from the ground using techniques such as open pit, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake). Uranium is produced in many countries such as Canada, Australia, Kazakhstan and the U.S.

During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

The third step is called enrichment. Natural uranium contains 0.711 % of uranium at an atomic mass of 235 (U-235) and 99.289 % of uranium at an atomic mass of 238 (U-238). Similar to current reactors, the next generation of nuclear power reactors will use uranium with a higher percentage of U-235 atoms, up to five percent (5%). Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711 % to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF6.

During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

In developing prices for each step of the fuel fabrication process, different forecasts are reviewed to help establish a range of prices to reflect various scenarios of future supply and demand scenarios. A later section of this report will address availability of supply which formed the bases for the range of prices, used in this study.

A reference, nuclear fuel cost forecast was utilized in the analyses of the three resource plans. This forecast is provided in Appendix E. The calculations for the fuel cost forecasts were developed in a manner consistent with the method currently used for FPL's Fuel Clause filings, including the assumption of a fuel lease. Because current

nuclear fuel price forecasts did not extend to 2060, FPL extended the forecasts by escalating them at 2.5% per annum.

c) Fuel Supply, Availability, and Delivery

(i) Natural gas

It was assumed that, for all gas-fired CC units contained in the three resource plans used in the analyses, natural gas was the primary fuel source and light oil was the backup fuel. (Please refer to section VI.C for details regarding these three resource plans.)

Natural gas is currently delivered into Florida from the U.S. Gulf Coast on-shore and off-shore regions via the Florida Gas Transmission (FGT) and Gulfstream Natural Gas System (Gulfstream) pipelines and from the regasification of imported LNG at the Elba Island, Georgia terminal via the Cypress pipeline. On May 1, 2007, Phase I of the Cypress pipeline was placed into service and began providing an incremental 220,000 MMBTU per day of natural gas into Florida. Phase I of the Cypress pipeline operates near or at capacity today, and future Phase II and Phase III expansions should be available by 2008 and 2010. While the FGT and Gulfstream infrastructure has provided a high level of reliability over the years, the demands on both pipelines have continued to grow. FGT is currently fully subscribed and by mid-2009 Gulfstream will be fully subscribed. Even with the planned Phase II and Phase III expansions of the Cypress pipeline, the addition of incremental natural gas-fired generation will likely require an expansion of one or both of the FGT and Gulfstream pipelines.

The need to consider alternatives to promote the diversity of supply is also critical to maintaining system reliability. Alternatives could include the addition of a new interstate pipeline, additional underground natural gas storage and the development of alternate supply sources, including access to new producing regions as well as the addition of LNG supply. Deepwater LNG receiving ports have been proposed on both the east and west coast of Florida and both projects are currently in the Maritime Administration (MARAD) approval process. In addition to providing incremental transportation capacity, these projects will also provide natural gas supply diversity from offshore and onshore locations in the Gulf of Mexico region.

(ii) Oil

The three resource plans assumed that all combined cycle additions will be capable of burning light oil as a backup fuel in the event of a natural gas supply disruption. Light oil would be trucked from local markets to the plant sites where it would be stored.

(iii) Coal (Domestic and International)

The fuel supply plan for the IGCC units included in one of the three resource plans analyzed for this filing assumes that low-sulfur bituminous coal from domestic and international sources will supply 50% of the fuel mix. These coal sources are expected to be the least-cost on a delivered basis because of the proximity of these coals to Florida,

resulting in lower transportation costs. The principal domestic coal source is the Central Appalachia coal supply region in East Kentucky, Virginia, Tennessee, and Southern West Virginia. This is the largest coal-producing region in the East, with 2005 production exceeding 230 million tons. A diverse group of producing companies report 38 years of coal reserves at current production rates. Demand for this coal is expected to decline, as utilities in the Midwest switch to local high sulfur coals, which will extend the supply availability of low sulfur coal for plants in Florida and the Southeast. Central Appalachia coal would be delivered by two railroads that serve the coal fields, the CSX railroad and the Norfolk Southern railroad.

International coal supplies would be delivered by ocean vessel to a port facility in the Southeastern U.S. The coal would be loaded into railcars at the terminal for final delivery to the plant. The most likely sources of imported coal will be from Colombia and/or Venezuela which have large and growing coal supplies. These are the most likely sources because their proximity to Florida minimizes the cost of ocean freight. Coal from a number of other countries would also be potential sources of supply including Russia, South Africa, Indonesia, and Australia.

(iv) Petroleum Coke

Petroleum coke is expected to be a low-cost source of fuel which will supply 50% of the solid fuel mix for the IGCC units included in one of the three resource plans analyzed for this filing. This fuel is a by-product of the refining of crude oil. The largest worldwide

source of petroleum coke supply is from oil refineries located on the Gulf Coast (Texas, Louisiana, and Mississippi) and in the Caribbean. With increasing demand for transportation fuels, petroleum coke production is expected to continue to grow, as refineries add coking capacity to upgrade heavy oil into light products. Petroleum coke would be delivered by vessel to a port in the Southeastern U.S. and loaded into railcars at the terminal for final delivery to the IGCC plants.

(v) Solid Fuel Receiving Terminal

FPL's solid fuel price forecasts have assumed access to a solid fuel receiving terminal with direct access to rail. The terminal Throughput Fee that was included in the delivered cost of solid fuel to the IGCC units in all three fuel cost forecasts assumed that the terminal could receive large vessels and maintain adequate throughput capacity to handle 100% of the proposed fuel requirements for the IGCC units. In addition, the site would be able to store up to 30 days supply of coal and petroleum coke in order to allow for uninterrupted service to be provided at the terminal for loading of unit trains.

(vi) Fuel Reliability via On-site Storage

Although a significant amount of on-site fuel supply is inherent in the design of, and included in the cost estimates for, the IGCC and Turkey Point 6 & 7 units (60 days of supply for the IGCC and up to 18 months for Turkey Point 6 & 7), the on-site fuel supply

for the CC units is for three to four days of backup fuel oil supply. Therefore, the Turkey Point 6 & 7 units offer a very substantial advantage over CC units in terms of fuel supply reliability. This advantage is difficult to quantify, however, because the amount of unburned fuel remaining in a nuclear generating unit declines steadily over the course of an operating cycle and hence there is no fixed, consistent level of nuclear fuel "reserve" on-site from which to calculate the cost of equivalent fuel supply at a CC unit. In any event, FPL's analyses show that the Plan with Nuclear appears to be at least as economic as the Plan without Nuclear – CC even without including a quantified benefit for the inherent on-site fuel supply at a nuclear unit.

The IGCC units would be able to store up to 60 days of solid fuel at the plant site and the capital cost, operation and maintenance expenses, and working capital were assumed in the economic evaluation of the IGCC units. In comparison, a natural gas-fired combined cycle plant is assumed to not have access to on-site natural gas storage, mainly due to the lack of economically viable sites for natural gas storage in Florida.

viii. Uranium

Uranium supply, Availability, and Current Delivery

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert firms. Though there is a current shortage of uranium, which has pushed the current spot market price up, these higher market prices have motivated additional production expected to come on line over the next few years, which should bring uranium prices back to a level consistent with market fundamentals. The higher demand scenario is due to a more optimistic projection of construction of new

nuclear units. As firm orders for new units are placed, uranium suppliers will commit to support the higher demand. Because the lead times to bring on line new nuclear units and new mining production are similar, it is expected that the higher demand will be met with higher uranium production in the future.

Other Steps of the Fuel Fabrication

The other steps of the fuel fabrication have and will continue to behave consistent with the market fundamentals. The reference costs scenario used in this study uses the most likely price scenarios which FPL developed by reviewing a number of consultant reports.

Conversion Services Supply, Availability, and Delivery

Similar to the market for raw uranium, an increase in demand for conversion services would result from the need to supply new nuclear units. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made to building new nuclear units. Capacity expansion of conversion services can be handled within the lead time for constructing a new nuclear unit, leading to sufficient supply with long term prices following cost fundamentals.

Enrichment Services Supply, Availability and Delivery

With no new production capacity, and if the current restrictions on imports of enrichment services from Russia and France were to continue, the current tight market supply for economically produced enrichment services would continue. Fortunately, there are a number of new facilities coming on line in that time frame and FPL expects that the

current restrictions will be lifted, at least partially if not totally. In addition, as with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible and anticipated within the lead time for constructing new nuclear units.

Fabrication Services Supply, Availability, and Delivery

The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

(i) Nuclear Fuel Reliability

The practice in the industry continues to be the scheduling of deliveries of fuel assemblies no later than 2 months prior to a refueling outage. In addition to allowing plant personnel proper time to stage the fuel to be reloaded ahead of the outage, this time also allows sufficient contingency in case of supply disruption during the fabrication process.

In addition, nuclear units have the capability to continue power production beyond the end of fuel life. This is done by slightly reducing core temperature at first, and reducing power level over time. Although power production is reduced during that period, the rate of power reduction is between 0.3% to 1.2% on the average per day, depending on the specific nuclear unit, or whether the unit is a boiling water reactor or a pressurized water reactor. In case of supply disruption, either in the nuclear fuel or other fuels supply chain, a nuclear unit can provide power for an extended time, beyond its initially scheduled outage.

3. Environmental Regulations

Turkey Point 6 & 7 will be required to obtain federal, state and regional environmental approvals and permits. The principal state environmental approval is the Site Certification under Florida's PPSA. Site Certification is a comprehensive review of environmental and land use aspects of Turkey Point 6 & 7 coordinated through the Florida Department of Environmental Protection (FDEP) and involving state and regional agencies with environmental and land use responsibility and those agencies potentially affected by the project. This includes, but is not limited to, the FDEP, Florida Department of Community Affairs, Florida Department of Transportation, Florida Fish and Wildlife Conservation Commission, South Florida Water Management District (SFWMD), and Miami-Dade County. This comprehensive environmental review evaluates the environmental controls for Turkey Point 6 & 7 and determines compliance with applicable state, regional, and local environmental standards. PPSA process ultimately leads to a comprehensive analysis and report by agencies that include Conditions of Certification that set forth environmental requirements. The PPSA also provides opportunity for public comment and public hearings regarding the land use and environmental aspects of Turkey Point 6 & 7. Decisions on the environmental aspects of Turkey Point 6 & 7 are made by the Secretary of FDEP or by the Governor and Cabinet acting as the Siting Board.

Turkey Point 6 & 7 will also require federal approval and federally delegated permits. Under the requirements of the Nuclear Regulatory Commission (NRC) an environmental review is conducted by the NRC staff in accordance with the National Environmental

Policy Act (NEPA). The review is conducted pursuant to 10 CFR Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Matters, Subpart A, National Environmental Policy Act, Regulations Implementing Section 102(2). These regulations specify the procedures and requirements for the NRC staff environmental review. After completing the initial review, the NRC issues a Draft Environmental Impact Statement for comment by the appropriate Federal, State, and local agencies as well as by the public. Afterwards, the agency issues a Final Environmental Impact Statement that addresses all comments received.

Other possible federal approvals include an approval by the U.S. Army Corp of Engineers (ACOE) for impacts to wetlands, a Prevention of Significant Deterioration (PSD)/Air Construction Permit by the FDEP for support facilities, and an Underground Injection Control (UIC) Permit from the FDEP.

The ACOE permit is required under Section 404 of the Clean Water Act and includes a demonstration that impacts to wetlands have been minimized and providing compensatory wetland mitigation. Turkey Point 6 & 7 will be designed to minimize impacts to wetlands and higher quality wetlands in the Everglades Mitigation Bank and other areas of the Turkey Point site are available for mitigation.

Under the federally authorized FDEP PSD program, support equipment for Turkey Point 6 & 7 such as emergency generators and cooling towers may be required to install Best Available Control Technology (BACT) and demonstrate that the project will comply with all air quality standards including those applicable to the PSD Class I Areas, which

includes the Everglades National Park. FDEP PSD rules are codified in Rule 62-212 Florida Administrative Code (F.A.C.). The support equipment for Turkey Point 6 & 7 will be designed to meet these requirements.

Turkey Point 6 & 7 may be required to obtain approval under FDEP's federally delegated UIC Program codified in Rule 62-528 F.A.C. in the event wastewater disposal is required. This process may consist of obtaining approval to perform an exploratory UIC well at the Turkey Point site and converting this to a test injection well after site-specific information is developed.

In the future, Turkey Point 6 & 7 will have economic advantages relative to fossil-fuel fired electrical generation alternatives regarding the potential regulation of CO_2. Although there are no current laws regulating emissions of CO_2, the future regulation of CO_2 is likely. Over the last several years, including this year, there have been federal legislative initiatives that have proposed different forms of CO_2 regulation. These initiatives have included both multi-sector and electric sector regulation with variable reductions of CO_2 emissions and cap-and-trade systems. Since electrical generation from nuclear technology does not emit CO_2 from operations, nuclear technology may be given preferential economic consideration over fossil-fuel fired generation. For example, the CO_2 emissions from a natural gas fired combined cycle plant are about 750 pounds per megawatt-hour (lb/MWh). For a 1,000 MW combined cycle plant, about 3 million tons per year of CO_2 will be emitted assuming a 90% capacity factor. In contrast, nuclear power generation has no associated CO_2 emissions, which could result in even lower

relative operational costs than natural gas combined cycle if CO_2 emissions are regulated for this type of fossil fuel plant.

While it is uncertain what type of legislation will ultimately be adopted, at the very least there would be no direct economic impact on nuclear technology compared to other generation options. However, costs for fossil fuel generation options, especially operational costs, will increase. Nuclear generation technology would not only have economic benefits if potential future CO_2 regulation were enacted but would have the significant environmental advantage of providing electric generation with no CO_2 emissions. For example, if a $10 per ton of CO_2 cost were placed on fossil fuel-fired generation, a 1,000 MW natural gas-fired combined cycle plant would have an additional operational cost of about $30,000,000 per year, assuming that the plant was not granted offsetting CO_2 allowances. The same amount of generation from nuclear units would not incur any cost from CO_2 emissions. In addition, since natural gas has the lowest amount of CO_2 emissions of all fossil fuel-fired generation, the regulation of CO_2 emissions would increase the pressure on the supply and cost of natural gas. While the extent of CO_2 costs and the influence on natural gas price is unknown, it is certain the costs associated with any regulation of CO_2 emissions and the resulting increase in natural gas costs would improve the relative economics of Turkey Point 6 & 7.

4. Transmission Facilities

a. Overview

The transmission facilities required to interconnect and integrate Turkey Point 6 & 7 were determined for the range of unit sizes; 1,100 and 1,520 MW, being considered for these units. This section discusses the transmission facilities associated with the two nuclear units.

With respect to the Turkey Point site, substantial new transmission facilities will be required in order to reliably interconnect and integrate the amounts of additional generation being projected at this site. The requirement to add major transmission facilities is the result of the need to deliver from 2,200 MW (from two 1,100 MW units) to 3,040 MW (from two 1,520 MW units) of new generation northward from the existing Turkey Point site in the southern most part of Miami-Dade County in order to serve FPL's load. This results in significant transmission facilities being required in the area from Turkey Point to central Miami-Dade County.

An additional factor that may affect the interconnection of Turkey Point 6 & 7 is the size of the generator selected. Turley Point 6 & 7 are each individually expected to be the single largest generating unit in Peninsular Florida. The size of the single largest generator in peninsular Florida is a significant factor because the transmission system must be capable of sustaining the loss of that generator without violating any North American Electric Reliability Corporation (NERC) or Florida Reliability Coordinating Council (FRCC) Reliability Standards. This requirement may have a direct impact on the

import capability from the Southeast Electric Reliability Council (SERC). The import capability into peninsular Florida from SERC is in large part determined based on the contingency of the instantaneous loss of the largest single generating unit in the FRCC, and the attendant sudden in-rush of power from the eastern U.S. interconnection reacting to replace such lost power source until more generation is dispatched in the FRCC region (within thirty minutes). Currently, based upon preliminary assessments by FPL, the sudden outage of a unit size of approximately 1,200 MW gross output or less should not adversely impact the FRCC's import capability from SERC in this time frame. If the unit size increases, more detailed studies will be needed to determine the specific impacts and mitigation alternatives.

b. Transmission Interconnection and Integration Assumptions

Turkey Point 6 & 7 will be connected to a new 500 kilovolt (kV) switchyard at the Turkey Point site because the existing Turkey Point 230 kV switchyard that serves the Turkey Point fossil units 1, 2, and 5 and nuclear units 3 and 4 is utilized at near full capacity. This new 500 kV switchyard will be connected to the FPL transmission system by two 500 kV transmission lines to the 500 kV section of the existing Levee substation in central Miami-Dade County which is located approximately 42 miles north of the Turkey Point site.

A new 230 kV line, approximately 13 miles long, also will be required from the Levee substation to the Gratigny substation located northeast of the Levee substation in central Miami-Dade County. The new switchyard at Turkey Point also will have a 230 kV

section. The new 500 and 230 kV sections will be connected via a 500/230 kV auto-transformer. The new 230 kV section will be connected to the Davis substation in southern Miami-Dade County utilizing an approximately 18 mile line which will be rerouted from the existing Turkey Point plant switchyard and rebuilt to larger capacity. Additionally, the 230 kV line rerouted from the existing Turkey Point plant switchyard will be replaced with a new 230 kV circuit from the switchyard to the Levee 230 kV substation. The aforementioned facilities are required for either the 1,100 MW units or the 1,520 MW units.

Finally, depending upon the amount of generation output of Turkey Point 6 & 7, certain other 230 and 138 kV upgrades to existing facilities are also required. A summary of the base and additional facilities is set forth below:

Base Facilities Required for Two 1,100 MW Net Units:

- The connection of Turkey Point 6 Generator Step-Up (GSU) transformer to the new Turkey Point switchyard, and attendant bus equipment
- The connection of Turkey Point 7 GSU transformer to the new Turkey Point switchyard, and attendant bus equipment
- The new Turkey Point 500/230 kV switchyard
- The two 500 kV transmission lines from the new Turkey Point switchyard to Levee Substation (Approximately 42 miles each)
- The 230 kV transmission line from the Levee Substation to the Gratigny Substation (Approximately 13 miles)

• Rebuild and rerouting of the existing Turkey Point-Davis #1 230 kV line to the new Turkey Point 230 kV switchyard

• Replace the line removed from the existing Turkey Point switchyard with a new line from the existing Turkey Point switchyard to Levee 230 kV (Approximately 42 miles)

• Upgrade Killian-Turkey Point 230 kV line

• Upgrade Turkey Point-Galloway Tap 230 kV line

• Upgrade Davis-Montgomery 138 kV line

• Upgrade Dadeland Tap-Snapper Creek 138 kV line

• Two 5-Ohm Reactors installed on the 230 kV side of the autotransformers at Levee (one per autotransformer)

• Two 5-Ohm Reactors installed on the 230 kV side of the autotransformers at Andytown (one per autotransformer)

• Two 5-Ohm Reactors installed on the 230 kV buses at the existing Turkey Point 230 kV switchyard.

Additional Facilities Required for Two 1,520 MW Net Units[3]

• Upgrade Killian-Miller 230 kV line

• Upgrade Mitchell-Court 138 kV line

• Upgrade Kendall-Suniland 138 kV line

• Upgrade Marion-Village Green 138 kV line

• Upgrade Marion-Montgomery 138 kV line

[3] These facilities do not include other potential facilities that may be required to mitigate the effect of the largest unit in the FRCC being larger than 1,200 MW gross output.

5. Nuclear Project Cost Estimate Range

In August of 2005, a joint study was published by the Tennessee Valley Authority (TVA) that provided a detailed assessment of new generation nuclear construction cost in the U.S.[4]. The study included contributions from key industry participants such as General Electric, Toshiba Corporation, Bechtel Corporation and Global Nuclear Fuels – America. The study provides the most comprehensive cost and schedule evaluation conducted in recent years, providing significant guidance into all facets of developing a cost and schedule estimate for a third generation nuclear project. While the study focused on proposed GE ABWR technology units to be built at TVA's Bellefonte Site, the information is representative of all third generation technologies because it is based on the construction methods and approaches that will be applied in new nuclear construction in the next decade. As such, the unit cost information (or the dollar-per-kilowatt value) provides a good indicator of unit costs of construction for other third generation designs.

FPL analyzed the TVA Study to obtain an understanding of the costs and schedules associated with the construction of a third generation nuclear unit, and adapted that information to reflect the issues and features of FPL's proposed project. By reviewing the study and making appropriate modifications, FPL was able to form the basis of a cost estimate range for new nuclear at FPL's Turkey Point Site. The cost estimate range created through this approach benefits from an industry effort to ensure all costs were captured and characterized.

[4] ABWR Cost/Schedule/COL Project at TVA's Bellefonte Site, DE-AI07-04ID14620, Tennessee Valley Authority, August 2005.

The following provides the cost estimate range for the Turkey Point 6 & 7 project in three stages. First, an overnight cost estimate range is developed using the TVA Study for comparison to the Economically Feasible capital cost range developed by the system cost based analysis. Next, a project schedule and associated expenditure plan is developed. Finally the Economically Feasible range is paired with the project schedule and expenditure plan to illustrate the annual expenditures and time related costs of the total project cost estimate range.

a) Development of the Overnight Cost Estimate Range

The overnight cost is an approximation of the expenditures necessary to build a specific project if all costs could be paid at one point in time. The overnight cost is a common way of comparing projects and leveraging cost information from other projects for application to a specific project. The TVA Study presents the overnight cost (in 2004$) for the construction of the power island, but does not address the site specific additional costs or time-related costs (such as escalation or interest) that are required to develop a complete cost perspective. FPL began with this information as our starting point in developing the cost estimate range.

Modifications were made to the base construction cost information provided in the TVA Study to adapt the information to an FPL specific cost estimate range. First, cost information was reviewed in line-item detail to ensure a complete scope of supply was included. This involved adding to the cost estimate to reflect site specific issues, such as

site preparation costs. Second, FPL developed estimates for certain Owner Cost areas (staffing, fuel, licensing, etc.) that were not addressed in the TVA Study. Then the basic assumptions developed in the TVA Study were reviewed. Once the scope was determined to be complete and the basic assumptions had been reviewed, the study costs were escalated to current year dollars (2007$) using appropriate construction cost indices to reflect the recent escalation seen on equipment, materials and labor related to power plant construction. Finally, several key areas were evaluated to determine their effect on the range of the estimate.

The areas that most influenced the cost estimate range are; 1) the recent and dramatic escalation of material, equipment and labor indices, 2) the items included in Owner's scope which can vary between designs, 3) the accuracy of the Owner' scope estimate and 4) the cost estimate range of the transmission integration proposed for the Turkey Point 6 & 7 project. Table V.A.5.1 provides a summary of the three cases developed for the overnight construction cost estimate range. A more detailed breakdown of costs is provided as an Exhibit to FPL Witness Scroggs' testimony.

Table V.A.5.1 - Overnight Construction Cost Estimate Range

Cost Category	Case A. TVA Study Modified for FPL Scope (2007$, $/kW)	Case B. Reduced Escalation, Owner's scope and Owner's costs (2007$, $/kW)	Case C. Increased Escalation and Owner's costs (2007$, $/kW)
Power Island Costs	$2,802	$2,444	$3,582
Owner's Costs	$579	$466	$717
Transmission Costs	$215	$198	$242
Total Overnight Costs (2007$, $/kW)	**$3,596**	**$3,108**	**$4,540**

Cost Escalation - Between 2004 and 2007, the two key materials escalators increased by 54% and 63%, respectively. Application of these escalators to the 2005 costs would represent the cost of material and equipment if procured at today's indexed costs. However, the procurement of these items will occur over the span of the construction. Application of the 2007 index may turn out to be a fair representation of the final cost, or it may over- or under-estimate the index at the time of procurement. Therefore, a reduced escalation is shown (representative of 27% and 32% for materials) in Case B as well as an increased escalation (representative of 81% and 95% for materials) and increased labor costs in Case C.

Owner's Scope – Various additional scope areas, such as cooling towers and auxiliary boilers, were identified. Discussions with various technology vendors have indicated that they are included in some vendor scope and excluded in others. These scope items were removed for Case B, and included in Cases A and C.

Owner's Cost Estimate – The Owner's cost could also vary based on the technology selected, as well as the conditions placed on the project through the final approvals phase by the Construction and Operating License or Site Certification process. A base cost estimate was developed for Case A, with a 10% reduction applied in Case B and a 10% premium applied in Case C to non-labor items, with a 30% premium applied to labor items.

Transmission Integration – The costs to integrate the selected technology will be the result of a series of transmission studies that are just now beginning. A cost estimate range has been developed, however, based on preliminary information covering the range of the technologies under consideration. The average of the cost estimate range is used in Case A, while the low end of the range is applied in Case B and the high end of the range in Case C.

b) Construction Schedule and Expenditure Plan

In order to estimate the time related costs of construction, a construction schedule and corresponding expenditure plan was developed. FPL consulted with each technology vendor to obtain input into the key milestones in the construction schedule and how

expenditures in the various categories were expected to be incurred. The resulting construction schedule and expenditure curves are representative and achievable with any of the technologies under consideration. Table V.A.5.2 presents the project milestones and the percentage of the overall project expenditure estimated for each year of the project. Optional activities are identified and included that allow completion of Unit 1 by 2018 and Unit 2 by 2020.

Table V.A.5.2 - Project Construction Schedule and Expenditure Plan

Project Year	Milestones	Annual Expenditure (%)	Cumulative Expenditure (%)
2008	Site Selection complete, COLA Preparation begins, Detailed Engineering begins Optional: Long Lead Procurement (Ultra-Heavy Forgings: Pressure Vessels, Steam Generator Vessels)	0.9%	0.9%
2009	COLA filed at NRC, SCA filed at FDEP, Application Review begins, Detailed Engineering Optional: Long Lead Procurement (Forgings, Training Simulator)	0.7%	1.6%
2010	Detailed Engineering and COLA review continues, SCA Hearing, Optional: Site clearing and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)	1.1%	2.7%
2011	COLA review complete, Detailed Engineering continues Optional: Site Preparation and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)	1.1%	3.7%
2012	ASLB convenes license hearing, Detailed Engineering continues, Non-nuclear Construction commences Optional: Site Preparation completes	5.5%	9.2%
2013	Safety Related (NRC jurisdictional) Construction commences, foundation for Unit 1 constructed	8.5%	17.7%
2014	Reactor Pressure Vessel and major components for Unit 1 delivered and set	11.0%	28.7%
2015	Unit 1 system construction, foundation for Unit 2 constructed	14.7%	43.4%
2016	Reactor Pressure Vessel and major components for Unit 2 delivered and set	17.3%	60.8%
2017	Unit 1 Substantial Completion and ITAAC Hearing	14.9%	75.7%
2018	Unit 1 Fuel Load, Testing and commercial operation.	14.9%	90.6%
2019	Unit 2 Substantial Completion and ITAAC Hearing	5.2%	95.8%
2020	Unit 2 Fuel Load, Testing and commercial operation.	4.2%	100.0%

* Optional activities needed to maintain earliest practical deployment schedule.

Based on the TVA Study, costs were grouped into four major cost categories. These categories are materials (11%), vendor equipment (46%), miscellaneous (11%) and labor/services (32%). This allows the overnight cost to be allocated among the four categories and each category escalated as appropriate over time.

c) Total Project Cost Estimate Range

The deployment schedule associated with a new nuclear project includes a licensing phase of up to 5 years, as well as a construction phase of 5 years. Therefore, the impacts of time through cost escalation and the accumulation of interest during construction is more significant on the final project costs than the impact would be to the shorter timeline for conventional fossil fuel deployment.

The rate at which the components of the project escalate over time is difficult to predict and is a source of uncertainty in the cost estimate. This is particularly challenging in the case of new nuclear, where the beginning of construction is over four years into the future. Couple this challenge with the fact that recent activity in the industrial sector has created significant near term increases to the cost of raw materials, fabrication and labor required to construct power plants. As with all market driven commodities the long term price trajectory may continue to rise, may moderate or could potentially decline. The impact of escalation on the project is further complicated by the fact that materials and equipment are procured in advance of when they are required in the construction period. FPL assumed that the escalation of materials, equipment and labor matched the pace of inflation in the long term in its construction cost estimate range development.

Interest charges that accumulate during construction also have an influence on overall project cost. The implementation of the Nuclear Cost Recovery Clause will reduce the impact of these interest charges. Table V.A.5.3 and Table V.A.5.4 provide summaries of the time related costs and the corresponding project cost estimate range.

Table V.A.5.3 - Project Construction Cost Estimate Range for 2,200 MW Project [1]

Cost Category	A. TVA Study Modified for FPL Scope ($/kW)	B. Reduced Escalation, Owner's scope and Owner's costs ($/kW)	C. Increased Escalation and Owner's costs ($/kW)
Total Overnight Costs (2007$, $/kW)	$3,596	$3,108	$4,540
Escalation @ 2.5%	$892	$764	$1,139
CCC [2] @ 11.04%	$1,837	$1,573	$2,345
Preconstruction Cost adjustment [3]	$47	$47	$47
Project Unit Cost (Year Spent $, $/kW)	**$6,700**	**$5,780**	**$8,071**
Total Cost for 2,200 MW Project (Year Spent $, $B)	**$14.0**	**$12.1**	**$17.8**

1) 2,200 MW is representative of a project deploying 2 Westinghouse AP 1000 units.
2) Carrying Charges of Construction (CCC)
3) Preconstruction Cost Adjustment separates costs included in the preconstruction phase totaling $191 $/kW in the TVA Study, and scales them for the 2,200 MW project. Adjustment = $191 * (1,371/1,100 - 1).

Table V.A.5.4 - Project Construction Cost Estimate Range for 3,040 MW Project [1]

Cost Category	A. TVA Study Modified for FPL Scope ($/kW)	B. Reduced Escalation, Owner's scope and Owner's costs ($/kW)	C. Increased Escalation and Owner's costs ($/kW)
Total Overnight Costs (2007$, $/kW)	$3,596	$3,108	$4,540
Escalation @ 2.5%	$892	$764	$1,139
CCC @ 11.04%	$1,837	$1,573	$2,345
Preconstruction Cost adjustment [3]	($19)	($19)	($19)
Project Unit Cost (Year Spent $, $/kW)	$6,306	$5,426	$8,005
Total Cost for 3,040 MW Project (Year Spent $, $B)	**$19.2**	**$16.5**	**$24.3**

1) 3,040 MW is representative of a project deploying 2 General Electric ESBWR units.
2) Carrying Charges of Construction (CCC)
3) Preconstruction Cost Adjustment separates costs included in the preconstruction phase totaling $191 $/kW in the TVA Study, and scales them for the 3,040 MW project. Adjustment = $191 * (1,371/1,520-1).

d) Cost Escalation Sensitivity

As previously discussed, the uncertainty of the final cost of material, equipment and labor has a significant impact on the cost estimate range. The initial cases addressed the gross impact of cost escalation as it relates to the overnight cost estimate. The time related contribution of escalation to uncertainty can be estimated by a simple sensitivity.

An increase of 1% (from 2.5% to 3.5%) to all escalators would increase the contribution of escalation to total project costs from $892 MM to $1,307 MM, an increase of $415 MM for Case A of the Cost Estimate Range for a 2,200 MW project. A decrease of 1%

to all escalators would reduce the contribution of escalation from $892 MM to $512 MM, a decrease of $380 MM for Case A, 2,200 MW project.

6. Financial and Economic Data

The financial and economic assumptions used in FPL's IRP process and in all analyses conducted that led to the selection of Turkey Point 6 & 7 are presented in Appendix G.

VI. GEOGRAPHIC OR LOCATIONAL PREFERENCE

The siting of nuclear generation requires a comprehensive and thorough assessment of a wide range of criteria. FPL's process was guided by the Electric Power Research Institute (EPRI) Siting Guide, NRC site suitability requirements, and the need to comply with National Environmental Policy Act (NEPA) requirements to consider alternative sites.

Twenty three candidate sites were identified and evaluated. Criteria such as water supply, regional population, transmission access, and ecology/environmental factors were developed and given weighting factors by a panel of experts. Through a series of screening steps, the list of candidate sites was narrowed, increasing the level of detail at each screening step. In the final analysis, the Turkey Point site rated highest among the candidate sites. Turkey Point scored high in many areas because of the supporting infrastructure that exists at or near the site. This is consistent with NRC findings recognizing that incremental generation at existing sites has specific attributes that generally recommend these projects above projects on previously undeveloped sites.

From a system perspective, the high rating of Turkey Point as a site for incremental nuclear generation makes sense. The site has 11,000 acres that would allow development of additional generation with limited impact on surrounding areas. Transmission infrastructure to deliver the new capacity to the grid is available with modest improvements, particularly in comparison to undeveloped sites. Additionally, location of the generation near the load center reduces the amount of transmission loss and increases the overall system efficiency. Location of new generation that is not dependent on contemporaneous fuel delivery for the production of electricity at the southern end of the FPL system provides significant system reliability advantages in the event of fuel supply disruptions.

The unique combination of these beneficial characteristics, make the Turkey Point site the most favorable location for the addition of the new nuclear generating units in the FPL system.

VII. MAJOR AVAILABLE GENERATING ALTERNATIVES EVALUATED

A. NUCLEAR DESIGN CHOICES

1. Design Choices Background and Evaluation

The nuclear power industry commonly recognizes several generations of reactors: the first generation of prototype reactors developed in the 1950s and 1960s; the second generation of reactors typified by the current U.S. fleet and most of the nuclear power plants in operation today; and the third generation, which are the advanced reactors

recognized as the latest technology for commercial power plants in the industry. The third generation consists of improved light-water reactors offering enhanced safety and economy, and is the focus of FPL's review process.

FPL conducted an engineering evaluation of current design options available for new nuclear generation in mid-2006. This survey canvassed thirteen known designs, screening the list of candidates to five principal designs that were considered in detail. The initial screening selection was made based on the current commercial offerings and licensing activities at the NRC. These five principal designs are summarized in Table VII.A.1.

Table VII.A.1 Nuclear Designs Evaluated

Supplier	Reactor Model	MWe (Type) *	NRC Status
Areva	US EPR	1573 (PWR)	Application late 2007
Mitsubishi NES	APWR	1560 (PWR)	Application late 2007
General Electric	ABWR	1350 (BWR)	Certified Design
General Electric	ESBWR †	1520 (BWR)	Application in Review
Westinghouse	AP1000 †	1100 (PWR)	Certified Design

*) PWR = Pressurized Water Reactor; BWR = Boiling Water Reactor.[5]

†) Technologies designated as reference designs in the NuStart Consortium COLA projects

[5] Pressurized Water Reactors (PWRs) have three distinct, separate loops of water. In the primary system, the uranium fuel heats water through a fission process. This hot water is circulated through thousands of tubes in a steam generator. Here, a separate supply of water flows over the hot tubes containing the water that has been heated by the reactor. This secondary water turns into steam, which turns the fan-like blades of a turbine. As the generator turbine spins, it produces electricity. The non-radioactive steam flows through tubes of cooling water in a condenser and is turned back into water by a third system that circulates cooling water around the tubes.

In a Boiling Water Reactor (BWR), heat from nuclear fission boils water in the upper portion of the reactor vessel to form steam, eliminating the need for steam generators. From there, the steam flows to the turbine and turns it to make electricity. The spent steam is condensed back into water for recirculation to the reactor vessel and the process is repeated.

A Request for Information (RFI) was sent to the four companies to provide documentation on all five designs. The review is summarized in Appendix J of the Need Study Document. Based on the review of the information, FPL concluded that all five designs were technically acceptable. However, there are significant differences in the status of the deployment of these new technologies in the U.S.

2. Technology Summary

Third generation nuclear technologies can be broadly categorized by how the designs were developed and the type of safety strategy they employ to protect the plant in the event of a design basis accident. "Evolutionary" designs, such as the EPR, APWR, and ABWR, are designs that have evolved from similar generation two designs. They employ an "active" safety strategy wherein action is required by operators and associated systems to protect the plant. Alternatively, "non-evolutionary" reactors with inherent safety features contain design elements that are new. These technologies, ESBWR and AP 1000, employ a "passive" safety strategy wherein the design does not require operator action to protect the plant. The following is a summary of the designs considered and the deployment status of these designs. The capacity (MW) values listed for each design are all net MW.

Areva EPR – 1,573 megawatts

Areva's model is an evolutionary pressurized water reactor with active safety features. The design is based on an original Westinghouse PWR design. Design features include four 100-percent capacity trains, or sub-systems, each of them capable of performing the

entire safety function on its own; a double-walled containment; and a "core catcher" for containment and cooling of core materials in case of reactor vessel failure. In the event of a power blackout, diesel generators, housed in two separate buildings, supply electricity to the safety functions.

Areva is developing the Design Certification Application for filing with the NRC in early 2008, with a targeted completion by mid-2011. No models are operating, but a similar design is under construction in Finland with plans for others in France. Four industry groups are preparing COLA applications that will reference the EPR design.

Mitsubishi APWR (Japan) – 1,560 megawatts

Mitsubishi's model is an evolutionary pressurized water reactor with active safety features. The design is based on an original Westinghouse PWR design. The design includes high-performance steam generators, a neutron reflector around the core to increase fuel economy, redundant core cooling systems, refueling water storage inside the containment building, and fully digital instrumentation and control systems.

Mitsubishi is developing the Design Certification Application for filing with the NRC in early 2008, with a targeted completion by mid-2011. No models are operating, but a unit of similar design is under construction in Japan. One company (Texas Utilities) is preparing COLA applications that will reference the APWR design.

General Electric ABWR - 1,350 megawatts

General Electric's model is an evolutionary boiling water reactor with active safety features. The design incorporates features of BWR designs in Europe, Japan, and the U.S. using improved electronics, computer, turbine, and fuel technology. The design is expected to increase plant availability, operating capacity, safety, and reliability. The design also includes safety enhancements such as protection against over-pressurizing containment, passive core debris flooding capability, an independent water makeup system, three emergency diesels, and a combustion turbine as an alternate power source.

The original GE-ABWR design was certified by the NRC and built only in Asia. Upgrades and modifications under consideration for the U.S. market will require an amendment to the original design certification. One U.S. company, NRG Energy, is preparing a COLA for this model. The ABWR, while certified with operating reactors in place, is not expected to be as cost-effective as GE's larger ESBWR due to economies of scale.

General Electric ESBWR - 1,520 megawatts

The ESBWR design is a non-evolutionary boiling water reactor with passive safety features. The design uses features of the certified advanced boiling water reactor. A passive safety system is a key feature of this design. Natural circulation replaces recirculation pumps. The plant's simplified design means that operating and maintenance staff requirements are reduced; and low-level waste generation is reduced. Fewer active

components (active safety systems) reduce the maintenance and online surveillance requirements. According to General Electric, reductions in building volumes and required manufactured components shorten the length of time needed for ESBWR construction, resulting in improved cost-effectiveness.

General Electric filed the Design Certification Application with the NRC in 2005 and is currently responding to requests for additional information to support the NRC review with a targeted completion by mid-2010. No models of this design are operating. Two utilities will submit three COLAs referencing this design in early 2008.

The ESBWR is one of two designs that are to be designated as Reference COLAs. The Reference COLAs have been developed and supported by the NuStart Consortium and will serve as a base document which can be replicated by other NuStart members. As a member of NuStart, FPL would be able to leverage the work accomplished by the earlier filings, and address issues identified in these reviews.

Westinghouse AP1000 – 1,100 megawatts

The AP 1000 is a non-evolutionary pressurized water reactor with passive safety features. It is design-certified, but no models are operating or under construction. Five U.S. utilities are preparing combined operating license applications for this model. The AP1000 is a larger version of the previously approved AP600 design, using a longer reactor vessel to accommodate longer fuel, and includes larger steam generators and a larger pressurizer. Compared to today's plants, the AP 1000 will need 50% less building volume, 50% fewer valves, 80% fewer pipes, 35% fewer large pumps, and 70% less

control cable. Therefore, the actions required by the plant operator are reduced. Westinghouse affirms that modular construction will reduce construction time to 36 months and lead to savings in plant costs.

The design received initial Certification in 2006. A Design Certification Amendment is currently being developed that will modify specific aspects of the design in response to NRC requests for additional information with a targeted completion by 2009. No models of this design are operating; however, this design is the most referenced in current COLA activity. Six utilities will submit COLAs referencing this design by 2009.

The AP 1000 is the second design that will be designated as a Reference COLA. As a member of NuStart, FPL would also be able to benefit from the work accomplished by the earlier filings.

3. Technological Improvement in the Future

Existing technologies, such as natural gas CC or wind power, often demonstrate improvements in efficiency, capital cost, or both. The rate at which these technologies improve is generally related to the rate at which they become adopted into the mainstream of power generation applications. The efficiency improvements and cost reductions seen in gas turbine- and wind turbine-based generation over the last thirty years has been dramatic, but is now stabilizing as these technologies mature.

Emerging technologies are those technologies which do not currently provide a significant portion of electrical generation, but hold some potential for doing so in the future. Technologies such as IGCC or ocean current generation qualify as emerging generation technologies.

FPL continues to track the technological development of existing and emerging generation technologies, developing a view of what is currently achievable and what may be achievable in the future. Many of these technologies have potential, but are in early stages of development where the true long term cost and reliability has yet to be proven. FPL does not anticipate that the improvements to existing or emerging technologies will be sufficient in the next ten to twenty years to cast doubt on the pursuit of new nuclear technology today. Moreover, FPL evaluates third generation nuclear as having the best potential for improvement among existing technologies and therefore offers the largest potential for benefiting FPL's customers.

B. NON-NUCLEAR TECHNOLOGIES

1. General Process

The previous section discussed information considered as part of FPL's decision to further evaluate the addition of new nuclear generating units that could be brought in-service starting in 2018. However, in order to fully evaluate the decision to add new nuclear generating units to FPL's system, it was necessary to also analyze non-nuclear choices that FPL would likely choose to build if the new Turkey Point 6 & 7 nuclear units were not built.

The process FPL used to perform this analysis involved the selection of gas-fired and coal-fired units that are representative of what FPL might build if Turkey Point 6 & 7 were not built, and then combining these units into generic, representative alternate resource plans that could be compared to a resource plan featuring Turkey Point 6 & 7. The resource plan that included Turkey Point 6 & 7 was designated as the Plan with Nuclear. The two alternate resource plans were designated as the Plan without Nuclear – CC and the Plan without Nuclear - IGCC.

2. Gas-Fired Technologies Selected

In the process of selecting gas-fired CC units for this analysis, FPL decided that the most representative type of CC unit for the near-term would be a unit similar to those recently approved for construction at the West County Energy Center (WCEC) site. These CC units are 3x1 G Technology (G) machines with a summer net capacity rating of 1,219 MW. These 3x1 G machines were used as the basis for the near-term CC capacity options that were used in all three resource plans for the years 2012 through 2016 and in place of the Turkey Point 6 & 7 units in the Plan without Nuclear - CC. In all three plans a 2x1 Class G CC unit was assumed to be added in 2017. For the 2021 – on time period, smaller 2x1 F Technology (F) CC machines with a summer capacity rating of 553 MW were used as filler units in all three resource plans. All of the three resource plans also included the proposed 414 MW capacity uprates to FPL's four existing nuclear units, the 1,899 MW of assumed DSM additions from August 2006 through August 2020, and the assumed 287 MW of renewable energy purchases. All of these resource additions have been previously discussed.

In the Plan without Nuclear – CC, one 1,219 MW CC is assumed to be added in 2018 and another 1,219 MW CC is assumed to be added in 2020.

3. Coal-Fired Technologies Selected

For purposes of the analyses conducted in support of this filing, FPL assumed that IGCC units would be used as the coal-based technology that would be included in the coal-based alternate resource plan.

In the Plan without Nuclear – IGCC, it is assumed that one pair of 600 MW IGCC units would be added in 2018 and a second pair of these units is added in 2020.

C. Analysis Approach

1. Economic Analysis

a) Development of Resource Plans to be Analyzed

FPL selected new nuclear units at FPL's existing Turkey Point site as potentially the best economic choice to meet future capacity needs, to promote fuel diversity, and to lower CO_2 emissions on FPL's system starting in 2018. For analysis purposes, specific in-service dates are required and FPL's analyses assume that the two nuclear units will come in-service in June 2018 and June 2020, respectively. These dates represent the earliest practical deployment schedule for new nuclear units to be added to FPL's system. However, in order to fully evaluate that selection, FPL needed to develop a long-term resource plan that could be used to analyze the long-term system impacts of the addition of the new nuclear units. This resource plan is referred to in this filing as the Plan with

Nuclear. In addition, FPL needed to develop alternate resource plans that did not include new nuclear unit additions that could be used in comparative analyses with the nuclear-based resource plan. These are referred to in this filing, respectively, as the Plan without Nuclear – CC in which comparably sized CC capacity is added in 2018 and 2020, and the Plan without Nuclear – IGCC in which comparably sized IGCC capacity is added in 2018 and 2020.

In developing these resource plans, FPL had several criteria. First, each resource plan chosen must meet FPL's system reliability criteria for all years, especially the reliability criterion that currently drives FPL's resource needs, the 20% Summer reserve margin criterion that FPL currently believes is necessary to provide reliable service. This ensures that the resource plans will be both meaningful and comparable in regard to system reliability. Second, the cost and performance assumptions (heat rate, availability, etc.) for the generating units that are included in each resource plan should be current assumptions of comparable confidence levels to the extent possible. Third, the resource plans should focus as much as possible on the assumed in-service or decision years in question, 2018 - 2020, and should seek to minimize as much as possible influencing the cost and other system impact differences between resource plans that could be caused by the addition of units in other years.

Therefore, the three resource plans are identical through 2017 and all of the plans meet all of the criteria discussed above. These three resource plans are presented in Table VII.C.1.a.1.

Table VII.C.1.a.1

The Three Resource Plans Utilized in the Analyses

Plan with Nuclear	2011	2012	2013	2014	2015	2016	2017	2018
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	Turkey Point 6
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,100
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	5,983
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	22.9%

Plan without Nuclear - CC	2011	2012	2013	2014	2015	2016	2017	2018
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	3x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,219
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,102
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.4%

Plan without Nuclear - IGCC	2011	2012	2013	2014	2015	2016	2017	2018
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	2 - IGCC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,200
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,083
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.3%

Notes: - assumes extension of DSM implementation through 2020 at currently planned implementation rates for 2012 - 2014 time frame
- assumes extension of three expiring waste-to-energy purchases and addition of three renewable energy capacity purchases totaling 287 MW
- assumes no peak load or annual energy growth after 2040

* One of the four nuclear uprates is scheduled to occur in Dec 2011, one in May 2012, one in June 2012, and one in Dec 2012. Because the 2011 uprate will occur after the Summer calculation purposes the first three uprates are accounted for starting with the 2012 Summer reserve margin calculation. The fourth uprate is accounted for starting with the 2013 S

The assumption of gas-fired combined cycle units for all three plans in the 2011 – 2017 time period does not represent definitive resource decisions for FPL for those years. Resource plans are dynamic and decisions for those years have not yet been made. As those decisions are eventually made, a variety of resource options will be evaluated including additional DSM, renewable energy, power purchases, and gas-fired and coal-fired generating units.

For purposes of analysis, FPL had to make certain assumptions regarding the three multi-year resource plans and how future capacity needs prior to the 2018 – 2020 time period would be met. For these analyses, an identical assumption of combined cycle units for each of the three resource plans was selected. It is important to note that whichever resource options are eventually selected for 2011 – 2017, these decisions would have been made for any of the three resource plans analyzed for this filing.

b) Development of Fuel Cost and Environmental Compliance Cost Forecasts to be Used in the Analyses

When comparing generating technologies that burn different fuels, i.e., nuclear units, natural gas units, and coal units, it is appropriate that different fuel cost forecasts be utilized in order to determine the relative economics between the technologies. In this way the analyses can address the uncertainty that exists regarding future fuel costs, particularly in regard to the future cost differential between natural gas, coal, and nuclear fuel.

Although there are virtually an inexhaustible number of possible future fuel cost outcomes, a small number of forecasts that effectively reflect a reasonable range of future fuel costs are sufficient to conduct a meaningful economic analysis. Consequently, three different fossil fuel cost forecasts that reflect a reasonable range of future fossil fuel costs were developed and used in these analyses. These three fossil fuel cost forecasts are referred to as the High Gas Cost forecast, the Medium Gas Cost forecast, and the Low Gas Cost forecast. In addition, forecasted nuclear fuel costs were also developed and used in the analyses. All of these fuel cost forecasts are provided in Appendix E of this document.

Just as there is uncertainty in regard to the future cost of fuels, there is uncertainty in regard to the future environmental regulations and the costs of complying with those regulations. When comparing generating technologies that burn different fuels and have different emission profiles, such as is the case with nuclear, natural gas, and coal units, the future environmental regulations will determine how the differences in the emission profiles of the generating technologies will affect the relative cost of the technologies. Therefore, FPL found it appropriate to conduct its analyses using different environmental compliance cost forecasts to address the uncertainty that exists regarding future environmental regulations and the costs of complying with those regulations. These environmental compliance cost forecasts addressed four emissions: sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and CO_2.

As is the case with future fuel costs, there are also a large number of future environmental cost outcomes. However, a small number of forecasts that effectively reflect a reasonable range of future environmental compliance costs are sufficient to conduct a meaningful economic analysis. Therefore, four different environmental compliance cost forecasts that reflect a reasonable range of future environmental compliance costs were developed and used in these analyses. These four environmental compliance cost forecasts, referred to as Env I through Env IV, are provided in Appendix F of this document.

FPL initially combined the three fuel cost forecasts with the four environmental compliance cost forecasts to develop a total of 12 initial scenarios of forecasted fuel costs and environmental compliance costs. Then, after examining the different scenarios, FPL removed from further consideration three scenarios comprised of a low natural gas price forecast and medium-to-high compliance costs for CO_2 based on FPL's belief that medium-to-high compliance costs for CO_2 will result in upward pressure on natural gas prices. In other words, an assumption of medium-to-high environmental compliance costs for CO_2 is incompatible with an assumption of low natural gas prices. Each of the remaining 9 scenarios was then utilized separately in both the economic and non-economic analyses of the three resource plans.

Because the fuel cost forecasts are designated as High Gas Cost, Medium Gas Cost, and Low Gas Cost, and the environmental compliance cost forecasts are designated as Env I through Env IV, the 9 scenarios of fuel costs and environmental compliance costs are

designated as High Gas Cost Env I through High Gas Cost Env IV, Medium Gas Cost Env I through Medium Gas Cost Env IV, and Low Gas Cost Env I. (The three eliminated scenarios are Low Gas Cost Env II, Low Gas Cost Env III, and Low Gas Cost Env IV.)

c) Two Steps in the Economic Analyses

The economic analysis approach utilized for analyzing the addition of two new nuclear units to FPL's system consisted of two steps. In the first step, the cumulative present value of revenue requirements (CPVRR) in 2007$ for the Plan with Nuclear, the Plan without Nuclear – CC, and the Plan without Nuclear – IGCC were developed and compared. The analysis approach used in this step was virtually identical to the approach used in FPL's most recent Need filings. However, there are two differences in this analysis approach step as applied for Turkey Point 6 & 7 when compared to this approach as utilized in the most recent Need filings.

The first difference is that the cost of transmission losses for the resource plans is not included because there are no known sites for the CC and IGCC units selected to compete with the new nuclear units in 2018 and 2020. Consequently, it is not possible to calculate losses for the two alternate Plans without Nuclear.

The second difference in the economic analysis approach step that developed CPVRR costs for the resource plans is that no generation or transmission capital costs associated with Turkey Point 6 & 7 were included in the analysis. The reason for this is that FPL

does not believe it is currently possible to develop a precise projection of the capital costs associated with new nuclear units with in-service dates of 2018 – on.

Consequently, FPL's economic analysis approach normally used to evaluate generation options has been modified to include a second economic analysis step.

The second step in the economic analysis consists of taking the CPVRR cost differential between the Plan with Nuclear and one of the Plans without Nuclear for a given scenario of fuel costs and environmental compliance costs, then using this differential to determine the capital cost (generation and transmission) of the two nuclear units that could be spent so that the CPVRR costs for the two plans would be identical. In other words, a "breakeven" capital cost for the nuclear units is determined for each of the 9 scenarios versus both CC and IGCC capacity that might otherwise be added. These breakeven costs are presented in terms of $/kW in 2007$.

In summary, the objective of this two-step economic analysis is to allow FPL to determine a breakeven capital cost range of potential generation and transmission capital costs for Turkey Point 6 & 7 in which these new nuclear units are projected to be equal to the cost of alternative, non-nuclear generating technologies. This cost-effective range of potential generation and transmission capital costs were then compared to FPL's current capital cost estimate for Turkey Point 6 & 7 in terms of $/kW in 2007$.

2. Non-Economic Analysis

In addition to economic analyses of the two resource plans, non-economic analyses were also performed. These analyses focused on two different perspectives of the FPL system: projections of FPL's annual system fuel mix and projections of FPL's annual system CO_2 emissions. In regard to FPL's annual system fuel mix, projections of the percentages of total annual energy output that is provided by coal/petroleum coke, natural gas, oil, nuclear, and "other" (i.e., primarily purchases from waste-to-energy facilities) for each of the three resource plans for the 2018 – 2021 time period were developed. The years 2018 – 2021 were chosen to address the range of years from the year when the first new nuclear unit is projected to go in-service (2018) through the first year in which both new nuclear units are in-service for a full year (2021).

In regard to FPL's annual system CO_2 emissions, projections of system CO_2 emissions for each of the three resource plans for the 2007 – 2021 time period were developed.

D. Results of the Analysis

1. Economic Analysis Results

Table VII.D.1.1 presents the economic evaluation results for the three resource plans for one fuel cost and environmental compliance cost scenario, the High Gas Cost Env I scenario, using the same presentation format that FPL used in its most recent Need filings. The values presented are cumulative present value of revenue requirements (CPVRR) for the time period 2007 through 2060 in 2007$.

In this table, the costs for the Generation System are broken out into two categories; Fixed Costs and Variable Costs, and a list of what costs are included in these two categories is shown.

Table VII.D.1.1

Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario:
(millions, CPVRR, 2007$, 2007 - 2060)

Fuel Cost Forecast = High Gas Cost
Environmental Compliance Cost Forecast = Env I

	(1)	(2)	(3) = (1) + (2)	(4)
	System Costs			Difference from Lowest
Resource Plan	Fixed Costs *	Variable Costs **	Total Costs	Cost Plan
Plan with Nuclear	22,676	198,228	220,904	0
Plan without Nuclear - CC	23,684	209,368	233,052	12,148
Plan without Nuclear - IGCC	30,171	204,002	234,173	13,269

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation. (Note that nuclear generation and transmission capital costs are assumed to be zero in this analysis.)

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

Although these results are valid for only one of the 9 fuel cost and environmental compliance cost scenarios, these values do indicate two cost results that will hold true for all of the analyses involving the remaining 8 scenarios.

The first such result is that the Plan with Nuclear has lower fixed costs, lower variable costs, and lower total costs than does either of the two alternate plans without Nuclear. This is expected because, as previously discussed, the Plan with Nuclear contains no capital costs for the two new nuclear units. Therefore, the Plan with Nuclear is expected to have lower fixed costs. Nuclear units also have lower energy costs than either CC or IGCC units so a resource plan containing new nuclear units is expected to have lower variable costs than a comparable plan without nuclear units. The second such result is that the System Fixed Costs for a specific plan are established solely by the generation capacity additions in that resource plan and will not change as fuel costs and/or environmental compliance costs change. Therefore, the System Fixed Costs shown in this document for the three resource plans will remain unchanged for all 9 fuel cost and environmental compliance cost scenarios while the System Variable Costs will change from one scenario to another.

Table VII.D.1.2 presents the total costs for the three resource plans for all 9 of these scenarios. In addition, the total cost differences between the three plans are also shown. The total cost results shown on this document for the High Gas Cost Env I scenario for the three resource plans are the same as the total cost results presented for the resource plans in Table VII.D.1.1.

Table VII.D.1.2

Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

(millions, CPVRR, 2007$, 2007 - 2060)

(1)	(2)	(3)	(4)	(5)	(6) = (3) - (4)	(7) = (3) - (5)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans			Total Cost Difference Plan with Nuclear - Plan without Nuclear - CC	Total Cost Difference Plan with Nuclear - Plan without Nuclear - IGCC
		Plan with Nuclear	Plan without Nuclear - CC	Plan without Nuclear - IGCC		
High Gas Cost	Env I	220,904	233,052	234,173	(12,148)	(13,269)
High Gas Cost	Env II	233,322	246,544	249,099	(13,222)	(15,777)
High Gas Cost	Env III	242,937	256,648	259,966	(13,711)	(17,029)
High Gas Cost	Env IV	252,296	266,663	270,943	(14,367)	(18,647)
Medium Gas Cost	Env I	170,391	179,356	182,648	(8,965)	(12,257)
Medium Gas Cost	Env II	182,700	192,694	197,474	(9,994)	(14,774)
Medium Gas Cost	Env III	192,190	202,702	208,218	(10,512)	(16,028)
Medium Gas Cost	Env IV	201,428	212,635	219,099	(11,207)	(17,671)
Low Gas Cost	Env I	129,850	136,175	141,533	(6,325)	(11,683)

Note: A negative value in Columns (6) and/or (7) indicates that the Plan with Nuclear is less expensive than the comparative Plan without Nuclear (CC or IGCC). Conversely, a positive value in Columns (6) and/or (7) indicates that the Plan with Nuclear is more expensive than the comparative Plan without Nuclear (CC or IGCC).

The results from Table VII.D.1.2 show that, as expected for the first step of the economic analysis, the Plan with Nuclear has a lower CPVRR cost under all scenarios of fuel cost forecasts and environmental compliance cost forecasts for the reasons discussed above.

Table VII.D.1.2 provides a significant amount of cost and cost differential data for the three resource plans. In order to simplify this comparison of costs for the plans, the cost differentials for the plans that are shown in Table VII.D.1.2 are reorganized and presented again in matrix format in Table VII.D.1.3.

Table VII.D.1.3

Economic Analysis Results: Matrix of Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

Plan with Nuclear - Plan without Nuclear-CC

Total Cost Differentials
(millions, CPVRR, 2007$, 2007 - 2060)

Fuel Cost Forecasts

		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental Compliance Cost Forecasts	Env I	(12,148)	(8,965)	(6,325)
	Env II	(13,222)	(9,994)	
	Env III	(13,711)	(10,512)	
	Env IV	(14,367)	(11,207)	

Plan with Nuclear - Plan without Nuclear-IGCC

Total Cost Differentials
(millions, CPVRR, 2007$, 2007 - 2060)

Fuel Cost Forecasts

		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental Compliance Cost Forecasts	Env I	(13,269)	(12,257)	(11,683)
	Env II	(15,777)	(14,774)	
	Env III	(17,029)	(16,028)	
	Env IV	(18,647)	(17,671)	

Note: A negative value indicates that the Plan with Nuclear is less expensive than the comparative Plan without Nuclear (CC or IGCC). Conversely, a positive value indicates that the Plan with Nuclear is more expensive than the comparative Plan without Nuclear (CC or IGCC).

The results of the first step in the economic analysis presented above show the expected result: that the Plan with Nuclear (that assumes no capital costs for the new nuclear units) has a lower CPVRR cost for all scenarios than do either of the Plans without Nuclear. Second, the CPVRR cost advantage of the Plan with Nuclear versus the Plan without Nuclear – CC is greater on the left side of the matrix presented due to the higher gas cost forecasts on the left hand side. Also, the CPVRR cost advantage of the Plan with Nuclear versus either of the Plans without Nuclear is greater in the bottom rows of the matrix due to the higher environmental compliance costs in those rows and the fact that operation of the new nuclear units will result in essentially no SO_2, NO_x, Hg, or CO_2 emissions.

These results are then used to determine the breakeven capital costs of the new nuclear units in the second step of the economic analysis.

Having determined the CPVRR cost differentials between the three plans for all 9 scenarios in the first step of the economic analysis, FPL then developed an estimated projection of the recovery schedule of nuclear capital costs prior to the in-service dates of Turkey Point 6 & 7. This information, when combined with the traditional recovery of annual revenue requirements after the in-service dates for the two nuclear units, allows the calculation of how a $1/kW capital cost in 2007$ translates into a CPVRR capital cost. Appendix H presents this projection and CPVRR calculation. This calculation shows that a new nuclear unit cost of $1/kW in 2007$ equates to $1.973 million CPVRR in 2007$.

Using the CPVRR cost differentials for each scenario presented in Table VII.D.1.3, and the above-mentioned $1.973 million CPVRR capital cost calculated in Appendix H, a

nuclear capital breakeven cost was calculated for each of the 9 scenarios versus the alternate Plans without Nuclear. The nuclear breakeven capital costs are presented in Table VII.D.1.4.

Table VII.D.1.4

Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios

Plan with Nuclear vs. Plan without Nuclear-CC

Breakeven Nuclear Capital Costs
($/kw in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
Env I	6,157	4,543	3,206
Env II	6,701	5,065	
Env III	6,949	5,327	
Env IV	7,281	5,680	

Plan with Nuclear vs. Plan without Nuclear-IGCC

Breakeven Nuclear Capital Costs
($/kw in 2007$)

Environmental Compliance Cost Forecasts	Fuel Cost Forecasts: High Gas Cost	Medium Gas Cost	Low Gas Cost
Env I	6,725	6,212	5,921
Env II	7,996	7,487	
Env III	8,630	8,123	
Env IV	9,450	8,956	

These breakeven capital costs range from $3,206/kW in 2007$ to $7,281/kW in 2007$ versus the Plan without Nuclear – CC, and ranged from $5,921/kW in 2007$ to $9,450/kW in 2007$ versus the Plan without Nuclear - IGCC. As expected from the CPVRR cost differences presented in Table VII.D.1.3, the higher breakeven costs were calculated for the scenarios on the left hand side versus the Plan without Nuclear – CC due to higher gas costs and in the bottom rows of the matrix versus both Plans without Nuclear due to higher environmental compliance costs.

The breakeven nuclear capital cost ranges show the current projection for the range of nuclear capital costs that would allow the addition of two new nuclear units, one in 2018 and one in 2020, to yield identical CPVRR system costs over a 40-year period compared to an equivalent amount of gas-fired or coal-fired capacity added in the same years.

These two breakeven nuclear capital cost ranges are generally higher than FPL's current non-binding cost estimate range for new nuclear units i.e., the non-binding cost estimate of $3,108/kW to $4,540/kW in 2007$ presented in section V.A.5. Consequently, FPL believes it is reasonable to begin making these expenditures in order to continue to obtain refined cost and performance projections for new nuclear units; i.e., to retain the options of adding new nuclear generating capacity, Turkey Point 6 & 7, by the 2018-2020 time period.

2. Non-Economic Analysis Results

The first non-economic analysis focused on the projected annual system fuel mixes for the three resource plans for the 2018 – 2021 time period in order to determine the impact

of the two new nuclear units on FPL system fuel diversity. Table VII.D.2.1 provides the results of these analyses for two scenarios, High Gas Cost Env III and Low Gas Cost Env I, selected to represent a range of fuel cost forecasts and environmental compliance cost forecast scenarios.

Table VII.D.2.1

Non-Economic Analysis Results: FPL System Fuel Mix Projections by Plan

Scenario: High Gas Cost Env III

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2018	7.3%	69.6%	2.0%	20.8%	0.3%	7.3%	73.3%	1.8%	17.3%	0.3%	10.6%	69.7%	2.2%	17.3%	0.2%
2019	7.1%	67.6%	2.6%	22.3%	0.4%	7.1%	73.4%	2.4%	16.9%	0.2%	12.7%	67.4%	2.8%	16.9%	0.2%
2020	7.0%	65.2%	1.9%	25.7%	0.2%	7.0%	74.5%	1.5%	16.7%	0.3%	15.4%	65.4%	2.2%	16.7%	0.3%
2021	6.6%	64.7%	1.9%	26.5%	0.3%	6.6%	74.9%	2.1%	16.1%	0.3%	17.2%	63.6%	2.9%	16.1%	0.2%

Scenario: Low Gas Cost Env I

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2018	6.6%	70.4%	1.9%	20.8%	0.3%	6.6%	74.1%	1.7%	17.3%	0.3%	9.9%	70.8%	1.8%	17.3%	0.2%
2019	6.5%	68.4%	2.5%	22.3%	0.3%	6.6%	74.1%	2.2%	16.9%	0.2%	12.0%	68.5%	2.3%	16.9%	0.3%
2020	6.4%	65.9%	1.7%	25.7%	0.3%	6.5%	75.2%	1.3%	16.7%	0.3%	14.9%	66.4%	1.7%	16.7%	0.3%
2021	6.2%	65.3%	1.7%	26.5%	0.3%	6.2%	75.5%	1.9%	16.1%	0.3%	16.7%	64.6%	2.4%	16.1%	0.2%

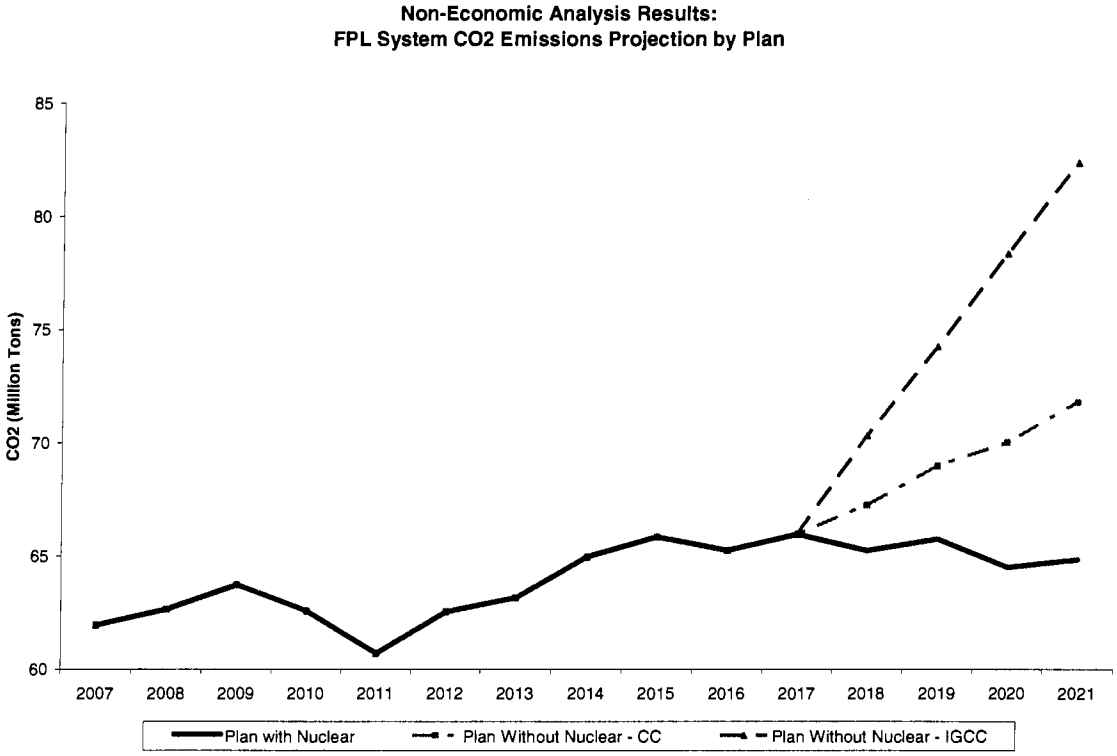
As shown in the above table, the Plan with Nuclear holds a significant advantage in regard to fuel diversity compared to the Plan without Nuclear – CC, and has a similar fuel diversity impact to the Plan without Nuclear - IGCC. When looking at the results for the High Gas Cost Env III scenario for the year 2021, it is projected that the Plan with Nuclear will result in FPL's system supplying approximately 27% of its energy with nuclear, 65% with natural gas, and 7% with coal/petroleum coke. By comparison, it is projected that the Plan without Nuclear - CC will result in FPL's system supplying only 16 % of its energy with nuclear, 75% with natural gas, and 7% with coal/petroleum coke and the Plan without Nuclear – IGCC will result in FPL's system supplying only 16% with nuclear, 64% with natural gas, and 17% with coal.

For the Low Gas Cost Env I scenario, the relative fuel mix percentages for the various fuels are relatively unchanged for the three resource plans.

Therefore, the Plan with Nuclear is projected to have a significant fuel diversity advantage, as indicated by its approximately 10% higher reliance on nuclear energy and 10% lower dependence upon natural gas, over the Plan without Nuclear – CC and has a similar fuel diversity advantage as the Plan without Nuclear - IGCC.

The second non-economic analysis focused on the projected annual CO_2 system emissions for the three resource plans for the 2007 – 2021 time period. Figure VII.D.2.2 provides the results of these analyses.

Figure VII.D.2.2



As expected there are no differences between the three plans for the years 2007 through 2017 because the plans are identical. However, starting in 2018, there are significant differences in CO_2 emissions between the plans. The Plan with Nuclear shows dramatically lower CO_2 emissions in the 2018 – 2021 time period due to the fact that nuclear power plant operations result in essentially zero CO_2 emissions.

For 2021, the first year for which the 2018 and 2020 unit additions are operating for a full year, the projected FPL system CO_2 emissions for the three plans are as follows:

- Plan with Nuclear = 64.9 million tons

- Plan without Nuclear – CC = 71.8 million tons

- Plan without Nuclear – IGCC = 82.4 million tons

Comparing these values shows that the CO_2 emission projection for 2021 for the Plan without Nuclear – CC is 6.9 million tons per year higher than for the Plan with Nuclear, and the Plan without Nuclear – IGCC is 17.5 million tons per year higher than for the Plan with Nuclear.

From a percentage perspective, the Plan with Nuclear would result in approximately a 10% reduction from the Plan without Nuclear – CC and approximately a 21% reduction from the Plan without Nuclear – IGCC.

3. Summary of Analysis Results

The economic analyses resulted in a wide range of breakeven capital costs for new nuclear units. This wide range of $3,206/kW to $7,281/kW in 2007$ versus the Plan without Nuclear – CC, and $5,921/kW to $9,450/kW in 2007$ versus the Plan without Nuclear – IGCC, compares favorably to the current non-binding estimate range of $3,108/kW to $4,540/kW in 2007$ for new nuclear units. Therefore, it appears there is a very good possibility that new nuclear units at Turkey Point can be constructed at a cost that would, at worst, break even with the total system cost of non-nuclear units that might otherwise be constructed, and that there is a very good chance that the new nuclear units would result in lower total system costs

The non-economic analyses showed that the Plan with Nuclear has a significant advantage in regard to system fuel diversity compared to the Plan without Nuclear –CC, and similar fuel diversity impacts compared to the Plan without Nuclear - IGCC. The non-economic analyses also showed that the Plan with Nuclear will result in reducing FPL system CO_2 emissions by approximately 10% compared to the Plan without Nuclear – CC and by 21% compared to the Plan without Nuclear – IGCC.

In summary, the results of the analyses show that new nuclear units are likely to be the economic choice compared to either CC or IGCC units starting in 2018 over a variety of fuel cost and environmental compliance cost forecasts. In addition, new nuclear units offer significant system fuel diversity and CO_2 emission reduction advantages over either of these non-nuclear alternatives.

VIII. NON-GENERATING ALTERNATIVES

A. FPL's Demand Side Management Efforts

FPL has a long history of identifying, developing, and implementing DSM resources to cost-effectively avoid or defer the construction of new power plants. FPL first began offering DSM programs in the late 1970s with the introduction of its Watt-Wise Home Program. FPL has continued to develop and offer additional DSM programs to its customers. These programs have included both conservation and load management programs, targeting the residential and business markets.

FPL's portfolio of DSM programs has evolved over time. FPL continually looks for new DSM opportunities as part of its research and development activities. When a new DSM opportunity is identified and projected to be cost-effective, FPL attempts to either implement a new DSM program or incorporate this DSM opportunity into one or more of its existing DSM programs. In addition, FPL has modified DSM programs over time in order to maintain the cost-effectiveness of the programs. This allows FPL to continue to offer the most cost-effective programs available. On occasion, FPL has also terminated DSM programs that were no longer cost-effective and could not be modified to become cost-effective.

Since the inception of FPL's DSM programs through the end of 2006, the last full year for which data was available at the time this document was prepared, FPL has achieved 3,659 MW (at the generator) of Summer peak demand reduction, 2,816 MW (at the generator) of Winter peak demand reduction, 38,169 GWh (at the generator) of energy savings, and has completed over 2,360,000 energy audits of its customers' homes and facilities. This amount of peak demand reduction has eliminated the need for the equivalent of 11 power plants of 400 MW Summer capacity each (after accounting for the impact of reserve margin requirements).

Most importantly, FPL has achieved this level of demand reduction without penalizing customers who are non-participants in its DSM programs. FPL has been able to avoid penalizing non-participating customers by offering only DSM programs that reduce electric rates for all customers, DSM participants and non-participants alike.

DOE reports on the effectiveness of utility DSM efforts through its Energy Information Administration. Based on the most current data available, which is for the year 2005, FPL is ranked number one nationally for cumulative conservation achievement and number four in load management. To put this further in perspective, FPL serves about 3% of the total U.S. consumers but has achieved 13% of the total US conservation and 6% of the total load management. Therefore, FPL's success is not attributed just to its size relative to other utilities, but to its commitment to achieving the maximum amount of cost-effective DSM.

B. FPL's Current DSM Goals, Plan, and Projection

DSM Goals were first set for Florida utilities in 1994 in Order No. PSC-94-1313 FOF. In 2004, new DSM Goals were set for FPL and other Florida utilities in Order No. PSC-04-0763-PPA-EG. In that order, the Commission established for FPL goals of achieving 883 MW of incremental Summer MW at the generator through DSM during the period from 2005 through 2014. This goal reflected what FPL and the Commission believed to be the reasonably achievable, cost-effective levels of incremental DSM on FPL's system.

FPL continually investigates additional cost-effective DSM opportunities and requests Commission approval of revisions to its DSM plan as appropriate. In 2005, FPL's peak load forecast increased significantly. There were also modifications to minimum equipment efficiency standards and other changing market conditions. As a result of these changes, FPL performed a comprehensive review of all its DSM programs as well as other potential measures. This resulted in FPL revising 8 of its existing DSM programs. These modifications included changing the minimum qualifying Seasonal

Energy Efficiency Ratio for air conditioners to reflect minimum mandated levels by the DOE, modifying incentive levels for numerous program measures, enhancing program operating parameters, and adding new measures to existing DSM programs. In addition, FPL requested Commission approval of two new DSM programs -- Business Water Heating and Business Refrigeration. After review and consideration, the Commission issued Order No. PSC-06-0535-PAA-EG in Docket No. 060286-EG (Consummating Order No. PSC-06-0624-CO-EG issued July 20, 2006), approving changes to FPL's residential and business HVAC programs. On September 1, 2006, the Commission issued Order No. PSC-06-0740-TRF-EI in Docket No. 060408-EI (Consummating Order No. PSC-06-0801-CO-EI, issued September 26, 2006) approving the remaining modifications to FPL's DSM Plan for achieving these DSM reductions.

The next Commission-sponsored DSM goals-setting docket, which will include the time period 2015-2019, is expected to occur in 2009. While FPL does not have approved DSM goals past 2014, for purposes of the analyses conducted for this filing, FPL assumed a continuation of DSM signups at currently projected trends.

The net result is that FPL projects the addition of 1,899 MW of cost-effective DSM from August 2006 through August 2020. As mentioned in Section III, FPL assumed the successful accomplishment of this amount of DSM in determining its future capacity needs.

FPL forecasts that it will achieve its DSM Plan through a number of Commission-approved DSM programs. FPL's current DSM Plan includes seven residential DSM programs and ten business DSM programs. A brief summary of each of these programs appears in Appendix K.

C. FPL's Demand Side Management Renewable Efforts

FPL has a long history of programs and research and development addressing the needs of its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to the revisions of the Florida Model Energy Building Code. The revision was brought about in part by FPL's Passive Home Program.

In early 1991, FPL received approval from the Commission to conduct a research project to evaluate the feasibility of using PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. However, the high

cost of PV, the significant percentage of sites with unacceptable shading and various customer satisfaction issues remain as barriers to wide acceptance and use of this particular solar application.

FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach did not require all of its customers to bear PV's high cost, but allowed customers who were interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased PV modules and installed them at FPL's Martin Plant site.

In 2000, FPL launched the Photovoltaic Research, Development and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems) and assess the homeowner's financial benefits and costs of PV roof tile systems. This project, which was completed in 2003, provided valuable data to assess the cost-effectiveness of this technology for FPL and its customers.

In November of 2004, FPL launched its Green Power Pricing Research Project (GPPRP) that was marketed as the Sunshine Energy® program. The objective of the project was to allow residential customers to sign up voluntarily and pay for energy produced by renewable resources, thus fostering the development of supplies of renewable energy that would not otherwise be developed. GPPRP participants paid a monthly premium of $9.75 per month for a 1,000 kWh block of renewable energy attributes. To supply the renewable energy for the GPPRP, FPL entered into a contract with a supplier for the purchase of tradable renewable energy credits (TRECs). In addition, for every 10,000 participants, FPL agreed to have built 150 kW of photovoltaic capacity in Florida. In its short history, the GPPRP became one of the top programs in the country with 28,742 customers enrolled by the end of 2006. The GPPRP purchased 1,894 GWhs of TRECs as of year end 2006 making it the third largest renewable energy program in the country. It also received the 2005 Green Power Leadership Award from the U.S. Department of Environmental Protection and the Department of Energy. The program has continued to grow, with 34,000 participants as of June, 2007.

On September 17, 2006, FPL filed a petition with the Commission to convert the GPPRP to a permanent program and to extend the program to business customers. On December 1, 2006, the Commission issued Order No. PSC-06-0924-TRF-EI in Docket No. 060577-EI approving this request.

D. The Potential for Additional Cost-Effective DSM

FPL is confident there is not sufficient additional, cost-effective DSM that could eliminate or significantly mitigate FPL's total capacity needs through 2020. There are several bases for this conclusion.

First, in 2006 FPL completed a comprehensive review of all demand side management opportunities. This analysis identified all the cost-effective DSM potential for this time frame. In addition, while FPL does not have Commission approved DSM goals for 2015 through 2019, it is projecting to implement 1,899 MW of cost-effective DSM from August 2006 through August 2020. In addition, while there has been a small increase in the penetration of demand side renewable energy options over the last several years, the economics of the various technologies has not yet reached the level to make any significant impact on FPL's summer peak.

Second, FPL has already counted this level of reasonably achievable DSM in its reliability assessment, which resulted in the projected need for new capacity resources in the 2018 – 2020 time period. Otherwise stated, FPL's analysis had already captured the cost-effective DSM available on FPL's system and determined that FPL still needed additional capacity resources.

Third, if the resource needs for just 2018 through 2020 were to be met solely by additional new DSM resources, FPL would need to identify and implement an additional 538 MW at the generator of cost-effective DSM to meet the 2018 resource needs and another 1,114 MW at the generator to meet the 2019 and 2020 resource needs, for a total

of 1,652 MW at the generator just to meet that 3-year resource requirement. FPL's DSM commitment already take into account both maintaining FPL's large existing DSM resources and substantially increasing DSM through implementation of all of the additional cost-effective DSM that FPL has identified. Accordingly, there is no reasonable basis for concluding that FPL could implement sufficient new cost-effective DSM programs – over and above those already being performed and planned to be implemented - to meet these needs. While FPL hopes to identify and implement additional sources of cost-effective DSM in future years, FPL has no basis for believing that 1,652 MW at the generator of additional cost-effective DSM resources could be identified and implemented prior to 2020, especially when considering that 1,899 MW of DSM represents all of the currently known cost-effective DSM from August 2006 through August 2020, including a continuation of cost-effective DSM from 2015 through 2020, and that this amount of DSM is already incorporated into FPL's resource planning.

IX. ADVERSE CONSEQUENCES IF THE PROPOSED CAPACITY ADDITIONS ARE DENIED

As the Commission is well aware, FPL's recent plan to add new baseload coal generation was not approved. Significant uncertainty exists as to whether any other projects that use coal as a fuel, even with IGCC technology, will be approved for the foreseeable future. In any event, the likelihood that significant reductions in GHG emissions will be required in the future raises questions regarding the practical feasibility of coal-fueled additions in Florida until carbon capture and sequestration becomes readily applicable in Florida. Although FPL will actively continue to pursue cost-effective DSM increases and additional generation from renewable resources, currently available information indicates

that that these alternatives will make only a modest contribution compared to the projected need for new resources to meet growth in electricity demand based largely on population growth and to replace expiring power purchases from coal generation. Without nuclear generation, the only alternative that can be counted on to provide sufficient new generation capacity to ensure reliable electric service through 2020 is additional natural gas generation.

With further reliance on natural gas generation, FPL's customers would face significant adverse consequences related primarily to the reduced system reliability due to significantly lower fuel diversity for the foreseeable future. As evidenced by the fuel diversity results presented in Table VI.D.2.1 and discussed above, with the addition of Turkey Point 6 & 7, nuclear generation would be used to produce approximately 27% of the electricity delivered to FPL's customers in 2021. Conversely, without new nuclear generation, by 2021 nuclear fuel would contribute only 16% while natural gas would contribute 75%, if combined cycle units are added instead..

In this situation, a gas supply interruption would severely affect electric service reliability throughout Florida. Fuel diversity contributes to greater system reliability because it helps offset reduced availability of one fuel, be it due to supply constraints or transportation interruptions, and helps mitigate the effect of equipment problems that affect one type of generation technology.

From an economic perspective, greater reliance on natural gas is expected to result in higher electricity costs and greater volatility in the cost of electricity. FPL believes that the effort to avoid GHG emissions will result in greater utilization of natural gas throughout the U.S. and that this general increase in gas utilization will contribute to higher natural gas prices. Without additional nuclear generation, because a greater portion of electricity would be generated using natural gas, the price of electricity would

be more directly affected by the rising price of natural gas. Similarly, any volatility in natural gas prices will translate very directly in volatility in the price of electricity.

Moreover, FPL's analyses show that the addition of Turkey Point 6 & 7 can provide to FPL's customers all these benefits at a cost that is projected to be lower than that of adding additional gas-fueled generation under almost all conditions, and lower than adding IGCC, and that its reliability would be as good as that of combined cycle generation and far better than that of IGCC.

The failure to approve Turkey Point 6 & 7 would be a missed opportunity to significantly lower FPL's system CO2 emissions. As shown in Table VII.D.2.2 the FPL system is projected to have CO2 emissions 10% higher if CC capacity were to be installed in 2018 and 2020 instead of Turkey Point 6 & 7, or 21% higher if IGCC capacity were to be installed instead in 2018 and 2020. A denial of FPL's petition would eliminate the best, most cost-effective means of reducing GHG emissions in the future, while continuing to meet the future electricity needs of FPL's customers. Denial of FPL's petition would not be in FPL's customers' best interests.

It is important to note that an affirmative determination of need for Turkey Point 6 & 7 is a first step, not an irreversible decision, because FPL and the Commission will periodically review the Project's benefits on behalf of FPL's customers in light of new information that may be developed over time. However, granting this petition enables FPL to move forward and maintain the ability to bring the benefits of new nuclear generation to its customers in the 2018-2020 time frame – an extremely valuable option given the analysis results obtained for a wide range of future fuel and environmental scenarios – through a commitment of a comparatively modest level of resources. In contrast, denial of FPL's petition will preclude that option.

X. CONCLUSIONS

FPL, through its 2007 integrated resource planning (IRP) process, determined that 8,350 MW of new resources (demand side and generation capacity) would be needed between 2011 and 2020, including about 1,600 MW to replace expiring power purchase agreements, to continue to meet the reliability criterion of 20% summer reserve margin approved by the Commission and considered necessary by FPL to provide reliable service. Of this resource need, FPL projects that 1,490 MW can be avoided through increased DSM, about 290 MW could be provided by renewable resource purchases, 414 MW will be provided by capacity uprates at FPL's existing nuclear units, and between 2,200 MW and 3,040 MW will be provided by the proposed Turkey Point 6 & 7 addition in 2018 and 2020. The remaining resource need (between 3,120 MW and 3,960 MW) will be provided between 2011 and 2017 by a combination of resources that could include additional DSM and additional generation capacity (self-build or purchased) from renewable resources, new gas-fueled generation and coal-fueled generation.

Assuming that sufficient resources have been added between 2011 and 2017 to maintain a 20% reserve margin through 2017, without the proposed addition of Turkey Point 6 & 7, FPL's summer reserve margin would drop to 17.5% in 2018, 15.1% in 2019, and 12.6% in 2020, far less than the reserve margin requirement that FPL and the Commission have agreed is necessary to ensure system reliability. In addition, without these capacity additions in 2018 and 2020, by 2021 FPL's need would exceed 2,700 MW, and the need would continue to grow thereafter.

FPL has also determined that if all new generation capacity added to FPL's system through 2020 were to be natural gas-fired generation, fuel diversity in FPL's system would be significantly reduced. Specifically, by 2021 natural gas would provide more than 75% of all electricity delivered by FPL to its customers.

FPL conducted an evaluation of various generation alternatives to identify the best plan to address key objectives of its resource planning process, including meeting projected capacity needs in the future in a cost-effective manner, maintaining system fuel diversity and reducing GHG emissions. FPL's analysis indicated that adding the proposed Turkey Point Nuclear Units 6 and 7 in 2018 and 2020, respectively, would be the best plan to meet these objectives. Because of the nature of these proposed additions, FPL would be required to obtain a Determination of Need to support a site certification for each of these units. In this proceeding, FPL seeks a Need Determination for Turkey Point 6 & 7 and associated transmission facilities.

In order to determine how adding nuclear generation to FPL's portfolio compared to continuing to add natural gas-fired generation, or adding new coal-fueled IGCC generation, FPL conducted economic, fuel diversity and GHG emission evaluations to compare a resource plan that includes the addition of Turkey Point 6 & 7 in 2018 and 2020, respectively, to an alternate plan that includes the addition of gas-fueled generation instead of nuclear generation in those years, and to another alternate resource plan that includes the addition of IGCC generation instead of nuclear generation. FPL utilized 9 of forecasted fuel costs and environmental compliance costs in these analyses in order to reflect the range of uncertainty regarding future fuel costs and environmental

requirements. The results of those analyses showed that the resource plan with Turkey Point 6 & 7 is more cost effective than the alternate plans that do not include new baseload nuclear generation.

The resource plan with Turkey Point 6 & 7 provides the only effective means of maintaining fuel diversity in FPL's system in 2018 and 2020, which is essential in maintaining system reliability and mitigating the effect of volatility in the price of natural gas. Furthermore, the addition of Turkey Point 6 & 7 is a necessary part of any strategy to reduce GHG emissions in the future, even while demand for electricity continues to increase.

In short, FPL needs Turkey Point 6 & 7 to maintain system reliability, to maintain system fuel diversity, to provide adequate electricity at a reasonable cost to its customers and to reduce GHG emissions. There is not sufficient additional cost-effective DSM or other renewable resources available to mitigate the need for these new nuclear baseload units.

FPL is also requesting that any need order reflect strong support for the Project, affirming the importance of taking steps now to preserve nuclear as a resource option to meet needs as early as 2018, acknowledging the risks and costs associated with a project of such magnitude, and clearly indicating the importance of, and Commission's intent to provide, continued regulatory support throughout the process.

Therefore, the Commission should grant FPL's petition for a determination of need for Turkey Point 6 and 7 in 2018 and 2020, respectively.

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 070650-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR TURKEY POINT NUCLEAR UNITS 6 AND 7 ELECTRICAL POWER PLANT

NEED STUDY FOR ELECTRICAL POWER

APPENDICES A-K

Appendix A

Major FPL Interconnections (Projected 2018-2020)

List of FPL Major Interconnections (230 KV and 500 KV)		
FPL	**PEF[1/]**	**KV**
Poinsett	Holopaw	230
Sanford Plant	North Longwood	230
Sanford Plant	Debary	230
Sanford Plant	Altamonte	230
Whidden	Vandolah	230
Charlotte	Vandolah	230
Poinsett	Bithlo (2009)	230
Sanford	Bithlo (2009)	230
FPL	**TECO[1/]**	**KV**
Ringling	Big Bend	230
Manatee	Big Bend	230
Manatee	Ruskin	230
FPL	**JEA[1/]**	**KV**
Duval	Brandy Branch (3 circuits)	230
FPL120G1	Switzerland	230
FPL	**OUC[1/]**	**KV**
Cape Canaveral	Indian River (2 circuits)	230
FPL	**SECI[1/]**	**KV**
Calusa	Lee (2 circuits)	230
Rice	Seminole Plant (2 circuits)	230
Putnam	Seminole Plant	230
Duval	Seminole Plant	230
FPL	**FMPA[1/]**	**KV**
Orangedale	Sampson	230
Duval	Greencove	230
FPL120G1	Sampson	230
Ralls	FMP-TCEC (2008)	230
FPL	**SOCO[1/]**	**KV**
Duval	Hatch	500
Duval	Thalman	500
Yulee	Kingsland	230

Note:

1/ PEF: Progress Energy Florida
TECO: Tampa Electric Company
JEA: Jacksonville Electric Authority
OUC: Orlando Utilities Commission
SECI: Seminole Electric Cooperative, Inc.
FMPA: Florida Municipal Power Authority
SOCO: Southern Company

Appendix B

FPL Generation Facilities - 2007

Plant Name	Unit No.	Location	Unit Type	Fuel		Net Capability 1/	
				Pri.	Alt.	Winter MW	Summer MW
Cape Canaveral	1	Brevard County	Steam	Heavy Oil	Natural Gas	398	396
	2		Steam	Heavy Oil	Natural Gas	398	396
Cutler	5	Miami Dade County	Steam	Natural Gas	None	69	68
	6		Steam	Natural Gas	None	138	137
Fort Myers	2	Lee County	Combined Cycle	Natural Gas	None	1,599	1,440
	3A & B		Combustion Turbine	Natural Gas	Distillate Oil	372	324
	1-12		Gas Turbine	Distillate Oil	None	769	648
Lauderdale	4	Broward County	Combined Cycle	Natural Gas	Distillate Oil	464	436
	5		Combined Cycle	Natural Gas	Distillate Oil	464	436
	1-12		Gas Turbine	Natural Gas	Distillate Oil	509	420
	13-24		Gas Turbine	Natural Gas	Distillate Oil	509	420
Manatee	1	Manatee County	Steam	Heavy Oil	Natural Gas	831	819
	2		Steam	Heavy Oil	Natural Gas	831	819
	3		Combined Cycle	Natural Gas	None	1,197	1,104
Martin	1	Martin County	Steam	Heavy Oil	Natural Gas	844	839
	2		Steam	Heavy Oil	Natural Gas	844	839
	3		Combined Cycle	Natural Gas	None	503	478
	4		Combined Cycle	Natural Gas	None	503	478
	8		Combined Cycle	Natural Gas	Distillate Oil	1,180	1,104
Port Everglades	1	Broward County	Steam	Heavy Oil	Natural Gas	222	220
	2		Steam	Heavy Oil	Natural Gas	222	220
	3		Steam	Heavy Oil	Natural Gas	389	387
	4		Steam	Heavy Oil	Natural Gas	394	392
	1-12		Gas Turbine	Natural Gas	Distillate Oil	509	420
Putnam	1	Putnam County	Combined Cycle	Natural Gas	Distillate Oil	283	249
	2		Combined Cycle	Natural Gas	Distillate Oil	283	249
Riviera	3	Palm Beach County	Steam	Heavy Oil	Natural Gas	280	277
	4		Steam	Heavy Oil	Natural Gas	291	288
Sanford	3	Volusia County	Steam	Heavy Oil	Natural Gas	140	138
	4		Combined Cycle	Natural Gas	None	1,067	958
	5		Combined Cycle	Natural Gas	None	1,057	948
Scherer 2/	4	Monroe, GA	Bituminous Coal	Bituminous Coal	None	652	646
St. Johns River Power Park 3/	1	Duval County	Bituminous Coal	Bituminous Coal	Petroleum Coke	125	125
	2		Bituminous Coal	Bituminous Coal	Petroleum Coke	125	125
St. Lucie 4/	1	St. Lucie County	Nuclear	Uranium	None	790	777
	2		Nuclear	Uranium	None	790	777
Turkey Point	1	Miami Dade County	Steam	Heavy Oil	Natural Gas	398	396
	2		Steam	Heavy Oil	Natural Gas	394	392
	3		Nuclear	Uranium	None	717	693
	4		Nuclear	Uranium	None	717	693
	5		Combined Cycle	Natural Gas	None	1,181	1,144
	1-5		Internal Combustion	Distillate Oil	None	12	12

1/ These ratings are peak capability.

2/ These ratings reprasent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.

3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.

4/ Total capability is 853/839 MW. Capabilities shown represent FPL's share of each unit's output (approximately 92.5%) and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of each unit's output (approximately 7.5%).

Appendix C

Computer Models Used in FPL's Resource Planning*

TIGER

TIGER, the "Tie Line Assistance and Generation Reliability" program, is a model originally developed by Florida Power Corporation. The model has been modified by FPL and is used to determine the magnitude and the timing of FPL's resource needs. The system reliability analyses performed by TIGER are based on three planning criteria: 20% minimum Summer reserve margin, 20% minimum Winter reserve margin, and a maximum loss-of-load probability (LOLP) of 0.1 days/year.

TIGER is a program capable of modeling two geographic areas. FPL models its service territory (and its connections to other utilities) as a single area. The expected assistance levels from other utility systems are modeled as an additional generator within FPL's service territory.

TIGER performs the calculations of excess firm capacity at the times of the annual system peaks (i.e., reserve margin calculations). It performs these calculations for the Winter peak (January) and the Summer peak (August). TIGER checks the Winter and Summer reserve margins to determine if additional capacity is needed to meet FPL's reserve margin criteria.

In addition, TIGER performs the calculation of LOLP by looking at the peak demand for each day of the year, while taking into consideration the unavailability of generators due to planned/scheduled maintenance or forced outages. Therefore, 365 daily peaks (366 for leap years) are used to calculate annual LOLP values.

* FPL regularly utilizes other models in various aspects of its integrated resource planning (IRP) work. The models listed here were used in analyses leading directly to this Determination of Need filing.

P-MArea

P-MArea is a detailed, hourly production costing model developed by P-Plus Corporation. The model has been used extensively for developing the information used in FPL's Fuel Cost Recovery filings and in numerous fuel-related as well as in the analyses for the Determination of Need filings for the two West County Energy Center combined cycle units and FPL's Glades Power Park (FGPP) coal units.

In regard to the current Determination of Need filing for the two new nuclear units at Turkey Point, P-MArea was used to develop production costs (fuel, variable O&M, and system emission costs) for the two resource plans for all of the fuel cost and environmental compliance cost forecast scenarios. The model also used transmission transfer limits in order to capture the impacts on system production costs of the geographic location of the new generation resources included in each of the resource plans.

Fixed Cost Spreadsheet

The Fixed Cost Spreadsheet is an FPL spreadsheet designed to capture all fixed costs associated with a resource plan. Fixed costs addressed include: generator capital, capacity payments, fixed O&M, capital replacement, transmission interconnection & integration capital, firm gas transportation costs, fuel inventory-related costs, upstream gas costs, etc. The Fixed Cost Spreadsheet was used in the analyses for the Determination of Need filings for the two West County Energy Center combined cycle units and the FGPP coal units.

In regard to the current Determination of Need filing for the two new nuclear units, the Fixed Cost Spreadsheet was used to calculate all fixed costs associated with the two resource plans. These fixed costs, when combined with the production costs developed with P-MArea, provided FPL with a complete perspective of the system costs associated with each resource plan.

MetrixND

MetrixND is an advanced statistics program for analysis and forecasting of time-series data that is stored in Excel or Access databases. This statistical package is used to develop the regression models to forecast sales, net energy for load, and peak demand.

Residential Sales Regression Model

Residential energy sales are forecast by multiplying the projected residential use per customer by the projected number of residential customers. A regression model is used to project the electric usage per customer. The regression model utilizes the following explanatory variables: real residential price of electricity, Florida Real Personal Income, Cooling and Heating Degree Days, and dummy variables for hurricanes and historical periods.

Commercial Sales Regression Model

The commercial sales forecast is also developed using a regression model. The regression model utilizes the following explanatory variables: Gross Domestic Product, commercial real price of electricity, Cooling Degree Days, and dummy variables for hurricanes and historical periods.

Industrial Sales Linear Multiple Regression Model

Industrial sales were forecasted using a linear multiple regression model. The linear multiple regression model utilizes the following explanatory variables: Gross Domestic Product, Cooling Degree Days, and several dummy variables for outliers, hurricanes, and months.

Net Energy for Load (NEL) Regression Model

An econometric model is developed to produce a Net Energy for Load (NEL) forecast. The explanatory variables used in the model are the following: total customers, the real price of electricity, Heating and Cooling Degree days, and Florida Real Personal Income.

System Summer Peak Econometric Model

The summer peak forecast is developed using an econometric regression model. This econometric model utilizes the following explanatory variables: total average customers, the real price of electricity, Florida Real Personal Income, average temperature on peak day, and a heat buildup weather factor consisting of the sum of the Cooling Degree Hours during the peak day and three prior days.

System Winter Peak Econometric Model

The winter peak forecast is developed using the same econometric regression methodology as is used for summer peak forecasts. The winter peak model is a per customer model which contains the following explanatory variables: the square of the minimum temperature on the peak day and Heating Degree Hours for the prior day as well as for the morning of the winter peak day. The model also includes an economic variable: Florida Real Personal Income.

The Hourly Load Forecast: System Load Forecasting "Shaper" Program

Forecasted values for system hourly load are produced using a System Load Forecasting "Shaper" Program. This model uses 16 years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows

calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Appendix D

FPL's Forecast of Peak Demands and Net Energy for Load (NEL)

Annual Peaks

Year	January (Winter) MW	August (Summer) MW	Net Energy for Load GWh
2007	22,247	22,259	117,551
2008	22,627	22,770	122,024
2009	23,115	23,435	126,270
2010	23,587	24,003	130,499
2011	24,047	24,612	134,766
2012	24,498	25,115	139,038
2013	24,952	25,590	142,379
2014	25,416	26,100	146,257
2015	26,048	26,772	150,291
2016	26,692	27,410	154,556
2017	27,342	28,079	158,179
2018	27,994	28,737	162,140
2019	28,649	29,391	166,097
2020	29,308	30,091	170,661
2021	29,936	30,780	174,470
2022	30,562	31,466	178,576
2023	31,191	32,160	182,763
2024	31,826	32,859	187,465
2025	32,475	33,581	191,516
2026	33,123	34,290	195,831
2027	33,772	35,007	200,204
2028	34,422	35,731	205,080
2029	35,084	36,474	209,257
2030	35,750	37,219	213,798
2031	36,416	37,964	218,372

Annual Peaks

Year	January (Winter) MW	August (Summer) MW	Net Energy for Load GWh
2032	37,086	38,716	223,527
2033	37,773	39,480	227,829
2034	38,480	40,279	232,681
2035	39,205	41,084	237,670
2036	39,943	41,909	243,334
2037	40,670	42,720	247,895
2038	41,443	43,588	251,835
2039	42,235	44,478	257,105
2040	43,047	45,393	263,219

Note: For the analyses discussed in this Determination of Need filing, it was assumed that the load was held constant for the years 2040 through 2061. Therefore, the 2040 forecast values shown above were also used for each year in the 2041 through 2061 time period.

Appendix E

Fuel Cost Forecast 1 (High Price): Natural Gas

YEAR	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM - SESH PIPELINE $/MMBTU	GULFSTREAM FIRM - MOBILE BAY $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	UPS REPLACEMENT $/MMBTU	WILLIAMS - TRANSCO ZONE 4 $/MMBTU	PROGRESS $/MMBTU	HENRY HUB $/MMBTU
2007	$9.89	$10.04	$10.48	$10.61	$11.03		$10.34	$11.15	$11.65		$10.03	$10.35	$9.58
2008	$11.92	$12.07	$12.31	$12.35	$12.82	$11.74	$12.05	$12.87	$13.41		$11.70	$12.48	$11.55
2009	$12.33	$12.48	$12.66	$12.66	$13.13	$12.07	$12.35	$13.16	$13.70		$12.07	$12.90	$11.95
2010	$11.23	$11.38	$11.56	$11.56	$12.03	$11.00	$11.28	$12.09	$12.63	$11.19			$10.89
2011	$10.66	$10.81	$10.99	$10.99	$11.46	$10.51	$10.79	$11.60	$12.14	$10.72			$10.33
2012	$9.80	$9.95	$10.13	$10.13	$10.60	$9.67	$9.95	$10.76	$11.30	$9.87			$9.51
2013	$10.13	$10.28	$10.46	$10.46	$10.93	$9.99	$10.27	$11.09	$11.62	$10.20			$9.83
2014	$10.61	$10.76	$10.94	$10.94	$11.41	$10.46	$10.74	$11.56	$12.09	$10.67			$10.29
2015	$11.23	$11.38	$11.56	$11.56	$12.03	$11.08	$11.36	$12.17	$12.71	$11.29			$10.89
2016	$11.57	$11.73	$11.90	$11.91	$12.37	$11.41	$11.69	$12.51	$13.05				$11.22
2017	$11.92	$12.07	$12.25	$12.25	$12.72	$11.75	$12.03	$12.85	$13.39				$11.55
2018	$12.27	$12.42	$12.60	$12.60	$13.07	$12.10	$12.38	$13.19	$13.73				$11.89
2019	$12.91	$13.06	$13.24	$13.24	$13.71	$12.73	$13.01	$13.82	$14.37				$12.51
2020	$13.56	$13.71	$13.89	$13.89	$14.36	$13.37	$13.65	$14.46	$15.01				$13.14
2021	$14.06	$14.21	$14.39	$14.39	$14.86	$13.86	$14.14	$14.96	$15.50				$13.62
2022	$14.58	$14.73	$14.91	$14.91	$15.38	$14.37	$14.65	$15.47	$16.01				$14.12
2023	$15.12	$15.27	$15.45	$15.45	$15.91	$14.90	$15.18	$15.99	$16.54				$14.64
2024	$15.67	$15.82	$16.00	$16.00	$16.47	$15.45	$15.73	$16.54	$17.09				$15.17
2025	$16.25	$16.40	$16.58	$16.58	$17.05	$16.02	$16.30	$17.11	$17.66				$15.73
2026	$16.85	$17.00	$17.18	$17.18	$17.65	$16.60	$16.89	$17.70	$18.25				$16.31
2027	$17.47	$17.62	$17.80	$17.80	$18.27	$17.21	$17.50	$18.31	$18.86				$16.91
2028	$18.11	$18.26	$18.44	$18.44	$18.91	$17.85	$18.13	$18.94	$19.50				$17.53
2029	$18.78	$18.93	$19.11	$19.11	$19.57	$18.50	$18.78	$19.60	$20.15				$18.17
2030	$19.47	$19.62	$19.80	$19.80	$20.27	$19.18	$19.46	$20.28	$20.84				$18.84
2031	$20.18	$20.33	$20.51	$20.51	$20.98	$19.89	$20.17	$20.98	$21.54				$19.53
2032	$20.92	$21.07	$21.25	$21.26	$21.72	$20.62	$20.90	$21.71	$22.28				$20.24
2033	$21.69	$21.84	$22.02	$22.03	$22.49	$21.38	$21.66	$22.47	$23.04				$20.99
2034	$22.49	$22.64	$22.82	$22.82	$23.29	$22.16	$22.44	$23.26	$23.82				$21.76
2035	$23.32	$23.47	$23.65	$23.65	$24.12	$22.98	$23.26	$24.07	$24.64				$22.55
2036	$24.18	$24.33	$24.51	$24.51	$24.98	$23.82	$24.10	$24.92	$25.49				$23.38
2037	$25.06	$25.22	$25.39	$25.40	$25.86	$24.70	$24.98	$25.79	$26.36				$24.24
2038	$25.99	$26.14	$26.32	$26.32	$26.79	$25.60	$25.89	$26.70	$27.27				$25.13
2039	$26.94	$27.09	$27.27	$27.27	$27.74	$26.55	$26.83	$27.64	$28.22				$26.05
2040	$27.93	$28.08	$28.26	$28.26	$28.73	$27.52	$27.80	$28.61	$29.19				$27.00
2041	$28.96	$29.11	$29.29	$29.29	$29.76	$28.53	$28.81	$29.63	$30.21				$28.00
2042	$30.02	$30.17	$30.35	$30.36	$30.82	$29.58	$29.86	$30.67	$31.26				$29.02
2043	$31.13	$31.28	$31.46	$31.46	$31.93	$30.67	$30.95	$31.76	$32.35				$30.09
2044	$32.27	$32.42	$32.60	$32.60	$33.07	$31.79	$32.07	$32.89	$33.48				$31.19
2045	$33.46	$33.61	$33.79	$33.79	$34.26	$32.96	$33.24	$34.05	$34.65				$32.34
2046	$34.68	$34.84	$35.01	$35.02	$35.48	$34.17	$34.45	$35.26	$35.86				$33.52
2047	$35.96	$36.11	$36.29	$36.29	$36.76	$35.42	$35.71	$36.52	$37.12				$34.75
2048	$37.28	$37.43	$37.61	$37.61	$38.08	$36.73	$37.01	$37.82	$38.42				$36.03
2049	$38.65	$38.80	$38.98	$38.98	$39.45	$38.07	$38.36	$39.17	$39.77				$37.35
2050	$40.07	$40.22	$40.40	$40.40	$40.87	$39.47	$39.75	$40.57	$41.18				$38.72
2051	$41.54	$41.69	$41.87	$41.87	$42.34	$40.92	$41.20	$42.02	$42.63				$40.14
2052	$43.07	$43.22	$43.40	$43.40	$43.87	$42.42	$42.71	$43.52	$44.13				$41.61
2053	$44.65	$44.80	$44.98	$44.98	$45.45	$43.98	$44.26	$45.08	$45.70				$43.14
2054	$46.29	$46.44	$46.62	$46.62	$47.09	$45.60	$45.88	$46.69	$47.32				$44.72
2055	$47.99	$48.14	$48.32	$48.32	$48.79	$47.27	$47.55	$48.36	$48.99				$46.36
2056	$49.75	$49.90	$50.08	$50.08	$50.55	$49.01	$49.29	$50.10	$50.73				$48.06

Fuel Cost Forecast 1 (High Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	IGCC DISPATCH PRICE WITHOUT SO2 $/MMBTU
2007	$2.43	$2.79	$3.96	$2.79	$4.57
2008	$2.48	$3.28	$3.93	$3.28	$3.93
2009	$2.55	$3.28	$3.91	$3.32	$3.73
2010	$2.60	$3.26	$3.94	$3.32	$3.78
2011	$2.68	$2.43	$3.99	$2.56	$3.84
2012	$2.74	$2.47	$4.04	$2.59	$3.89
2013	$2.78	$2.50	$3.94	$2.63	$3.68
2014	$2.82	$2.53	$3.99	$2.66	$3.73
2015	$3.71	$2.57	$4.05	$2.70	$3.78
2016	$3.76	$2.61	$4.13	$2.75	$3.85
2017	$3.81	$2.65	$4.23	$2.79	$3.91
2018	$3.86	$2.69	$4.33	$2.83	$3.98
2019	$3.92	$2.73	$4.43	$2.87	$4.06
2020	$3.98	$2.77	$4.54	$2.92	$4.13
2021	$4.04	$2.82	$4.63	$2.97	$4.20
2022	$4.09	$2.87	$4.74	$3.02	$4.28
2023	$4.14	$2.91	$4.84	$3.07	$4.35
2024	$4.20	$2.97	$4.95	$3.12	$4.44
2025	$4.25	$3.02	$5.12	$3.18	$4.54
2026	$4.31	$3.07	$5.23	$3.24	$4.62
2027	$4.36	$3.13	$5.34	$3.30	$4.71
2028	$4.42	$3.19	$5.46	$3.36	$4.80
2029	$4.48	$3.25	$5.59	$3.42	$4.89
2030	$4.54	$3.31	$5.71	$3.49	$4.99
2031	$4.60	$3.37	$5.84	$3.55	$5.08
2032	$4.66	$3.43	$5.98	$3.61	$5.18
2033	$4.73	$3.49	$6.11	$3.68	$5.27
2034	$4.80	$3.55	$6.25	$3.74	$5.37
2035	$4.86	$3.61	$6.40	$3.80	$5.47
2036	$4.93	$3.67	$6.54	$3.87	$5.57
2037	$5.00	$3.73	$6.69	$3.94	$5.68
2038	$5.08	$3.80	$6.84	$4.00	$5.79
2039	$5.15	$3.87	$7.00	$4.07	$5.90
2040	$5.22	$3.93	$7.16	$4.14	$6.01
2041	$5.30	$4.00	$7.33	$4.22	$6.12
2042	$5.37	$4.07	$7.50	$4.29	$6.24
2043	$5.45	$4.15	$7.67	$4.36	$6.36
2044	$5.53	$4.22	$7.85	$4.44	$6.48
2045	$5.61	$4.29	$8.04	$4.52	$6.60
2046	$5.69	$4.37	$8.23	$4.60	$6.73
2047	$5.77	$4.45	$8.42	$4.68	$6.86
2048	$5.86	$4.52	$8.62	$4.76	$6.99
2049	$5.94	$4.60	$8.83	$4.84	$7.13
2050	$6.03	$4.68	$9.04	$4.92	$7.26
2051	$6.12	$4.77	$9.26	$5.01	$7.41
2052	$6.20	$4.85	$9.48	$5.10	$7.55
2053	$6.29	$4.94	$9.71	$5.18	$7.69

Fuel Cost Forecast 1 (High Price): Residual Fuel Oil

YEAR	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 1% $/MMBTU	INDIAN RIVER & CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2007	$13.54	$13.54	$13.54	$13.56	$13.55	$13.96	$13.54
2008	$15.24	$15.23	$15.24	$15.26	$15.24	$15.66	$15.24
2009	$15.06	$15.06	$15.06	$15.08	$15.07	$15.48	$15.06
2010	$14.76	$14.76	$14.76	$14.78	$14.76	$15.18	$14.76
2011	$15.16	$15.16	$15.17	$15.18	$15.17	$15.58	$15.16
2012	$15.54	$15.53	$15.54	$15.56	$15.54	$15.95	$15.54
2013	$15.98	$15.98	$15.98	$16.00	$15.99	$16.40	$15.98
2014	$16.48	$16.48	$16.48	$16.50	$16.49	$16.90	$16.48
2015	$17.07	$17.07	$17.08	$17.09	$17.08	$17.49	$17.07
2016	$17.87	$17.87	$17.87	$17.89	$17.87	$18.29	$17.87
2017	$18.65	$18.65	$18.65	$18.67	$18.66	$19.07	$18.65
2018	$19.41	$19.41	$19.41	$19.43	$19.42	$19.83	$19.41
2019	$20.19	$20.18	$20.19	$20.21	$20.19	$20.60	$20.19
2020	$20.96	$20.96	$20.97	$20.98	$20.97	$21.38	$20.96
2021	$21.71	$21.71	$21.71	$21.73	$21.72	$22.13	$21.71
2022	$22.48	$22.48	$22.48	$22.50	$22.49	$22.90	$22.48
2023	$23.28	$23.28	$23.29	$23.31	$23.29	$23.70	$23.28
2024	$24.12	$24.12	$24.12	$24.14	$24.12	$24.54	$24.12
2025	$24.98	$24.98	$24.98	$25.00	$24.99	$25.40	$24.98
2026	$25.88	$25.88	$25.88	$25.90	$25.88	$26.30	$25.88
2027	$26.81	$26.81	$26.81	$26.83	$26.81	$27.23	$26.81
2028	$27.77	$27.77	$27.77	$27.79	$27.78	$28.19	$27.77
2029	$28.77	$28.77	$28.78	$28.79	$28.78	$29.19	$28.77
2030	$29.81	$29.81	$29.81	$29.83	$29.82	$30.23	$29.81
2031	$30.89	$30.89	$30.89	$30.91	$30.90	$31.31	$30.89
2032	$32.01	$32.00	$32.01	$32.03	$32.01	$32.43	$32.01
2033	$33.17	$33.16	$33.17	$33.19	$33.17	$33.59	$33.17
2034	$34.37	$34.37	$34.37	$34.39	$34.38	$34.79	$34.37
2035	$35.62	$35.62	$35.62	$35.64	$35.63	$36.04	$35.62
2036	$36.91	$36.91	$36.92	$36.93	$36.92	$37.33	$36.91
2037	$38.26	$38.26	$38.26	$38.28	$38.26	$38.68	$38.26
2038	$39.65	$39.65	$39.65	$39.67	$39.66	$40.07	$39.65
2039	$41.10	$41.10	$41.10	$41.12	$41.11	$41.52	$41.10
2040	$42.60	$42.60	$42.60	$42.62	$42.61	$43.02	$42.60
2041	$44.16	$44.15	$44.16	$44.18	$44.16	$44.58	$44.16
2042	$45.77	$45.77	$45.77	$45.79	$45.78	$46.19	$45.77
2043	$47.45	$47.45	$47.45	$47.47	$47.46	$47.87	$47.45
2044	$49.19	$49.19	$49.19	$49.21	$49.19	$49.61	$49.19
2045	$50.99	$50.99	$50.99	$51.01	$51.00	$51.41	$50.99
2046	$52.86	$52.86	$52.87	$52.88	$52.87	$53.28	$52.86
2047	$54.81	$54.80	$54.81	$54.83	$54.81	$55.23	$54.81
2048	$56.82	$56.82	$56.82	$56.84	$56.83	$57.24	$56.82
2049	$58.91	$58.91	$58.91	$58.93	$58.92	$59.33	$58.91
2050	$61.08	$61.08	$61.08	$61.10	$61.09	$61.50	$61.08
2051	$63.33	$63.33	$63.33	$63.35	$63.34	$63.75	$63.33
2052	$65.67	$65.66	$65.67	$65.69	$65.67	$66.09	$65.67
2053	$68.09	$68.09	$68.09	$68.11	$68.10	$68.51	$68.09

Fuel Cost Forecast 1 (High Price): Distillate Oil

YEAR	SHADY HILLS $/MMBTU	DESOTO $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN & WCEC $/MMBTU
2007	$22.72	$22.83	$22.88	$21.94	$21.94	$22.72	$22.99	$22.94
2008				$23.87	$23.87	$24.65	$24.92	$24.87
2009				$23.47	$23.47	$24.25	$24.53	$24.47
2010				$18.93	$18.93	$19.71	$19.99	$19.93
2011				$19.21	$19.21	$19.99	$20.26	$20.21
2012				$20.70	$20.70	$21.48	$21.76	$21.70
2013				$21.49	$21.49	$22.26	$22.54	$22.48
2014				$22.25	$22.25	$23.03	$23.31	$23.25
2015				$22.99	$22.99	$23.77	$24.05	$23.99
2016				$23.98	$23.98	$24.76	$25.03	$24.98
2017				$24.99	$24.99	$25.77	$26.04	$25.99
2018				$25.99	$25.99	$26.77	$27.04	$26.99
2019				$27.01	$27.01	$27.78	$28.06	$28.01
2020				$28.03	$28.03	$28.81	$29.09	$29.03
2021				$28.99	$28.99	$29.76	$30.04	$29.98
2022				$29.97	$29.97	$30.75	$31.03	$30.97
2023				$31.00	$31.00	$31.77	$32.05	$32.00
2024				$32.05	$32.05	$32.83	$33.11	$33.05
2025				$33.15	$33.15	$33.93	$34.20	$34.15
2026				$34.28	$34.28	$35.06	$35.34	$35.28
2027				$35.45	$35.45	$36.23	$36.51	$36.45
2028				$36.67	$36.67	$37.44	$37.72	$37.66
2029				$37.92	$37.92	$38.70	$38.97	$38.92
2030				$39.22	$39.22	$40.00	$40.27	$40.22
2031				$40.56	$40.56	$41.34	$41.62	$41.56
2032				$41.95	$41.95	$42.73	$43.01	$42.95
2033				$43.39	$43.39	$44.17	$44.44	$44.39
2034				$44.88	$44.88	$45.65	$45.93	$45.87
2035				$46.42	$46.42	$47.19	$47.47	$47.41
2036				$48.01	$48.01	$48.78	$49.06	$49.01
2037				$49.66	$49.66	$50.43	$50.71	$50.65
2038				$51.36	$51.36	$52.14	$52.41	$52.36
2039				$53.12	$53.12	$53.90	$54.18	$54.12
2040				$54.95	$54.95	$55.73	$56.00	$55.95
2041				$56.84	$56.84	$57.61	$57.89	$57.84
2042				$58.79	$58.79	$59.57	$59.85	$59.79
2043				$60.81	$60.81	$61.59	$61.87	$61.81
2044				$62.91	$62.91	$63.68	$63.96	$63.90
2045				$65.07	$65.07	$65.85	$66.12	$66.07
2046				$67.31	$67.31	$68.09	$68.36	$68.31
2047				$69.63	$69.63	$70.40	$70.68	$70.62
2048				$72.02	$72.02	$72.80	$73.08	$73.02
2049				$74.50	$74.50	$75.28	$75.56	$75.50
2050				$77.07	$77.07	$77.85	$78.12	$78.07
2051				$79.73	$79.73	$80.50	$80.78	$80.72
2052				$82.47	$82.47	$83.25	$83.53	$83.47
2053				$85.32	$85.32	$86.09	$86.37	$86.31

Fuel Cost Forecast 3 (Medium Price): Natural Gas

YEAR	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM - SESH PIPELINE $/MMBTU	GULFSTREAM FIRM - MOBILE BAY $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	UPS REPLACEMENT $/MMBTU	WILLIAMS - TRANSCO ZONE 4 $/MMBTU	PROGRESS $/MMBTU	HENRY HUB $/MMBTU
2007	$7.23	$7.34	$7.67	$7.76	$8.07		$7.56	$8.16	$8.52		$7.34	$7.57	$7.01
2008	$8.72	$8.83	$9.00	$9.04	$9.38	$8.58	$8.82	$9.41	$9.81		$8.56	$9.13	$8.45
2009	$9.02	$9.13	$9.26	$9.26	$9.60	$8.83	$9.03	$9.63	$10.02		$8.83	$9.44	$8.74
2010	$8.22	$8.33	$8.46	$8.46	$8.80	$8.05	$8.25	$8.84	$9.24	$8.18			$7.96
2011	$7.79	$7.90	$8.04	$8.04	$8.38	$7.69	$7.89	$8.49	$8.88	$7.84			$7.56
2012	$7.17	$7.28	$7.41	$7.41	$7.75	$7.07	$7.28	$7.87	$8.26	$7.22			$6.96
2013	$7.41	$7.52	$7.65	$7.65	$8.00	$7.31	$7.52	$8.11	$8.50	$7.46			$7.19
2014	$7.76	$7.87	$8.00	$8.00	$8.34	$7.65	$7.86	$8.45	$8.85	$7.81			$7.53
2015	$8.22	$8.33	$8.46	$8.46	$8.80	$8.10	$8.31	$8.90	$9.30	$8.26			$7.97
2016	$8.47	$8.58	$8.71	$8.71	$9.05	$8.35	$8.55	$9.15	$9.54				$8.21
2017	$8.72	$8.83	$8.96	$8.96	$9.30	$8.60	$8.80	$9.40	$9.79				$8.45
2018	$8.97	$9.08	$9.22	$9.22	$9.56	$8.85	$9.05	$9.65	$10.04				$8.70
2019	$9.44	$9.55	$9.69	$9.69	$10.03	$9.31	$9.52	$10.11	$10.51				$9.15
2020	$9.92	$10.03	$10.16	$10.16	$10.50	$9.78	$9.98	$10.58	$10.98				$9.61
2021	$10.28	$10.39	$10.53	$10.53	$10.87	$10.14	$10.34	$10.94	$11.34				$9.96
2022	$10.66	$10.77	$10.90	$10.91	$11.25	$10.51	$10.72	$11.31	$11.71				$10.33
2023	$11.06	$11.17	$11.30	$11.30	$11.64	$10.90	$11.10	$11.70	$12.10				$10.71
2024	$11.46	$11.57	$11.70	$11.71	$12.05	$11.30	$11.50	$12.10	$12.50				$11.10
2025	$11.89	$12.00	$12.13	$12.13	$12.47	$11.71	$11.92	$12.52	$12.92				$11.51
2026	$12.32	$12.43	$12.56	$12.57	$12.91	$12.15	$12.35	$12.95	$13.35				$11.93
2027	$12.78	$12.89	$13.02	$13.02	$13.36	$12.59	$12.80	$13.39	$13.80				$12.37
2028	$13.25	$13.36	$13.49	$13.49	$13.83	$13.06	$13.26	$13.86	$14.26				$12.82
2029	$13.73	$13.84	$13.97	$13.98	$14.32	$13.53	$13.74	$14.34	$14.74				$13.29
2030	$14.24	$14.35	$14.48	$14.48	$14.82	$14.03	$14.24	$14.83	$15.24				$13.78
2031	$14.76	$14.87	$15.00	$15.01	$15.35	$14.55	$14.75	$15.35	$15.76				$14.28
2032	$15.31	$15.42	$15.55	$15.55	$15.89	$15.08	$15.29	$15.88	$16.29				$14.81
2033	$15.87	$15.98	$16.11	$16.11	$16.45	$15.64	$15.84	$16.44	$16.85				$15.35
2034	$16.45	$16.56	$16.69	$16.69	$17.04	$16.21	$16.42	$17.01	$17.43				$15.91
2035	$17.06	$17.17	$17.30	$17.30	$17.64	$16.81	$17.01	$17.61	$18.02				$16.50
2036	$17.68	$17.79	$17.93	$17.93	$18.27	$17.42	$17.63	$18.23	$18.64				$17.10
2037	$18.33	$18.44	$18.58	$18.58	$18.92	$18.07	$18.27	$18.87	$19.28				$17.73
2038	$19.01	$19.12	$19.25	$19.25	$19.59	$18.73	$18.93	$19.53	$19.95				$18.38
2039	$19.71	$19.82	$19.95	$19.95	$20.29	$19.42	$19.62	$20.22	$20.64				$19.05
2040	$20.43	$20.54	$20.67	$20.67	$21.02	$20.13	$20.34	$20.93	$21.35				$19.75
2041	$21.18	$21.29	$21.42	$21.43	$21.77	$20.87	$21.08	$21.67	$22.10				$20.48
2042	$21.96	$22.07	$22.20	$22.20	$22.55	$21.64	$21.84	$22.44	$22.86				$21.23
2043	$22.77	$22.88	$23.01	$23.01	$23.35	$22.43	$22.64	$23.23	$23.66				$22.01
2044	$23.60	$23.71	$23.85	$23.85	$24.19	$23.25	$23.46	$24.05	$24.49				$22.82
2045	$24.47	$24.58	$24.71	$24.71	$25.06	$24.11	$24.31	$24.91	$25.34				$23.65
2046	$25.37	$25.48	$25.61	$25.61	$25.96	$24.99	$25.20	$25.79	$26.23				$24.52
2047	$26.30	$26.41	$26.54	$26.55	$26.89	$25.91	$26.12	$26.71	$27.15				$25.42
2048	$27.27	$27.38	$27.51	$27.51	$27.85	$26.86	$27.07	$27.66	$28.10				$26.35
2049	$28.27	$28.38	$28.51	$28.51	$28.86	$27.85	$28.06	$28.65	$29.09				$27.32
2050	$29.31	$29.42	$29.55	$29.55	$29.89	$28.87	$29.08	$29.67	$30.12				$28.32
2051	$30.39	$30.50	$30.63	$30.63	$30.97	$29.93	$30.14	$30.73	$31.18				$29.36
2052	$31.50	$31.61	$31.74	$31.75	$32.09	$31.03	$31.24	$31.83	$32.28				$30.44
2053	$32.66	$32.77	$32.90	$32.90	$33.24	$32.17	$32.38	$32.97	$33.43				$31.55

Fuel Cost Forecast 3 (Medium Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	IGCC DISPATCH PRICE WITHOUT SO2 $/MMBTU
2007	$1.97	$2.26	$3.20	$2.26	$3.70
2008	$2.01	$2.65	$3.18	$2.65	$3.18
2009	$2.06	$2.66	$3.16	$2.68	$3.02
2010	$2.11	$2.64	$3.19	$2.69	$3.06
2011	$2.17	$1.97	$3.23	$2.07	$3.11
2012	$2.21	$1.99	$3.27	$2.10	$3.15
2013	$2.25	$2.02	$3.19	$2.13	$2.98
2014	$2.29	$2.05	$3.23	$2.16	$3.01
2015	$3.00	$2.08	$3.27	$2.19	$3.06
2016	$3.04	$2.11	$3.34	$2.22	$3.11
2017	$3.08	$2.14	$3.42	$2.25	$3.16
2018	$3.12	$2.17	$3.50	$2.29	$3.22
2019	$3.17	$2.21	$3.59	$2.32	$3.28
2020	$3.22	$2.24	$3.67	$2.36	$3.34
2021	$3.27	$2.28	$3.75	$2.40	$3.40
2022	$3.31	$2.32	$3.83	$2.44	$3.46
2023	$3.35	$2.36	$3.91	$2.48	$3.52
2024	$3.39	$2.40	$4.00	$2.53	$3.59
2025	$3.44	$2.44	$4.14	$2.57	$3.67
2026	$3.48	$2.49	$4.23	$2.62	$3.74
2027	$3.53	$2.53	$4.32	$2.67	$3.81
2028	$3.57	$2.58	$4.42	$2.72	$3.88
2029	$3.62	$2.63	$4.52	$2.77	$3.96
2030	$3.67	$2.68	$4.62	$2.82	$4.03
2031	$3.72	$2.73	$4.73	$2.87	$4.11
2032	$3.77	$2.77	$4.84	$2.92	$4.19
2033	$3.83	$2.82	$4.95	$2.97	$4.27
2034	$3.88	$2.87	$5.06	$3.02	$4.34
2035	$3.94	$2.92	$5.17	$3.08	$4.43
2036	$3.99	$2.97	$5.29	$3.13	$4.51
2037	$4.05	$3.02	$5.41	$3.18	$4.59
2038	$4.11	$3.07	$5.54	$3.24	$4.68
2039	$4.17	$3.13	$5.66	$3.30	$4.77
2040	$4.23	$3.18	$5.79	$3.35	$4.86
2041	$4.29	$3.24	$5.93	$3.41	$4.95
2042	$4.35	$3.30	$6.07	$3.47	$5.05
2043	$4.41	$3.35	$6.21	$3.53	$5.15
2044	$4.47	$3.41	$6.35	$3.59	$5.24
2045	$4.54	$3.47	$6.50	$3.65	$5.34
2046	$4.60	$3.53	$6.66	$3.72	$5.45
2047	$4.67	$3.60	$6.82	$3.78	$5.55
2048	$4.74	$3.66	$6.98	$3.85	$5.66
2049	$4.81	$3.72	$7.14	$3.92	$5.77
2050	$4.88	$3.79	$7.31	$3.98	$5.88
2051	$4.95	$3.86	$7.49	$4.05	$5.99
2052	$5.02	$3.92	$7.67	$4.12	$6.11
2053	$5.09	$3.99	$7.85	$4.19	$6.23

Fuel Cost Forecast 3 (Medium Price): Residual Fuel Oil

YEAR	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 1% $/MMBTU	INDIAN RIVER & CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2007	$8.79	$8.79	$8.79	$8.81	$8.80	$9.07	$8.79
2008	$9.90	$9.89	$9.90	$9.91	$9.90	$10.17	$9.90
2009	$9.78	$9.78	$9.78	$9.79	$9.78	$10.05	$9.78
2010	$9.58	$9.58	$9.59	$9.60	$9.59	$9.86	$9.58
2011	$9.85	$9.85	$9.85	$9.86	$9.85	$10.12	$9.85
2012	$10.09	$10.09	$10.09	$10.10	$10.09	$10.36	$10.09
2013	$10.38	$10.37	$10.38	$10.39	$10.38	$10.65	$10.38
2014	$10.70	$10.70	$10.70	$10.72	$10.71	$10.98	$10.70
2015	$11.09	$11.09	$11.09	$11.10	$11.09	$11.36	$11.09
2016	$11.60	$11.60	$11.60	$11.62	$11.61	$11.87	$11.60
2017	$12.11	$12.11	$12.11	$12.12	$12.12	$12.38	$12.11
2018	$12.61	$12.60	$12.61	$12.62	$12.61	$12.88	$12.61
2019	$13.11	$13.11	$13.11	$13.12	$13.11	$13.38	$13.11
2020	$13.61	$13.61	$13.61	$13.63	$13.62	$13.88	$13.61
2021	$14.10	$14.10	$14.10	$14.11	$14.10	$14.37	$14.10
2022	$14.60	$14.60	$14.60	$14.61	$14.60	$14.87	$14.60
2023	$15.12	$15.12	$15.12	$15.13	$15.13	$15.39	$15.12
2024	$15.66	$15.66	$15.66	$15.67	$15.67	$15.93	$15.66
2025	$16.22	$16.22	$16.22	$16.24	$16.23	$16.49	$16.22
2026	$16.80	$16.80	$16.81	$16.82	$16.81	$17.08	$16.80
2027	$17.41	$17.41	$17.41	$17.42	$17.41	$17.68	$17.41
2028	$18.03	$18.03	$18.04	$18.05	$18.04	$18.31	$18.03
2029	$18.68	$18.68	$18.69	$18.70	$18.69	$18.96	$18.68
2030	$19.36	$19.36	$19.36	$19.37	$19.36	$19.63	$19.36
2031	$20.06	$20.06	$20.06	$20.07	$20.06	$20.33	$20.06
2032	$20.78	$20.78	$20.79	$20.80	$20.79	$21.06	$20.78
2033	$21.54	$21.54	$21.54	$21.55	$21.54	$21.81	$21.54
2034	$22.32	$22.32	$22.32	$22.33	$22.32	$22.59	$22.32
2035	$23.13	$23.13	$23.13	$23.14	$23.13	$23.40	$23.13
2036	$23.97	$23.97	$23.97	$23.98	$23.98	$24.24	$23.97
2037	$24.84	$24.84	$24.85	$24.86	$24.85	$25.12	$24.84
2038	$25.75	$25.75	$25.75	$25.76	$25.75	$26.02	$25.75
2039	$26.69	$26.69	$26.69	$26.70	$26.69	$26.96	$26.69
2040	$27.66	$27.66	$27.66	$27.68	$27.67	$27.94	$27.66
2041	$28.67	$28.67	$28.68	$28.69	$28.68	$28.95	$28.67
2042	$29.72	$29.72	$29.73	$29.74	$29.73	$30.00	$29.72
2043	$30.81	$30.81	$30.81	$30.83	$30.82	$31.08	$30.81
2044	$31.94	$31.94	$31.94	$31.96	$31.95	$32.21	$31.94
2045	$33.11	$33.11	$33.11	$33.13	$33.12	$33.39	$33.11
2046	$34.33	$34.33	$34.33	$34.34	$34.33	$34.60	$34.33
2047	$35.59	$35.59	$35.59	$35.60	$35.59	$35.86	$35.59
2048	$36.90	$36.90	$36.90	$36.91	$36.90	$37.17	$36.90
2049	$38.26	$38.26	$38.26	$38.27	$38.26	$38.53	$38.26
2050	$39.66	$39.66	$39.67	$39.68	$39.67	$39.94	$39.66
2051	$41.13	$41.13	$41.13	$41.14	$41.13	$41.40	$41.13
2052	$42.64	$42.64	$42.64	$42.66	$42.65	$42.91	$42.64
2053	$44.22	$44.21	$44.22	$44.23	$44.22	$44.49	$44.22

Fuel Cost Forecast 3 (Medium Price): Distillate Oil

YEAR	SHADY HILLS $/MMBTU	DESOTO $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN & WCEC $/MMBTU
2007	$14.75	$14.82	$14.86	$14.25	$14.25	$14.75	$14.93	$14.90
2008				$15.50	$15.50	$16.00	$16.18	$16.15
2009				$15.24	$15.24	$15.75	$15.93	$15.89
2010				$12.29	$12.29	$12.80	$12.98	$12.94
2011				$12.47	$12.47	$12.98	$13.16	$13.12
2012				$13.44	$13.44	$13.95	$14.13	$14.09
2013				$13.95	$13.95	$14.46	$14.64	$14.60
2014				$14.45	$14.45	$14.96	$15.14	$15.10
2015				$14.93	$14.93	$15.43	$15.61	$15.58
2016				$15.57	$15.57	$16.08	$16.26	$16.22
2017				$16.23	$16.23	$16.73	$16.91	$16.88
2018				$16.88	$16.88	$17.38	$17.56	$17.52
2019				$17.54	$17.54	$18.04	$18.22	$18.19
2020				$18.20	$18.20	$18.71	$18.89	$18.85
2021				$18.82	$18.82	$19.33	$19.51	$19.47
2022				$19.46	$19.46	$19.97	$20.15	$20.11
2023				$20.13	$20.13	$20.63	$20.81	$20.78
2024				$20.82	$20.82	$21.32	$21.50	$21.46
2025				$21.53	$21.53	$22.03	$22.21	$22.18
2026				$22.26	$22.26	$22.77	$22.95	$22.91
2027				$23.02	$23.02	$23.53	$23.71	$23.67
2028				$23.81	$23.81	$24.31	$24.49	$24.46
2029				$24.62	$24.62	$25.13	$25.31	$25.27
2030				$25.47	$25.47	$25.97	$26.15	$26.12
2031				$26.34	$26.34	$26.84	$27.02	$26.99
2032				$27.24	$27.24	$27.75	$27.93	$27.89
2033				$28.18	$28.18	$28.68	$28.86	$28.82
2034				$29.14	$29.14	$29.65	$29.83	$29.79
2035				$30.14	$30.14	$30.65	$30.83	$30.79
2036				$31.18	$31.18	$31.68	$31.86	$31.82
2037				$32.25	$32.25	$32.75	$32.93	$32.89
2038				$33.35	$33.35	$33.86	$34.04	$34.00
2039				$34.50	$34.50	$35.00	$35.18	$35.15
2040				$35.68	$35.68	$36.19	$36.37	$36.33
2041				$36.91	$36.91	$37.41	$37.59	$37.56
2042				$38.18	$38.18	$38.68	$38.86	$38.83
2043				$39.49	$39.49	$40.00	$40.18	$40.14
2044				$40.85	$40.85	$41.35	$41.53	$41.50
2045				$42.26	$42.26	$42.76	$42.94	$42.90
2046				$43.71	$43.71	$44.21	$44.39	$44.36
2047				$45.21	$45.21	$45.72	$45.90	$45.86
2048				$46.77	$46.77	$47.27	$47.45	$47.42
2049				$48.38	$48.38	$48.89	$49.07	$49.03
2050				$50.05	$50.05	$50.55	$50.73	$50.70
2051				$51.77	$51.77	$52.28	$52.46	$52.42
2052				$53.56	$53.56	$54.06	$54.24	$54.20
2053				$55.40	$55.40	$55.91	$56.09	$56.05

Fuel Cost Forecast 4 (Low Price): Natural Gas

YEAR	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM - SESH PIPELINE $/MMBTU	GULFSTREAM FIRM - MOBILE BAY $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	UPS REPLACEMENT $/MMBTU	WILLIAMS - TRANSCO ZONE 4 $/MMBTU	PROGRESS $/MMBTU	HENRY HUB $/MMBTU
2007	$4.97	$5.05	$5.27	$5.34	$5.55		$5.20	$5.61	$5.86		$5.04	$5.21	$4.82
2008	$5.99	$6.07	$6.19	$6.21	$6.45	$5.90	$6.06	$6.47	$6.74		$5.88	$6.27	$5.81
2009	$6.20	$6.28	$6.37	$6.37	$6.60	$6.07	$6.21	$6.62	$6.89		$6.07	$6.49	$6.01
2010	$5.65	$5.72	$5.82	$5.82	$6.05	$5.53	$5.67	$6.08	$6.35	$5.63			$5.48
2011	$5.36	$5.44	$5.53	$5.53	$5.76	$5.29	$5.43	$5.84	$6.11	$5.39			$5.20
2012	$4.93	$5.01	$5.10	$5.10	$5.33	$4.86	$5.00	$5.41	$5.68	$4.97			$4.78
2013	$5.10	$5.17	$5.26	$5.26	$5.50	$5.03	$5.17	$5.58	$5.85	$5.13			$4.94
2014	$5.34	$5.41	$5.50	$5.50	$5.74	$5.26	$5.40	$5.81	$6.08	$5.37			$5.17
2015	$5.65	$5.73	$5.82	$5.82	$6.05	$5.57	$5.71	$6.12	$6.39	$5.68			$5.48
2016	$5.82	$5.90	$5.99	$5.99	$6.22	$5.74	$5.88	$6.29	$6.56				$5.64
2017	$6.00	$6.07	$6.16	$6.16	$6.40	$5.91	$6.05	$6.46	$6.73				$5.81
2018	$6.17	$6.25	$6.34	$6.34	$6.57	$6.08	$6.23	$6.64	$6.91				$5.98
2019	$6.49	$6.57	$6.66	$6.66	$6.90	$6.40	$6.54	$6.95	$7.23				$6.29
2020	$6.82	$6.90	$6.99	$6.99	$7.22	$6.72	$6.87	$7.28	$7.55				$6.61
2021	$7.07	$7.15	$7.24	$7.24	$7.47	$6.97	$7.11	$7.52	$7.80				$6.85
2022	$7.33	$7.41	$7.50	$7.50	$7.73	$7.23	$7.37	$7.78	$8.05				$7.10
2023	$7.60	$7.68	$7.77	$7.77	$8.00	$7.49	$7.64	$8.04	$8.32				$7.36
2024	$7.88	$7.96	$8.05	$8.05	$8.28	$7.77	$7.91	$8.32	$8.60				$7.63
2025	$8.17	$8.25	$8.34	$8.34	$8.57	$8.06	$8.20	$8.61	$8.88				$7.91
2026	$8.47	$8.55	$8.64	$8.64	$8.88	$8.35	$8.49	$8.90	$9.18				$8.20
2027	$8.79	$8.86	$8.95	$8.95	$9.19	$8.66	$8.80	$9.21	$9.49				$8.50
2028	$9.11	$9.18	$9.27	$9.28	$9.51	$8.98	$9.12	$9.53	$9.81				$8.82
2029	$9.44	$9.52	$9.61	$9.61	$9.85	$9.31	$9.45	$9.86	$10.14				$9.14
2030	$9.79	$9.87	$9.96	$9.96	$10.19	$9.65	$9.79	$10.20	$10.48				$9.47
2031	$10.15	$10.23	$10.32	$10.32	$10.55	$10.00	$10.15	$10.55	$10.84				$9.82
2032	$10.52	$10.60	$10.69	$10.69	$10.93	$10.37	$10.51	$10.92	$11.20				$10.18
2033	$10.91	$10.99	$11.08	$11.08	$11.31	$10.75	$10.89	$11.30	$11.59				$10.56
2034	$11.31	$11.39	$11.48	$11.48	$11.72	$11.15	$11.29	$11.70	$11.98				$10.94
2035	$11.73	$11.80	$11.89	$11.90	$12.13	$11.56	$11.70	$12.11	$12.39				$11.34
2036	$12.16	$12.24	$12.33	$12.33	$12.56	$11.98	$12.12	$12.53	$12.82				$11.76
2037	$12.61	$12.68	$12.77	$12.77	$13.01	$12.42	$12.56	$12.97	$13.26				$12.19
2038	$13.07	$13.15	$13.24	$13.24	$13.47	$12.88	$13.02	$13.43	$13.72				$12.64
2039	$13.55	$13.63	$13.72	$13.72	$13.95	$13.35	$13.49	$13.90	$14.19				$13.10
2040	$14.05	$14.13	$14.22	$14.22	$14.45	$13.84	$13.98	$14.39	$14.68				$13.58
2041	$14.57	$14.64	$14.73	$14.73	$14.97	$14.35	$14.49	$14.90	$15.19				$14.08
2042	$15.10	$15.18	$15.27	$15.27	$15.50	$14.88	$15.02	$15.43	$15.72				$14.60
2043	$15.66	$15.73	$15.82	$15.82	$16.06	$15.42	$15.57	$15.97	$16.27				$15.13
2044	$16.23	$16.31	$16.40	$16.40	$16.63	$15.99	$16.13	$16.54	$16.84				$15.69
2045	$16.83	$16.90	$16.99	$16.99	$17.23	$16.58	$16.72	$17.13	$17.43				$16.26
2046	$17.45	$17.52	$17.61	$17.61	$17.85	$17.19	$17.33	$17.74	$18.04				$16.86
2047	$18.09	$18.16	$18.25	$18.25	$18.49	$17.82	$17.96	$18.37	$18.67				$17.48
2048	$18.75	$18.83	$18.92	$18.92	$19.15	$18.47	$18.61	$19.02	$19.33				$18.12
2049	$19.44	$19.52	$19.61	$19.61	$19.84	$19.15	$19.29	$19.70	$20.01				$18.79
2050	$20.15	$20.23	$20.32	$20.32	$20.56	$19.85	$20.00	$20.40	$20.71				$19.47
2051	$20.89	$20.97	$21.06	$21.06	$21.30	$20.58	$20.72	$21.13	$21.44				$20.19
2052	$21.66	$21.74	$21.83	$21.83	$22.06	$21.34	$21.48	$21.89	$22.20				$20.93
2053	$22.46	$22.53	$22.62	$22.63	$22.86	$22.12	$22.26	$22.67	$22.98				$21.70

Fuel Cost Forecast 4 (Low Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	IGCC DISPATCH PRICE WITHOUT SO2 $/MMBTU
2007	$1.72	$1.97	$2.00	$1.97	$3.23
2008	$1.75	$2.32	$2.34	$2.32	$2.77
2009	$1.80	$2.32	$2.37	$2.34	$2.64
2010	$1.84	$2.30	$2.37	$2.35	$2.67
2011	$1.89	$1.72	$1.78	$1.81	$2.72
2012	$1.93	$1.74	$1.81	$1.83	$2.75
2013	$1.96	$1.77	$1.83	$1.86	$2.60
2014	$2.00	$1.79	$1.85	$1.88	$2.63
2015	$2.62	$1.82	$1.88	$1.91	$2.67
2016	$2.66	$1.84	$1.91	$1.94	$2.72
2017	$2.69	$1.87	$1.93	$1.97	$2.76
2018	$2.73	$1.90	$1.96	$2.00	$2.81
2019	$2.77	$1.93	$1.99	$2.03	$2.87
2020	$2.82	$1.96	$2.02	$2.06	$2.92
2021	$2.85	$1.99	$2.06	$2.10	$2.97
2022	$2.89	$2.03	$2.09	$2.13	$3.02
2023	$2.93	$2.06	$2.12	$2.17	$3.08
2024	$2.97	$2.10	$2.16	$2.21	$3.14
2025	$3.00	$2.13	$2.20	$2.25	$3.21
2026	$3.04	$2.17	$2.24	$2.29	$3.27
2027	$3.08	$2.21	$2.28	$2.33	$3.33
2028	$3.12	$2.25	$2.32	$2.37	$3.39
2029	$3.16	$2.30	$2.36	$2.42	$3.46
2030	$3.21	$2.34	$2.40	$2.46	$3.52
2031	$3.25	$2.38	$2.44	$2.51	$3.59
2032	$3.30	$2.42	$2.49	$2.55	$3.66
2033	$3.34	$2.46	$2.53	$2.60	$3.73
2034	$3.39	$2.51	$2.57	$2.64	$3.79
2035	$3.44	$2.55	$2.61	$2.69	$3.87
2036	$3.49	$2.59	$2.66	$2.73	$3.94
2037	$3.54	$2.64	$2.70	$2.78	$4.01
2038	$3.59	$2.69	$2.75	$2.83	$4.09
2039	$3.64	$2.73	$2.80	$2.88	$4.17
2040	$3.69	$2.78	$2.84	$2.93	$4.25
2041	$3.74	$2.83	$2.89	$2.98	$4.33
2042	$3.80	$2.88	$2.94	$3.03	$4.41
2043	$3.85	$2.93	$2.99	$3.08	$4.49
2044	$3.91	$2.98	$3.05	$3.14	$4.58
2045	$3.96	$3.03	$3.10	$3.19	$4.67
2046	$4.02	$3.09	$3.15	$3.25	$4.76
2047	$4.08	$3.14	$3.21	$3.30	$4.85
2048	$4.14	$3.20	$3.26	$3.36	$4.94
2049	$4.20	$3.25	$3.32	$3.42	$5.04
2050	$4.26	$3.31	$3.37	$3.48	$5.13
2051	$4.32	$3.37	$3.43	$3.54	$5.23
2052	$4.38	$3.43	$3.49	$3.60	$5.33
2053	$4.45	$3.49	$3.55	$3.66	$5.44

Fuel Cost Forecast 4 (Low Price): Residual Fuel Oil

YEAR	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 1% $/MMBTU	INDIAN RIVER & CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2007	$6.88	$6.88	$6.88	$6.89	$6.88	$7.09	$6.88
2008	$7.74	$7.74	$7.74	$7.75	$7.74	$7.95	$7.74
2009	$7.65	$7.65	$7.65	$7.66	$7.65	$7.86	$7.65
2010	$7.50	$7.50	$7.50	$7.51	$7.50	$7.71	$7.50
2011	$7.70	$7.70	$7.70	$7.71	$7.71	$7.92	$7.70
2012	$7.89	$7.89	$7.89	$7.90	$7.90	$8.10	$7.89
2013	$8.12	$8.12	$8.12	$8.13	$8.12	$8.33	$8.12
2014	$8.37	$8.37	$8.37	$8.38	$8.38	$8.59	$8.37
2015	$8.67	$8.67	$8.67	$8.68	$8.68	$8.89	$8.67
2016	$9.08	$9.08	$9.08	$9.09	$9.08	$9.29	$9.08
2017	$9.47	$9.47	$9.48	$9.48	$9.48	$9.69	$9.47
2018	$9.86	$9.86	$9.86	$9.87	$9.86	$10.07	$9.86
2019	$10.25	$10.25	$10.25	$10.26	$10.26	$10.47	$10.25
2020	$10.65	$10.65	$10.65	$10.66	$10.65	$10.86	$10.65
2021	$11.03	$11.03	$11.03	$11.04	$11.03	$11.24	$11.03
2022	$11.42	$11.42	$11.42	$11.43	$11.42	$11.63	$11.42
2023	$11.83	$11.83	$11.83	$11.84	$11.83	$12.04	$11.83
2024	$12.25	$12.25	$12.25	$12.26	$12.25	$12.46	$12.25
2025	$12.69	$12.69	$12.69	$12.70	$12.69	$12.90	$12.69
2026	$13.15	$13.14	$13.15	$13.16	$13.15	$13.36	$13.15
2027	$13.62	$13.62	$13.62	$13.63	$13.62	$13.83	$13.62
2028	$14.11	$14.11	$14.11	$14.12	$14.11	$14.32	$14.11
2029	$14.62	$14.62	$14.62	$14.63	$14.62	$14.83	$14.62
2030	$15.14	$15.14	$15.15	$15.15	$15.15	$15.36	$15.14
2031	$15.69	$15.69	$15.69	$15.70	$15.69	$15.90	$15.69
2032	$16.26	$16.26	$16.26	$16.27	$16.26	$16.47	$16.26
2033	$16.85	$16.85	$16.85	$16.86	$16.85	$17.06	$16.85
2034	$17.46	$17.46	$17.46	$17.47	$17.46	$17.67	$17.46
2035	$18.09	$18.09	$18.09	$18.10	$18.10	$18.31	$18.09
2036	$18.75	$18.75	$18.75	$18.76	$18.76	$18.96	$18.75
2037	$19.43	$19.43	$19.44	$19.44	$19.44	$19.65	$19.43
2038	$20.14	$20.14	$20.14	$20.15	$20.15	$20.36	$20.14
2039	$20.88	$20.88	$20.88	$20.89	$20.88	$21.09	$20.88
2040	$21.64	$21.64	$21.64	$21.65	$21.64	$21.85	$21.64
2041	$22.43	$22.43	$22.43	$22.44	$22.43	$22.64	$22.43
2042	$23.25	$23.25	$23.25	$23.26	$23.26	$23.46	$23.25
2043	$24.10	$24.10	$24.10	$24.11	$24.11	$24.32	$24.10
2044	$24.99	$24.99	$24.99	$25.00	$24.99	$25.20	$24.99
2045	$25.90	$25.90	$25.90	$25.91	$25.91	$26.12	$25.90
2046	$26.85	$26.85	$26.86	$26.86	$26.86	$27.07	$26.85
2047	$27.84	$27.84	$27.84	$27.85	$27.84	$28.05	$27.84
2048	$28.86	$28.86	$28.87	$28.87	$28.87	$29.08	$28.86
2049	$29.93	$29.93	$29.93	$29.94	$29.93	$30.14	$29.93
2050	$31.03	$31.03	$31.03	$31.04	$31.03	$31.24	$31.03
2051	$32.17	$32.17	$32.17	$32.18	$32.17	$32.38	$32.17
2052	$33.36	$33.36	$33.36	$33.37	$33.36	$33.57	$33.36
2053	$34.59	$34.59	$34.59	$34.60	$34.59	$34.80	$34.59

Fuel Cost Forecast 4 (Low Price): Distillate Oil

YEAR	SHADY HILLS $/MMBTU	DESOTO $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN & WCEC $/MMBTU
2007	$11.54	$11.60	$11.62	$11.15	$11.15	$11.54	$11.68	$11.65
2008				$12.13	$12.13	$12.52	$12.66	$12.63
2009				$11.92	$11.92	$12.32	$12.46	$12.43
2010				$9.62	$9.62	$10.01	$10.15	$10.12
2011				$9.76	$9.76	$10.15	$10.29	$10.27
2012				$10.52	$10.52	$10.91	$11.05	$11.02
2013				$10.91	$10.91	$11.31	$11.45	$11.42
2014				$11.30	$11.30	$11.70	$11.84	$11.81
2015				$11.68	$11.68	$12.07	$12.21	$12.19
2016				$12.18	$12.18	$12.58	$12.72	$12.69
2017				$12.69	$12.69	$13.09	$13.23	$13.20
2018				$13.20	$13.20	$13.60	$13.74	$13.71
2019				$13.72	$13.72	$14.11	$14.26	$14.23
2020				$14.24	$14.24	$14.63	$14.77	$14.75
2021				$14.72	$14.72	$15.12	$15.26	$15.23
2022				$15.23	$15.23	$15.62	$15.76	$15.73
2023				$15.75	$15.75	$16.14	$16.28	$16.25
2024				$16.28	$16.28	$16.68	$16.82	$16.79
2025				$16.84	$16.84	$17.23	$17.37	$17.35
2026				$17.41	$17.41	$17.81	$17.95	$17.92
2027				$18.01	$18.01	$18.40	$18.55	$18.52
2028				$18.63	$18.63	$19.02	$19.16	$19.13
2029				$19.26	$19.26	$19.66	$19.80	$19.77
2030				$19.92	$19.92	$20.32	$20.46	$20.43
2031				$20.60	$20.60	$21.00	$21.14	$21.11
2032				$21.31	$21.31	$21.70	$21.85	$21.82
2033				$22.04	$22.04	$22.44	$22.58	$22.55
2034				$22.80	$22.80	$23.19	$23.33	$23.30
2035				$23.58	$23.58	$23.97	$24.11	$24.09
2036				$24.39	$24.39	$24.78	$24.92	$24.89
2037				$25.22	$25.22	$25.62	$25.76	$25.73
2038				$26.09	$26.09	$26.48	$26.63	$26.60
2039				$26.99	$26.99	$27.38	$27.52	$27.49
2040				$27.91	$27.91	$28.31	$28.45	$28.42
2041				$28.87	$28.87	$29.27	$29.41	$29.38
2042				$29.87	$29.87	$30.26	$30.40	$30.37
2043				$30.89	$30.89	$31.29	$31.43	$31.40
2044				$31.95	$31.95	$32.35	$32.49	$32.46
2045				$33.05	$33.05	$33.45	$33.59	$33.56
2046				$34.19	$34.19	$34.59	$34.73	$34.70
2047				$35.37	$35.37	$35.76	$35.90	$35.88
2048				$36.59	$36.59	$36.98	$37.12	$37.09
2049				$37.85	$37.85	$38.24	$38.38	$38.35
2050				$39.15	$39.15	$39.54	$39.69	$39.66
2051				$40.50	$40.50	$40.89	$41.03	$41.01
2052				$41.89	$41.89	$42.29	$42.43	$42.40
2053				$43.34	$43.34	$43.73	$43.87	$43.85

Appendix E

Nuclear Fuel Costs

$/MMBTU

Year	St Lucie #1	St Lucie #2	Turkey Pt #3	Turkey Pt #4	Proposed Turkey Pt #6	Proposed Turkey Pt #7
2007	0.442	0.461	0.426	0.423	--	--
2008	0.550	0.531	0.609	0.603	--	--
2009	0.645	0.566	0.681	0.645	--	--
2010	0.741	0.588	0.700	0.783	--	--
2011	0.782	0.760	0.763	0.788	--	--
2012	0.802	0.779	0.782	0.807	--	--
2013	0.822	0.798	0.801	0.827	--	--
2014	0.842	0.818	0.821	0.848	--	--
2015	0.863	0.838	0.842	0.869	--	--
2016	0.885	0.859	0.863	0.891	--	--
2017	0.907	0.881	0.884	0.913	--	--
2018	0.930	0.903	0.906	0.936	0.872	0.000
2019	0.953	0.925	0.929	0.960	0.867	0.000
2020	0.977	0.949	0.952	0.984	0.956	0.872
2021	1.001	0.972	0.976	1.008	1.041	0.867
2022	1.026	0.997	1.001	1.033	1.036	0.956
2023	1.052	1.021	1.026	1.059	0.982	1.041
2024	1.078	1.047	1.051	1.086	1.007	1.036
2025	1.105	1.073	1.077	1.113	1.032	0.982
2026	1.133	1.100	1.104	1.141	1.058	1.007
2027	1.161	1.128	1.132	1.169	1.084	1.032
2028	1.190	1.156	1.160	1.198	1.111	1.058
2029	1.220	1.185	1.189	1.228	1.139	1.084
2030	1.251	1.214	1.317	1.259	1.168	1.111
2031	1.282	1.245	1.970	1.549	1.197	1.139
2032	1.314	1.276	1.898	1.905	1.227	1.168
2033	1.347	1.308	--	1.991	1.258	1.197
2034	1.574	1.340	--	--	1.289	1.227
2035	2.258	1.374	--	--	1.321	1.258
2036	2.129	1.408	--	--	1.354	1.289
2037	--	1.443	--	--	1.388	1.321
2038	--	1.479	--	--	1.423	1.354
2039	--	1.516	--	--	1.458	1.388
2040	--	1.554	--	--	1.495	1.423
2041	--	1.593	--	--	1.532	1.458
2042	--	1.633	--	--	1.570	1.495
2043	--	1.674	--	--	1.610	1.532
2044	--	--	--	--	1.650	1.570
2045	--	--	--	--	1.691	1.610
2046	--	--	--	--	1.733	1.650
2047	--	--	--	--	1.777	1.691
2048	--	--	--	--	1.821	1.733
2049	--	--	--	--	1.867	1.777
2050	--	--	--	--	1.913	1.821
2051	--	--	--	--	1.961	1.867
2052	--	--	--	--	2.010	1.913
2053	--	--	--	--	2.061	1.961
2054	--	--	--	--	2.112	2.010
2055	--	--	--	--	2.165	2.061
2056	--	--	--	--	2.219	2.112
2057	--	--	--	--	2.274	2.165
2058	--	--	--	--	2.331	2.219
2059	--	--	--	--	2.390	2.274
2060	--	--	--	--	2.449	2.331

Appendix F

Environmental Compliance Costs

(nominal $ per ton)

SO_2:	Year	ENV I	ENV II	ENV III	ENV IV
	2007	970	888	867	867
	2008	1,062	972	950	950
	2009	1,163	1,065	1,040	1,040
	2010	1,273	1,165	1,138	1,138
	2011	1,394	1,276	1,247	1,247
	2012	1,527	1,398	1,366	1,366
	2013	1,673	1,532	1,496	1,496
	2014	1,833	1,677	1,639	1,639
	2015	2,007	1,838	1,793	1,793
	2016	2,198	2,013	1,964	1,964
	2017	2,406	2,203	2,149	2,149
	2018	2,633	2,411	2,353	2,353
	2019	2,881	2,638	2,576	2,576
	2020	3,153	2,888	2,818	2,818
	2021	3,454	3,163	3,088	3,088
	2022	3,783	3,465	3,383	3,383
	2023	4,144	3,795	3,704	3,704
	2024	4,539	4,155	4,057	4,057
	2025	4,972	4,552	4,444	4,444
	2026	5,168	4,679	4,419	4,419
	2027	5,373	4,810	4,395	4,395
	2028	5,587	4,944	4,369	4,369
	2029	5,808	5,083	4,345	4,345
	2030	6,038	5,224	4,320	4,320
	2031	6,189	5,395	4,489	4,489
	2032	6,344	5,571	4,665	4,665
	2033	6,503	5,753	4,847	4,847
	2034	6,665	5,941	5,037	5,037
	2035	6,832	6,135	5,234	5,234
	2036	7,003	6,336	5,439	5,439
	2037	7,178	6,543	5,652	5,652
	2038	7,357	6,756	5,874	5,874
	2039	7,541	6,977	6,104	6,104
	2040	7,730	7,205	6,343	6,343
	2041	7,923	7,440	6,591	6,591
	2042	8,121	7,683	6,849	6,849
	2043	8,324	7,934	7,118	7,118

Environmental Compliance Costs

(nominal $ per ton)

NO_X:	Year	ENV I	ENV II	ENV III	ENV IV
	2007	0	0	0	0
	2008	0	0	0	0
	2009	1,755	1,674	1,633	1,633
	2010	1,772	1,826	1,786	1,786
	2011	1,788	1,991	1,955	1,955
	2012	1,960	2,182	2,142	2,142
	2013	2,147	2,391	2,347	2,347
	2014	2,352	2,619	2,571	2,571
	2015	2,576	2,867	2,815	2,815
	2016	2,820	3,140	3,082	3,082
	2017	3,087	3,436	3,374	3,374
	2018	3,377	3,761	3,693	3,693
	2019	3,696	4,116	4,041	4,041
	2020	4,045	4,506	4,423	4,423
	2021	3,843	3,337	3,590	3,590
	2022	3,650	2,473	2,912	2,912
	2023	3,467	1,831	2,363	2,363
	2024	3,293	1,356	1,918	1,918
	2025	3,128	1,004	1,557	1,557
	2026	3,158	1,100	0	0
	2027	3,187	1,205	0	0
	2028	3,217	1,320	0	0
	2029	3,247	1,445	0	0
	2030	3,276	1,583	0	0
	2031	3,358	1,635	0	0
	2032	3,442	1,688	0	0
	2033	3,528	1,744	0	0
	2034	3,616	1,801	0	0
	2035	3,706	1,859	0	0
	2036	3,799	1,920	0	0
	2037	3,894	1,983	0	0
	2038	3,991	2,048	0	0
	2039	4,091	2,114	0	0
	2040	4,193	2,184	0	0
	2041	4,298	2,255	0	0
	2042	4,406	2,328	0	0
	2043	4,516	2,405	0	0

Environmental Compliance Costs

(nominal $ per ton)

CO_2:	Year	ENV I	ENV II	ENV III	ENV IV
	2007	0	0	0	0
	2008	0	0	0	0
	2009	0	0	0	0
	2010	7	0	11	15
	2011	7	2	13	17
	2012	7	5	14	19
	2013	9	8	15	19
	2014	9	9	16	21
	2015	10	11	18	23
	2016	10	13	20	26
	2017	11	16	22	28
	2018	12	19	23	30
	2019	13	22	25	33
	2020	13	26	29	38
	2021	13	28	31	41
	2022	15	32	35	45
	2023	16	35	37	49
	2024	16	38	42	54
	2025	16	41	44	58
	2026	17	44	49	63
	2027	17	47	53	69
	2028	18	49	60	78
	2029	18	51	65	85
	2030	19	52	70	92
	2031	19	54	73	95
	2032	19	55	76	99
	2033	20	57	79	103
	2034	20	59	83	107
	2035	21	61	86	112
	2036	22	63	89	116
	2037	22	65	93	121
	2038	23	67	97	126
	2039	23	70	100	131
	2040	24	72	104	136
	2041	24	74	108	141
	2042	25	77	113	147
	2043	26	79	117	152

Appendix F

Environmental Compliance Costs

(nominal $ per lb)

Hg:	Year	ENV I	ENV II	ENV III	ENV IV
	2007	-	-	-	-
	2008	-	-	-	-
	2009	-	-	-	-
	2010	28,303	29,986	29,832	29,832
	2011	29,252	29,680	29,533	29,533
	2012	30,232	29,377	29,237	29,237
	2013	31,246	29,077	28,943	28,943
	2014	33,238	30,270	30,134	30,134
	2015	36,394	33,145	32,994	32,994
	2016	39,851	36,292	36,127	36,127
	2017	43,616	39,723	39,540	39,540
	2018	47,738	43,354	43,276	43,276
	2019	52,250	47,588	47,366	47,366
	2020	57,188	52,085	51,840	51,840
	2021	62,637	57,050	56,782	56,782
	2022	68,607	62,487	62,195	62,195
	2023	75,144	68,443	68,123	68,123
	2024	82,305	74,966	74,617	74,617
	2025	90,148	82,109	81,746	81,746
	2026	98,743	89,935	89,520	89,520
	2027	108,154	98,505	98,052	98,052
	2028	118,465	107,892	107,398	107,398
	2029	129,758	118,173	117,636	117,636
	2030	142,127	129,435	128,847	128,847
	2031	146,770	132,671	133,893	133,893
	2032	151,564	135,988	139,137	139,137
	2033	156,515	139,387	144,586	144,586
	2034	161,628	142,872	150,248	150,248
	2035	166,908	146,444	156,132	156,132
	2036	172,360	150,105	162,246	162,246
	2037	177,991	153,857	168,600	168,600
	2038	183,805	157,704	175,203	175,203
	2039	189,809	161,647	182,064	182,064
	2040	196,010	165,688	189,194	189,194
	2041	202,413	169,830	196,603	196,603
	2042	209,025	174,076	204,302	204,302
	2043	215,853	178,428	212,303	212,303

Appendix G

Financial and Economic Assumptions

I. FPL Capital Structure, Discount Rate, and AFUDC Rate:

a) Projected Capitalization Ratios and Projected Cost of Capital:

Component	Ratio	Cost
Debt	44.20%	6.43%
Preferred	0%	0%
Equity	55.80%	11.75%

b) Projected Discount Rate = 8.40 % for generation costs and 8.30% for all other costs.

c) Projected AFUDC Rates

Year	Rate (%)
2007	7.42
2008	8.03
2009	8.17
2010	8.19
2011	8.20
2012 and beyond	8.19

d) Rate used for recovery of nuclear unit (pre-tax AFUDC) = 11.04%

II. Tax Assumptions:

a) Composite Effective Income Tax Rate (Federal and State tax rates adjusted for federal production tax credits for each unit) =
35.100% for generation facilities
38.575% for transmission facilities

b) Combined Cycle Book Life = 25 years

c) Combined Cycle Tax Depreciation Life = 20 years

d) Transmission Book Life = 40 years

e) Transmission Tax Depreciation Life = 15 years

III. General Inflation Rate = 2.5%

Appendix H

Revenue Requirements Including Carrying Costs of Construction

Overnight Cost (in 2007 $/kW) 1.0

Turkey Point 6

		Site Selection costs ($ 000)	Pre-construction cash-flows I ($ 000)	Construction cash-flows ($ 000)	Site selection and Pre-construction AFUDC ($ 000)	Construction CCC ($ 000)	Construction Revenue Requirements ($ 000)	Total Revenue Requirements ($ 000)
1	2007	2.23	0.00	0.00	0	0.00	0.00	0.00
2	2008	0.00	13.06	0.00	0	0.00	0.00	0.00
3	2009	0.00	14.06	0.00	31.10	0.00	0.00	31.10
4	2010	0.00	25.73	0.00	27.57	0.00	0.00	27.57
5	2011	0.00	26.37	0.00	29.33	0.00	0.00	29.33
6	2012	0.00	0.00	201.85	3.52	11.14	0.00	14.66
7	2013	0.00	0.00	258.34	3.52	36.54	0.00	40.06
8	2014	0.00	0.00	264.14	3.52	65.39	0.00	68.90
9	2015	0.00	0.00	292.50	3.52	96.11	0.00	99.63
10	2016	0.00	0.00	278.50	3.52	127.63	0.00	131.15
11	2017	0.00	0.00	188.88	3.52	153.43	0.00	156.95
12	2018	0.00	0.00	191.76	1.46	72.68	169.83	243.98
13	2019	0	0	0	0.00	0.00	282.11	282.11
14	2020	0	0	0	0.00	0.00	270.63	270.63
15	2021	0	0	0	0.00	0.00	259.86	259.86
16	2022	0	0	0	0.00	0.00	249.74	249.74
17	2023	0	0	0	0.00	0.00	240.21	240.21
18	2024	0	0	0	0.00	0.00	231.09	231.09
19	2025	0	0	0	0.00	0.00	222.10	222.10
20	2026	0	0	0	0.00	0.00	213.11	213.11
21	2027	0	0	0	0.00	0.00	204.12	204.12
22	2028	0	0	0	0.00	0.00	195.13	195.13
23	2029	0	0	0	0.00	0.00	186.14	186.14
24	2030	0	0	0	0.00	0.00	177.14	177.14
25	2031	0	0	0	0.00	0.00	168.15	168.15
26	2032	0	0	0	0.00	0.00	159.16	159.16
27	2033	0	0	0	0.00	0.00	151.35	151.35
28	2034	0	0	0	0.00	0.00	145.89	145.89
29	2035	0	0	0	0.00	0.00	141.62	141.62
30	2036	0	0	0	0.00	0.00	137.35	137.35
31	2037	0	0	0	0.00	0.00	133.07	133.07
32	2038	0	0	0	0.00	0.00	128.80	128.80
33	2039	0	0	0	0.00	0.00	124.52	124.52
34	2040	0	0	0	0.00	0.00	120.25	120.25
35	2041	0	0	0	0.00	0.00	115.97	115.97
36	2042	0	0	0	0.00	0.00	111.70	111.70
37	2043	0	0	0	0.00	0.00	107.43	107.43
38	2044	0	0	0	0.00	0.00	103.15	103.15
39	2045	0	0	0	0.00	0.00	98.88	98.88
40	2046	0	0	0	0.00	0.00	94.60	94.60
41	2047	0	0	0	0.00	0.00	90.33	90.33
42	2048	0	0	0	0.00	0.00	86.06	86.06
43	2049	0	0	0	0.00	0.00	81.78	81.78
44	2050	0	0	0	0.00	0.00	77.51	77.51
45	2051	0	0	0	0.00	0.00	73.23	73.23
46	2052	0	0	0	0.00	0.00	68.96	68.96
47	2053	0	0	0	0.00	0.00	64.68	64.68
48	2054	0	0	0	0.00	0.00	60.41	60.41
49	2055	0	0	0	0.00	0.00	56.14	56.14
50	2056	0	0	0	0.00	0.00	51.86	51.86
51	2057	0	0	0	0.00	0.00	47.59	47.59
52	2058	0	0	0	0.00	0.00	0.00	0.00
53	2059	0	0	0	0.00	0.00	0.00	0.00
54	2060	0	0	0	0.00	0.00	0.00	0.00

Total CPVRR TP6 1,352.71

Turkey Point 7

		Site Selection costs ($ 000)	Pre-construction cash-flows I ($ 000)	Construction cash-flows ($ 000)	Site selection and Pre-construction AFUDC ($ 000)	Construction CCC ($ 000)	Construction Revenue Requirements ($ 000)	Total Revenue Requirements ($ 000)
1	2007	0	0	0	0	0	0	0
2	2008	0	0	0	0	0	0	0
3	2009	0	0	0	0	0	0	0
4	2010	0	0	0	0	0	0	0
5	2011	0	0	0	0	0	0	0
6	2012	0	0	0	0	0	0	0
7	2013	0	0	32	0	2	0	2
8	2014	0	0	88	0	8	0	8
9	2015	0	0	161	0	22	0	22
10	2016	0	0	223	0	43	0	43
11	2017	0	0	170	0	65	0	65
12	2018	0	0	131	0	82	0	82
13	2019	0	0	87	0	94	0	94
14	2020	0	0	47	0	42	94	136
15	2021	0	0	0	0	0	156	156
16	2022	0	0	0	0	0	150	150
17	2023	0	0	0	0	0	144	144
18	2024	0	0	0	0	0	138	138
19	2025	0	0	0	0	0	133	133
20	2026	0	0	0	0	0	128	128
21	2027	0	0	0	0	0	123	123
22	2028	0	0	0	0	0	118	118
23	2029	0	0	0	0	0	113	113
24	2030	0	0	0	0	0	108	108
25	2031	0	0	0	0	0	104	104
26	2032	0	0	0	0	0	99	99
27	2033	0	0	0	0	0	94	94
28	2034	0	0	0	0	0	89	89
29	2035	0	0	0	0	0	85	85
30	2036	0	0	0	0	0	82	82
31	2037	0	0	0	0	0	79	79
32	2038	0	0	0	0	0	77	77
33	2039	0	0	0	0	0	74	74
34	2040	0	0	0	0	0	72	72
35	2041	0	0	0	0	0	70	70
36	2042	0	0	0	0	0	67	67
37	2043	0	0	0	0	0	65	65
38	2044	0	0	0	0	0	62	62
39	2045	0	0	0	0	0	60	60
40	2046	0	0	0	0	0	58	58
41	2047	0	0	0	0	0	55	55
42	2048	0	0	0	0	0	53	53
43	2049	0	0	0	0	0	50	50
44	2050	0	0	0	0	0	48	48
45	2051	0	0	0	0	0	46	46
46	2052	0	0	0	0	0	43	43
47	2053	0	0	0	0	0	41	41
48	2054	0	0	0	0	0	38	38
49	2055	0	0	0	0	0	36	36
50	2056	0	0	0	0	0	34	34
51	2057	0	0	0	0	0	31	31
52	2058	0	0	0	0	0	29	29
53	2059	0	0	0	0	0	26	26
54	2060	0	0	0	0	0	0	0

Total CPVRR TP7 620.61

Total CPVRR - both units 1,973.32

Notes:

-The overnight cost of both units in 2007 $ would be obtained by multiplying the $1/kw cost * 2 units * 1100 Mw per unit *1000

-The cost figures above are in thousands of dollars.

-CPVRR = Cumulative Present Value Revenue Requirements

-CCC = Carrying Costs of Construction

Appendix I

FPL's New Generating Unit Options (Non-Nuclear)

In-service year	3 x 1 CC 2011	2 x 1 CC 2017	3 x 1 CC 2018	IGCC 2018	2 x 1 CC 2021
All costs are shown in in-service year $s	G Moderate Duct Fired Greenfield	G Moderate Duct Fired Greenfield	G Moderate Duct Fired Greenfield	2 x 1 CC Greenfield	7FA Moderate Duct Fired Greenfield
I. Construction Costs ($1,000)					
Total Direct Cost	$686,572	$613,160	$816,118	$2,149,854	$457,804
Total Indirect Cost	$104,862	$93,446	$124,648	$486,128	$103,147
Total Other Cost (transmission interconnection)	$26,492	$23,042	$31,490	$147,610	$35,324
Grand Total Cost (In Service Year)	$817,925	$729,648	$972,256	$2,783,592	$596,275
II. Plant Characteristics (Unit Average)					
Net Sum 95FCapability (mw) - Base	1115	743	1115	600	492
Net Win 35F Capability (mw) - Base	1246	831	1246	692	543
Heat Rate btu/kwh 75F100% -Base	6,582	6,582	6,582	9,250	6,885
Duct Firing-Incremental from Base Sum MW 95F	104	69	104	n/a	48
Duct Firing-Incremental from Base Win MW 35F	89	59	89	n/a	47
Duct Firing-Incremental from Base Ann Avg Heat Rate 75F	8,770	8,770	8,770	n/a	8,620
Peak Firing- Incremental from Base Sum MW 95F	0	0	0	n/a	13
Peak Firing- Incremental from Base Win MW 35F	0	0	0	n/a	0
Peak Firing- Incremental from Base Ann Avg Heat Rate 75F	n/a	n/a	n/a	n/a	5,500
Annual Availability	96.8%	96.8%	96.8%	80.0%	97.0%
Ramp Rate (MW/Minute)	30	30	30	20	20
Minimum Load	320	320	320	180	180
III. Operation Costs					
Fixed O&M ($/kw-yr)(Summer Peak Output)	4.4	6.5	5.2	53.5	10.6
Variable (excl. fuel) ($/mwh) (Summer Peak Output @ 85% CF)	0.7	0.8	0.8	5.3	0.9
Capital Replace ($/kw-yr)(Summer Peak Output)	10.8	12.1	12.8	38.6	15.8
IV. Emission Rates					
NOx Emission Rates (lb/mmbtu)	0.010	0.010	0.010	0.015	0.010
SO2 Emission Rates (lb/mmbtu)	0.006	0.006	0.006	0.023	0.006
CO2 (lb/mmbtu)	119	119	119	213	119
Mercury, Hg (lb/Tbtu) (T=trillion)	0.000	0.000	0.000	0.500	0.000
V. Spending Curves (1,000) $					
Year 7				$55,698	
Year 6				$250,543	
Year 5	$1,656	$1,536	$1,968	$556,718	$1,272
Year 4	$56,736	$50,563	$67,441	$1,113,437	$41,259
Year 3	$469,672	$418,972	$558,293	$556,718	$342,364
Year 2	$222,529	$198,541	$264,517	$222,661	$162,209
Year 1	$67,333	$60,036	$80,037	$27,816	$49,171

Note:

* The costs of the 2018 in-service 3 x 1 G CC and IGCC units shown above do not include transmission integration costs because sites for these assumed units are not known. However, for analysis purposes, it was assumed that for each of these technologies, building 2400 MW of capacity at a greenfield site will incur transmission costs of $500 million (2007$).

** The "Total Indirect Costs" for the IGCC unit also include $32 million (2207$) of solid fuel transportation costs (railroad cars and rail spur).

Appendix J

Construction Unit Cost Estimate Range Based on TVA Study - Two Unit ABWR Project, at 1,371 MW per unit	CASE A: TVA Study Adjusted to 2007$ (Index 206/238) and Modified for FPL Owners Scope and PTN Site Cost Estimates		CASE B: Reduced Material Escalation (Index 170/192), Reduced Owner Scope, 10% lower Owners Costs, Low Transmission Estimate		CASE C: Increased Material Escalation (Index 242/284), Added Owner Scope, 10% higher Owner's Costs, High Labor & Transmission Estimate	
	2007 $	$/kWe	2007 $	$/kWe	2007 $	$/kWe
Power Plant Island and Supporting Construction						
Structure & Improvements	$792,000,000	$289	$654,000,000	$239	$931,000,000	$340
Reactor Plant Equipment	$1,399,000,000	$510	$1,155,000,000	$421	$1,644,000,000	$600
Turbine Plant Equipment	$934,000,000	$341	$771,000,000	$281	$1,097,000,000	$400
Electric Plant Equipment	$413,000,000	$151	$333,000,000	$121	$493,000,000	$180
Misc. Plant Equipment	$146,000,000	$53	$118,000,000	$43	$174,000,000	$63
Main Cond. Heat Reject Sys	$84,000,000	$31	$84,000,000	$31	$84,000,000	$31
Circ. Water Pumps & Pipe	$26,000,000	$9	$26,000,000	$9	$26,000,000	$9
Construction Labor, Manual	$1,422,000,000	$519	$1,422,000,000	$519	$1,848,600,000	$674
Construction Services	$534,000,000	$195	$431,000,000	$157	$694,200,000	$253
Engineers Home Office Services	$834,000,000	$304	$834,000,000	$304	$1,084,200,000	$395
Additional Required Scope	$98,000,000	$36	$0	$0	$107,800,000	$39
Allowance for Cost Risk	$1,002,300,000	$366	$874,200,000	$319	$1,636,760,000	$597
Subtotal	$7,684,300,000	$2,802	$6,702,200,000	$2,444	$9,820,560,000	$3,582
Owners Costs						
Security infrastructure	$109,000,000	$40	$98,100,000	$36	$119,900,000	$44
Cooling Towers	$131,000,000	$48	$0	$0	$144,100,000	$53
Aux Boilers	$16,000,000	$6	$0	$0	$17,600,000	$6
Switch Yard	$93,000,000	$34	$83,700,000	$31	$102,300,000	$37
Site work	$257,000,000	$94	$231,300,000	$84	$282,700,000	$103
EPC startup costs	$139,000,000	$51	$125,100,000	$46	$152,900,000	$56
Fuel	$45,000,000	$16	$40,500,000	$15	$49,500,000	$18
Site Security	$91,000,000	$33	$81,900,000	$30	$100,100,000	$37
Permits/Licensing	$104,000,000	$38	$93,600,000	$34	$114,400,000	$42
Other Owner costs	$38,000,000	$14	$34,200,000	$12	$41,800,000	$15
Owner Project Management	$166,000,000	$61	$149,400,000	$54	$237,380,000	$87
Owner Transition	$192,000,000	$70	$172,800,000	$63	$274,560,000	$100
Land Costs - Site	$0	$0	$0	$0	$0	$0
Land Costs - Offsite	$0	$0	$0	$0	$0	$0
Allowance for Cost Risk	$207,150,000	$76	$166,590,000	$61	$327,448,000	$119
Subtotal	$1,588,150,000	$579	$1,277,190,000	$466	$1,964,688,000	$717
Additional Project Related Costs						
Transmission Integration	$512,000,000	$187	$471,000,000	$172	$553,000,000	$202
Allowance for Cost Risk	$76,800,000	$28	$70,650,000	$26	$110,600,000	$40
Subtotal	$588,800,000	$215	$541,650,000	$198	$663,600,000	$242
Grand Total	**$9,861,250,000**	**$3,596**	**$8,521,040,000**	**$3,108**	**$12,448,848,000**	**$4,540**

Appendix K

FPL's Approved DSM Plan

FPL's Current DSM Programs

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation, reflective roofs, and roof membranes in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Residential Low Income Weatherization: This program addresses the needs of low-income housing retrofits by providing monetary incentives to various housing authorities including: weatherization agency providers (WAPS), non-weatherization agency providers (non-WAPS), and other providers approved by FPL. The incentives are used by these providers to

leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing businesses by identifying DSM opportunities and providing recommendations to business customers.

Business Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation, and air conditioning (HVAC) systems for business customers.

Business Efficient Lighting: This program encourages the installation of energy-efficient lighting measures for business customers.

Business Custom Incentive: This program encourages business customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial Demand Reduction: This program, which started in 2002, is similar to the Commercial/Industrial Load Control program mentioned above. It reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Business Building Envelope: This program encourages the installation of energy-efficient building envelope measures such as: roof/ceiling insulation, reflective roof coatings, and window treatments for business customers.

Business On Call: This program offers load control of central air conditioning units to both small non–demand-billed, and medium demand-billed, business customers in exchange for monthly electric bill credits.

Business Water Heating: This program encourages the installation of energy-efficient water heating equipment such as heat pump water heaters and heat recovery units for business customers.

Business Refrigeration: This program encourages the installation of qualifying controls and equipment that reduce electric strip heater usage in refrigeration equipment for business customers.

FPL's Renewable Program

Green Power Pricing: In November of 2004, FPL launched its Green Power Pricing Research Project (GPPRP) that was marketed as the *Sunshine Energy*® program. The object of the Project was to allow residential customers to sign up voluntarily and pay for energy produced by renewable resources, thus fostering the development of supplies of renewable energy that would not otherwise be developed. Project participants paid a monthly premium of $9.75 per month for a 1,000 kWh block of renewable energy attributes. To supply the renewable energy for the Project, FPL entered into a contract with a supplier for the purchase of tradable renewable energy credits (TRECs). In addition, for every 10,000 residential participants, FPL agreed to cause to be built 150 kW of solar capacity in Florida. As a result of this Program construction of a 250 kW site in Sarasota is currently in progress with expected completion in October 2007. There are also several other smaller projects that have been completed, with additional projects underway.

On September 17, 2006, FPL filed a petition with the Commission to convert the GPPRP to a permanent program and to extend the program to business customers. On December 1, 2006, the Commission issued Order No. PSC-06-0924-TRF-EI in Docket No. 060577-EI approving this request.

FPL's Research and Development Initiatives

FPL continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities, not only through its Conservation Research and Development program (discussed below), but also through individual research projects. These efforts will examine a wide variety of

technologies that build on prior FPL research and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program: FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies such as: condenser coil cleaner and coating, ultraviolet lights for evaporator coils, Energy Recovery Ventilators (ERV), fuel cell demonstrations, carbon dioxide (CO2) ventilation control, two-speed air handlers, and duct plenum repair. Many of the technologies examined have resulted in enhancements to existing programs or the development of new programs such as: Residential New Construction, Business Building Envelope, and Business On Call. FPL is currently investigating several technologies including: Cromer Cycle HVAC, commercial kitchen exhaust hoods, HVAC optimizers, and commercial refrigeration flow controls.

Residential Thermostat Load Control Pilot Project: On June 15, 2007 FPL filed a petition with the Commission for the Residential Thermostat Load Control Pilot Project. A typical barrier to customer acceptance of utility load control programs is reluctance to surrender control of heating and air conditioning appliances. Consequently, for an initial 24-month period, FPL is proposing to evaluate whether the benefits of the On-Call Program can be expanded through use of a new generation of communication and control technologies that put residential customers in charge of decisions that could lower energy costs, while allowing customers to override FPL control of their heating and air conditioning appliances. The Commission approved FPL's request on August 14, 2007.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 97
COMPANY Excerpts from US Emmission +
WITNESS Fuel Markets Outlook 2006
DATE 01/30-02/01/08

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 98
COMPANY Not Moved into
WITNESS The Record
DATE

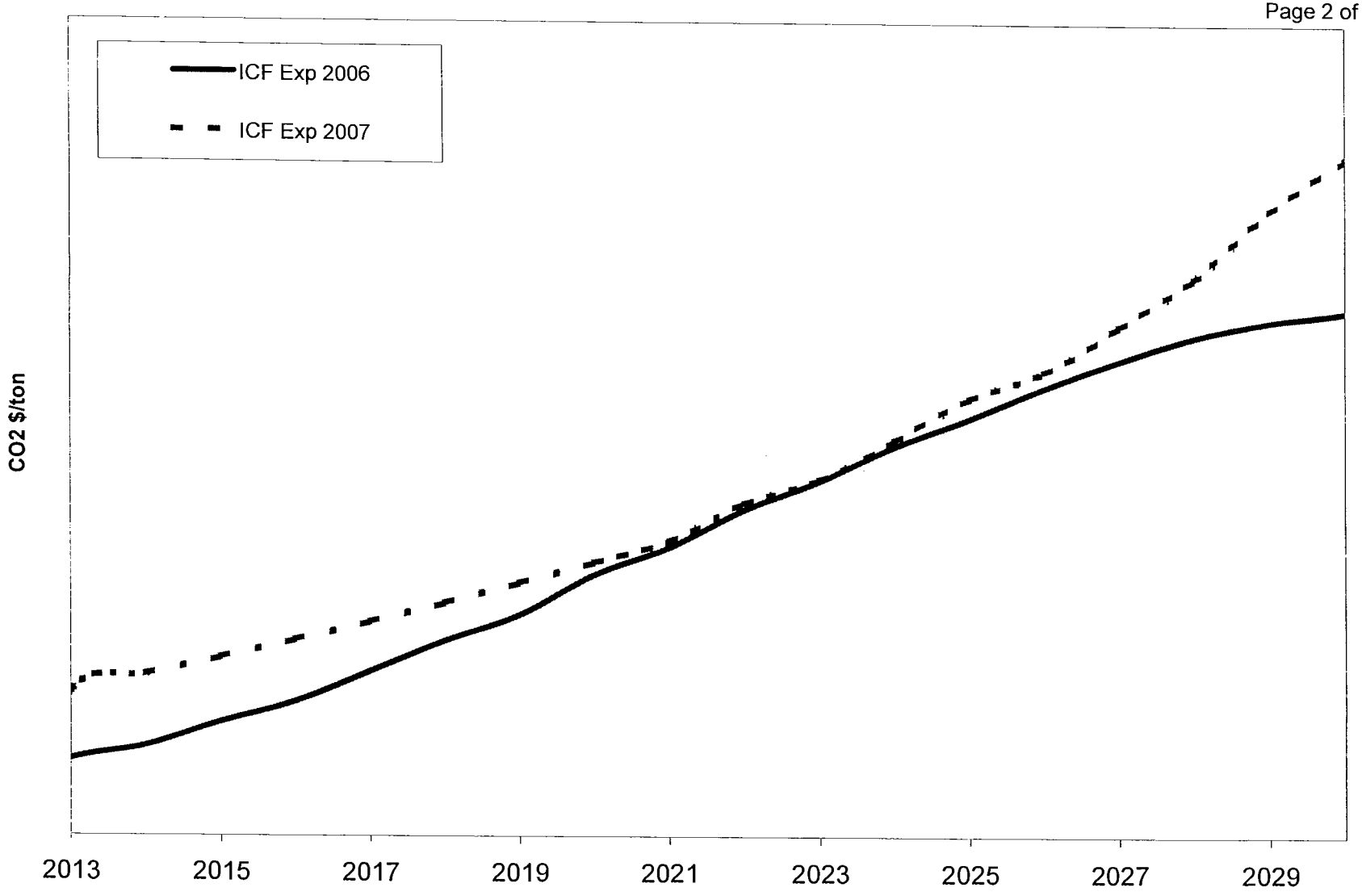
CO2 Environmental Compliance Costs
(nominal $ per ton)

	APPENDIX F				Adjusted APPENDIX F values using ICF 2007projections as requested by OPC corresponding to:			
Year	ENV I	ENV II	ENV III	ENV IV	ENV I	ENV II	ENV III	ENV IV
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	7	0	11	15	0	0	0	0
2011	7	2	13	17	0	0	0	0
2012	7	5	14	19	0	0	0	0
2013	9	8	15	19	10	14	23	29
2014	9	9	16	21	11	16	24	32
2015	10	11	18	23	12	17	26	34
2016	10	13	20	26	13	19	28	37
2017	11	16	22	28	14	21	31	41
2018	12	19	23	30	15	23	34	44
2019	13	22	25	33	17	25	37	48
2020	13	26	29	38	18	27	41	53
2021	13	28	31	41	20	29	45	58
2022	15	32	35	45	22	33	49	64
2023	16	35	37	49	24	35	53	69
2024	16	38	42	54	27	39	58	75
2025	16	41	44	58	29	43	64	83
2026	17	44	49	63	31	46	70	92
2027	17	47	53	69	35	50	77	100
2028	18	49	60	78	38	55	84	110
2029	18	51	65	85	42	62	92	119
2030	19	52	70	92	45	67	101	132

Prepared at the request of the Office of Public Counsel.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI EXHIBIT 99
COMPANY Florida Power + Light
WITNESS Late Filed Recalculated Appendix F
DATE 01/30-02/01/08

Comparison of ICF Expected Cases
CO2 Cost Trends



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COMPANY NOT Moved
WITNESS Into Record
DATE

EXHIBIT NO. _____

DOCKET NO: 070650-EI

PARTY: FLORIDA POWER & LIGHT COMPANY

DESCRIPTION: STAFF'S EXHIBIT

DOCUMENT:

1. Florida Power & Light Company's Response to Staff's Fourth Request for Production of Documents (No. 20).

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070650-EI **EXHIBIT** 101
COMPANY FL PSC Staff
WITNESS FPL's MIT Study
DATE 01/30 - 02/01/08

Q.

Please provide documents ("review of recent assessments") relied upon to formulate the 2031 to 2043 compliance costs as referenced on Page 22, Lines 10-13, of Witness Kosky's Direct Testimony.

A.

See also document provided in response to Staff's 4th Request for Production of Documents No. 17.

MIT Joint Program on the Science and Policy of Global Change

Assessment of U.S. Cap-and-Trade Proposals

Sergey Paltsev, John M. Reilly, Henry D. Jacoby, Angelo C. Gurgel, Gilbert E. Metcalf, Andrei P. Sokolov and Jennifer F. Holak

Report No. 146
April 2007

The MIT Joint Program on the Science and Policy of Global Change is an organization for research, independent policy analysis, and public education in global environmental change. It seeks to provide leadership in understanding scientific, economic, and ecological aspects of this difficult issue, and combining them into policy assessments that serve the needs of ongoing national and international discussions. To this end, the Program brings together an interdisciplinary group from two established research centers at MIT: the Center for Global Change Science (CGCS) and the Center for Energy and Environmental Policy Research (CEEPR). These two centers bridge many key areas of the needed intellectual work. Additional essential areas are covered by other MIT departments, by collaboration with the Ecosystems Center of the Marine Biology Laboratory (MBL) at Woods Hole, and by short- and long-term visitors to the Program. The Program involves sponsorship and active participation by industry, government, and non-profit organizations.

To inform processes of policy development and implementation, climate change research needs to focus on improving the prediction of those variables that are most relevant to economic, social, and environmental effects. In turn, the greenhouse gas and atmospheric aerosol assumptions underlying climate analysis need to be related to the economic, technological, and political forces that drive emissions, and to the results of international agreements and mitigation. Further, assessments of possible societal and ecosystem impacts, and analysis of mitigation strategies, need to be based on realistic evaluation of the uncertainties of climate science.

This report is one of a series intended to communicate research results and improve public understanding of climate issues, thereby contributing to informed debate about the climate issue, the uncertainties, and the economic and social implications of policy alternatives. Titles in the Report Series to date are listed on the inside back cover.

Henry D. Jacoby and Ronald G. Prinn,
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Assessment of U.S. Cap-and-Trade Proposals

Sergey Paltsev, John M. Reilly, Henry D. Jacoby, Angelo C. Gurgel, Gilbert E. Metcalf, Andrei P. Sokolov, and Jennifer F. Holak

Abstract

The MIT Emissions Prediction and Policy Analysis model is applied to an assessment of a set of cap-and-trade proposals being considered by the U.S. Congress in spring 2007. The bills specify emissions reductions to be achieved through 2050 for the standard six-gas basket of greenhouse gases. They fall into two groups: one specifies emissions reductions of 50% to 80% below 1990 levels by 2050; the other establishes a tightening target for emissions intensity and stipulates a time-path for a "safety valve" limit on the emission price that approximately stabilizes U.S. emissions at the 2008 level. A set of three synthetic emissions paths are defined that span the range of stringency of these proposals, and these "core" cases are analyzed for their consequences in terms of emissions prices, effects on energy markets, welfare cost, the potential revenue generation if allowances are auctioned and the gains if permit revenue were used to reduce capital or labor taxes.

Initial period prices for the first group of proposals, in carbon dioxide equivalents, are estimated between $30 and $50 per ton CO_2-e depending on where each falls in the 50% to 80% range, with these prices rising by a factor of four by 2050. Welfare costs are less than 0.5% at the start, rising in the most stringent case to near 2% in 2050. If allowances were auctioned these proposals could produce revenue between $100 billion and $500 billion per year depending on the case. Emissions prices for the second group, which result from the specified safety-valve path, rise from $7 to $40 over the study period, with welfare effects rising from near zero to approximately a 0.5% loss in 2050. Revenue in these proposals depends on how many allowances are freely distributed.

To analyze these proposals assumptions must be made about mitigation effort abroad, and simulations are provided to illuminate terms-of-trade effects that influence the emissions prices and welfare effects, and even the environmental effectiveness, of U.S. actions. Sensitivity tests also are provided of several of the design features imposed in the "core" scenarios including the role of banking, the specification of less than complete coverage of economic sectors, and the development of international permit trading. Also, the effects of alternative assumptions about nuclear power development are explored. Of particular importance in these simulations is the role of biofuels, and analysis is provided of the implications of these proposals for land use and agriculture.

Finally, the U.S. proposals, and the assumptions about effort elsewhere, are extended to 2100 to allow exploration of the potential role of these bills in the longer-term challenge of reducing climate change risk. Simulations using the MIT Integrated System Model show that the 50% to 80% targets are consistent with global goals of atmospheric stabilization at 450 to 550 ppmv CO_2 but only if other nations, including the developing countries, follow.

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1. INTRODUCTION

A number of alternative approaches to greenhouse-gas mitigation are under consideration in the United States, but the policy instrument now receiving greatest attention is a national cap-and-trade system. Several bills have been filed in the Congress or are under development. In this report we assess the economic and energy system implications of these proposals, not comparing particular bills in detail but studying synthetic versions that span their main features and illuminate the differences among them. To carry out the economic aspects of the assessment we rely on the MIT Emissions Prediction and Policy Analysis (EPPA) model. The implications of different emissions paths for atmospheric greenhouse gas concentrations and potential climate change are explored using the earth science portions of the MIT Integrated Global System Model (IGSM) of which EPPA is a component.

The term "cap-and-trade" is used to describe a policy that identifies greenhouse-gas-emitting entities covered by the system, sets caps on their emissions and allows trading in the resulting emissions allowances. The "entities" are the points of responsibility for emissions and they may be defined at various levels in the economic system from the coal mine and refinery gate (upstream) to the firm or gasoline station (downstream). At these points the emissions accounting is carried out. Emissions allowances (actually entries in an electronic bookkeeping system) are distributed such that the total is equal to the national cap, and covered entities must surrender allowances equal to their emissions, or the emissions that result when the fuel they supply is burned. Market trading in these allowances establishes a price on emissions that in turn creates economic incentives for cost-effective abatement.[1] It is common practice to distribute allowances to the entities that are the point of regulation, but this procedure is not a requirement of the system. Allowances could be distributed without charge to any persons, firms or other organizations in the economy, or they could be auctioned.

We begin the assessment of current proposals in Section 2 by laying out aspects of system design, and conditions external to the U.S., that influence the performance of cap-and-trade systems. In Section 3 the economic model used in the analysis is described and the assumptions underlying a set of "core" policy cases are identified, including the relative stringency of

[1] For a discussion of the history of cap-and-trade systems in the U.S. and analysis of their application to CO_2 see Ellerman *et al.* (2003). A previous U.S. proposal of a cap-and-trade system for greenhouse gases was the Climate Stewardship Act of 2003 (S. 139) introduced in 2003 by Senators McCain and Lieberman. Analyses of this earlier legislation are available in Paltsev *et al.* (2003) and the US EIA (2003).

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abatement, the emissions allowance paths, and mitigation undertaken abroad. Section 4 then presents results for the core cases, including price and welfare effects, impacts on energy markets and revenue potential if allowances are auctioned. It is worth noting that, although the focus is on a cap-and-trade system, many of the results are directly applicable to a carbon tax with the same coverage and emissions target.[2] In Section 4 it becomes evident how dependent the results are on assumptions about mitigation undertaken in other countries, through terms-of-trade effects, and Section 5 explores this phenomenon in greater detail.

Of necessity the comparison of the core cases requires a common set of system definitions so in Section 6 we investigate various alternative specifications including differences in banking, sectoral coverage, revenue recycling, the provision of a safety valve and international permit trading. One important difference among cases is the role of biofuels, and Section 7 provides a more detailed look at this option and its implications for land use.

The proposals under study specify targets only to 2050, which is too short a period for consideration of the climate impacts. Therefore in Section 8 assumptions are made for the latter half of the century and estimates are provided of the resulting reduction in atmospheric CO_2 concentrations and in projected global temperature change. Section 9 offers some conclusions.

2. ISSUES IN SYSTEM DESIGN AND IMPLEMENTATION

The economic and environmental effects of a cap-and-trade system depend on its features within a particular country, and also on activities in other countries through the influence of trade in energy, non-energy goods and emissions allowances. As background for the assumptions applied in assessing potential U.S. systems, a brief review of these factors is in order. Definitions of terms used in discussing greenhouse gas control policies, especially cap-and-trade systems, are provided in **Appendix A.**

2.1 System Design Features

Cap-and-trade legislation will include a large number of details, and any U.S. system likely will be a negotiated compromise among current proposals. In forming judgments about economic implications of system design a few of these features are of greatest importance.

Stringency of the emissions target. The targeted emissions reduction over the time horizon of the policy is among the most important determinants of policy cost and its climate benefits. Many of the bills considered here state an emissions target for 2050, and that is one way to compare them. However, a better measure of stringency is the sum of national emissions permitted between the start of the policy and mid-century. Such a comparison is used to benchmark the analysis below.

Point of regulation. Current proposals differ in the points in the economic system where the cap is applied (upstream or downstream) and the method of allowance distribution (for free or by

[2] Tax and quantity instruments have different properties in terms of economic cost and effectiveness under uncertainty, but the scenarios analyzed in this report are simulated in a non-stochastic framework, and in this context tax and quantity constraints are equivalent. Choice between tax and quantity constraints raises important economic issues that deserve attention but are beyond the scope of this analysis.

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auction). The primary effect of this choice of point of regulation is to determine which entities must comply with the regulatory system by monitoring emissions, maintaining records, and submitting allowances. The direct cost of emissions abatement may not be incurred at this stage in the production process. For example, in an upstream system where one point of regulation likely would be at oil refineries, emissions abatement would come mainly from reductions in fuel use downstream. The costs of this abatement would include additional spending for more efficient vehicles, heating equipment and alternative fuels, or the sacrifice of amenities that increase fuel consumption (*e.g.*, larger, more powerful vehicles). Refiners do not directly control abatement (except for emissions in the refinery process itself) but only influence fuel use by passing on the allowance cost to petroleum product consumers.

Similarly, a chemical company will make essentially the same decisions about product line and equipment choices whether it pays a separate natural gas price and surrenders allowances for the emissions released, or simply pays a higher fuel price that includes the allowance cost premium. An upstream allowance system thus assumes that the coal mine, gas gathering point, refinery gate and import terminal will pass through the bulk of the allowance cost to subsequent stages in the economic system and ultimately to goods and services.

How much of the direct mitigation cost is passed forward to consumers is not a choice made by firms but rather depends on the underlying elasticities of supply and demand for the goods and services being produced, and this can be further affected by rate-setting agencies that oversee regulated utilities depending on how the value of allowances are treated in setting rates. The essential point that bears emphasis is that the ultimate distribution of control costs under a cap-and-trade system, especially in unregulated markets, is determined by market forces, not by the choice of upstream or downstream implementation. This fact frees up policy makers to implement such systems at the stage of production where implementation costs are lowest.

Method of allowance distribution and distributional implications. Whether the point of obligation is upstream, downstream or some hybrid, emission allowances are valuable assets and the way they are distributed can have a substantial effect on equity aspects of the system. If allowances are auctioned, then the overall distributional effect depends on what is done with the revenue. If the allocations are distributed on some "grandfathering" principle to firms at the point of regulation, then these firms receive the asset value or scarcity rent.[3] The U.S. sulfur system and the EU Emissions Trading Scheme (EU ETS) are directed toward the point of combustion, and so the firms covered by them are bearing some direct cost of abatement, in spending on improved efficiency, fuel switching, sulfur scrubbing and the like. In trial phase of the EU ETS, however, electricity price changes have appeared to reflect not so much the direct mitigation expenses but the changing marginal cost of permits, even though they were distributed for free. Given that the electricity markets are mostly deregulated in Europe such a pass through of permit price is, or should have been, expected.

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[3] In markets under cost-of-service regulation, like some U.S. electric utilities, public authorities may not allow firms to realize scarcity rents in this way.

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In the U.S., on the other hand, where much of the electricity market remains regulated by public utility commissions, rates may not be allowed to rise unless there is an actual cost incurred by the utility. Under that circumstance the value of the allowance asset does not create value for the utility and electricity consumers will benefit relative to the case where rates fully reflected CO_2 prices; *i.e.* rates will not rise as much and utilities will not recover the permit value through higher electricity rates. The downside of this aspect of regulated utility markets is that, because electricity prices will not rise to reflect the full allowance cost, electricity consumers will not have as much of an incentive to reduce their electricity consumption. If the most efficient abatement response involves mostly fuel-switching within the electric sector the inefficiency imposed in such a regulatory setting may be limited. On the other hand, in the refinery example used above very little abatement would occur if fuel prices did not increase to reflect marginal CO_2 prices, and so if concern about rising fuel prices led to some form of price regulation, such as imposition of price controls, it would defeat the purpose of the CO_2 policy.

To summarize, who bears the ultimate burden of the costs of abatement depends on the complex interaction of markets (see, *e.g.*, Fullerton and Metcalf, 2002). In an idealized "neoclassical" model of the economy the burden of the mitigation costs under a cap-and-trade program is independent of the point of regulation. One implication of this principle is that while upstream regulation would create incentives for abatement, the costs of abatement need not be borne upstream. Thus, free distribution of allowances to upstream entities can create an inequitable outcome where they receive a valuable asset but ultimately pass on most of the cost to downstream fuel users. Of course, the actual economy diverges from the way it is represented in idealized economic models, and so the point of regulation can affect outcomes in substantial ways. However, that qualification does not change the conclusion that, to the degree the distributional impacts of the policy are a concern, the focus needs to be on who actually bears the economic burden of the policy, *not* who happens to be given the task of turning in allowances or even who is directly responsible for abating emissions. On equity grounds, the revenue from auctioning permits or the distribution of free allowances could be directed to those who ultimately bear the cost of abatement, whether it is low-income consumers, coal mine owners, coal miners or other groups. To correctly assess the cost implications for different groups requires a detailed representation of the economy, including representation of features such as cost-of-service regulation as in some U.S. electric utilities.

Banking and borrowing of permits. Cap-and-trade systems generally define a set of accounting periods and allocate allowed emissions separately for each period. An important design feature is whether entities under the cap can shift their obligations across periods. If higher costs are expected in the future, firms have an incentive to over-comply early-on and "bank" the excess for use in meeting future obligations. Or they might be allowed to under-comply, "borrowing" from the future by shifting the deficit forward to add to the obligation in subsequent periods. Many cap-and-trade systems allow banking. Provision for borrowing is less common, perhaps because of default risk. In systems that plan for tightening over time, creating the expectation of rising cost, banking is an economic response that will tend to convert any

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prescribed period-by-period set of targets into a cost-minimizing path with the same total emissions over the policy horizon.

Coverage by sector and greenhouse gas. Cap-and-trade systems are sometimes proposed that include CO_2 only, or CO_2 plus some combination of the other greenhouse gases. A multi-gas implementation then requires some set of exchange rates (Global Warming Potentials or GWPs are used in this study) to allow aggregation of their various effects. Also, systems vary by the number of sectors covered. The EU ETS, for example, covers only electric utilities and heavy industry, and some of the systems assessed below omit households, agriculture, and small entities.

Revenue recycling. If a portion of the allowances is auctioned, or a safety valve provision (discussed next) yields sales proceeds, the system will generate government revenue. One possible application of these funds is the reduction of taxes either on capital (corporate income, dividends or capital gains) or labor (earned income). Existing taxes distort choices in the economy and reducing them may lower this distorting effect and increase economic activity, an effect termed a "double dividend" because the greenhouse gas (GHG) policy would yield not only an environmental dividend but also an economic one. There is a possibility that the efficiency improvements from tax reduction could completely offset the direct cost of the abatement policy, an outcome called a "strong" double dividend. The case where the emission control cost is reduced but not completely offset by revenue recycling has been referred to as a "weak" double dividend. It is also possible if energy is highly taxed that revenue recycling can actually reduce economic activity (see Metcalf *et al.*, 2004) but this outcome is unlikely in the U.S. where energy is only lightly taxed.

Provision of a safety valve. When the emissions cap is set there is uncertainty as to how high the emissions price may rise. To guard against price spikes that may threaten excess short-run economic cost (or the survival of the system itself) a price ceiling may be added to the system. Under such a so-called "safety valve" the government offers to sell allowances in unlimited amounts at a fixed price, perhaps at levels rising over time.[4] Whether the safety valve is likely to be triggered can be controlled by joint selection of the number of allowances issued and the safety valve price. The tighter (looser) the cap the higher (lower) the expected allowance price in the absence of the safety valve. If the safety valve price is set relatively high in relation to the expected emissions price then resort to government sales would be less likely. If the safety valve is set relatively low in relation to the expected price then this provision is better thought of as an emissions tax with allocated exemptions.

Note that with a safety valve the original cap is no longer met with certainty. A tight cap with a relatively low safety valve will mean the cap very likely will be exceeded. A loose cap with a relatively high safety valve will make it much more likely that the cap is actually met.

Linkage with non-U.S. systems. The emissions price realized in a U.S. cap-and-trade system could be substantially affected by linkage to outside systems. Relatively low cost emission reductions may be available in projects carried out in other countries (*e.g.*, forest projects) and

[4] For an analysis of these systems and their relation to banking and borrowing see Jacoby and Ellerman (2004).

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the admission of such credits can reduce the domestic emissions price and economic cost. If the U.S. is linked to foreign trading systems, a common emissions price will emerge, but whether that result is higher or lower than the autarkic U.S. price would depend on the relative stringency of the before-connection caps in the different systems.

2.2 External Factors

In addition to the features that may be built into cap-and-trade legislation, a number of external factors will influence the economic effects of the system. Two are of particular interest.

Non-U.S. mitigation measures. Estimates of the cost of emissions mitigation in the U.S. will be influenced by emissions control measures being taken elsewhere. Most important, the level of global control will affect the prices of crude oil and other fossil fuels that the U.S. either imports or exports, and the prices of traded quantities of biofuels. Trade in non-energy goods also will be affected, although the effects on the U.S. are generally small in relation to the influence on trade in energy goods. These so-called terms-of-trade effects play an important role in assessment the cost of potential U.S. measures as will be seen below.

Trade restriction. Biofuels offer a relatively low-cost alternative for emission mitigation in the transport sector, and if unrestrained (and depending on emissions targets in other countries) the trade in these fuels could have large effects on land use and related issues of environmental degradation and food prices. In the U.S. biofuels are popularly seen as an abundant domestic resource that could reduce dependence on foreign oil, although imports of ethanol into the U.S. are currently restricted by tariffs.

In the analysis we try to provide insight into many of the issues identified above. However the nature of the model we employ is better suited to examine some of them than others. In the next section we describe the model and some of its limitations.

3. ANALYSIS METHOD

3.1 The Emissions Prediction and Policy Analysis (EPPA) Model

To assess costs and energy system implications of these proposed mitigation measures we apply the MIT Emissions Prediction and Policy Analysis (EPPA) model. The standard version of the EPPA model is a multi-region, multi-sector recursive-dynamic representation of the global economy (Paltsev *et al.*, 2005). In a recursive-dynamic solution economic actors are modeled as having "myopic" expectations.[5] This assumption means that current period investment, savings,

[5] An alternative, forward-looking version of the EPPA model optimizes choices over time where economic actors are said to have "perfect foresight." Such a forward-looking solution provides a more complete realization of neoclassical economic theory, leading to economic choices that are optimized over time as well as across sectors and regions. In a companion report Gurgel *et al.* (2007) compare the forward-looking EPPA results with those of the recursive model used here for the same core scenarios. They find that the basic behavior of the forward-looking model in terms of abatement and CO_2-e prices is very similar to the recursive model, the main difference being that optimization through time leads to somewhat lower welfare costs as one might expect. They explore additional aspects of policies for which the forward-looking version is particularly appropriate, and results for revenue recycling are summarized below.

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and consumption decisions are made on the basis of current period prices. This version of the model is applied below.

The level of aggregation of the model is presented in **Table 1**, and model features are further elaborated in **Appendix B**. The model includes representation of abatement of non-CO_2 greenhouse gas emissions (CH_4, N_2O, HFCs, PFCs and SF_6) and the calculations consider both the emissions mitigation that occurs as a byproduct of actions directed at CO_2 and reductions resulting from gas-specific control measures. Targeted control measures include reductions in the emissions of: CO_2 from the combustion of fossil fuels; the industrial gases that replace CFCs controlled by the Montreal Protocol and produced at aluminum smelters; CH_4 from a number of sources, and N_2O from chemical production and improved management of inorganic fertilizer applications. More detail on how abatement costs are represented for these substances is provided in Hyman *et al.* (2003).

Non-energy activities are aggregated to six sectors, as shown in the table. The energy sector, which emits several of the non-CO_2 gases as well as CO_2, is modeled in more detail. The synthetic coal gas industry produces a perfect substitute for natural gas. The oil shale industry produces a perfect substitute for refined oil. All electricity generation technologies produce perfectly substitutable electricity except for Solar and Wind, which is modeled as producing an imperfect substitute, reflecting its intermittent output. Biomass use is included both in transport fuel and electric generation although it does not penetrate the electric sector in these simulations. There are 16 geographical regions represented explicitly in the model including major countries (the U.S., Japan, Canada, China, India, and Indonesia) and 10 regions that are an aggregations of countries.

Table 1. EPPA Model Details.

Country or Region[†]	Sectors	Factors
Developed	***Non-Energy***	Capital
United States (USA)	Agriculture (AGRI)	Labor
Canada (CAN)	Services (SERV)	Crude Oil Resources
Japan (JPN)	Energy-Intensive Products (EINT)	Shale Oil Resources
European Union+ (EUR)	Other Industries Products (OTHR)	Coal Resources
Australia & New Zealand (ANZ)	Transportation (TRAN)	Natural Gas Resources
Former Soviet Union (FSU)	Household Transportation (HTRN)	Nuclear Resources
Eastern Europe (EET)	***Energy***	Hydro Resources
Developing	Coal (COAL)	Wind/Solar Resources
India (IND)	Crude Oil (OIL)	Land
China (CHN)	Refined Oil (ROIL)	
Indonesia (IDZ)	Natural Gas (GAS)	
Higher Income East Asia (ASI)	Electric: Fossil (ELEC)	
Mexico (MEX)	Electric: Hydro (HYDR)	
Central & South America (LAM)	Electric: Nuclear (NUCL)	
Middle East (MES)	Electric: Solar & Wind (SOLW)	
Africa (AFR)	Electric: Biomass (BIOM)	
Rest of World (ROW)	Electric: Natural Gas Combined Cycle (NGCC)	
	Electric: Coal with CSS	
	Electric: Gas with CSS	
	Oil from Shale (SYNO)	
	Synthetic Gas (SYNG)	
	Liquids from Biomass (B-OIL)	

[†] Specific detail on regional groupings is provided in Paltsev *et al.* (2005).

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When viewing the EPPA model results for emissions prices and welfare costs it is well to remember that in any period the model seeks out the least-cost reductions regardless of which of the six categories of gases is controlled or from which sector they originate, applying the same marginal emissions penalty across all controlled sources. This set of conditions, often referred to as "what" and "where" flexibility, will tend to lead to least-cost abatement. To the degree that cap-and-trade legislation departs from these ideal conditions, costs for any level of greenhouse gas reduction will be higher than computed in a model of this type.

The results also depend on a number of aspects of model structure and particular input assumptions that greatly simplify the representation of economic structure and decision-making. For example, the difficulty of achieving any emissions path is influenced by assumptions about population and productivity growth that underlie the no-policy reference case. The simulations also embody a particular representation of the structure of the economy including the relative ease of substitution among the inputs to production and the behavior of consumers in the face of changing prices of fuels, electricity and other goods and services. Further critical assumptions must be made about the cost and performance of new technologies and what might limit their market penetration. Specifications of alternatives to conventional technologies in the electric sector and in transportation are particularly important. Finally, the EPPA model draws heavily on neoclassical economic theory. While this underpinning is a strength in some regards, the model fails to capture many economic rigidities that could lead to unemployment or misallocation of resources nor does it capture regulatory and policy details that are, as discussed earlier, particularly important in the utility sector.

Given the many assumptions that are necessary to model national and global economic systems, the precise numerical results are not as important as the insights to be gained about the general direction of changes in the economy and components of the energy system and about the approximate magnitude of the price and welfare effects to be expected given alternative features of cap-and-trade design. An uncertainty analysis of these proposals (*e.g.*, Webster *et al.*, 2002), a task beyond the scope of this study, would be required to quantify the range about any particular result, although the relative impacts of caps of different stringency likely would be preserved. Policy design inevitably involves a process to reevaluate decisions as new information is gained, rather then deciding once and for all on a long-term policy based on any single numerical analysis.

3.2 Policy Options and Scenario Assumptions for the "Core" Results

In presenting the assessment results we first explore (in Section 4) a set of "core" results applying features that are most common among the proposed cap-and-trade bills. Then, in Section 5, we consider variation in system features over such dimensions as coverage, banking and borrowing, trade restrictions and revenue recycling. We focus the discussion on results that illustrate measures of cost, and effects on energy and agricultural markets. A more complete set of results for each of the scenarios is provided in **Appendix C**. The key features of the set of "core" simulations are the following.

Stringency, coverage, banking and the safety valve. Most of the current proposals specify emissions reductions goals for the period from 2012 to 2050. A selection of these is presented in **Table 2** along with their most prominent features. In several cases a target is stated for 2050 in terms of a percentage reduction below 1990 emissions, providing a firm numerical goal for allowance allocation only in that year. The initial year allowance level is often benchmarked to emissions in the year the bill is passed, or in one case an average of the three years after. The most recent year's emissions inventory available as of this writing is 2005, and so assuming the bill is passed in 2007 or 2008 requires some extrapolation. While some of the bills provide a formula for computing allowances in intervening years others do not, offering targets only for one or two intermediate years. Still other proposals describe emissions allowances that depend on economic growth. For the core cases, we have specified three allowance paths that start in 2012 by returning to 2008 levels, extrapolating 2008 emissions from the 2005 inventory by assuming growth at the recent historical rate of 1% per year as documented in U.S. EPA (2006). We then assume a linear time-path of allowance allocation between this level in 2012 and a 2050 target equal to: (1) 2008 emissions levels, (2) 50% below 1990, and (3) 80% below 1990.

Following the convention noted above, cases are labeled by the cumulative number of allowances that would be made available between 2012 and 2050 in billions of metric tons (bmt), or gigatons, of carbon dioxide equivalent (CO_2-e) greenhouse gas emissions. These amounts are 287 bmt in the case of holding emission flat at 2008 levels, 203 bmt when allowance allocations are cut to 50% below 1990 by 2050, and 167 bmt when allowance allocations are cut to 80% below 1990 by 2050. These allowance paths are plotted in **Figure 1**. Also shown in the figure is our approximation of the allowance paths specified in current bills. In some cases judgments were

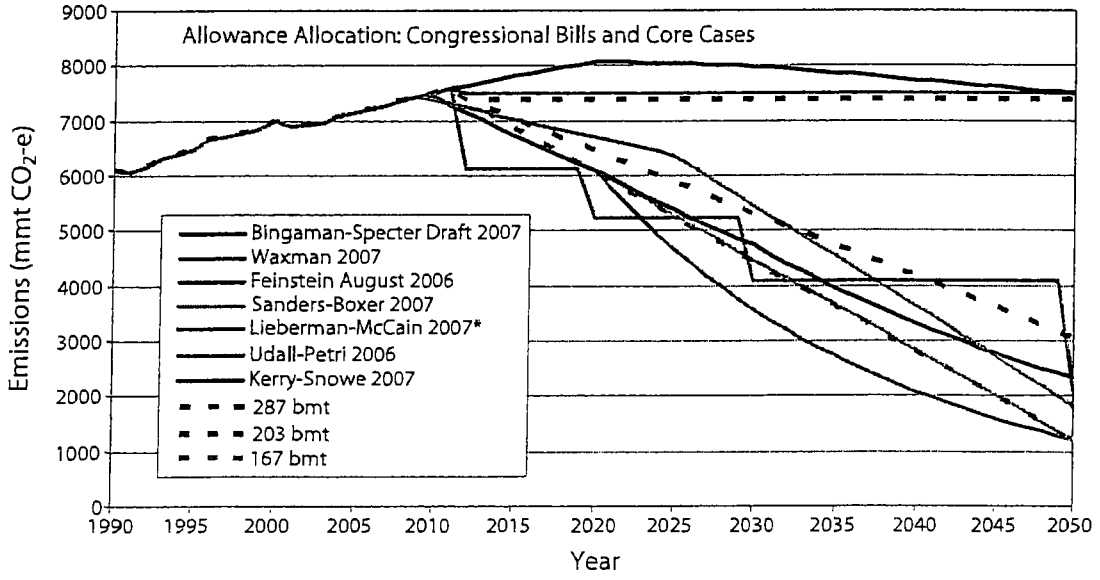

Figure 1. Scenarios of allowance allocation of Congressional bills and core cases over time.
[*For Lieberman-McCain, this is the allowance path for covered sectors only.]

Table 2a. Congressional Bills, Basic Features.

	Lieberman-McCain 2007	Bingaman-Specter Draft 2007	Kerry-Snowe 2007	Sanders-Boxer 2007	Waxman 2006	Feinstein August 2006	Udall-Petri 2006
Bill Number/ Name	S.280; Climate Stewardship and Innovation Act of 2007		S.485; Global Warming Reduction Act of 2007	S.309; Global Warming Pollution Reduction Act of 2007	H.R.5642; The Safe Climate Act of 2006 (companion bill to Boxer-Sanders)		H.R.5049; Keep America Competitive Global Warming Policy Act of 2006
Basic Framework	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade	Mandatory, market-based, cap on GHG "intensity" (emissions per $ GDP): cap & trade with safety valve	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade	Mandatory, market-based, system to be determined by EPA, allows for cap & trade in 1 or more sectors	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade with safety valve
Targets	Return emissions to 2004 levels by 2012, to 1990 levels by 2020, and to 60% below 1990 levels by 2050. Target emissions are (in mmt of CO_2): 2012-2019 = 6,130; 2020-2029 = 5,239; 2030-2049 = 4,100; 2050 on = 2,096.	Targeted reduction in GHG intensity is 2.6% annually between 2012 and 2021, then 3.0% per year beginning in 2022.	Freeze emissions in 2010, and gradually reduce to 65% below 2000 levels by 2050. Reduce to 1990 levels by 2020, then 2.5% per year between 2020 and 2029, and 3.5% per year between 2030 and 2050.	Freeze emissions in 2010, achieve 1990 levels by 2020, reduce by 1/3 of 80% below 1990 levels by 2030, by 2/3 of 80% below 1990 levels by 2040, and 80% below 1990 levels by 2050.	Freeze emissions in 2010, reduce by 2% per year starting in 2011 to reach 1990 levels by 2020, then by 5% per year starting in 2021 to reach 80% below 1990 levels by 2050.	Cut emissions to 70% below 1990 levels by 2050.	Cap for emissions set prospectively at emission levels three years after the enactment of the legislation.
Allocation of Allowances	Undetermined percent auctioned, balance allocated free	10% auctioned, 55% free (but gradually phased out), 29% to states, 5% for agric. sequestration, 1% early reduction	Undetermined percent auctioned, balance allocated free	Undetermined allocation, any allowances not allocated to covered entities should be given to non-covered entities	Undetermined percent auctioned, balance allocated free	Undetermined auctioning and allocation	20% free, 20% to states (reduced yearly), remaining 60% to Treasury, Energy Department, and State Department
Additional Details	• Covered sectors produce about 85% of national emissions; • Covered entities emit, or produce or import products that emit, over 10,000 metric tons of GHGs per year • Banking • Borrowing (up to 25%) • Provisions to track, report, verify emissions • Non-compliance penalties	• Regulated at upstream • Safety valve: if traded allowances hit safety valve price, gov. issues more allowances at that price: $7/metric ton of CO_2 (escalates annually at 5% real) • Banking • Non-compliance penalties • Emissions can increase if GDP grows faster than intensity reductions, and can exceed cap if safety valve is used	• Total GHGs less than 450 ppmv • Banking • Provisions to track, report, verify emissions • Non-compliance penalties	• Less then 3.6°F (2°C) temperature increase, and total GHGs less than 450 ppmv • Suggests declining emissions cap with technology-indexed stop price • Provisions to track, report, verify emissions	• Less then 3.6°F (2°C) temperature increase, and total GHGs less than 450 ppmv • Banking • Provisions to track, report, verify emissions • Non-compliance penalties	• Keep temperature increase to 1 or 2°C	• Regulated at upstream • Safety valve: $25 per ton of carbon (just under $7 per ton of CO_2), price can only increase if the President and Sec. of State certify that other countries are controlling their emissions

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Table 2b. Congressional Bills, Additional Details and Features.

	Lieberman-McCain 2007	Bingaman-Specter Draft 2007	Kerry-Snowe 2007	Sanders-Boxer 2007	Waxman 2006	Feinstein August 2006	Udall-Petri 2006
Provisions Related to Foreign Reductions	• Credits for approved projects in developing countries (e.g. CDM) • Acceptance of foreign allowances	• Every 5 yrs review of trading partners, and Congress can change US cap or safety valve • Credits for approved projects in developing countries (e.g. CDM) • Acceptance of foreign allowances		• Task Force on International Clean, Low Carbon Energy Cooperation to increase clean technology use and access in developing countries		• Credits for protecting rain forests in developing countries • Proposed acceptance of foreign allowances	• 10% of allowances to the State Department for spending on zero-carbon and low-carbon projects in developing nations
Credit Provisions	• Limited use of credits from sequestration, non-covered entities, and international projects (can offset up to 30%) • Farmers and foresters, can earn credits to sell through sequestration	• Use of credits from sequestration, non-covered entities, the use of fuels as feedstocks, the export of covered fuel or other GHGs, and international projects • Farmers and foresters, can earn credits to sell through sequestration	• Credits from sequestration	• Credits from sequestration • Renewable energy credit program		• Use of credits from sequestration, non-covered entities, international projects, and responsible land use • Farmers and foresters, can earn credits to sell through sequestration	• Credits from sequestration
Other Features	• Climate Change Credit Corporation: proceeds from allowance auctions and trading activities, used for transition assistance, habitat restoration, and technology R&D	• Climate Change Trust Fund: proceeds from allowance auctions and safety-valve payments, used for technology R&D. Fund capped at $50 billion (excess goes to U.S. Treasury)	• Climate Reinvestment Fund: proceeds from auctions, civil penalties, and interest, used to further Act and for transition assistance • National Climate Change Vulnerability and Resilience Program • EPA to carry out R&D • Renewable and energy efficiency portfolios: 20% of electricity must be renewable by 2020 • Motor vehicle emission standard • Renewable fuel required in gasoline • E-85 fuel pumps • Consumer tax credits for energy efficient motor vehicles	• EPA to carry out R&D • Sense of Senate to increase federal funds for R&D 100% each year for 10 years • Transition assistance • Renewable and energy efficiency portfolios: 20% of electricity must be renewable by 2020 • Mandatory emissions standards for all electric generation units built after 2012 and final standards for all units, regardless of when they were built, by 2030 • Motor vehicle emission standard	• Climate Reinvestment Fund: proceeds from allowance auctions and civil penalties, used to further Act and for transition assistance • Renewable and energy efficiency portfolios: 20% of electricity must be renewable by 2020 • Motor vehicle emission standard	• Climate Action Fund: proceeds from allowance auctions and interest, used for technology R&D, wildlife restoration, and natural resource protection • Renewable portfolio for utilities; • Carmakers must improve mileage by 10 mpg by 2017 • Emission standards for power producers • Increase availability of biodiesel and E-85 fuel pumps; • Plans to extend California-style green-technology programs nationwide	• Advanced Research Projects Agency-Energy: 25% of allowances for new Energy Department technology program • 25% of allowances to the Secretary of the Treasury, who deposits proceeds from selling the allowances into the Treasury

Notes: **Feinstein Bill**: Based on a San Francisco Chronicle article (Hall and Kay, 2006). Implementation is now expected to be proposed through 5 separate bills to be introduced in 2007. **Olver-Gilchrist**: HR-620, the Climate Stewardship Act of 2007, is similar to McCain-Lieberman 2007 above.

Sources: US House of Representatives (2006a,b); US Senate (2007a,b,c,d).

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required to fill in an allowance path that is incompletely specified in the legislation. Also, some of these bills were drafts, or subject to revision, and so readers need to check their status to insure the comparison remains appropriate.

With fixed total allowances over the whole period, and banking, the actual time-path of allowance allocation will not affect the CO_2 prices, energy markets, and other projections simulated by the model in these core runs.[6] It is for this reason that an informative way to compare the bills studied here is by the cumulative allowance allocations under each. This is also a good way to show which of the scenarios we have run is most comparable to specific bills. **Table 3** arranges the bills in the order of stringency, least to most, along with our three core cases. The 287 bmt case is close to the Udall-Petri Bill, the 203 bmt case comes just about at the Feinstein Bill level, and the 167 bmt case is very close to the Sanders-Boxer Bill. Our estimate of total emissions including uncovered sectors for the Lieberman-McCain Bill places it slightly above the 203 bmt case. Kerry-Snowe lies just about halfway between the 167 and 203 bmt cases. On the low side of the 167 bmt case is Waxman and on the high side of the 287 bmt case is Bingaman-Specter, each about 18-19 bmt outside our range. Note that the Bingaman-Specter draft and Udall-Petri include a safety valve feature and so to the extent the safety valve is triggered emissions are determined by the price mechanism and are not necessarily fixed.

Table 3. Cumulative allowances available from 2012 to 2050.

Allowance Path	Cumulative Allowances 2012-2050 (bmt)
Bingaman-Specter Draft 2007	306
Udall-Petri 2006	293
287 bmt	287
Lieberman-McCain 2007	216 (186)*
203 bmt	203
Feinstein August 2006	195
Kerry-Snowe 2007	179
Sanders-Boxer 2007	167
167 bmt	167
Waxman 2007	148

* 186 are the actual allowances for covered sectors; 216 is the estimate of total emissions including uncovered sectors from WRI (2007). The actual national emissions depend on growth in uncovered sectors.

Throughout the analysis the cap covers the emissions of the six categories of greenhouse gases identified in U.S. policy statements and in the Kyoto Protocol (CO_2, CH_4, N_2O, SF_6, HFSs and PFCs), with the gases aggregated at the 100-year GWP rates used in US EPA (2006). The "core" definition also assumes that the cap applies to all sectors of the economy except emissions of CO_2 from land use, and no credits for CO_2 sequestration by forests or soils are included. It is also important to note that in the core cases nuclear power is assumed to be limited by concerns for safety and siting of new plants, and thus nuclear capacity is not allowed to expand.

[6] In cases where allowances are auctioned, the time-path affects the auction revenue in each year, and if this revenue is recycled to lower taxes the timing has some effect on the economy and emissions, and potentially affects emissions prices policy cost. The effects of recycling on CO_2-e prices are small, however.

The focus of current cap-and-trade legislation on the pre-2050 period leaves open the question of what level of allowances will be available afterward. Extrapolating a linear decline rate would lead eventually to negative allowances.[7] When we extend the policies beyond 2050 in the analysis below we assume that the allowance level in 2050 is simply held constant at that level for the remainder of the century. However, we do not simulate banking into the post-2050 period and so the economic results reported are unaffected by the post-2050 assumptions.

International linkage, non-U.S. mitigation measures and trade restriction. The "core" policy scenarios provide no possibility for crediting reductions achieved in ex-U.S. systems such as the Kyoto-sanctioned Clean Development Mechanism (CDM) or other trading systems such as the EU Emission Trading Scheme. However, it assumed that other regions pursue climate policies as follows: Europe, Japan, Canada, Australia, and New Zealand follow an allowance path that is falling gradually from the simulated Kyoto emissions levels in 2012 to 50% below 1990 in 2050.[8] All other regions adopt a policy beginning in 2025 that returns and holds them at year 2015 emissions levels through 2034, and then returns and maintains them at 2000 emissions levels from 2035 to 2050. We assume no emissions trading among regions, although implicitly a trading system operates within each of the EPPA regions/countries that include, for example, the EU as a single region (see Table 1).

Allowance allocation and revenue recycling. Allowances are assumed to be distributed for free. The distributional implications of abatement and allowance allocation were discussed Section 2.1. In a model like EPPA, however, with a single representative agent that owns all resources (*i.e.* labor, capital, other assets), all costs necessarily fall on that single agent and there is no difference if allowances are dispensed for free in a lump sum manner, or allowances are auctioned and the revenue is distributed in a lump sum manner. Thus, we are not able to deal with the variety of distributional issues raised in Section 2.1.

Distributional effects will vary depending on who owns what resources and how the costs of different goods change. For example, if lower income people spend a larger percentage of their

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[7] A negative allowance allocation is not impossible. If, for example, international emissions trading were in effect developed countries could receive a negative allowance allocation, and they would be required to purchase allowances from developing countries to make up for this negative allocation in addition to any emissions they have. Or some have discussed the possibility of using biomass as a feedstock for hydrogen, stripping out the carbon and storing it underground, or stripping carbon out of the air and storing it. Were these technologies considered realistically feasible at large-scale, a global net allocation could eventually be negative and atmospheric concentrations would then reverse and decline.

[8] To provide an allowance path that falls gradually at first, accelerating as 2050 is approached, we fit a simple quadratic function, solving the equation:

$$X_{2050} - X_{2012} = b_{target} * t^2,$$

for the coefficient b_{target} where t is time (2012 = 0; 2050 =38) and X_{2012} and X_{2050} are emissions targets for the year 2012 and 2050 respectively. With X_{2012} set to the 2008 emission level as estimated above and the X_{2050} target given above we can solve the equation for b_{target} (target = 10, 30, 50, 70, 80) when t = 50 – 12 = 38. We can then use the equation below to solve for all other years (X_{YEAR}):

$$X_{YEAR} = b_{target} * t^2 + X_{2012}.$$

The EPPA model solves only every 5-years, and so the first year for which we simulate policy costs is the year 2015.

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income on energy, the impact of rising energy prices will have a disproportionately large effect on them. Similarly, if energy costs are higher because of heating requirements in Northern States or for air conditioning in the South, people there may be disproportionately affected compared to the Pacific States where the climate is relatively mild. If the point of regulation is midstream—*e.g.*, electric utilities, industrial emitters and refiners—and allowances are given to them freely, this new asset will represent increased value for these firms and their shareholders to the extent product prices reflect the marginal CO_2 prices. Meanwhile, asset values and employment at upstream coal companies could decline. If, on the other hand, allowances were auctioned and the revenue distributed in a lump sum manner (*e.g.*, equally to every citizen, every adult citizen, or every taxpayer), the distributional effects would change substantially.

4. CORE RESULTS

The estimates presented in this section are dependent on assumptions in Section 3.2 about how U.S. policy is implemented and on emissions controls assumed to be imposed in other countries. The core assumptions are designed to set a context for assessment of these proposals but many factors come into play and other assumptions are also plausible. Moreover, the bills include different features, some of which may or may not be exercised, are incompletely specified, or may change. For example, linkage with emissions trading with other countries is authorized or anticipated in some of the bills, but may depend on a later judgment by the Administration that the foreign system is sound. Also, several of the bills include regulatory measures (*e.g.*, tightening of auto design regulations), renewable portfolio standards, and specific expenditure programs (*e.g.*, R&D and technology subsidies) that we do not model. Thus, this section is a starting point for exploration of the costs and other impacts of the proposed legislation. Section 4 addresses the sensitivity of these results to several of the core assumptions.

4.1 Emissions, Greenhouse Gas Prices and Welfare Cost

All three emissions reductions paths show net banking, with GHG emissions below the allocations in early years and exceeding them in later ones (**Figure 2**). Thus, for example, projected emissions in 2050 in the 167 bmt case (allowances in 2050 at 80% below 1990) are only about 50% below 1990. Similarly, for the 203 bmt case emissions in 2050 are a little over 40% below 1990 even though allowances allocated in 2050 are 50% below 1990. The 287 bmt case has emissions in 2050 about 5.5% above the allowance allocation in that year.

The bump-up in emissions in 2035 is due to assumptions about policies abroad and the resulting effects on international fuel markets, as the developing countries ramp down their emissions in 2035. Their emissions reductions result in lower demand for fossil fuels, especially petroleum, reducing their prices. The U.S., with the banking provision, takes advantage of this effect by consuming relatively more petroleum products when the fuel price falls. Since the U.S. must meet its overall cap over the period to 2050 these added emissions must be made up for with greater reductions (and banking) in earlier periods. Other assumptions about policies abroad could smooth out or eliminate this effect, but the U.S. would still likely exhibit net banking.

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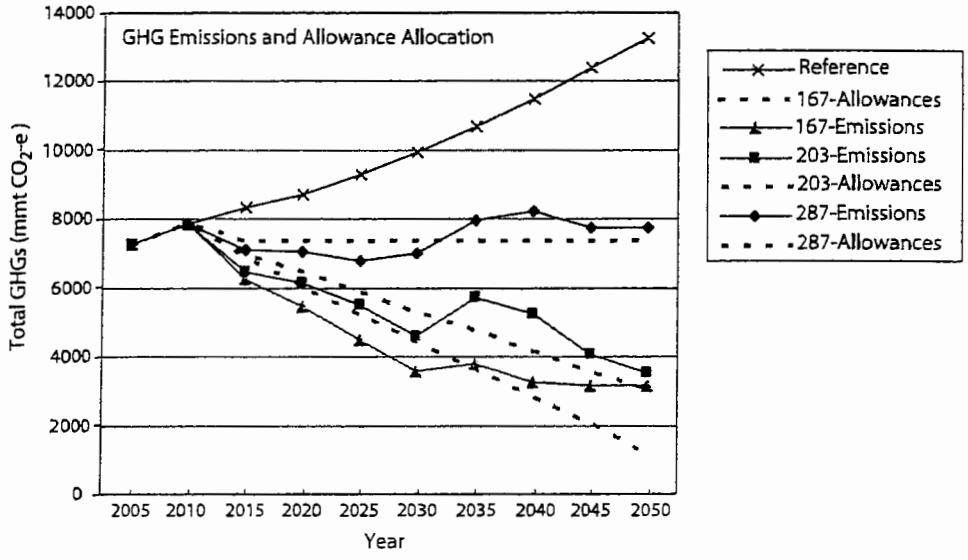

Figure 2. Total greenhouse gas emissions and associated allowance allocation path.

The core scenarios assume all-greenhouse-gas policies with emissions trading among gases at their Global Warming Potential (GWP) values. All prices are thus CO_2-equivalent prices (noted CO_2-e) and that is the case throughout this report. CO_2-e prices for the 287, 203, and 167 bmt cases in the initial projection year (2015) are \$18, \$41, and \$53 per ton CO_2-e (all in 2005 prices) as graphed in **Figure 3a** and shown in **Table 4**. The design of the scenarios ensures that prices rise at the real interest rate, assumed constant at 4% per annum. With banking allowance, holders decide whether to bank or not by comparing the expected rate of return on abatement (and banking of allowances) to returns on other financial instruments and alter their banking behavior until these returns are equalized. The result is that by 2050 carbon prices reach \$70, \$161, and \$210 per ton CO_2-e for the 287, 203, and 167 bmt cases. (Solutions where banking is not allowed are explored in Section 6.1.)

Recognizing that there is uncertainty in emissions growth and abatement cost means it is highly unlikely that the price path would follow this smooth increase because market participants might start with one set of expectations only to have them change as new information was revealed.

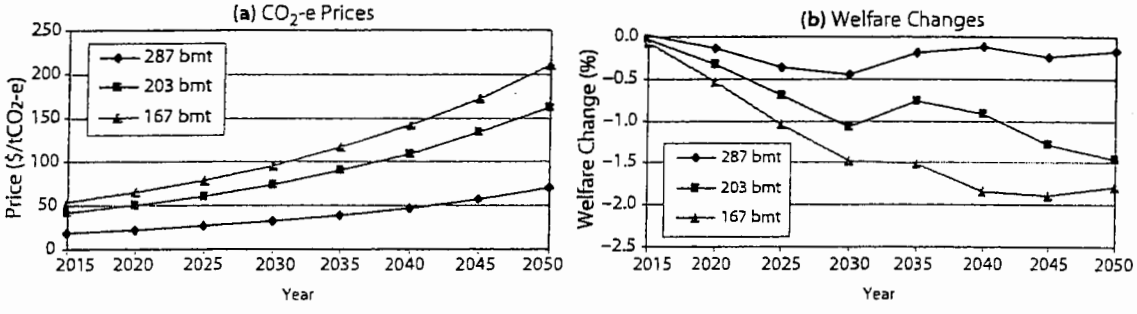

Figure 3. CO_2-e prices and welfare effects in the core scenarios: **(a)** CO_2-e prices, **(b)** welfare effects.

Table 4. Core price and welfare results: U.S. + World Policy.

	CO_2-e Price ($/t$CO_2$-e)			Change in Welfare (%)		
	287 bmt	203 bmt	167 bmt	287 bmt	203 bmt	167 bmt
2015	18	41	53	0.01	–0.04	–0.07
2020	22	50	65	–0.13	–0.32	–0.55
2025	26	61	79	–0.36	–0.69	–1.05
2030	32	74	96	–0.45	–1.08	–1.47
2035	39	90	117	–0.19	–0.77	–1.51
2040	47	109	142	–0.12	–0.92	–1.84
2045	57	133	172	–0.24	–1.28	–1.90
2050	70	161	210	–0.18	–1.45	–1.79

As discussed in Appendix B the version of the EPPA model used here incorporates endogenous labor supply, allowing employment to respond to changes in the market economy. Under this formulation the welfare measure includes not only changes in aggregate market consumption but also effects on leisure time. The main measure of overall economic cost we report is change in welfare that, following standard economic theory, is measured as equivalent variation.[9] The results for the three core scenarios are graphed in Figure 3b and shown in Table 4. Other macroeconomic measures (macro-economic market consumption, GDP) are provided in Appendix C. The initial (2015) levels of welfare effects are quite small at 0.01, –0.04%, and –0.08%, ending at –0.18, –1.45, and –1.79% in 2050 for the 287, 203, and 167 bmt cases, respectively.[10]

Given the smooth rise in the CO_2-e price a similarly smooth increase in the welfare cost might be expected. Instead the percentage loss increases through 2030, drops back in 2035, and then increases again. This pattern results because there are two components of the welfare change. One is the direct cost of abatement that can be calculated as the area under a marginal abatement curve. A second stems from general equilibrium interactions, and in this case it is mostly the effect of terms-of-trade impacts on the U.S. resulting from climate policy abroad. Thus, as with

[9] The general equilibrium modeling convention is based on economic theory whereby workers willingly choose to work or not, and when they choose not to work they value their non-work time at the marginal wage rate. Carbon dioxide mitigation tends to increase the cost of consuming market goods and thus workers have a tendency to choose to work less, and thus have more non-work time. As a result, the percentage welfare changes in Figure 3b and Table 4 combine a loss of market consumption that is partly offset by a gain in leisure. Moreover, the denominator is larger by the amount of leisure accounted for in the model, which for our accounting increases the denominator by about 17%. How much non-work time to account is somewhat arbitrary and so the denominator in this calculation can be made larger or smaller depending on how much time is accounted. For the model used here we assume a reasonable number of potential labor hours rather than accounting all waking hours of people of all ages. For a discussion, see Matus *et al.* (2007).

[10] If the endpoint percentage below 1990 is the same but the reduction path is more gradual following the quadratic path we have specified for other countries (see footnote 8) more cumulative allowances are available and the overall policy cost is less. We simulated the model in such cases for endpoints 50% and 80% below 1990. Cumulative emissions in these two cases are 230 and 206 bmt compared with 203 and 167 bmt with a linear decline, and thus they obviously lead to higher emissions. Consequently the CO_2-e prices are lower—initially $35 and $42 compared with $41 and $53 for the linear paths, rising to $140 and $165 by 2050, and the welfare losses are lower, 1.08 and 1.48 in 2050 compared with the 1.45 and 1.79 with the linear assumption.

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the emissions path shown in Figure 2, this pattern is driven by assumptions about policy in the rest of the world, especially the tightening of policies in developing countries in 2035.[11]

Because of the importance of these terms-of-trade effects it is useful to recall the core assumptions about international actions. These cases vary the stringency of the policy in the U.S. but leave unchanged the mitigation efforts of the rest of the world. In the 203 bmt case the U.S. takes on reduction targets similar to other developed countries with the developing countries following later. Whereas the U.S. and developed country allowance allocation is 50% below 1990 in 2050, developing countries are still at their 2000 levels. Although the developing country targets are less stringent relative to 1990 emissions levels, this policy nevertheless represents quite stringent reductions for rapidly growing developing countries. In the 167 bmt case the U.S. mitigation efforts are more stringent than other developed countries in terms of abatement relative to 1990 emissions levels, while in the 287 bmt case the U.S. lags behind them. In this less ambitious case the U.S. effort eventually falls behind that of developing countries, even while the U.S. benefits from terms-of-trade effects.

In viewing these results it is well to keep in mind the political realism of the more- and less-stringent cases, where the U.S. makes a stronger or weaker effort in relation to others. For our purpose a common assumption about external conditions provides a point of departure for comparing different U.S. effort levels. We alter the level of effort assumed abroad in sensitivity analysis discussed below to help isolate the terms-of-trade effects from the costs directly associated with abatement in the U.S. The importance of assumptions about mitigation efforts abroad in assessment of U.S. domestic proposals is further emphasized in Section 5 where we explore alternative scenarios of rest-of-world effort. Together these core and alternative scenarios highlight the strategic implications of cooperative and non-cooperative mitigation that arise through terms-of-trade effects, further complicating policy coordination among countries with different impressions of climate impacts and with incentives to "free ride" on abatement efforts elsewhere.

4.2 The Role of the Non-CO_2 Gases

Inclusion of non-CO_2 greenhouse gases in the policy can be important in reducing the policy cost. Recall that the reduction scenarios are defined in terms of CO_2 equivalents (CO_2-e) with the non-CO_2 gases weighted in terms of their GWPs. Initial levels of reduction of several of these gases can be achieved at low cost relative to CO_2, so they are a natural early target for control efforts. Their relative role, period by period, is illustrated in **Figure 4**, using the 203 bmt case as an example. Note that in 2015 these gases represent roughly one-third of CO_2-e reductions, their fraction falling to a quarter in 2020 and to one-fifth in 2025. After that time the reductions to be achieved from controlling these gases is pretty much exhausted, so the absolute level of abatement increases very little, and their contribution relative to total CO_2-e abatement falls to around a tenth in 2050.

[11] In the forward-looking version of EPPA (Gurgel *et al.*, 2007) consumption changes are smoothed over time as is expected when agents can look ahead and shift present consumptions and savings decisions when they anticipate a future shock.

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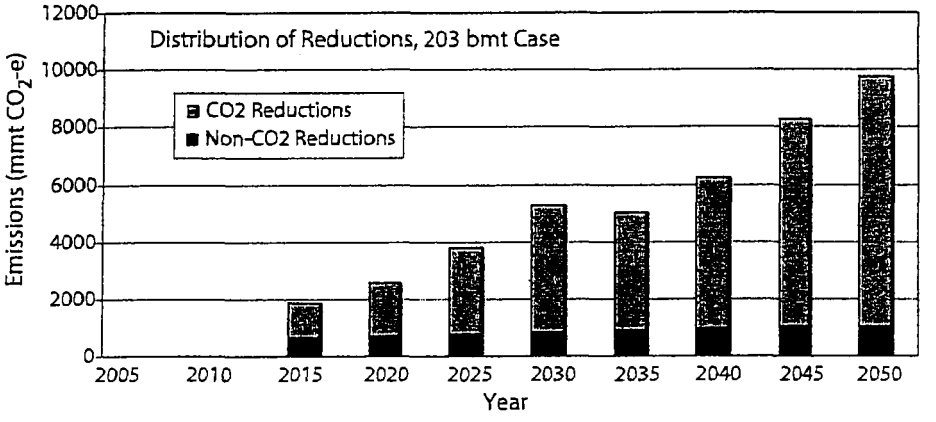

Figure 4. Distribution of emissions reductions in the 203 bmt case.

The same pattern holds in the other cases. In general, at lower CO_2-e prices the non-CO_2 gases play a larger relative role and can forestall the need for rapid adjustment in the energy sector while contributing, especially in the case of methane, near-term climate benefits. While beyond the scope of this analysis, Reilly *et al.* (2006) provide an evaluation of the cost-effectiveness and climate effects of including non-CO_2 GHGs in a control regime. These findings suggest that even though their relative importance falls over time in policies aimed at substantial reductions in greenhouse gases, their overall role in a cost-effective strategy should not be overlooked.

4.3 Energy Market Effects

The proposed policies have substantial effects on fuels and electricity markets, both in terms of prices and quantities consumed. In reviewing these results it is important to distinguish between the price of fuels themselves and the cost of using them, where the consumer expenditure includes the fuel price and the emissions charge. The carbon contents of fuels are relatively stable, so the price inclusive of the emissions charge can be calculated by adding the appropriate CO_2 penalty for a gallon, barrel, ton, or tcf of the fuel. **Table 5** shows the added cost resulting from a $27 per ton CO_2-e price for a variety of fuels and the percentage increase this implies relative to the average price for these fuels for 2001-2005 (excluding Federal and State excise taxes). In an upstream system the CO_2-e price will be embedded in the fuel price while in a downstream system the fuel user will pay separately for the fuel and for the allowance. Mixed systems will have the carbon charge embedded in some fuel prices and separate from others. We follow the convention of reporting the fuel prices, exclusive of any carbon charge, and electricity prices inclusive of carbon charges because the effect of carbon prices on the electricity price depends on the mix of fuels, and the degree of capture and sequestration, among other things, which change across scenarios.

The percentage price increases for fuels will vary from these estimates as the CO_2-e price varies, and also with changes in the fuel price. The EPPA model projects fuel price changes in the reference, and also that these prices will further change as a result of mitigation policy.

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Table 5. Relationship between ~$27 per ton CO_2-e price and recent average fuel prices.

Fuel	Base Price Ave. 2002-2006 (2005$)	Added Cost ($)	Added Cost (%)
Crude Oil ($/bbl)	$40.00	$12.20	30%
Regular Gasoline ($/gal)	$1.82	$0.26	14%
Heating Oil ($/gal)	$1.35	$0.29	21%
Wellhead Natural Gas ($/tcf)	$5.40	$1.49	28%
Residential Natural Gas ($/tcf)	$11.05	$1.50	14%
Utility Coal ($/short ton)	$26.70	$55.30	207%

Note: No adjustments for the effects of the policy on the producer price.

Source: U.S. average prices for 2002-2006 computed from DOE EIA price data. Base cost price is the 5-year average price, except coal (2001-2005). To the gasoline price we have added $0.42 to include the federal and an average of state gasoline excise taxes.

In addition, the base price and price projection for any particular year is most appropriately viewed as a five-year average because the model simulates the economy in 5-year time steps. The results for the reference and core cases are shown in **Figure 5**. For a sense of the actual fuel prices projected in these scenarios the index values in the figure can be multiplied by the base prices in Table 5.

The fuel price effects of mitigation policies can be summarized as follows. There are reductions in petroleum product prices relative to the reference projection due to reductions in the crude oil price. This result reflects the fact that there is significant rent in the crude oil price, and the global policy to restrict carbon emissions reduces oil consumption, acting in effect like a monopsony buyer that extracts some of the producer rent. The reduction in overall world demand for oil has a strong effect, relative to the reference, in all cases. The relatively smaller difference

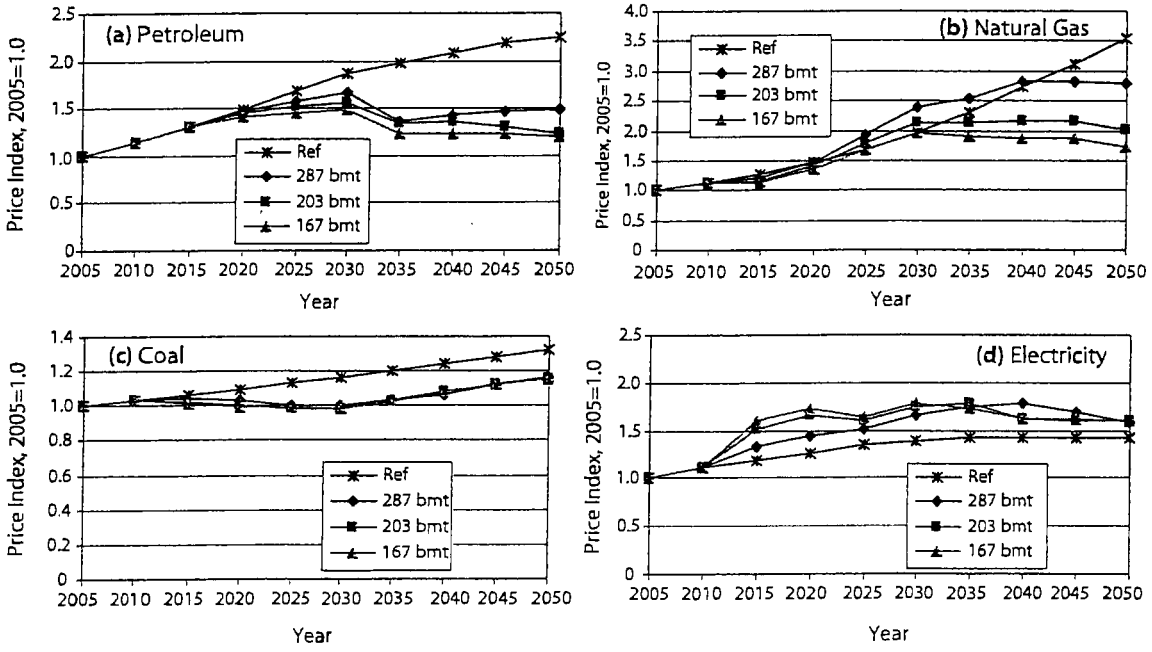

Figure 5. Fuel prices in the reference and core scenarios: **(a)** petroleum product prices, **(b)** natural gas prices, **(c)** coal prices, and **(d)** electricity prices.

among the policy cases occurs because only the stringency of the U.S. policy is varying. We also see the effect of strengthening of the policy in developing countries in 2035, which causes oil prices to fall relative to the reference. Across the core policy cases, then, petroleum product prices rise by about 25% in contrast to more than doubling in the no-policy reference.

Natural gas markets in EPPA are modeled such that international prices do not fully equalize, and so changes in domestic demand can have a larger effect on domestic prices. Whether this result accurately describes emerging global gas markets depends on how fast LNG infrastructure can be developed, especially whether terminals in the U.S. will be built to keep pace with demand, and LNG production facilities abroad can expand. Many analysts see a single world gas market emerging soon, and so the EPPA model structure may underestimate the potential role of natural gas and overestimate the rise in domestic prices. However, with a global policy other regions also change their demand for gas, and exert strong pressure on prices even with a world market. Under emissions mitigation U.S. gas prices approximately follow the reference level for the first 10 years, rising above the reference through 2030 or 2040 depending on the policy case, and then again falling below the reference price. This price pattern reflects the changing role of gas under CO_2 policy. Depending on the CO_2 and fuel prices, gas can be a relatively low-carbon fuel for electricity generation where it substitutes for coal. However, at higher carbon prices coal generation with CO_2 capture and storage (CCS) is even less CO_2 intensive and more economic. In other end uses for natural gas, such as in space heating, a CO_2 price spurs increased efficiency or a switch to electricity thereby reducing the demand for gas. Thus, the rise in the price of gas in middle years occurs when the increase in demand for gas for electricity generation is strong and offsets decreased demand elsewhere in the economy. As carbon prices rise further, coal with CCS displaces natural gas generation and the demand for gas, and its price, falls relative to the reference. How fast this transition occurs depends on the stringency of the policy.

There is relatively little rent in coal prices, so the model results show less adjustment in the price (and more in the quantity of coal consumed). The rents are mostly eliminated by 2030, but thereafter coal generation with CCS enters and coal demand and prices recover. The electricity price is inclusive of the carbon charge and emissions mitigation increases prices relative to the reference. The EPPA model includes increasing adjustment costs when technologies expand rapidly, and these policies involve a rapid transformation of electricity generation. This feature of the sector results in electricity prices overshooting the long-run level as this adjustment occurs, and then falling from that level by 2040, especially in the more stringent 167 and 203 bmt cases. By that time, the electricity sector is substantially de-carbonized. The difference between the electricity price in the policy cases and the reference is the marginal cost of adding capture and sequestration, plus any difference in the carbon dioxide price, times any remaining emissions. Since we assume a capture efficiency of 90% and upwards, differences in the carbon dioxide price across scenarios have a minimal effect on electricity prices.

Table 5 and Figure 5 can be used together with CO_2-e prices in Table 4 to estimate the projected user cost of fuel. Table 5 provides 5-year average prices for 2002-2006. (Ideally the 2003-2007 period would be used as a basis for comparison, as it is centered on 2005, but 2007

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data are not yet available.) Thus, for example, the petroleum product price index in the 167 bmt case is at 1.45 in 2025, and multiplying this result by the 5-year average gasoline price in Table 5 of $1.40 (the $0.42 from federal and state excise taxes must be subtracted from $1.82 so that the tax is not multiplied) gives a projected gasoline price (excluding the carbon charge and excise taxes) of about $2.03. Adding the excise tax back on gives a projected gasoline price of $2.45. The CO_2-e price in 2025 for the 167 bmt case is $79 per ton CO_2-e or about 2.92 times the $27 CO_2-e ($0.26 per gallon) benchmark in Table 5. The carbon charge per gallon then is 2.92 times $0.26, or $0.76. Adding this premium to the gasoline price gives a total user cost of gasoline of $3.21. (If the cap-and-trade implementation was upstream this would be the price consumers would see at the pump.) Absent the policy, the EPPA model projects a 2025 reference price for petroleum products of 1.69 times the 2005 level, which is $2.79 (including the excise tax). This means that the incidence of the $0.76 CO_2 cost per gallon for the 167 bmt policy is projected to be split such that $0.42 (the difference between the policy and reference gasoline prices) is passed through to the consumer and the remaining $0.34 is passed back to producers mainly affecting returns to crude oil. Note, however, that cost incidence is strongly affected by the assumption that the world pursues a carbon policy. If the policy were only implemented in the U.S., then the effect on world oil prices is smaller, and much more of the carbon tax burden would fall on U.S. consumers.

As presented in **Figure 6**, all three core policy cases show substantial reductions in primary energy use compared to the reference case, an increase in the use of natural gas through about 2030 that parallels a significant absolute reduction in the use of coal, and growth in the use of coal again after 2030. Shale oil production begins to take market share in the 2040-2045 period in the reference but it does not appear in any of the policy cases. The return of coal is a result of the economic viability of coal power generation with carbon capture and storage (CCS).

In many respects the three core policy cases are similar in their effects on primary energy use. The main difference among them is that the more stringent cases accelerate the shift in the power sector first to gas and then to coal with CCS, and generate greater reductions in overall energy use. The other major energy market change is the substantial growth in biofuel liquids to replace petroleum products in the 203 and 167 bmt cases.[12] In these cases, petroleum product use falls by 32% to over 40% from the present level of use, whereas in the reference case petroleum product use rises by about 87%. In the 287 bmt case only small amounts of biofuel liquids enter the market, and the CO_2-e price is not sufficient to induce much of a reduction in petroleum product use.

[12] At this point it is worth recalling the dependence of results on EPPA model structure and input assumptions. It is assumed that biofuels will be allowed to compete for market share on an economic basis, without constraints because of environmental or other side effects. The implications of this assumption are explored in Section 7. The same assumption applies to CO_2 capture and storage. Relaxation of these assumptions about competition on an economic basis would raise the estimated emissions price and welfare cost of each of the cap-and-trade cases. On the other hand, the reference scenario does not fully address environmental issues associated with shale oil development and continued expansion of fuel use and associated pollutant emissions. Adding environmental constraints on these could change technological choices in the reference and reduce fossil fuel use from what we project thus leaving less reduction needed to meet a given greenhouse gas target.

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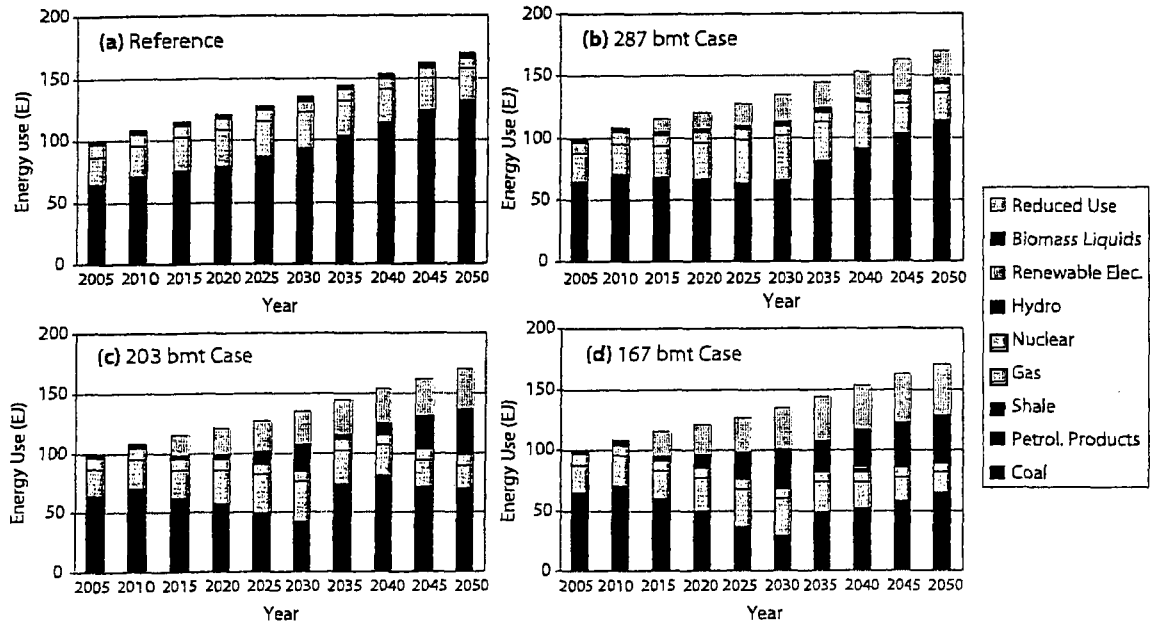

Figure 6. Primary energy use in the reference and core scenarios: **(a)** reference case, **(b)** 287 bmt case, **(c)** 203 bmt case, and **(d)** 167 bmt case.

The CO_2-e price has a substantial impact on the price of gasoline, especially in the more stringent cases. The CO_2-e price alone would add over $2.00 to the price of a gallon in the 167 bmt case and nearly $0.70 in the 287 bmt case. But because the reduction of fuel demand depresses petroleum product prices by $0.30 to over $1.00 per gallon in later periods, the incentive effects on gasoline consumption are reduced, especially in the less stringent cases. Thus, while the effects of the policy on the world market for petroleum and petroleum product prices convey a terms-of-trade advantage for the U.S., they at the same time lead to relatively smaller incentives for reducing petroleum product use.

A striking aspect of the 203 bmt case is that biofuels enter in 2025 and 2030, then shrink in 2035 only to again take market share toward the end of the study period. This again is a result that comes from the tightening of the policy in developing countries, which reduces the oil price but increases the price of liquids from biofuels as developing countries use them to meet their CO_2 obligations. Biofuels are modeled as a perfect substitute for refined oil products in EPPA and so the clearing price for biofuels is the refined oil price plus the CO_2 charge, which they do not bear, and so that margin goes to biofuels producers. An analysis limited to the U.S. might indicate biofuel entry into the U.S. market at lower net gasoline prices, and would not show the drop in 2035 in the 203 bmt case even as CO_2-e prices rise.

The broader lesson to be drawn from these results is not the specific timing of biofuel use in the U.S. but the importance of considering international competition for biofuels especially with strong CO_2 policies abroad. We examine some of the implications of expanded biofuel use in Section 7, but one result relevant to this behavior of U.S. biofuel use is that the fluctuation in the 203 bmt case is primarily a U.S. consumption effect: we do not see a drop in global production

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of biomass fuel in 2035. Thus, the reduction in biofuel use in the U.S. does not reflect a threat to the viability of a biofuel industry; quite the contrary, it results from increased demand for biofuels abroad. With flex-fuel vehicles it is not so hard to imagine that the fuel mix in the U.S. could change substantially from year to year as relative prices change.

It is important to note that the large demand for biofuel is a result of it being the main alternative to fossil-based transportation fuel in the EPPA model. If the model included relatively low cost vehicles that could be run in total or in part on electricity—an option requiring improvements in battery technology—then the demand for biofuels could be substantially reduced, to be replaced by demand for electricity. The basic determinant of which technology wins in an economic model, presuming an equal quality of service delivered, is which is less expensive. Where there are close technology competitors then small changes in estimated cost, well within ranges of uncertainty about where breakthroughs may occur, can lead to a different technology choice and mix of energy inputs. Section 6.3 considers nuclear and carbon capture and storage as alternatives in the electric, but a similar sensitivity analysis could well be applied to transportation alternatives.

4.4 Potential Revenue from an Allowance Auction or a Greenhouse Gas tax

As noted previously, there are various ways to administer a policy designed to create price incentives for reducing GHG emissions. In a cap-and-trade system the allowances can be given away or they can be auctioned. Or the emissions penalty could be set directly by a CO_2 tax. In the case of the tax or allowance auction a stream of revenue is generated. The CO_2-e price times the number of tons of allowances distributed in any period gives the total value of the allowances distributed, or alternatively the amount of auction or tax revenue that could have been collected. Options for use of the revenue include lump-sum distribution to households, reducing labor or capital taxes, or spending the funds for other purposes (*e.g.*, R&D or low-income fuel assistance). In Section 6.4 we explore the potential effects of revenue recycling. Here our interest is in the gross amount of potential revenue generated, or alternatively the size of the asset transfer involved in a lump sum distribution.

As can be seen from **Table 6** the potential revenue streams are substantial, ranging in just the first period of the policy from $130 billion in the 287 bmt case to $366 billion in the 167 bmt case. Potential revenue rises most rapidly in the 287 bmt case; the annual allowances distributed are the same in each year and the allowance price rises at 4% and so revenue necessarily rises at 4%. While the allowance prices are also rising at 4% in the 203 and 167 bmt cases, the number of allowances distributed each year is falling, thus revenue necessarily rises at less than 4% per year. In the 167 bmt case, revenue peaks around 2030 and declines by about 40% from this peak by 2050, ending up almost 32% below the 2015 level, and at about one-half the 2050 level of the other two cases. Table 6 also shows the potential tax disbursement to a family-of-four household each year. For this purpose we have simply divided the population by 4 as if the population were divided into four-person households and then divided the total revenue by this artificially constructed number of households. The amount ranges from about $1630 to $4560 in 2015, and ranges from about $2520 to $5190 in 2050.

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Table 6. Potential CO_2-e auction or tax revenue.

	2015	2020	2025	2030	2035	2040	2045	2050
Total Potential Auction/Tax Revenue (billions $/yr)								
287 bmt	130	159	193	235	286	348	423	515
203 bmt	287	321	356	391	425	455	477	489
167 bmt	366	392	413	425	423	399	346	250
US Pop.	321	334	347	359	369	379	388	397
Potential Tax disbursement/family of 4 ($/yr)*								
287 bmt	1,630	1,900	2,230	2,620	3,100	3,670	4,360	5,190
203 bmt	3,580	3,850	4,100	4,360	4,600	4,800	4,920	4,920
167 bmt	4,560	4,700	4,760	4,740	4,580	4,210	3,560	2,520
CO_2 Revenue as a Percentage of Non-CO_2 Federal Tax Revenue (%)								
287 bmt	7	7	7	8	8	9	9	10
203 bmt	15	14	14	13	12	11	11	10
167 bmt	19	17	16	14	12	10	8	5

* Rounded to nearest $10.

To further illustrate the fiscal potential of an allowance auction or equivalent emissions tax we also include in Table 6 the CO_2-e auction proceeds as a percentage of Federal tax revenue.[13] The potential auction revenue is substantial—about 10-15% of total Federal tax revenue in many periods across the three cases but ranging from a low of 5% to nearly 20%. Thus if the revenue were used to cut taxes evenly across different income groups and income sources, this would be approximately the percentage reduction in the Federal tax bill that taxpayers could expect to see. If, as we discuss in Section 6.4, the tax cuts were directed either toward labor or capital taxes then the rate cuts would be higher and the changes in individual tax bills would depend on the degree to which their income was from labor or from investment returns.

5. EXPLORATION OF TERMS-OF-TRADE EFFECTS

The core cases assume that the U.S. adopts a cap-and-trade measure that is not linked to policies in the rest of world and that, across alternative U.S. policy cases, the mitigation effort remains unchanged elsewhere. As shown above, policies abroad can influence the U.S. through a terms-of-trade effect even without linking emissions trading systems.

Recall that in the core cases developed countries pursue a gradual cut to 50% below 1990 by 2050, and that developing countries begin mitigating in 2025 by cutting emissions back to 2015 levels, returning to 2000 levels in 2035 and holding at this level through 2050. We do not simulate banking in countries abroad, nor do we allow international emissions trading among regions. To test alternatives to this scenario we consider two cases: (1) only the U.S. and other developed countries take mitigation action (noted US+DEV), and (2) mitigation policy is only pursued in the U.S. (noted US only). These are extreme assumptions—it would not make much sense for the U.S. to pursue these policies if no other country followed suit, and given the importance of developing countries it may even be unlikely that the developed countries

[13] Tax rates in EPPA are based on combined Federal, State and local taxes. For purposes of estimating the Federal share, we have assumed that it grows at the rate of GDP and that remaining tax revenue is State and local taxes.

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including the U.S. would pursue these paths through 2050 if others failed to follow. While less extreme cases could be simulated, the cases examined here allow us to identify the terms-of-trade effects of policies adopted abroad.

Figure 7 illustrates the effects of the different assumptions on the CO_2-equivalent price in the U.S. for the 203 bmt case, and **Figure 8** reports the U.S. welfare effects for all three cases.[14] As can be seen in Figure 7, the more aggressive the mitigation action taken abroad the higher the required CO_2-e price in the U.S. Consistently across all three of the U.S. policy variants the CO_2-e price is highest if all countries mitigate (here, represented by the assumed reductions

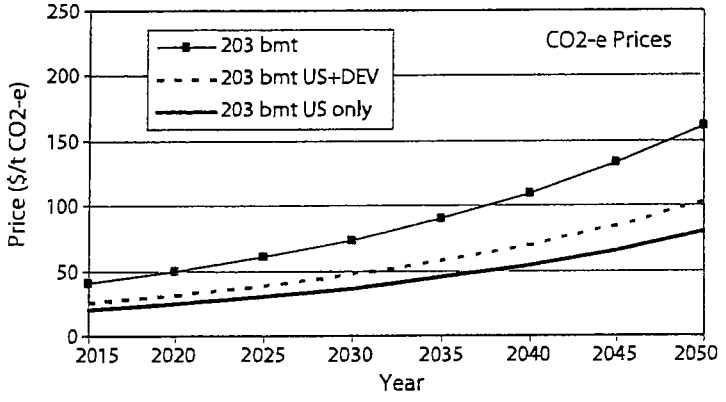

Figure 7. Effects of alternative policies abroad on US CO_2-e prices, no allowance trading.

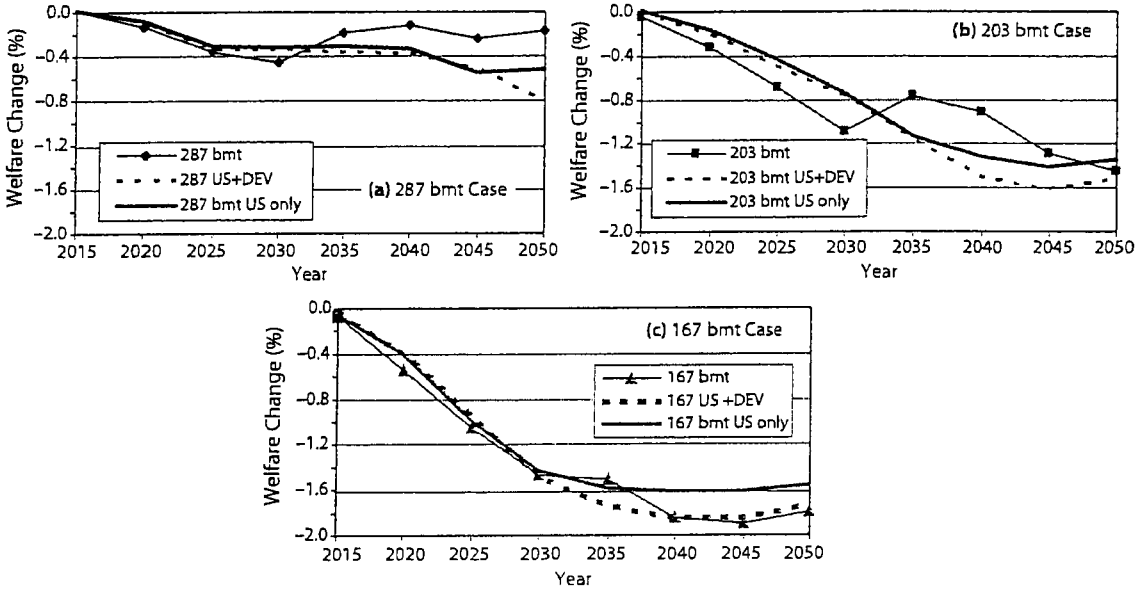

Figure 8. Effects of alternative policies abroad on US welfare, no trading: **(a)** 287 bmt case, **(b)** 203 bmt case, and **(c)** 167 bmt case.

[14] For the CO_2-e price, the 167 bmt and 287 bmt cases show a pattern similar to that shown for 203 bmt and are omitted to simplify the figure. The data for these other two cases is provided in Appendix C.

underlying the core 203 bmt case). U.S. prices are somewhat lower if only the developed countries reduce (US+DEV) and lower still if only the U.S. mitigates (US only). Two factors contribute to this result. As previously noted, mitigation policy abroad reduces the world oil price, so that achieving the same reduction of oil use at this lower price requires a higher CO_2-e price in the U.S.; in effect the U.S. emissions price needs to make up for the drop in the world oil price. Second, more stringent mitigation policy abroad leads to greater global biofuel use, and the resulting higher biofuel prices require higher U.S. CO_2-e prices to achieve the needed reductions.

Moving to the welfare costs in Figure 8, lower CO_2-e prices generally result in lower *direct*[15] mitigation cost, which is one part of the measured welfare change. Terms-of-trade effects, potentially through all markets but more importantly through oil and agricultural markets, also influence the results. Agricultural markets are strongly affected by competition for land from biomass energy production. Because of the different factors operating in each scenario, we need to take these one by one to understand the results.

In the 287 bmt cases the carbon price is somewhat lower with less mitigation abroad, and this lower direct cost of the policy tends to drive the results in early years. Few biofuels are used by the U.S in this scenario. However, after 2035 in the core cases, when the policy is tightened in developing countries, two important positive terms-of-trade benefits accrue to the U.S. First, world oil prices are lower and since the U.S. is a big oil importer this is beneficial. And second, demand for biofuels increases abroad, and even though the U.S. uses little in this case, this change raises agricultural prices through land-market impacts. Since the U.S. is a net agricultural exporter this effect also results in a terms-of-trade benefit. Thus, the welfare costs fall in the U.S. after 2035 compared with earlier years, even though the direct cost is growing. Reducing or eliminating mitigation abroad eliminates these positive terms-of-trade effects and a smoother pattern of costs emerges over time, as we would expect given the CO_2-e price path in the U.S.

The 203 bmt cases show the strongest effects on U.S. CO_2-e prices from changes in the mitigation policy abroad, and thus the direct cost of the policy is lower with less mitigation effort abroad compared to the core cases. This is the dominant effect in the near term and is responsible for the lower welfare cost through 2030 when less is done abroad. Without the strengthening of the developing country policy in 2035, we do not see the significant terms-of-trade benefit from lower oil prices at that point, and so the welfare loss continues to increase in these scenarios. By 2050, however, the added direct cost in the core case is beginning to cancel out the terms-of-trade benefit, and so the welfare cost in all three cases are similar. In large part this result is due

[15] It is useful again to distinguish between the *direct* abatement cost and additional economic impacts that stem from interactions with the rest of the economy—*general equilibrium (GE) effects*. The *direct* cost is a measure that can be obtained by integrating under a marginal abatement cost curve, or can be approximated as the triangle area under the abatement curve equal to 0.5 × CO_2-e price × quantity abated. GE effects can stem from interactions with pre-existing distortions (*e.g.*, taxes) from externally induced terms-of-trade effects, from the fact that the domestic policy itself creates terms-of-trade effects, and from other rigidities in the economy. Many aspects of model structure produce GE effects that are not easy to separately measure because of the inherent interactions in the economy.

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to the biofuels market. Recall that in the 203 bmt core case biofuels enter strongly in U.S. energy consumption in 2025, and 2030, and then shrink in 2035, reappearing later. Biofuel is mostly imported in these scenarios, and so its increasing price due to a stronger mitigation effort abroad creates a further terms-of-trade loss, but not if there are few imports as in 2035 in the core case. Since the mitigation level required in the U.S. can be achieved without biomass consumption in 2035, oil imports are considerably larger than in the preceding or following years, and the terms-of-trade benefit is that much greater. This sharp reduction in biofuels use does not occur in the cases with less mitigation abroad, and thus we see a smoother pattern of welfare change over time.

The 167 bmt cases show the smallest difference in the U.S. CO_2-e price and welfare effects among cases. In large part, this policy requires fairly drastic emissions reductions in the U.S. Thus, oil consumption is much lower in these cases so the flexibility to increase it when the price falls in 2035 is severely limited and the terms-of-trade benefit is less. When the U.S. is mitigating alone there is less pressure on biofuels markets, lowering the cost of substituting biofuels for petroleum products and reducing the terms-of-trade loss in the biofuels market. The bioenergy market and land-use implications of biofuels use are discussed in greater detail in Section 7.

One way to isolate the terms-of-trade effects that arise from policies outside the U.S. is to consider the difference in the welfare cost in the U.S. with and without action in the rest of the world. We make that calculation in **Table 7**. Also, because banking is redistributing the effects through time it is useful to look at the net difference over the whole period. For this purpose we calculate the discounted (Net Present Value) loss in percentage terms. If the net terms-of-trade effects originating from policy abroad are positive, then the NPV difference will be positive and *vice versa*. As shown in the table, the terms-of-trade calculation in the 287 bmt case is positive, reflecting the strong effect of lower world oil prices. The U.S. consumes very little biofuel in this scenario and so the potentially negative effect on the terms of trade from that source is not relevant. In the 203 and 167 bmt cases there are net terms-of-trade losses as discussed above because the CO_2 constraints greatly limit U.S. oil consumption and thus the terms-of trade benefits from this source. Imported biofuels become an important source of terms-of-trade losses.

Table 7. Isolating terms-of-trade effects on U.S. welfare (% change from reference).

	Welfare in the Core Cases Minus Welfare for U.S. Alone		
Year	287 bmt	203 bmt	167 bmt
2015-2050 NPV	0.09	–0.01	–0.12
2015	0.00	–0.05	–0.02
2020	–0.05	–0.17	–0.14
2025	–0.05	–0.25	–0.06
2030	–0.13	–0.35	–0.03
2035	0.12	0.35	0.08
2040	0.21	0.39	–0.23
2045	0.30	0.12	–0.28
2050	0.34	–0.10	–0.24

6. ALTERNATIVE DESIGN FEATURES AND EXTERNAL CONDITIONS

We next turn to a set of scenarios that consider alternative design features, exploring aspects of the scenarios that affect the estimated cost and highlighting other aspects of the results. In this part of the assessment a limited set of results is presented. More complete results for all scenarios, including welfare, consumption, GDP, energy market, greenhouse gas emissions by gas, fuels used in electricity generation, and biofuels and agricultural trade are presented in Appendix C.

6.1 The Effects of Banking

Many of the current proposals allow banking of allowances. As discussed above and shown in Figure 2, banking results in a reallocation of the abatement effort toward the near term so that less stringent reductions are needed in later years. In **Figure 9** we report the effect on CO_2-e prices (Panel a) and welfare (Panel b) of cases with No Banking (NB) compared with the results for core cases that include banking. We expect the CO_2-e prices to start out lower and end up higher in the no banking (NB) cases, and that is the pattern that emerges. The initial (2015) NB prices are \$6, \$10 and \$17 per ton CO_2-e compared with \$18, \$41, and \$53 for the 287, 203, and 167 bmt cases, respectively. They rise to \$77, \$262, and \$2559 by 2050 in the NB cases

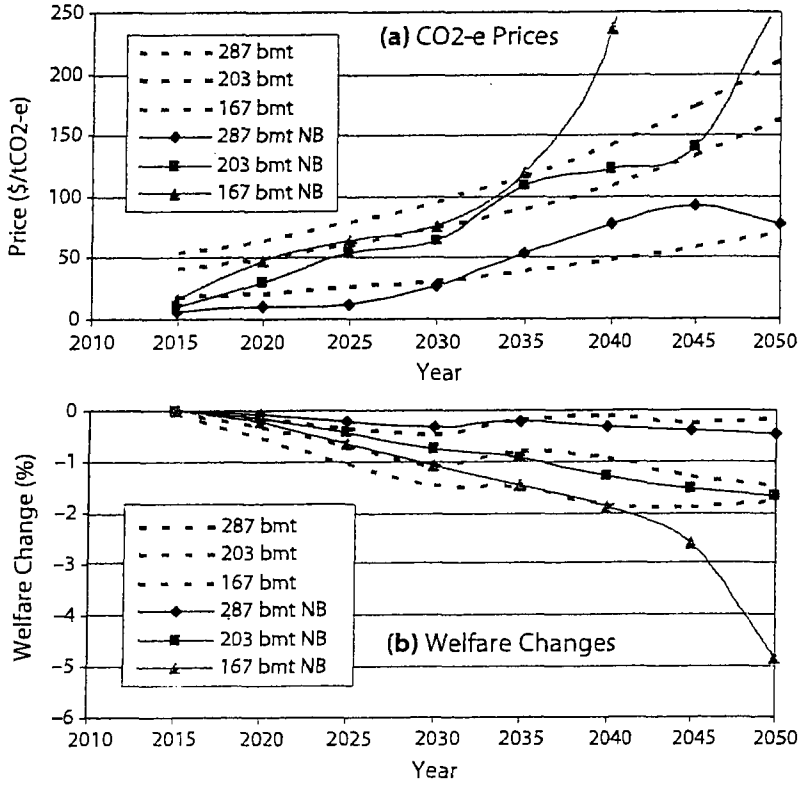

Figure 9. Effects of banking: no banking (NB) and core cases (dashed lines): **(a)** CO_2-e prices, **(b)** welfare changes.

compared with $70, $161, and $210 per ton CO_2-e for the 287, 203, and 167 bmt cases. The increase in CO_2-e prices in 2050 under the 203 bmt case and 2045 in the 167 bmt case (off the scale in Figure 9) result from the difficulties of reducing emissions in transportation. More details on this result are discussed below in Section 7 where we address biofuels and land-use implications.

Not surprisingly the welfare effects show a similar pattern, and losses rise to nearly 5% in the 167 bmt case. Note that without banking a target of 80% below 1990 emissions yields emissions 91% below the reference, and thus we are simulating an economy that is operating with less than 10% of reference emissions. Put another way, the economy of 2050 is more than three times the size of the current economy and population has increased by nearly one-third and yet the U.S. is emitting only about 15% of the GHGs of today. The EPPA model assumes substantial improvement in efficiencies throughout the economy, and price increases in transportation and other parts of the economy stimulate further technological substitution. Thus, even to achieve the results shown here considerable advance in technology is needed, but to achieve an economy that is nearly GHG-free at reasonable cost will require technological advances beyond those we have modeled.

We would expect the banking cases to show a lower Net Present Value welfare cost over the study period even considering that the higher costs in later years under No Banking are discounted at the 4% economy-wide interest rate. That result does hold for the 287 and 167 bmt cases but the difference is not very large. In the 287 bmt case, the NPV loss rounds to only 0.08% with banking and 0.07% without banking. Looking at more (and not necessarily meaningful) significant digits shows just how small the difference is—loss is 0.077% in the 287 bmt case and 0.074% in the NB case. The NPV loss for 167 bmt is 0.41% in the banking case and 0.42% in the NB case.

The 203 bmt case shows a slight advantage for the NB case (0.24% compared with 0.26%), an unexpected result. The likely reason is that there are extra-fuel-market influences, such as terms-of-trade effects that are not fully reflected in the allowance banking decision, and this may also reflect incomplete reallocation through time in the recursive-dynamic structure that does not fully optimize through time. While the banking-NB comparison shows very small differences in our scenarios in terms of NPV, banking provisions provide flexibility in the face of uncertainty that we have not modeled, and so the numerical result here should not be interpreted as suggesting that banking is not a useful policy design feature.

6.2 Limited Sectoral Coverage

Some of the proposals that focus on a downstream emissions cap exempt entities below some annual emissions level such as 10,000 tons of CO_2. One rationale is that monitoring small emitters would be too costly. In principle, such a provision would exclude the transportation sector with its many individual vehicles, but existing bills include it by moving the cap upstream to refiners who then must carry allowances for emissions that will result from the transportation fuel they sell. To represent this feature, we simulated a policy that exempts agriculture, households (*i.e.* natural gas and heating oil), and the service sector. Included under the cap are

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energy-intensive industry, other manufacturing, electric utilities, refineries, and transportation fuels. (The exempted sectors are not unaffected by the mitigation policy: inclusion of electric utilities under the cap means that their electricity prices will rise.) The limitation on coverage means that 77% of emissions as of 2005 are under the cap, and to simulate this policy we simply scale economy-wide allowances down by this amount over the whole period. It turns out in the EPPA reference that emissions from the covered sectors are growing somewhat more rapidly than the exempt sectors, and so by 2050 the covered sectors account for 83% of economy-wide emissions in the reference.

The CO_2-e prices are somewhat lower with sector exemptions compared with the economy-wide policy results (**Table 8**). Since the allowance allocation is proportionally scaled as a first approximation one might expect little difference. To the extent a difference exists it is because abatement is relatively easier or more difficult in the covered and exempted sectors, and over time there is differential growth between the two. Since emissions of the covered sectors are growing slightly more rapidly than the exempt ones, proportionally scaling down the allowances based on the share of emissions in the covered sectors in 2005 would, by itself, tend to lead to somewhat higher prices. Likely offsetting this effect is the inclusion of electric power under the cap where the availability of a variety of low carbon technologies usually results in this sector abating more than proportionally to other sectors. Additionally, the non-CO_2 GHGs are inexpensive to abate, especially those from non-agriculture sources, and they are included in the covered sectors. With fewer sectors competing for allowances released by abatement in the electric sector and from non-CO_2 GHG abatement, CO_2-e prices are lower compared with the economy-wide cases.

As shown in **Table 9** the welfare costs are lower with these sectors exempted than for the economy-wide cap. With sectors exempted the abatement required is proportionally less, and so as a first approximation we would expect the cost to be proportionally less as well. Costs are also lower because the CO_2-e price is somewhat lower. Once past the first few years, the sector welfare costs are about 70% of the economy-wide cost. In early years when the CO_2-e price is low much of the abatement is from non-CO_2 GHGs as shown in Figure 4 and even more so for the exemption case, lowering the welfare cost to about one-half that of the economy-wide policy.

Table 8. *CO_2-e prices with small emitting sectors exempted, banking case.*

	Economy-Wide Cap			Agricultural, Households, Services Excluded from Cap		
Year	287 bmt	203 bmt	167 bmt	287 bmt SEC	203 bmt SEC	167 bmt SEC
2015	18	41	53	14	31	41
2020	22	50	65	17	37	50
2025	26	61	79	20	45	61
2030	32	74	96	25	55	74
2035	39	90	117	30	67	90
2040	47	109	142	37	82	109
2045	57	133	172	44	99	133
2050	70	161	210	54	121	161

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Table 9. Welfare effects with small emitting sectors exempted, banking case.

	Economy-Wide Cap			Agricultural, Households, Services Excluded from Cap		
Year	287 bmt	203 bmt	167 bmt	287 bmt SEC	203 bmt SEC	167 bmt SEC
2015	0.01	–0.04	–0.07	0.01	–0.02	–0.04
2020	–0.13	–0.32	–0.55	–0.10	–0.23	–0.32
2025	–0.36	–0.69	–1.05	–0.34	–0.52	–0.74
2030	–0.45	–1.08	–1.47	–0.33	–0.82	–1.19
2035	–0.19	–0.77	–1.51	–0.14	–0.72	–1.11
2040	–0.12	–0.92	–1.84	–0.10	–0.80	–1.42
2045	–0.24	–1.28	–1.90	–0.17	–0.99	–1.41
2050	–0.18	–1.45	–1.79	–0.27	–1.11	–1.30

Of course, the lower cost is associated with a less environmentally effective policy because of the higher emissions (**Figure 10**). One concern would be a widening gap in emissions between economy-wide implementation and implementation with sector exemptions, which would occur if the exempt sector emissions were growing rapidly. This result might reflect leakage because the mitigation policy led to shifts of production among sectors. Leakage of CO_2—increases in emissions in the non-covered sectors compared to the reference emissions from these sectors—are 0.7, 1.0, and 1.1 bmt over the 38-year horizon of the policy in the 287, 203, and 167 bmt cases, respectively, relatively small compared with the total emissions allowed in these cases.

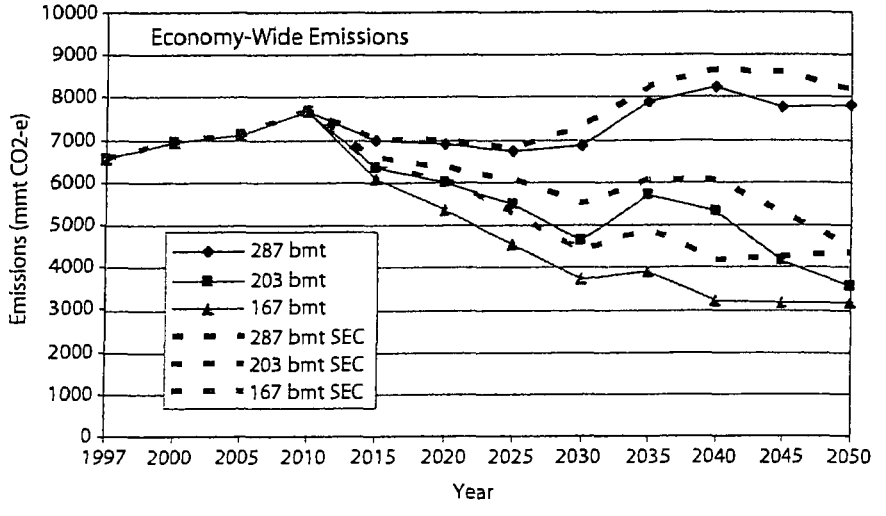

Figure 10. Economy-wide emissions with sectoral policies (SEC) compared with the core scenarios with banking.

6.3 Nuclear Power and Carbon Capture and Storage

In the core cases we limited nuclear electricity generation to that possible with current capacity on the basis that safety and siting concerns would prevent additional construction. With strong greenhouse gas policy such concerns may be overcome, especially if other major technologies such as carbon capture and storage can not be successfully developed, run into their own set of regulatory concerns, or turn out to be very expensive. To explore the possible

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outcome we relax the limitation on nuclear expansion, and assume that new generation plants become available that can produce delivered power at a 25% mark-up over coal generated electricity without CCS.[16] The coal CCS generation technology is assumed to have a mark-up of about 20% above coal without CCS.

Figure 11 shows the penetration of nuclear power and coal generation with and without CCS in the 203 bmt core case. The 25% mark-up on nuclear with a 20% mark-up on CCS is just about the level needed to make nuclear competitive with CCS given that CCS bears some cost associated with CO_2 emissions that are not captured and stored, and given the changing fuel and other prices simulated in the model. With removal of non-economic limitations nuclear penetrates strongly beginning in 2020, reaching 20 EJ by 2050, over six times current production (Figure 11a). The fate of CCS is the mirror image. With nuclear limited, CCS expands beginning in 2020 to about 18 EJ in 2050. When nuclear is allowed to compete on economic terms, some CCS is viable but it begins losing out to nuclear after 2040, when the CO_2-e price has risen substantially. Coal generation without CCS disappears in either case.

These relatively detailed results help illustrate the scale of effort required to meet these policy constraints. There are just over 100 nuclear reactors in the U.S. today, and so a six-fold increase in nuclear generation would require the construction of on the order of 500 additional reactors. If nuclear cannot penetrate the market the scale issue is not avoided but instead is transferred to CCS, requiring siting and construction of about the same number of new CCS plants. The need to

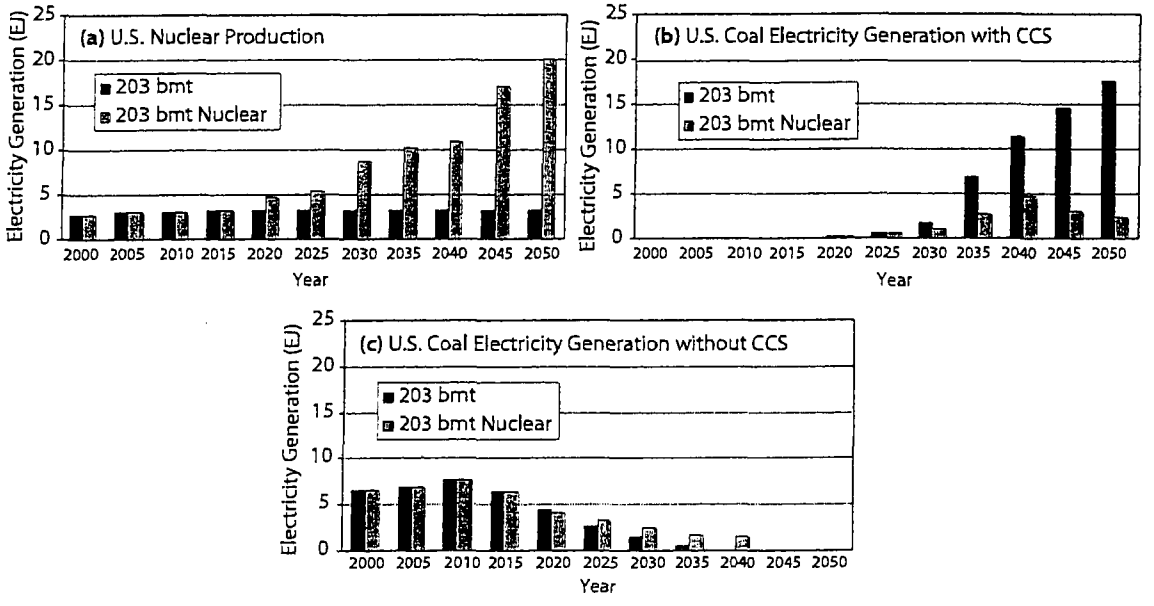

Figure 11. U.S. electricity generation in the expanded nuclear case and the core 203 bmt case: **(a)** nuclear generation, **(b)** coal generation with CCS, and **(c)** coal generation without CCS.

[16] The mark-up is relative to the cost of electricity including transmissions and distribution (T&D) charges. Engineering estimates typically compare costs at the busbar, and in such comparison the mark-up would be higher because T&D costs are the same regardless of the generation technology.

phase out coal without CCS indicates the potential value of a CCS technology that could be used to retrofit existing generation plants, extending the life of existing investment and limiting the number of completely new plants that were needed. The capital intensity of these technologies are a concern as we find that the investment demand needed for such expansions crowds out investment in other areas of the economy, and thus increases the welfare cost of the policy.

6.4 Revenue Recycling

A large body of economic analysis shows economic gains from auctioning allowances and using the revenue to lower existing taxes on labor and capital. The recursive dynamic structure of the standard EPPA model is not well-suited to evaluating these potential benefits. Gurgel *et al.* (2007) have developed a fully dynamic version of EPPA that results in very similar the abatement levels and CO_2-e prices as in the standard EPPA but is solved as a fully dynamic model where agents have perfect foresight. They use this version of EPPA to investigate revenue recycling and other issues, simulating the same 287, 203, and 167 bmt policies. It is not possible to completely investigate the many issues involved in revenue recycling here, but given the general interest in this topic it is useful to give some general indication of the magnitude of benefits revenue recycling could achieve.

Gurgel *et al.* (2007) find a 15% to as much as 70% reduction in the welfare cost when allowance auction revenue is used to lower capital taxes and a 5% to 20% reduction in cost when labor taxes are reduced. This result is consistent with other research that generally shows a greater benefit from capital tax recycling. The percentage reduction in cost is largest for the 287 bmt case and smallest for the 167 bmt case. One reason for this difference across cases lies in the fact that the denominator in this calculation—the welfare cost of the policy without recycling—is higher in the 167 bmt case. Another is that any benefit from revenue recycling depends first on how much revenue there is. Recall from Table 6 that while potential revenue starts out much higher in the 167 bmt case because of the high initial CO_2-e price, it actually falls off substantially by the end of the period because so few permits are available for auction when the policy becomes very tight. In the 287 bmt case, the revenue stream starts low but grows substantially over the period. Thus, the tax rate cut is not very different across the cases because they yield similar flows of revenue, so the numerator in the calculation—the recycling benefit—is not that different across the cases.[17] An important insight to be gained, then, is that a very tight policy that auctions very few permits will generate very little revenue. Stabilization ultimately requires very low emissions and so revenue recycling benefits are a transitory feature in stabilizations policies.

[17] An important aspect to consider is that the welfare costs of the policy in forward-looking model are considerably lower than in the recursive model because it is optimizing over time as well as among sectors. Thus, applying these percentage cost reductions to results from the recursive model may overstate the potential revenue recycling benefits.

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6.5 Provision of a Safety Valve

At various points in the discussion we have pointed out the similarities between a cap-and-trade system and an emissions tax. Another option introduced in Section 2.1 is a hybrid consisting of cap-and-trade system with a safety valve. In such a regime provisions are included that cap the CO_2-e price. This idea was prominently part of a report by a National Commission on Energy Policy (NCEP, 2004), and the level of the price cap identified in one of the proposals summarized in Table 2 follows the recommendations of that report. Usually the proposed price caps follow a time-path that rises at an estimated (real) rate of interest. Such a price path approximates an efficient allocation of abatement over time by keeping the net present value emissions price constant, and this approach is consistent with the price path we derive for a cap-and-trade system with banking.

The term "safety valve" comes from the notion that the price cap would be set substantially above expected prices under the cap to prevent the price from spiking in extreme circumstances. Recall from Section 2.1 that "high" is relative to the stringency of the cap and the expected emission price. A low level in relation to the stringency of the cap can assure that the safety operates frequently which, as noted above, would work much like a CO_2 tax with allocated exemptions. If the safety valve is likely to always be triggered, the level of allowances distributed for free regulates how much revenue the government receives. If the cap is high enough so that the safety valve is only rarely triggered the policy becomes equivalent to a pure cap-and-trade system.

The analysis we conduct can provide only limited insights with regard to the value of the safety valve in policy design. In particular, the above discussion highlights the fact that the motivation for a safety valve is to limit cost *given uncertainty*. To capture the value of the safety valve we would need to stochastically simulate the EPPA model, a task that is beyond the scope of this effort. As long as we are simulating EPPA in a non-stochastic mode, however, for every quantity constraint there is a price path that will deliver that same amount of abatement. And *vice versa*: the amount of abatement generated by a price path can be observed and the policy instead specified as a quantity constraint. Thus, the policy cases as simulated above can be interpreted as a cap-and-trade system, as a tax system in which the tax level is set at the prices observed in our simulations, or as a cap-and-trade system with a safety valve set at the price level we simulate.

For example, the 203 bmt case could be interpreted instead as a CO_2 tax policy with the tax rising from $41 to $161 per ton CO_2-e. Or that price level can be interpreted as a safety valve price path as long as allowance allocation was no more than the 203 bmt. If, for example, the cap was set at one-half of the 203 bmt and the allowance path was just cut in half each year, the only effect would be to reduce tax revenue by one-half. No other aspects of the scenario are changed by this reinterpretation. The only case where differences will appear is if tax or auction revenue is used to cut taxes as in Section 6.4. Cutting the revenue in half by distributing half of the allowances for free would mean that the capital tax rate could not be cut as far, and any tax recycling benefits would be reduced.

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It is also useful to note that, in the world of certainty that we are simulating, if the safety valve price rises at an economy-wide rate of interest and that is the same rate at which banking decisions are made, then either the safety valve is always triggered or it is never triggered. This result follows from simple algebra—both the banking price and the safety valve price rise at the same rate, and so if one is higher than the other at any point it is higher at all points. Of course, the safety valve need not rise at the rate of interest—it could be fixed at a flat level—or the legislatively prescribed rate of increase might not match the actual rate that traders are using in their banking decisions.[18] The inter-relationship of banking behavior and the safety valve should not be surprising. They are competing policy features that are both intended to smooth out short-term variations in the prices that might come about because economic activity and emissions can vary from a long-term trend. If both are included in a policy, one of them will likely dominate the other depending on the safety valve level and increase compared with the banking rate.

Finally, it is worth pointing out that setting the level of a safety valve to limit cost must consider whether it will achieve the desired level of abatement or not. Legislation that prescribes either a safety valve price or a cap is inevitably subject to review as to the adequacy of the policy and its cost, and such reviews are written into the various legislative proposals. The popular view of a price/safety valve policy instrument is that it provides certainty in the policy cost while creating uncertainty in how much abatement will be achieved, while a cap-and-trade instrument creates certainty in environmental effectiveness but leaves uncertainty in the cost. This stark characterization of the difference is only valid in a world where the policies are never revised. A cap that turns out more expensive than anticipated could be revised and loosened. A safety valve path that is not achieving significant reductions might be revised upward. Changing evidence of the threat of climate change could also lead to revisions, in either direction, of a price or quantity instrument. There is thus likely to be less difference between these instruments over the long-term where over-arching goals of the policy are shaped by improved understanding of the science and economics of the problem, and prices and quantities are revised to be consistent with that improving knowledge.

Applying these concepts we construct a policy case with a price path similar to the one proposed in the National Energy Commissions report (NCEP, 2004) that begins at $6 per ton CO_2-e and rises to about $39 per ton CO_2-e by 2050.[19] Then to explore the potential costs and effectiveness of the safety valve we conduct four simulations reported in Figure 12: (1) the safety valve (SV) case in the U.S. with the standard assumptions in the core cases about mitigation efforts abroad (US+ROW), (2) the SV case in the U.S. and no mitigation action abroad (US only), (3) no action in the U.S., and the standard assumptions about effort abroad (ROW only), and

[18] A difference between the rate of increase in the safety valve and the banking rate would tend, in a "certain" world, to generate two periods—one where the safety valve is triggered and one where it is not. Which comes first depends on whether the banking rate is higher or lower than the prescribed rate of increase in the safety valve. The U.S. Energy Information Administration (US EIA, 2007) used a banking rate of 8% with a safety valve rising at 5%. As a result the cap was binding in early years and the banking price rose at 8% eventually catching up to and triggering the safety valve.

[19] This level has also been adopted in the Bingaman-Specter draft legislation and analyzed by the EIA (US EIA, 2007).

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(4) the SV case in the U.S. with the safety valve price being revised upward in 2030 and standard assumptions about action abroad (SV Revised 2030). The SV Revised 2030 case is an artificial construction to illustrate the possibility that events may unfold in ways that lead to a revision some time before 2050. If we knew now what these events were we would reshape the overall price path to start higher and rise at 5%, without a sudden revision.

Figure 12a shows the standard safety valve price path and the path when the price is revised in 2030. In the revised path, the price is doubled in 2030 and then continues to grow at 5% per year. Figure 12b shows the welfare effects. Here, as in the 287 bmt revenue recycling case, the U.S. welfare change is small initially and then welfare actually improves relative to the no-policy reference case; that is, the policy appears to be beneficial to the economy. The US Only and ROW Only simulations confirm that the welfare benefit in the US+ROW case is a terms-of-trade effect. In the US Only case there is always a welfare cost and it rises over time as the CO_2-e price rises. The ROW Only case shows even larger benefits for the U.S. than the US+ROW case. Thus, relative to that case the addition of a policy in the U.S. reduces welfare.

The plausibility of the rest of the world pursuing a fairly stringent policy while the U.S. is pursuing a relatively weaker one can be questioned. In that regard, one way to motivate the SV Revised 2030 case is that with developing countries joining in 2025, the U.S. might then see reason to intensify its efforts by revising upward the safety valve price in 2030, with this leadership move then bringing a further commitment of developing countries in 2035. As the SV Revised 2030 case shows in Figure 12b, the upward revision of the safety valve basically eliminates the net terms-of-trade gain from the ROW policy, leaving the U.S. better off with the revision than if it had pursued the safety valve without the rest of the world. Obviously, such a

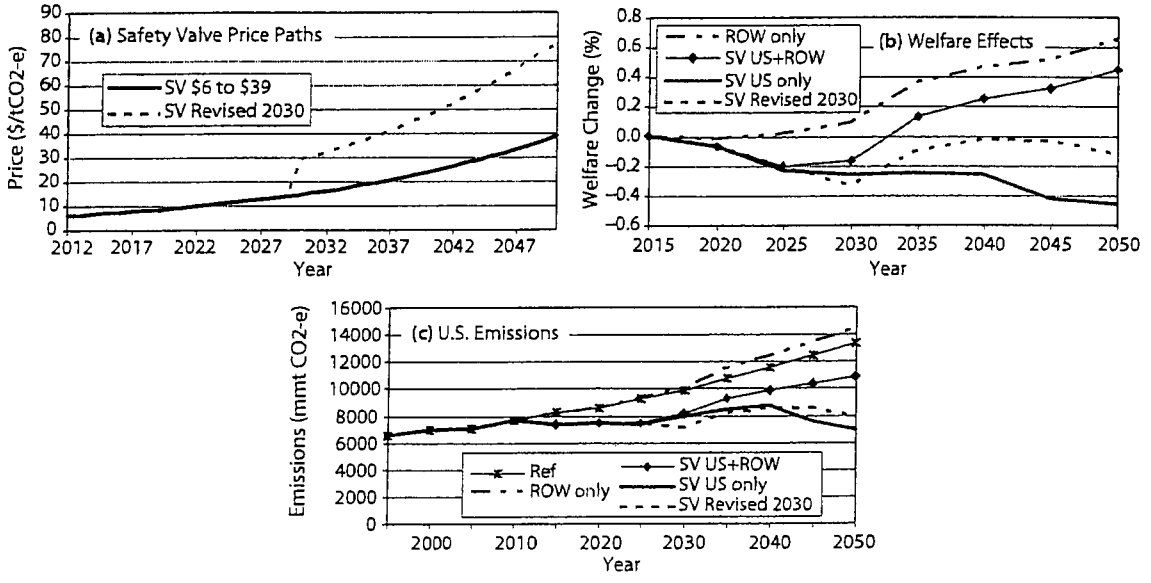

Figure 12. Effects of a "safety valve" at $6 in 2012 rising to $39/t$CO_2$-e in 2050: **(a)** safety valve price paths, **(b)** welfare effect, and **(c)** U.S. emissions.

scenario of international cooperation is fairly simple-minded speculation on our part, but it does illustrate the degree to which decisions about the level of U.S. effort over an extended period depends on what other countries do, and whether or not U.S. leadership generates a following.

In cap-and-trade cases total emissions must be less than the cap. With a price instrument the price is certain but the level of emissions is uncertain. While we do not represent many of the inevitable uncertainties in economic projections the different assumptions about international policy can be seen as one of the uncertain aspects of the future. And, as shown in Figure 12c, what the rest world does in terms of mitigation strongly affects U.S. emissions and the effectiveness of a price instrument. Here we also plot the reference level of emissions when there is no policy in the U.S. or the rest of the world. First, note that the U.S. emissions drop about 1800 mmt of CO_2-e below the reference in the US+ROW case by 2025, and then do not drop much more below the reference for most of the rest of the period even though the CO_2-e price is escalating at 5% per year. However, it can be seen from the ROW Only case that U.S. emissions without a policy would have risen above the reference, reflecting leakage from the ROW policy into the U.S. The main source of this leakage in the EPPA model is lower world oil prices that then lead to greater petroleum product use. Compared, then, to the ROW Only case the escalating CO_2-e price gradually increases the level of abatement. Somewhat more surprising is that in the US Only case, the policy with the specified safety valve becomes very effective toward the end of the period. Recall that the EPPA model reference petroleum product prices rise substantially if the world is not taking action, as shown previously in Figure 5. Thus with mitigation only by the U.S., biofuels become economically competitive with refined oil, lowering emissions at the safety valve-determined emissions price.

The SV Revised 2030 case can be further motivated by the observed pattern of emissions with and without policy in the rest of the world. One can imagine that a broad goal of the safety valve policy is to hold U.S. emissions flat over the longer term and that is being roughly accomplished in the US Only case. However, that goal is not being met by 2030/2035 in the US+ROW policy. Our doubling of the safety valve price in 2030 gets the U.S. back on track to hold emissions more or less flat, and that revision can be seen as an adjustment in the safety valve price to keep the U.S. headed toward a quantity target, retaining the safety valve instrument to protect against short-term price spikes but unwilling to live with the long-term implications for emissions if it is not adjusted.

6.6 International Allowance Trading

We turn next to the potential implications of international emissions trading. As shown above, banking reallocates abatement and cost through time making it difficult to sort out the impact of other design features. To isolate the effects of emissions trading, therefore, we simulate scenarios without banking. Note also that in the core scenarios there is no trading among regions. Here we create a scenario where all world regions except the U.S. trade among themselves. This further allows a focus on just the implications for the U.S. of joining an international emissions trading system.[20]

[20] Going from no trading to trading abroad has some effects on the U.S. through terms-of-trade changes but these are relatively minor.

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Pre-trade and trading prices for the 203 bmt and 167 bmt cases are shown in **Figure 13**.[21] Panel (a) shows pre-trade prices and panel (b) contrasts the world trading price with the pre-trade prices in the rest of the world (ROW). Note that the ROW pre-trade prices are affected by the policy in the U.S. The factors producing this effect are the same as those behind the influence of ROW actions on U.S. domestic prices: under more stringent U.S. controls, reduced U.S. demand for oil and higher demand for biofuels combine to widen the gap between fossil and non-fossil alternatives thus requiring a higher CO_2-e price abroad to meet the assumed emissions cap.

Figure 13a shows that the pre-trade price differences are relatively small in the 203 bmt case up to 2045, with the U.S. pre-trade price higher than the world price so the U.S. would be a net buyer of allowances if it joined the international trading system. The 167 bmt case has U.S. pre-trade prices further above those in the ROW, and so this is a case where the U.S. would be a strong net purchaser of allowances after 2035. Figure 13b compares the world trading price and the ROW pre-trade price (note the difference in vertical scale). The effect on the world price of the U.S. joining the emissions trading system is moderate in the 203 bmt case (an increase of about a little less than $10 per ton CO_2-e) in later years, and somewhat greater (around $20 per ton CO_2-e) in the 167 bmt case. It is noteworthy that the indirect effects on the world price through terms of trade and international price changes are at least as great as the direct effect of the U.S. entering the trading system.

Regarding the welfare effects of trading, shown in **Table 10**, we find the conventional result that emissions trading improves welfare for the U.S. in the 167 and 287 bmt cases. The improvement is substantial in the 167 bmt case because the pre-trade prices in the U.S. were quite large by the end of period, generating substantial direct mitigation policy costs. The U.S. is a small net seller of allowances in almost all years in the 287 bmt case, and this generates no change or small welfare gains in all years. The 203 bmt case shows emissions trading to be welfare worsening for the U.S. This perverse outcome can be produced by interactions with existing distortions in the economy or through terms-of-trade effects (Babiker *et al.*, 2004; Paltsev *et al.*, 2007). In this case, it is likely that terms-of-trade effects are driving this result.

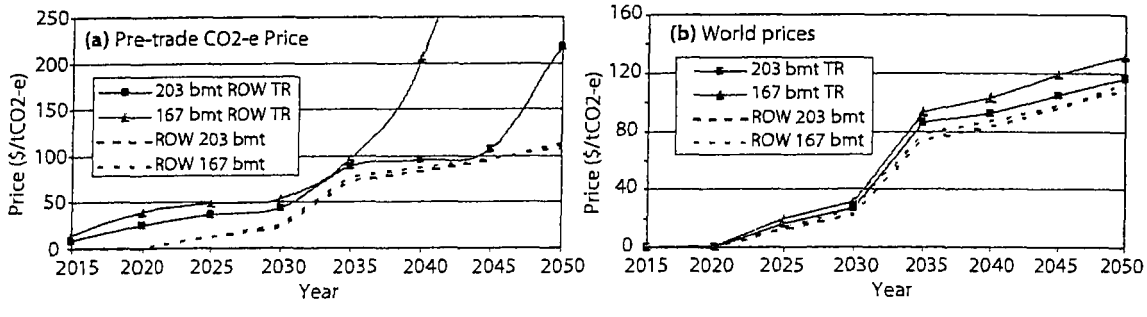

Figure 13. CO_2-e prices and emissions trading: **(a)** pre-trade prices, U.S. and the rest of the world (ROW), with trade among ROW regions; and **(b)** world prices with U.S. trading, ROW pre-trade.

[21] The U.S. pre-trade price in the 287 bmt case is very similar to the ROW pre-trade price, and thus there is little incentive for trade. To simplify the figure this case is omitted.

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Table 10. U.S. welfare effects of emissions trading (TR) in the no banking cases.

	287 bmt No TR	287 bmt TR	203 bmt No TR	203 bmt TR	167 bmt No TR	167 bmt TR	ROW only, No TR	ROW only, TR
2015	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01
2020	–0.06	0.00	–0.13	–0.01	–0.20	–0.02	–0.01	–0.01
2025	–0.22	–0.14	–0.43	–0.24	–0.64	–0.33	0.04	0.02
2030	–0.31	–0.23	–0.76	–0.47	–1.08	–0.62	0.09	0.09
2035	–0.23	–0.12	–0.93	–0.83	–1.48	–1.32	0.36	0.37
2040	–0.30	–0.26	–1.28	–1.27	–1.91	–1.91	0.46	0.46
2045	–0.39	–0.40	–1.54	–1.65	–2.62	–2.45	0.52	0.52
2050	–0.46	–0.41	–1.68	–1.88	–4.86	–2.81	0.62	0.65

As Webster *et al.* (2006) show, if the direct gains from trade are relatively small (because the pre-trade price difference is small) then indirect effects through changes in the terms of trade can dominate the direct trading benefits. Here the likely dominating terms-of-trade effects occur because by entering the permit market the U.S. forces more abatement abroad. A main avenue of abatement is the use of biofuels, and this drives up the world price of this fuel, which the U.S. imports. This effect worsens the terms of trade.

More broadly, in many policy-design discussions allowance credits from outside the U.S. trading system are seen as a means to lower the cost of the greenhouse gas policy in the U.S. But this argument assumes that there is a low-cost supply of credits for which there is little competition—*i.e.* that the U.S. is the only significant country pursuing a stringent mitigation policy. If other developed countries are pursuing a policy of similar stringency, the CO_2-e price in these regions will be similar to that in the U.S. and so they will not be a source of low-cost allowances.

Before the developing countries take on a policy they may be a source of credits through the Clean Development Mechanism (CDM) of the Kyoto Protocol, but the evidence suggests that because of the project-based nature of such credits only a relatively small percentage of the potential reductions in developing countries can actually be formulated as projects that would meet CDM criteria. Thus, the U.S. and other developed countries will compete for a relatively limited supply, with some but limited savings in the U.S. If the developing countries take on a real cap sometime in the next decade or so, and given their relatively rapidly growing emissions, the prices they would see are not that different from those obtained in the U.S. in our model simulations (under the 203 bmt case) and so there is little potential U.S. benefit. It is only when the U.S. agrees to bear a substantial share of the reduction burden by accepting a much tighter policy than other countries that emissions trading brings significant benefits.

Emissions trading probably ought to be seen, therefore, mainly as an instrument by which the U.S. and perhaps other developed countries might accept a large share of the cost burden, either on the basis that this is "fair" or to induce developing countries to take on at least some commitment by implicitly agreeing to pay for their reductions by awarding allowances that we will purchase from them. If instead U.S. policy is designed so that the U.S. mitigation effort is comparable to that of other regions (*i.e.* the CO_2-e price is likely to be within 50% or so of other

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regions) then there is a substantial chance that trading will have little benefit for the U.S., or may be welfare worsening.

Another aspect of these scenarios is the likely role of biofuels as a substitute for international allowance trading. To the extent biofuels are providing abatement at the margin, and this is especially true in the 203 bmt case, the common global biofuel price will tend to equalize CO_2-e prices among regions: regions with relatively tight constraints will import more biofuels causing the CO_2-e price to be lower than it would otherwise, whereas regions with relatively looser constraints will not compete as effectively for biofuels and their CO_2-e price will not be as low as it would be if the biofuel price had not been bid-up by countries with tighter constraints.[22]

7. BIOFUELS AND LAND USE

As already discussed in several sections, biofuel liquids play an important role in the mitigation scenarios, as they are the main non-carbon alternative to petroleum products that we represent in the EPPA model. Corn-based ethanol production has grown rapidly in the U.S. in the past few years, but even with that growth total ethanol production in the U.S. is a very small percentage of total gasoline consumption (about 2%). Brazil is one of the major producers internationally, and while production there is substantial relative to Brazil's domestic gasoline consumption, total Brazilian ethanol production is about equal to that in the U.S. This comparison simply highlights the fact that U.S. petroleum consumption is very large relative to existing ethanol production. It is also important to realize that the principal motivation for using ethanol in fuels in the U.S. currently is as an oxygenating additive. This source of demand (and the production needed to supply it) is not explicitly represented in the EPPA model, but is part of aggregated agriculture and industry sectors in the EPPA database.

For biofuels to make a substantial contribution to CO_2 abatement in the U.S. their supply would need to expand considerably beyond its role as a fuel additive. In addition, how ethanol is produced would need to change. Current ethanol production processes in the U.S. actually emit a fair amount of CO_2 because fossil fuels are used in the distillation process, and to a lesser extent in growing the corn. Further, the expansion of corn-based ethanol production is limited—if the entire U.S. corn crop were turned to ethanol one estimate is that it would supply less than 10% of U.S. gasoline demand. Focus has therefore shifted to production of biofuels from cellulosic plant material, which while not yet commercialized is highly promising. Cellulosic conversion utilizes much more of the energy in the biomass, and a broader range of crops can be used.

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[22] The possibility of the domestic prices of a non-traded good or factor input (in this case the CO_2-e allowance price) to equalize across countries is consistent with basic economic theory as expressed in the well-known factor price equalization theorem that predicts equalization of wages and returns to capital even in the presence of restrictions on capital and labor mobility. An important element of the theorem is perfect substitution of foreign and domestic goods, which we have represented in the case of biofuels. Imperfect substitution of other goods, and limits on mobility of labor and capital mean that CO_2-e prices actually diverge among regions in EPPA simulations. Relaxing these assumptions could tend to result in greater convergence in CO_2-e prices among regions even without emissions trading. One implication of this argument is that, if some regions are not capped, the CO_2-e price could approach zero because production and consumption activities would shift to the uncapped regions—leakage from the policy would be complete.

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Biofuel liquids in the EPPA model are based on the assumption that cellulosic conversion processes are successfully commercialized and that the energy needed in the conversion/ distillation process is also supplied by biomass so that there is no net CO_2 release. A source of biomass process energy could actually be the lignin in biomass, which cellulosic conversion processes closest to commercialization cannot convert to liquid fuels. While other processes are under development that would break down the lignin as well, if heat energy is required in the processing of ethanol anyway then the lignin by-product can be used directly for that purpose, without a further costly conversion. If not, some other, relatively expensive non-fossil source of energy would be required, or the process would need to include carbon capture and sequestration. The EPPA model assumptions about the cost and efficiency of ethanol production are in line with engineering estimates, once scale economies are realized and experience is gained with initial demonstration plants (see Paltsev *et al.*, 2005).

Before focusing attention on the EPPA results, the magnitude of the potential land pressure from biomass can be illustrated using some simple calculations presented in **Table 11**. On the assumptions detailed above and in the table, if all U.S. cropland, grassland, and forestland were used to produce biomass liquids, total U.S. production could reach about 81 exajoules (EJ). Coincidentally, this quantity would just cover the 78 EJ of petroleum product consumption in the U.S. in 2050 in our reference projection. Needless to say, converting every bit of grassland, forestland and cropland to biomass production would have massive implications for land use, and would leave no land left for food, forest, and fiber production—thus it is a purely hypothetical calculation. From this simple calculation it should be evident that biofuels production, even at levels that would offset 10 or 15% of petroleum product use, would have substantial effects on agricultural markets and on land use.

Some popular estimates of U.S. biomass potential suggest greater possibilities but often they involve a comparison of total biomass energy, failing to consider conversion losses or assuming some other source is available for process energy. Or studies compare U.S. biomass energy to just U.S. oil imports or current gasoline consumption, failing to consider the likelihood that

Table 11. Continental U.S. hypothetical maximum biomass energy potential.

Continental U.S., current land uses	Hectares (millions)	Acres (millions)	Maximum dry biomass (EJ)	Maximum liquid fuel (EJ)
Cropland	176	442	53	21
Grassland	235	587	70	28
Forest	260	651	78	31
Parks, etc	119	297	NA	NA
Urban	24	60	NA	NA
Desert, wetland, etc	91	228	NA	NA
US Total	906	2265	202	81

Source: Land area is from USDA (2006). Dry biomass production is based on production of 15 oven dry tons per hectare per year = 300 GJ/ha/yr (IPCC, 2001). Maximum assumes all land of that type is used for biomass production, and total assumes parks/preserves and urban land would not be used and that desert, wetland, etc. would not be used and/or would not be productive. Maximum liquid fuel assumes that 40% of the energy in the biomass is converted to liquid, and the remaining is used for process energy or remains in other by-products.

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demand for fuels will increase. Others further assume that greater efficiency in vehicles, without increased miles driven, will actually reduce fuel demand over time. The EPPA model projects continuing increase in vehicle fuel efficiency even in the reference case, where vehicle efficiency improves by nearly 60% by 2050 in vehicles of all types (*i.e.* including commercial transport) compared to the fleet average today. Thus, the 78 EJ of petroleum product use in the U.S. already includes assumptions about aggressive improvement in vehicle efficiency.

The EPPA model results for biofuels are presented in **Figure 14** with two assumptions: as in earlier simulations with free trade in biofuels, and in a set of cases where there is no biofuel trade (noted NobioTR). We find that with free trade, biofuel use is substantial in the 203 bmt and 167 bmt cases, rising to 34 to 36 EJ in the core cases, as shown in Figure 14a. The 287 bmt case results in very little U.S. biofuels consumption—less than 1 EJ in any year, and so we do not show it in the figure. World liquid biofuel use is substantial in all three cases (Figure 14b), reaching 92 to 127 EJ, because the rest of the world is pursuing the same strong greenhouse gas policy in all cases. Thus, the main difference is the changes in biofuel use in the U.S. The 287 bmt case, if the U.S. pursued the policy alone, would lead to substantial biofuels use in the U.S., but demand from the rest of the world prices the U.S. out of the market, with other mitigation options able to more cheaply meet the U.S. cap. As the estimates in Table 11 suggest, if produced domestically, the amounts used in the U.S. would require on the order of 40% of U.S. cropland, forestland, and grassland (about 700 million acres). To produce the world total ethanol production of 127 EJ would require about 2.5 billion acres (or about 1 billion hectares).

The EPPA model projects, however, that virtually all of the U.S. biofuels would be imported. Some U.S. domestic production (less than 0.8 EJ) finally occurs in 2050 in the 203 bmt and 167 bmt case. Interest in biofuels use in the U.S. is often heightened by the belief that we would be able to rely on a domestic resource. In that regard, the EPPA model may not ideally represent differential productivity of biofuels across the world. However, it is notable that the U.S. currently restricts biofuels imports to support the domestic industry. Might the U.S. rely on its domestic biofuels production capability? To examine this possibility we also show a case where trade in biofuels is restricted, requiring that any use in the U.S. (or in any region) be domestically produced within that region. Biofuel use in these cases is shown in Figure 14 as well, noted NobioTR. As might be expected, the restriction leads to lower biofuels use in the U.S. and in the

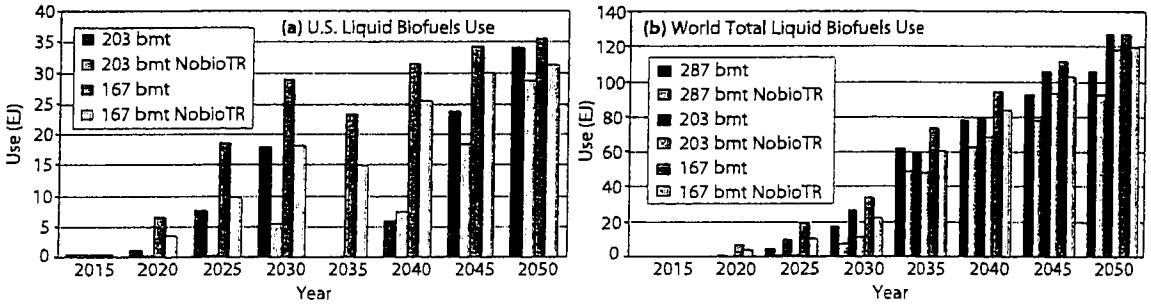

Figure 14. Liquid biofuel use, with and without international trade in biofuels: **(a)** U.S., **(b)** world total.

total for the world, but biofuel use, and hence production, in the U.S. is substantial, rising into the 25 to 30 EJ range by the end of the period as compared to the 30 to 35 EJ under free trade. This quantity of biofuel would still require about 30% of all U.S. crop, grass, and forestland or over 500 million acres of land.

Figure 15 illustrates one of the important implications of a substantial biofuels industry for the 167 bmt case. The U.S. now is a substantial net agricultural exporter, and under the EPPA reference without greenhouse gas policy this pattern is projected to continue. In the core cases, U.S. net agricultural exports are projected to more than double compared with the reference. As other regions expand biofuel production, they import more agricultural goods and thus U.S. net exports grow. The significant effect of barring biofuels imports into the U.S. under a stringent climate policy is that domestic production of biofuels significantly reduces agricultural production, and instead of the U.S. being a significant net exporter of agricultural products we become a large net importer. Whereas net exports today are on the order of $20 billion, the U.S. grows to be a net importer of over $80 billion of agricultural commodities. The agricultural sector in the EPPA model is highly aggregated—a single sector includes crops, livestock, and forestry. As a result, one should not put too much stock in the absolute value of net exports in the reference—it could be higher or lower depending on how agricultural productivity advances in the U.S. relative to other regions of the world. However, if on the order 25 EJ of ethanol must be produced in the U.S., requiring on the order of 500 million acres of land, it is nearly inevitable that this would lead to the U.S. becoming a substantial agricultural importer.

Several other critical aspects of this level of biofuels production are worth pointing out. In keeping with U.S. proposals as well as with policy developments abroad such the EU ETS or the Kyoto Protocol (see Reilly and Asadoorian, 2007), we have not extended the cap-and-trade system to cover land-use emissions. If included at all, land use is often covered under a crediting system. However, as shown by McCarl and Reilly (2006), except for quite low CO_2-e prices the economics of biofuels tends to dominate the economics of carbon sequestration in soils. The implication is that, at the level of biofuels demand simulated here, there would be scant incentive to protect carbon in soils and vegetation through a credit system. Landowners would instead tend to convert land to biofuels or more intense cropping.

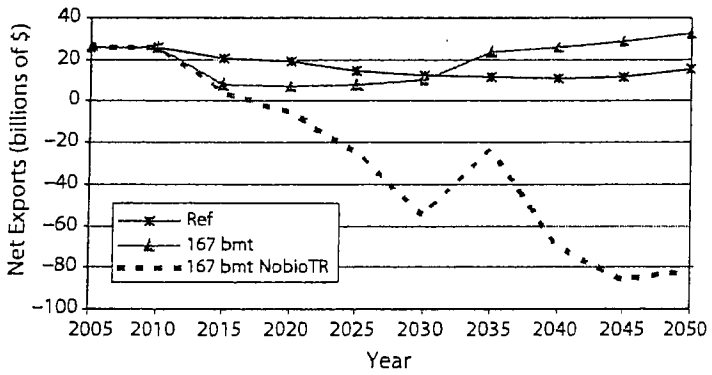

Figure 15. Net agricultural exports in the 167 bmt case, with and without biofuels trading.

Whether the biofuels themselves are produced on existing cropland or not, the overall need for cropland would require significant conversion of land from less intensively managed grass and forestland. This initial disruption would lead to significant CO_2 release from soils and vegetation. If mature forests are converted it can take decades of biofuels production to make up for the initial carbon loss. Whether the land is located in the U.S. or abroad its conversion is likely to contribute substantial carbon emissions, substantially negating the savings from reduced fossil energy use. Thus, one of the most serious issues raised in this analysis is the need to expand a cap-and-trade system to include land-use change emissions, and to be doubly concerned about leakage from reductions in the U.S., through biofuels imports, unless mitigation policies abroad *that include land-use emissions* are in place.

8. CENTURY SCALE EMISSIONS AND CLIMATE RESULTS

The policy time-horizon of 2050 in the current congressional proposals is long relative to the planning horizon for government efforts that may extend no more than a few years to a decade, but as described in the recent IPCC report (IPCC, 2007) the world is already committed to a substantial amount of warming through 2050, even if atmospheric greenhouse gas concentrations were stabilized at today's levels. Moreover, stabilization of concentrations at today's levels would require that the entire world immediately reduce emissions to very low levels, a feat that would be politically difficult and economically costly. To begin to assess the adequacy of proposed policies in the face of goals such as stabilization of greenhouse gases in the atmosphere, or of holding total warming below a target such as 2°C, requires a time horizon of at least 100 years and simulation of the emissions projections from human activities that result from these policy scenarios through an earth system model.

To explore climate response we use the MIT Integrated Global System Model (IGSM), described in detail in Sokolov *et al.* (2005) and summarized in **Box 1**, and we extend the emissions scenarios studied above through the year 2100. One advantage of the IGSM is its flexibility to vary key parameters of climate response to represent uncertainty or to allow it to reproduce the response of a full range of three-dimensional atmosphere-ocean general circulation models (AO GCMs) that would, themselves, require several months of computer time to produce a single 100-year simulation. For purposes of this report we developed parameterizations of the IGSM that represent each of three major U.S. AO GCM models—those of the Goddard Institute for Space Studies (GISS-SB), the Geophysical Fluid Dynamics Laboratory (GFDL-2.1), and the National Center for Atmospheric Research (CCSM3). These models show somewhat different climate responses to the same anthropogenic forcing and thereby illustrate some of the uncertainties in translating an emissions trajectory into an estimate of climate change.

We simulate the climate effects of six different climate policy scenarios through 2100 (see **Figure 16**). The first is a reference emissions forecast that includes no specific climate policy (Reference). Then three global participation scenarios include the international policy in our core policy scenarios in the 167, 203, and 287 bmt cases. We extend these three cases through 2100 by holding annual emissions allowances at their 2050 level through the end of the century.

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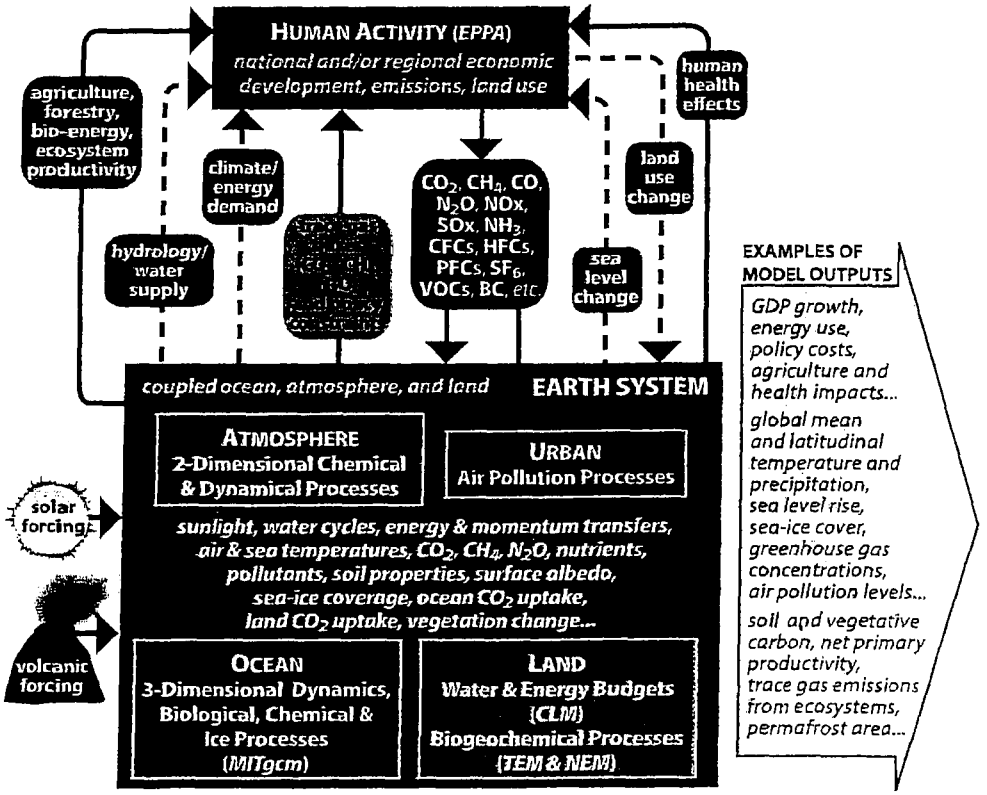
(Recall that in the 203 bmt case, the U.S., Europe, Japan, Canada, Australia, New Zealand are 50% below 1990 levels in 2050; all other countries are at their 2000 levels. In the 167 bmt case the U.S. is 80% below 1990 levels and in the 287 bmt case U.S. emissions are held at 2008 levels.) To examine the climate implications of the global versus partial participation, the fifth case assumes abatement efforts in developing countries are delayed until 2050, at which point mitigation efforts return them to 2000 levels where they remain through 2100 (Developing

Box 1. The MIT Integrated Global Systems Model (IGSM).

The EPPA model is part of a complete model of the interacting earth system (as depicted below) that includes models of the terrestrial systems, oceans, and the atmosphere. The configuration and capabilities of the IGSM Version 2 are described Sokolov *et al.* (2005). The IGSM has been used in a variety of applications and its components and applications using the full system have been published in the peer reviewed literature. A description of the system components used in Version 1, along with a sensitivity test of key aspects of its behavior, are reported in Prinn *et al.* (1999), and additional characteristics of particular components are described in Babiker *et al.* (2001), Mayer *et al.* (2000), and Kamenkovich *et al.* (2002). IGSM2 and its components have been described in Dutkiewicz *et al.* (2005a,b; 2006), Kasahara *et al.* (2007), and Sokolov *et al.* (2005). Recent applications of the IGSM include Felzer *et al.* (2005), US CCSP (2006), Reilly *et al.* (2007a,b), and Zhuang *et al.* (2006, 2007). Additional reports, technical notes and journal articles describing the system and applications of it available at http://mit.edu/globalchange/www/reports.html.



The schematic depicts the current framework and processes of the MIT Integrated Global System Model Version 2 (IGSM2).

Countries Delayed). The sixth case assumes developing countries take no abatement action through 2100 (Developed Only). Abatement in the developed countries remains unchanged in these latter two cases and the U.S. policy is set at the 203 bmt level.

Assumption of such abrupt changes in policy, such as developing countries suddenly returning to 2000 levels in 2050, is not very realistic but what matters for a long-term goal such as stabilization are cumulative emissions and so more realistic time-paths with the same level of cumulative emissions over the century can be imagined. Similarly, since we are not focusing on abatement cost after 2050, one can imagine different ways in which the abatement effort is shared among countries post 2050, and as long as cumulative global emissions are the same the long-term climate consequences will be little affected.

The scenarios include all greenhouse gases and policies to abate them. The EPPA model also projects aerosols and tropospheric ozone precursors, and while the GHG policies simulated here do not include targets for these substances, to the extent policy affects the level of combustion of fossil fuels and other activities that generate emissions, it affects these other greenhouse substances as well. The emissions levels projected by EPPA of these substances, as they change among GHG policy scenarios, are simulated through the IGSM and contribute to the projected changes in climate. We focus on the CO_2 concentrations (which are only indirectly affected by the level of other substances) and the global mean surface temperature change (which is affected by the level of GHGs and all other radiatively active substances). Concentrations of other gases such as methane, nitrous oxide, and of aerosols and ozone also change but are not shown here.

As shown in Figure 16, the CO_2 concentrations reach 880 ppmv by 2100 in the Reference, rising at an accelerating rate. The results show the importance of developing country participation

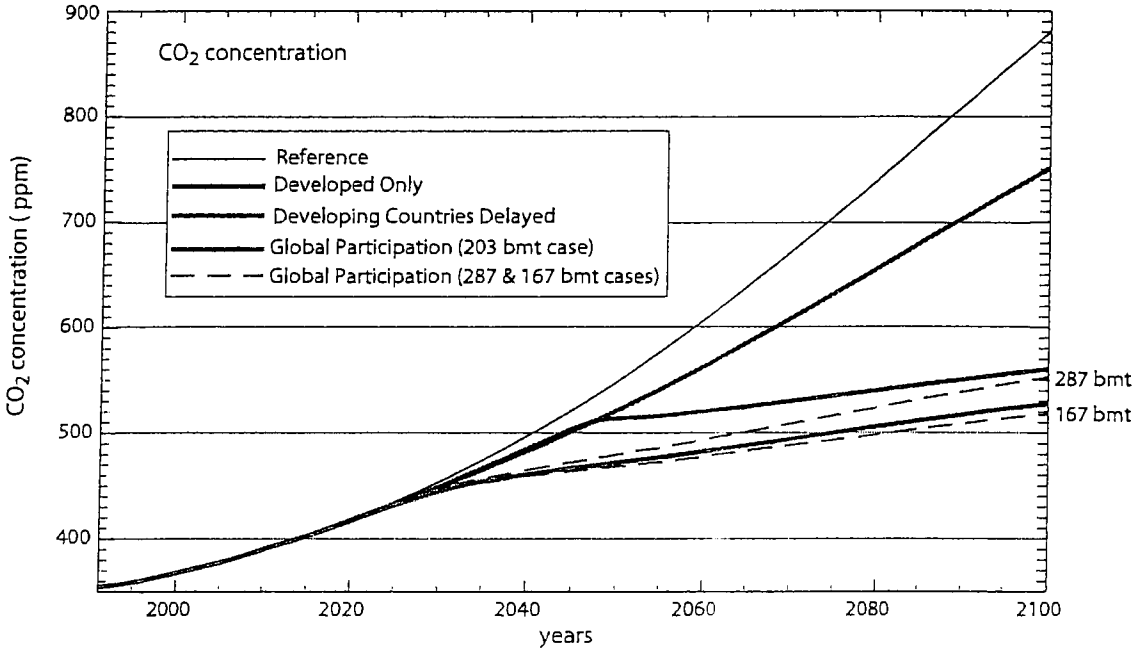


Figure 16. CO_2 concentrations in six scenarios using the MIT IGSM; see text for details.

in the determination of long-term CO_2 concentrations. In the Developed Only case the growth in atmospheric concentrations is slowed but it still reaches 750 ppmv. In the cases where developing countries participate, however, even when effort is delayed to 2050 concentration growth is restrained considerably and the CO_2 level is at 560 ppmv in 2100. A 450 ppmv goal is sometimes advanced as a desirable target. The most stringent policy we have simulated here, Global Participation with the U.S. at 167 bmt, is not sufficient to meet a 450 ppmv target: by 2050 concentrations are already at 460 ppmv.

The different U.S. policies have relatively small effects on the CO_2 concentration if other regions do not follow the U.S. lead. This result further highlights the need for significant international participation. The expectation of those supporting tighter targets in the U.S. may well be that it would lead other developed countries along the same more stringent path, and perhaps accelerate mitigation efforts in the developing countries, or that recognizing that developing countries may delay participation the U.S. would take stronger measures to make up for this delay. In that regard, the concentration difference in 2100 between the 167 and 287 bmt case is just about the concentration difference between cases where the developing countries join in 2025 versus delaying their participation until 2050. Thus, the 167 bmt case can be viewed as the U.S. making up for delayed developing country participation, with the 287 bmt case achieving approximately the same concentration result if developing country participation can be achieved earlier. In that regard, the policies we assumed to occur abroad are only a few highly stylized possibilities, but they, rather than differences in the U.S. policy, drive the climate results.

As far as atmospheric concentrations are concerned, it is not important where emissions are cut, and achieving any of the atmospheric targets now under discussion raises the question of how much more other developed countries and developing countries would be willing to do. Our extension of the policies beyond 2050 is obviously arbitrary. If the world pursued the Global Participation path the growth trajectory of CO_2 emissions would be altered significantly, but a goal of stabilization would require still further cuts.

As noted above, what matters most for long-term concentration goals are cumulative emissions over the century, so a useful way to understand how these policies contribute to stabilization goals is to compare cumulative emissions under these scenarios to those that would be consistent with particular stabilization levels. In that regard, the MIT IGSM was recently employed in development of stabilization scenarios as part of a U.S. Climate Change Science Program exercise (US CCSP, 2006). An idealized cap-and-trade system was implemented beginning in 2015 in which the whole world participated. The price path of the emissions constraint over the whole period (2015-2100) was constrained to rise at a 4% rate to simulate banking and cost-effective allocation of abatement over time.

We show in **Table 12** the cumulative emissions from 2012-2050 and from 2012-2100 for the U.S. and the world in the reference case and in the four stabilization levels of the CCSP study.[23] Also shown are the Global Participation, Delayed Developing, and Developed Only scenarios

[23] The results are from the MIT contribution to the CCSP study, which also involved two other models.

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Table 12. Global and U.S. Cumulative Emissions.

Policy/ Target		Global 2012-2050 (bmt CO2-e)	Global 2012-2100 (bmt CO2-e)	U.S. 2012-2050 (bmt CO2-e)	U.S. 2012-2100 (bmt CO2-e)
Reference		2,461	7,408	419	1,278
Global and U.S. emissions for a globally optimized time-path to meet stabilization targets [a]					
CO_2	CO_2-e [b]				
750	925	2,031	4,924	364	888
650	812	1,842	4,082	344	741
550	675	1,530	3,033	282	539
450	523	1,145	2,168	229	399
Global and U.S. emissions in long-term scenarios simulated in this report					
Global participation 287 bmt		1,577	3,133	287	662
Global participation 203 bmt		1,494	2,834	203	363
Global participation 167 bmt		1,456	2,710	167	236
Developing Delayed [c]		2,132	3,475	203	363
Developed Only [c]		2,132	5,789	203	363

(a) From US CCSP (2006) as simulated by the MIT IGSM.

(b) CO_2-e levels are calculated by estimating the concentrations of CO_2 that would generate the same radiative forcing that comes from CO_2, CH_4, N_2O, PFCs, HFCs, and SF_6 in the CCSP scenarios.

(c) Developing Delayed and Developed Only cases are based on the 203 bmt core case.

developed here. In the table we list the stabilization levels in the CCSP study in terms of CO_2 concentration levels, 450 through 750 ppmv, although that analysis formulated the targets as radiative forcing levels that allowed some additional increase in other greenhouse gases. Some policy discussions have been framed in terms of stabilization of CO_2-equivalent. Obviously, a 450 ppmv CO_2 target that allows additional increases in other gases is a looser target than a 450 ppmv CO_2-e target. To illustrate this difference for the CCSP targets we have calculated the CO_2-e target equivalent to the radiative forcing levels set out in the CCSP study. Thus, as shown in Table 12, the 450 CO_2 target, considering the additional radiative forcing from other greenhouse gases, is equivalent to a 523 CO_2-e target, and the 550 CO_2 target is equivalent to a 675 CO_2-e target.[24] Cumulative emissions in the table are GWP-weighted CO_2-e emissions.

Comparing the policy scenarios examined here to the CCSP results, a first observation is that U.S. emissions through 2050 (203 bmt) and through 2100 (363 bmt) are below emissions of the U.S. in the CCSP 450 ppmv case. Thus, if the emissions allowances in the 203 bmt case were assigned to the U.S. under an overall global target consistent with 450 ppmv as in the CCSP case, and with global emissions trading, then the U.S. would take on some of the cost of abatement in other countries by purchasing allowances from them. In that sense, the 203 bmt case is consistent with 450 ppmv, but the policy in the rest of the world in the Global Participation scenario is too loose. The 167 bmt of emissions in that tighter U.S. case (which would lead to 236 bmt for 2012-2100 if extended by holding at 80% below 1990 from 2050 through 2100) would transfer even more of the cost burden to the U.S. The core case with 287 bmt is very close to the 282 bmt of U.S. emissions in the 550 ppmv CCSP scenario, but it

[24] CO_2-e levels are calculated as the concentrations of CO_2 that would generate the same combined radiative forcing coming from CO_2, CH_4, N_2O, PFCs, HFCs, and SF_6.

would mean that the U.S. would not take any responsibility for costs of abatement in other regions. If emissions in the U.S. remained at the 2008 level through 2100, cumulative U.S. emissions would be 662 bmt, somewhat above the CCSP 550 ppmv cumulative emissions total of 539 bmt. Thus, even under the assumption that the U.S. took responsibility only for its own emissions it would need to further cut its emissions after 2050 to meet a 550 ppmv goal unless other countries took on some of that responsibility.

Looking at the global totals, in the Developing Delayed scenario the world still is within striking distance of the 550 ppmv goal if the post-2050 targets were tightened a little. However, this delay puts the 450 ppmv goal essentially out of reach because to achieve it would require that virtually no more emissions be allowed after 2050. We saw this in Figure 16 where 450 ppmv is already exceeded in these cases by 2050.[25] In the Developed Only case emissions through 2100 are more than 850 bmt above the cumulative emissions in the 750 ppmv CCSP stabilization scenario. Concentrations are rapidly approaching 750 ppmv in this case in 2100, and so only with draconian measures implemented in 2100 to cut global emissions to near zero would 750 ppmv be possible. The CCSP scenarios have concentrations in 2100 still well below 750 ppmv recognizing that further emissions would occur after 2100 as the world continued cutting toward levels that would eventually stabilize at 750 ppmv. There are, of course, uncertainties in uptake that would lead to either higher or lower concentrations for these emissions paths—one estimate is that an emissions path consistent with a 550 ppmv target might result in actual concentrations ±50 ppmv from the target given (Webster *et al.*, 2003). Putting those uncertainties aside, Table 12 provides a useful way to think about how much more effort would be required to meet specific goals, and opens the way for discussions about which countries take up that effort and whether it is taken on sooner or later.

Turning to the climate effects of these scenarios, **Figure 17** shows the increase in the global mean surface temperature from 2000 for our replication of the three U.S. GCMs. In the Reference the temperature rise by 2100 is about 3.5, 4.0 and 4.5 °C for the GFDL 2.1, CCSM3, and GISS_SB models, respectively. The Global Participation and Developing Countries Delayed scenarios restrain the increase to be in the range of 1.7 to 2.4 °C above year 2000. Since the year 2000 temperature was already approximately 0.8 °C above the pre-industrial level, even these assumed mitigation policies would yield a 2100 temperature 0.5 to 1.2 °C above the 2 °C goal identified by the EU. The Developed Only scenario cuts only about 0.5 °C of the warming from the reference, again illustrating the importance of developing country participation. As the CO_2 concentration results foreshadow, the differences in the global mean surface temperature increase among the three U.S. policy scenarios are relatively small, and thus a primary motivation for the U.S. to choose a tighter policy is to stimulate more stringent policies abroad.

[25] The approximate nature of the cumulative emissions comes into play here—if cumulative emissions could be exactly related to concentrations then they should be below 450 ppmv in 2050. However, if the emissions occur over a shorter period of time the ocean is not able to take the CO_2 up as fast, and so there is some difference if the cumulative emissions are over 50 years or 100 years—in this case about 10 ppmv.

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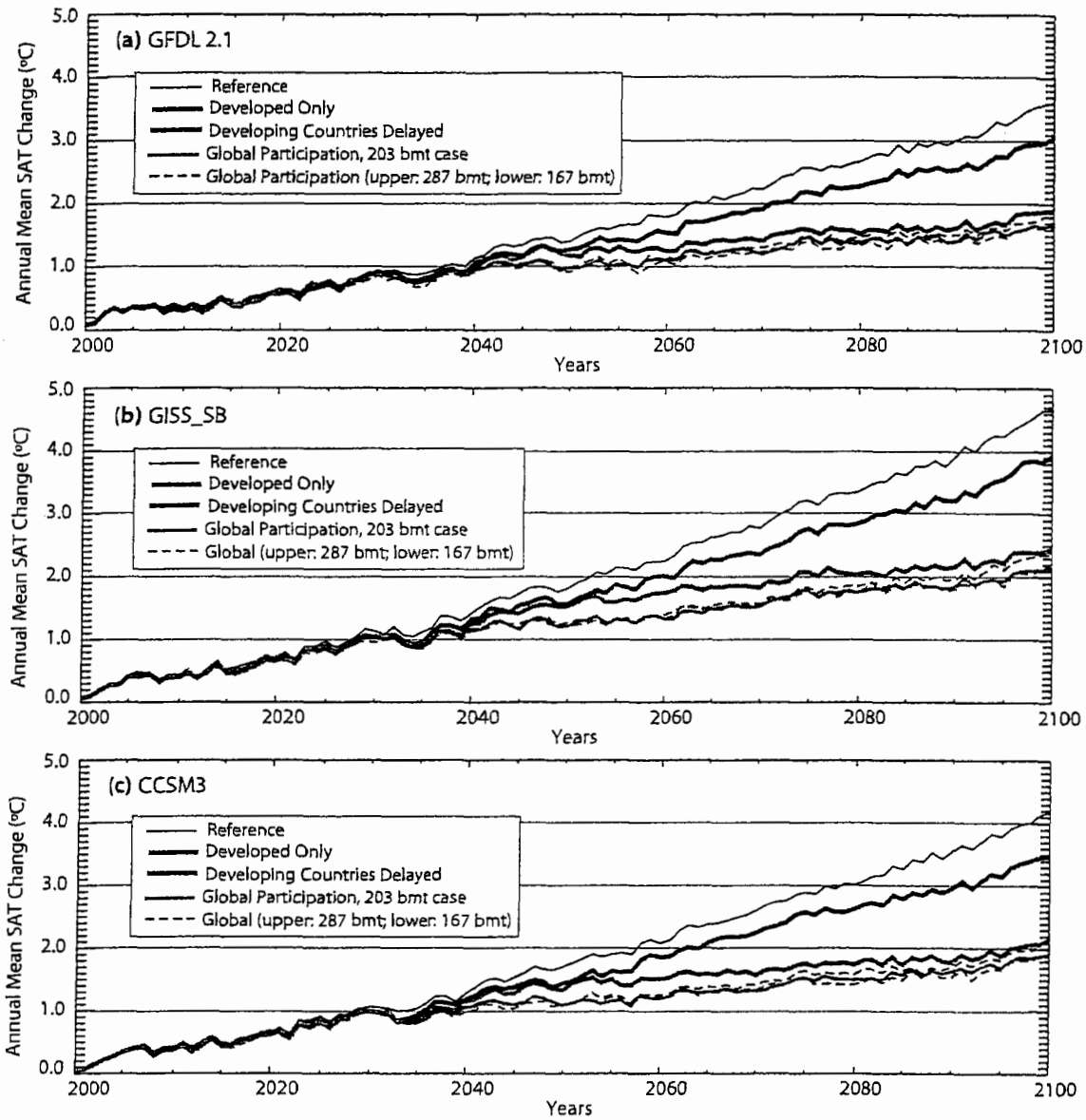

Figure 17. *Global mean surface air temperature increase in six scenarios using the MIT IGSM.*

Compared with previous proposals, many of the bills now in Congress propose much deeper cuts, and have specified a policy over a longer horizon. Thus, it is possible to begin to assess their implications for future climate, making some crucial but at least plausible assumptions about actions in the rest of the world. On the one hand, if U.S. measures can help bring along the world, then reduction in warming from what might occur without any mitigation action is substantial. On the other hand, even with the very substantial measures proposed, and the whole world eventually falling in line, we could expect to see additional warming of twice to three times that we have seen over the last century, if these AO GCMs reasonably represent the response of the earth system to increasing greenhouse gas concentrations. Failure to take any

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action, or failure to substantially involve the developing countries would, according to these estimates, lead to very substantial warming over the century.

9. CONCLUSIONS

There is a wide range of proposals in the U.S. Congress that would impose mandatory controls on U.S. greenhouse gas emissions, yielding substantial reductions in U.S. greenhouse gas emissions relative to a projected reference growth. The scenarios explored here span the range of stringency of these bills. Not all of the proposals have specified the mechanisms by which they would achieve their reduction targets. We implemented them as pure cap-and-trade systems with one alternative where we specified a price path.

It is probably useful to identify two groups of Congressional proposals. One set seeks dramatic reductions in U.S. greenhouse gas emissions, setting targets for 2050 that are as much as 80% below U.S. emissions in 1990. Several of these proposals have been crafted with a goal of putting the U.S. on a path toward targets like 450 ppmv CO_2 stabilization or 2 °C temperature increase from the pre-industrial level, assuming that the rest of the world takes substantial mitigation measures as well. This group includes the McCain-Lieberman, Boxer-Sanders, Feinstein, Waxman, and Kerr-Snowe bills. Another set of proposals have more modest reduction goals, deflecting U.S. emissions growth or possibly stabilizing U.S. emissions, and include a safety valve feature to limit the cost increase. This set includes the Bingaman-Specter and Udall-Petri proposals.

Table 13 summarizes these Bills and indicates their approximate costs by identifying the case we simulated that seems closest in terms of the overall cap or CO_2 price. The table reports the CO_2-e price in 2015 and 2050 and the welfare cost in 2020 and 2050. Apart from the many limitations of any modeling effort of this type, an important caveat to these cost estimates is that the scenarios we simulated represent pure economic-incentive based policies with banking undertaken on the assumption that the policies are expected to be implemented as designed to 2050. The actual Congressional proposals all include other provisions, from funds for R&D to other requirements such as a renewable portfolio standards or efficiency standards. In other cases the actual form of the policy that would achieve these quantitative targets is incompletely specified or left up to the executive agency that would implement the policy. Most also include provisions that would allow revision of the goals with changing evidence of the threat of climate change, and necessary provision, but one that adds uncertainty to the level of the cap or the price.

Those proposals with goals of substantially cutting U.S. emissions between now and 2050 would likely generate prices in the range of $30 to $55 per ton of CO_2-e in 2015, rising to the range of $120 to over $200 by 2050: economic welfare losses from the mitigation policy are estimated to rise to 1.1% to almost 2% by 2050. If economic decision-makers were less than confident that measures would be imposed without relaxation to 2050 then there might be somewhat lower levels of banking, leading to lower prices and costs in early periods and higher prices and costs later, as suggested by Figure 9. Banking also depends critically on expectations

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Table 13. Congressional Proposals Summary.

Allowance Path	Nearest Case	CO_2-e Price ($/T)		Welfare cost (%)		Comments
		2015	2050	2020	2050	
Bingaman-Specter Draft 2007	SV USA only SV USA+ROW	7	39	–0.06 –0.07	–0.46 +0.45	Gains in USA+ROW stem from terms-of-trade effects.
Udall-Petri 2006	Similar to Bingaman-Specter.					
Lieberman-McCain 2007	203 bmt SEC	31	121	–0.23	–1.11	National emissions allowed estimated at 216 bmt, costs would thus be slightly lower.
Feinstein August 2006	203 bmt	41	161	–0.32	–1.45	National emissions allowed is 195 bmt, costs would be slightly higher. Policies and measures rather than a pure cap and trade.
Kerry-Snowe 2007	Between 203 and 167 bmt	~47	~141	~–0.28	~–1.62	Calculated as halfway between these two cases. Includes additional efficiency standards and other features.
Sanders-Boxer 2007	167 bmt	53	210	–0.55	–1.79	Many other features of the Bill (e.g., efficiency standards, renewable portfolio requirements) are not included.
Waxman 2007	At 148 bmt, somewhat tighter than Sanders-Boxer, and so costs would be higher.					

about future technology, and the market may assess those prospects very differently from how we have specified them. Optimism about future technology would reduce banking and near-term abatement and CO_2-e prices. Greater pessimism on future technology or abatement potential would drive near term prices and abatement higher. No assessment was carried out of the economic effects of climate change avoided or ancillary benefits of emissions mitigation, but of course these benefits would provide at least a partial offset to the mitigation cost. However, because of the long-lived nature of greenhouse gases and the moderating influence of the ocean, much of the climate benefit of reductions through 2050 would accrue beyond the horizon of this analysis.

Those proposals that would slow or stop the rise in emissions but not substantially cut them from today's levels have somewhat lower costs. A policy that froze emissions at 2008 levels would generate a price of $18 per ton of CO_2-e in 2015, rising to around $70 by 2050. Related proposals specify a safety valve of $6 per ton of CO_2-e rising to $39 by 2050. If the U.S. pursued this target alone it would essentially freeze emissions at 2008 levels and have welfare costs that rose to just above 0.4%, but the effectiveness and cost of this proposal depends highly on assumptions about policy abroad, as well as other uncertainties that we have not explored.

More important than these specific numbers are some broad insights that may help shape U.S. greenhouse gas mitigation policy:

- The cost of policy in the U.S. is greatly affected by policies in the rest of the world. A stringent policy elsewhere reduces oil prices and confers a terms-of-trade advantage to the U.S. On the other hand, such a policy abroad raises the cost of biomass energy, conferring

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a substantial terms-of-trade loss when the U.S. has a strong mitigation policy. Together these two changes widen the gap between petroleum product and biofuels prices with a tighter target abroad. The implication is that a higher CO_2-e price in the U.S. is required to meet the same emissions target. If a price instrument is used instead, then the effectiveness of U.S. abatement depends on efforts elsewhere. With a less stringent U.S. policy, terms-of-trade benefits from reductions in the world oil price can lead to an improvement in welfare in the U.S. compared to the case where there was not mitigation policy anywhere.

- International emissions trading does not lead to substantial economic efficiency gains unless the U.S. policy is much more stringent than the policy in other regions. If the U.S. policy is similar in stringency (comparing pre-trade CO_2-e prices) trade can be welfare worsening because of terms-of-trade effects. One reason emissions trading is less important is that trade in biofuels tends to close the gap between pre-trade emissions prices so that this energy-trade substitutes for trading in emissions allowances.

- Cutting emissions in the U.S. and world implies a transition to carbon-free transportation fuels. One of the more technology-ready options is biofuels. However, at a scale to contribute substantially to abatement it would require hundreds of millions of acres of land in the U.S. and perhaps 1 billion hectares (2.5 billion acres) worldwide. This level of production would require conversion of land to bioenergy crops and in the process could release carbon stored in vegetation and soils. We were not able to investigate the magnitude of this effect, but given the area of land involved it would be large. To avoid reductions in carbon dioxide emissions from fuel use being offset by land use emissions, it will be necessary to price land-use emissions similarly to emissions from fossil fuel. Ideally, land-use emissions would be part of the same cap-and-trade system as fuel emissions, or would be subject to the same CO_2-e tax or price incentive.

- With no restrictions on biomass trade we find that the U.S. would mainly be an importer of biofuels when there is a stringent domestic mitigation policy. Rather than going to biofuels production, U.S. farmland would be used to produce food for export; regions abroad would devote more of their agricultural land to biomass and import agricultural products from the U.S. If we restrict U.S. biofuels use to domestically produced feedstock, on the order of 500 million acres of U.S. land would be required, more than the total of all current U.S. cropland. In this case, the U.S. would become a large importer of food, fiber, and forest products, rather than the net exporter of these products as is currently the case.

- Potential revenue from allowance sales or a CO_2-e tax (or windfall gain to those to whom allowances were freely distributed) are substantial under the emissions limits we examined, ranging from about $130 to $370 billion per year in 2015 to $250 to $515 billion per year in 2050. In more stringent policies revenue falls off in later years because the number allowances falls off faster than the CO_2-e price rises. If distributed to households, the annual distribution would be on the order of $1600 to $4900 per family-of-four household. The CO_2-e revenue is on the order of 10 to 15% of estimated future total Federal tax revenue, ranging across scenarios and over time from 5 to nearly 20%.

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- One use of auction or tax revenue is to cut existing taxes, for example on labor and capital. Capital tax reductions would likely reduce costs more than use of revenue to reduce labor taxes. Potential revenue under more stringent bills consistent with stabilization of concentrations falls because so few allowances are available for auction and this can ultimately limit the benefits of revenue recycling.

The purpose of U.S. mitigation measures is to substantially reduce the amount of climate change we would otherwise experience. Absent controls on greenhouse gas emissions, global temperatures could rise by 3.5 to 4.5 °C by 2100 given our reference emissions and reflecting a climate response to greenhouse gas emissions like that of the models of the three major U.S. climate modeling centers. Our results confirm the well-known fact of global climate change: to meet temperature or concentration goals requires concerted efforts from much of the world over a substantial period of time. With rapid growth in developing countries, failure to control their emissions could lead to a substantial increase in global temperature even if the U.S. and other developed countries pursue stringent policies.

It is useful to evaluate the global costs and global benefits of achieving such targets, as difficult as that is to do. However, it is not possible to connect specific U.S. policy targets with a particular global concentration or temperature target, and therefore the avoided damages, because any climate gains depend on efforts in the rest of the world. And unfortunately, absent a global agreement a country's best strategy in terms of its own self-interest is to do little and free-ride on the actions of others. Of course, if all behave in this way very little mitigation will be achieved. If a cooperative solution is at all possible, therefore, a major strategic consideration in setting U.S. policy targets should be their value in leading other major countries to take on similar efforts.

Also at issue is the equitable sharing of the cost burden of emissions reduction. Such equity concerns are inextricably linked to the strategic objective of getting other countries to mitigate their own greenhouse gas emissions. Poorer countries see a U.S. and developed world that has freely emitted CO_2 over the history of fossil use, and are thus responsible for the level of concentrations we see today. And they see economies with far higher incomes that are in a better position to afford the burden of mitigation. Thus, a perception of the U.S. taking on an equitable share of the burden of abatement is probably essential if the U.S. policy is going to serve the strategic goal of moving climate policy forward elsewhere. These issues are well beyond the scope of this analysis but consideration of them is essential in determining the best policy for the U.S.

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APPENDIX A: Some Useful Terms Defined

Cap and trade system: a system that identifies emitting entities, sets a cap on total emissions, distributes emissions allowances to covered entities that in total equal the cap, requires entities to turn in allowances equal to their emissions in each period (*e.g.*, year), and allows trade (purchasing and selling) so that a market for and a price of emissions allowances is established.

GHG or CO_2 tax: a tax per unit of greenhouse gas (GHG) or CO_2 whose level is set by a public entity, requiring covered entities to pay the tax for every ton of GHG or CO_2 emitted. The desire to avoid paying the tax provides an economic incentive to reduce emissions.

Covered entity: used here to refer to organizations or individuals who are covered by a cap and trade system (or a GHG/CO_2 tax) and therefore must surrender allowances or pay the tax to cover emissions for which they are deemed responsible.

Safety valve: A feature of a cap and trade system where the public entity managing the system announces a maximum price for allowances, and stands ready to sell as many additional allowances beyond the cap level that entities are willing to purchase at the set price.

Allowances: Certificates (more likely electronic entries) covered entities acquire and must surrender to cover there emissions, typically designated in tons of CO_2 or CO_2-equivalent.

Credits: If allowed under a cap and trade system, these are certificates that can be used in place of allowances. They are generated from activities of entities not covered by the cap and trade system. Entities hoping to sell into the system would need to have credits approved and certified on a project-by-project basis by the public entity overseeing the crediting activity. Approval and certification is meant to assure that the number of credits granted is consistent with the requirements spelled out in the policy. Usually this means that the entities reduced emissions from a baseline (that must be established and approved) by the amount of the credits they are claiming.

Opt in: A provision in a cap and trade system that would allow a non-covered entity to opt into the system and become a covered entity. This would typically involve establishing an allowance level for the entity and adding this level of allowances to the total cap for the whole system. Generally, the allowance level would be given freely to the entity thus providing an incentive to opt in: if the entity can reduce emissions at less than the going allowance price, they can then sell extra allowances into the system for a profit.

Revenue recycling: Using the revenue from a carbon tax or that obtained from auctioning allowances to reduce other taxes in the economy such as those on earned income or on capital.

Lump sum distribution of allowances (or allowance or tax revenue): Lump sum refers to a distribution mechanism that does not affect relative choices among goods or the relatively

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profitability of different activities. [Failure to insure lump sum distribution can undermine the efficiency of a cap and trade system. Basing distribution on some historical data (*e.g.*, historical emissions) that cannot be affected is a lump sum mechanism. However, if a program established the expectation allowance allocation in the future would be based on emissions in the future (*e.g.*, allocations in 2020 based on emissions in 2015) then entities would have an incentive to have high emissions in 2015 to ensure a larger allocation of allowances in 2020, and this would work counter to incentives to abate emissions in 2015. Distributing allowance revenue or revenue from a CO_2 tax to those who spent the most on energy could also undermine the system by creating an incentive to use more energy to get a bigger share of the revenue that would counter the intended goal of the tax or cap system to use less energy and emit less CO_2.]

Auctioning of allowances: in a cap and trade system, specifying that the allowances would be auctioned off to the highest bidders and the revenue from the auction collected by the public agency responsible for the system.

Grandfathering/free distribution of allowances: in a cap and trade system, specifying that the allowances would be distributed at no cost to those receiving them. Such allowances could be given to anyone or any regardless of whether they are a covered entity. If not covered, the presumption is that they would sell allowances into the market. In trading systems developed to date, the practice has been to distribute allowances to covered entities usually in some ratio that approximated how many they would "need" to cover their emissions, proportionally reduced to meet the overall cap. Grandfathering refers to one specific approach, using an historic year's emissions level as the basis for free allowance distribution.

Banking & borrowing: Banking refers to abating below the level of allowances available in a period and using the extra allowances to offset emission in future years. Borrowing is the reverse, using allowances from the future against emissions today.

Carbon and CO_2: Carbon dioxide (CO_2) is the gaseous combustion product that is the main greenhouse gas related to human activities. By some conventions, only the carbon is measured and reported. The difference is the molecular weight of carbon dioxide (44) to that of carbon dioxide (12). Different reporting conventions thus can lead to values that differ by the factor of 3.667—one ton of carbon is equivalent to 3.667 tons of CO_2 and a $100/ton carbon is equal to (approximately) $27/ton CO_2.

Greenhouse Gases (GHGs): Gaseous substances that are transparent to incoming short wave radiation (*i.e.* light) but reflect back long wave energy (*i.e.* heat) radiated from the earth's surface. This heat-trapping ability leads to warming of the troposphere (including air temperature at the earth's surface). Nearly all proposed GHG policies have focused on carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6). Ozone (O_3) and

chlorofluorcarbons are also important greenhouse gases. In addition, aerosol particles affect the radiative balance of the atmosphere, some cooling and some warming the troposphere.

CO_2-equivalent (CO_2-eq.) emissions and prices: Denotes that non-CO_2 gases are included and converted to a CO_2-equivalent amount (See Global Warming Potentials).

Global Warming Potentials (GWP). Indices that take into account the radiative properties and lifetimes of different greenhouse gases to describe their radiative effect relative to CO_2.

Market-based approaches: Emissions policies that achieve reductions by creating economic incentives for abatement. Either cap and trade or an emission tax are generally considered to be "market-based" in that they do not mandate a specific technology that must be used or a specific emissions limit for individual entities that must be met. Covered entities have the option of buying permits or paying the tax if that appears to be less costly than abating. However, complying with the rules is mandatory.

Emissions trading: a cap and trade system and/or the process of buying and selling emissions allowances under such a system.

International linkage: allowing a domestic cap and trade system to be linked to a cap and trade system in another country, requiring that each country honor the allowances issued by the other.

Covered entities: Those entities covered under a cap and trade system and who must surrender allowances to cover their emissions (or emissions for which they are deemed responsible), or equivalently for a tax system those entities who must pay the tax.

Upstream and downstream regulation: The point in the fuel production, refining, conversion, distribution, and combustion chain where emissions are regulated. Downstream refers to regulation of the final fuel users who burn the fuel and release the emissions. Upstream refers to fossil fuel producers (importers) deemed responsible for emissions equal to the carbon content of the fuel sold. There are possibilities of midstream regulation as well, for example, gasoline retailers, petroleum refiners, or natural gas utilities could be required to surrender allowances (or pay a CO_2 tax) for the carbon content of the fuel they sold.

Incidence of a tax or GHG abatement cost: Who bears the final cost of a tax or abatement taking into account the ability of those directly paying the tax or abating to pass along the cost either downstream to consumers by raising prices of goods or upstream to owners of production inputs (*e.g.*, capital, labor, energy resource assets) through lower wages or payments for capital or resource inputs.

APPENDIX B: EPPA Model Details

The EPPA model is multi-regional CGE model of the world economy (Babiker *et al.*, 2001; Paltsev *et al.*, 2005), which is built on the economic and energy data from the GTAP dataset (Dimaranan and McDougall, 2002; Hertel, 1997) and additional data for the greenhouse gas (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6) and urban gas emissions (CO, VOC, NOX, SO_2, BC, OC, NH_3) (Mayer *et al.*, 2001) based on United States EPA inventory data and projects (US EPA 2001a-c, 2002a,b), including endogenous costing of the abatement of non-CO_2 GHGs (Hyman *et al.*, 2003). It has been used extensively for the study of climate policy (Jacoby *et al.*, 1997; Babiker *et al.*, 2000, 2003; Paltsev *et al.*, 2003; Reilly *et al.*, 2003; McFarland *et al.*, 2004; Jacoby *et al.*, 2006), climate interactions and impacts (Reilly *et al.*, 1999; Felzer *et al.*, 2005; Sarofim *et al.*, 2005; Reilly *et al.*, 2007; Matus *et al.*, 2007), and to study uncertainty in emissions and climate projections for climate models (Webster *et al.*, 2002, 2003). The current level of disaggregation of the standard EPPA version is provided in Table 1 in the text.

Several improvements have been incorporated in the model from the version documented by Paltsev *et al.* (2005) that are important for the analysis in this report. In the standard version of EPPA labor supply is exogenous and investment is set equal to savings. We have improved the representation of taxes. Tax levels are recalculated from the GTAP tax data as described in Gurgel *et al.* (2007). Regarding labor supply we have followed a standard approach of introducing a labor-leisure trade-off as was done for an earlier EPPA version (Babiker *et al.*, 2002). We followed an approach of Bovenberg *et al.* (2005) applied in a static setting in the recursive model, separately representing investment in the market economy and in households (*i.e.* investment in owner-occupied housing). As shown in Babiker *et al.* (2001), the values for elasticity of substitution (used in the EPPA model) are related to supply elasticities and shares as:

$$\eta^S = \sigma \frac{1-a}{a},$$

where η^S is an own-price elasticity of supply, σ is the elasticity of substitution, and a is the value share (in our case, a share of labor or market investment).

Table B1. Parameter Values.

Labor Share[a]	0.8
Investment Share[b]	0.77
Labor Supply Elasticity[c]	0.25
Capital Supply Elasticity[d]	0.3

[a] A share of labor in the total value of labor and leisure.

[b] A share of non-residential investment in the total value of residential investment and the other investment.

[c] Based on Babiker *et al.* (2002).

[d] Based on Chirinko *et al.* (2004).

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APPENDIX C: Details of Simulation Results*

Page	Simulation Run
66	Reference case
67	Core scenario: 287 bmt
68	Core scenario: 203 bmt
69	Core scenario: 167 bmt
70	No banking: 287 bmt
71	No banking: 203 bmt
72	No banking: 167 bmt
73	Limited sectoral coverage: 287 bmt
74	Limited sectoral coverage: 203 bmt
75	Limited sectoral coverage: 167 bmt
76	International emissions trading: 287 bmt
77	International emissions trading: 203 bmt
78	International emissions trading: 167 bmt
79	Developed countries only pursue mitigation: 287 bmt
80	Developed countries only pursue mitigation: 203 bmt
81	Developed countries only pursue mitigation: 167 bmt
82	U.S. only pursues mitigation: 287 bmt
83	U.S. only pursues mitigation: 203 bmt
84	U.S. only pursues mitigation: 167 bmt
85	No biofuel trading: 287 bmt
86	No biofuel trading: 203 bmt
87	No biofuel trading: 167 bmt
88	Safety valve: U.S. and rest of world pursue mitigation
89	Safety valve: U.S. only pursues mitigation
90	Safety valve: Safety valve price revised in 2030
91	Nuclear expansion: 287 bmt
92	Nuclear expansion: 203 bmt
93	Nuclear expansion: 167 bmt
94	Quadratic path: 50% below 1990 levels (230 bmt)
95	Quadratic path: 80% below 1990 levels (206 bmt)

* ***Only a sample page is attached here.*** The full version of Appendix C is available as a separate file with this report at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixC.pdf.

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	Reference Case (Ref)									
	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
ECONOMY WIDE INDICATORS										
Population (million)	296	309	321	334	347	359	369	379	388	397
GDP (billion 2005$)	11981	14339	16921	19773	22846	26459	30534	34929	39530	44210
% Change GDP from Reference	–	–	–	–	–	–	–	–	–	–
Market Consumption (billion 2005$)	8217	9858	11533	13384	15364	17761	20467	23392	26456	29567
% Change Consumption from Reference	–	–	–	–	–	–	–	–	–	–
Welfare (billion 2005$)	9656	11773	13933	16342	18948	22016	25414	29032	32780	36553
% Change Welfare from Reference(EV)	–	–	–	–	–	–	–	–	–	–
CO_2-E Price (2005$/t$CO_2$-e)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PRICES (index, 2005=1.00)										
Petroleum Product	1.00	1.15	1.30	1.48	1.69	1.87	1.97	2.09	2.19	2.25
Natural Gas	1.00	1.11	1.27	1.48	1.66	1.95	2.31	2.73	3.12	3.55
Coal	1.00	1.04	1.07	1.09	1.13	1.16	1.20	1.24	1.28	1.32
Electricity	1.00	1.11	1.19	1.27	1.35	1.38	1.42	1.42	1.42	1.41
TRADE & PRODUCTION (selected indicators)										
Bio Liquids Production in US (EJ)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Bio Liquids Imports (EJ)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Bio Liquids Imports (billion 2005$)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Crude Oil Imports (billion 2005$)	77.40	85.21	93.97	102.60	110.94	126.11	149.39	170.99	159.14	144.83
Net Agriculture Exports (billion 2005$)	25.64	25.53	20.40	19.29	14.24	12.35	11.48	10.92	11.61	14.99
GHG EMISSIONS (mmt CO_2-e)										
GHG Emissions	7091.9	7680.1	8201.5	8595.6	9219.3	9884.8	10711.0	11507.3	12433.3	13283.3
CO_2 Emissions	5984.3	6517.4	6995.2	7357.3	7915.4	8518.8	9283.0	10012.9	10871.0	11655.9
CH_4 Emissions	583.4	602.0	611.6	617.1	630.5	643.1	652.2	663.6	676.5	683.1
N_2O Emissions	385.2	387.9	381.3	372.4	366.5	365.6	372.8	380.8	391.0	407.3
Fluorinated Gases Emissions	140.0	173.8	214.4	250.0	308.1	358.5	404.3	451.3	496.2	538.5
PRIMARY ENERGY USE (EJ)										
Coal	22.6	24.3	25.8	26.6	30.9	35.0	39.9	44.8	49.6	53.3
Total Petroleum Products	42.0	46.0	49.6	52.6	55.2	58.8	63.9	68.8	73.6	78.5
Including Shale Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.7	19.6
Natural Gas	22.5	24.7	26.8	28.9	28.4	28.3	27.7	26.8	25.8	25.1
Nuclear (primary energy eq)	9.3	9.0	8.8	8.7	8.6	8.5	8.4	8.4	8.3	8.3
Hydro (primary energy eq)	2.9	2.8	2.8	2.8	2.8	2.9	2.9	3.0	3.1	3.2
Renewable Elec. (primary energy eq)	0.6	0.7	0.8	1.0	0.9	1.2	1.1	1.4	1.5	1.6
Biomass Liquids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Primary Energy Use	99.8	107.6	114.6	120.5	126.8	134.6	143.9	153.1	161.9	170.0
Reduced Use from Reference	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ELECTRICITY PRODUCTION (EJ)										
Coal w/o CCS	6.9	7.6	8.3	8.6	10.2	11.7	13.4	15.2	17.0	18.5
Oil w/o CCS	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6
Gas w/o CCS	2.1	2.5	3.1	3.9	3.3	3.1	2.9	2.7	2.4	2.3
Nuclear	3.0	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1
Hydro	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.2
Other Renewables	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.6	0.6
Gas with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal with CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Electricity Production	13.4	14.6	15.9	17.1	18.2	19.7	21.3	23.1	24.7	26.2

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