BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : DOCKET NO. 980693-EI

Petition by Tampa Electric Company for Approval of Cost Recovery for a New Environmental Program, the Big Bend Units 1 & 2 Flue Gas Desulfurization System.

VOLUME 2

Pages 112 through 330

PROCEEDINGS: **HEARING**

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

DATE: **Wednesday, September 2, 1998**

TIME: Commenced at 9:40 a.m.
Concluded at 5:25 p.m.

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

REPORTED BY: JOY KELLY
Chief, Bureau of Reporting
H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter

APPEARANCES:

(As heretofore noted.)

I N D E X

MISCELLANEOUS

WITNESSES

EXHIBITS

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P R O C E E D I N G S

(Hearing reconvened at 12:40 p.m.)

(Transcript follows in sequence from Volume 1.)

CHAIRMAN JOHNSON: We're going to go back on the record. Ms. Kamaras, we're ready.

- - - - -

CHARLES R. BLACK

continues his testimony under oath from Volume 1:

CROSS EXAMINATION

BY MS. KAMARAS:

Q Good afternoon, Mr. Black. Since Mr. McWhirter and Mr. Howe have asked you most of the environmentalist questions today already, my questions are a little bit more limited than they were.

I have a couple of follow-up questions from some things you said earlier this morning about the number of allowances that Tampa Electric plans to purchase in the May 1998 compliance report that's attached to Mr. Hernandez's testimony on Bates stamp Page 118 and Bates stamp Page 136.

118 says with Big Bend 1 and 2 stand-alone scrubber, assumes up to 20,000 allowance purchases each year. Page 136 has an optimization of allowance purchases that looks like it starts at zero with the

Big Bend 1 and 2, and I wonder if you could speak to that apparent discrepancy or if I should ask Mr. Hernandez that question.

A Let me take a shot, and you can follow up w ch Mr. Hernandez if we need to.

The 20 to 25,000 allowances that I spoke about this morning was the value that we used as the maximum amount in our planning studies. We capped the amount at 20 to 25,000. In any given year, depending on the availability of the generating equipment, the load we have to meet, how well the equipment operates, we may or may not utilize any of those purchases; but for planning purposes, we arrived at a value of 20 to 25,000.

If the scrubber performs consistent with our expectation in the year 2000, that would be a very low number.

Q Was the potential cost of up to 25,000 allowances accounted for in determining the cost of the scrubber project?

A I believe that the cost associated with the allowances was included in the cost-effectiveness studies, but Mr. Hernandez could better speak to that.

Q Okay. We talked a little bit this morning about nitrogen oxide compliance. Will the installation and use of the scrubber increase nitrogen oxide emissions?

A The scrubber in and of itself, to my knowledge, doesn't have any direct impact on NOx emissions one way or the other.

Q You also mentioned this morning in your testimony that Powder River Basin coal could not be used for -- you said five units. Are those the Gannon units?

A Gannons 5 and 6, Big Bend 1, 2 and 3.

Q So the Powder River Basin coal is also not a coal that can be used at Big Bend?

A That's correct.

Q Tampa Electric's May 1998 compliance report attached to Mr. Hernandez's testimony refers to design coals as coal types that best fit the operating characteristics of a particular unit. Does TECO typically purchase design coals for its various units?

A The design coal refers to the specification of the fuel for which the boilers were designed to burn at the time the units went in service. Typically they burn their design fuel.

As environmental regulations changed through time, we have modified the specification for the fuel, so that we have many boilers now that are burning fuel that is different from that that they were designed to burn.

Q And does that require on-site blending of different coals?

A In some cases, yes, it does.

Q Is there a cost associated with on-site coal blending?

A We have the ability to blend fuel at Big Bend. We have a coal blending system that was installed coincident with the time that Big Bend 4 went into service in 1985. At Gannon we really have no good means of blending fuel on site.

Q Well, will the addition of the scrubber to Big Bend 1 & 2 affect the type of coal that's used in those two units?

A Yes, ma'am.

Q And how will that be changed?

A The fuel that we would operate or use in Big Bend 1 & 2 after the scrubber is in service would be a higher sulfur western Kentucky fuel more consistent with the parameters that the boilers were designed to burn, as opposed to the blends of lower sulfur fuel that we're currently using for our Phase 1 compliance.

Q Are Big Bend 1 & 2 and Big Bend 3 and 4 anticipated to use the same types of coal once the scrubber is installed?

A Big Bend 1 & 2, their fuel source would be a western Kentucky higher sulfur fuel. Big Bend 3 fuel source would be consistent with that. The design of the Big Bend 4 boiler is such that it requires a different fuel, and it typically burns a medium sulfur Illinois 6 type fuel.

Q Is the coal now used at Big Bend 1 & 2 best described as low, medium or high sulfur coal?

A I would describe it as medium.

Q And is the same true for Gannon?

A We burn coals of varying sulfur content at Gannon and manage that to stay within our compliance option. We range from, I would say, on the high side of a medium sulfur fuel to the low side of medium, but they would all be medium.

Q And what type of coal would you burn or are you burning or using at Polk; low, medium or high sulfur coal?

A At what location, ma'am?

Q The Polk unit.

A The initial operation at Polk was done on a Pittsburgh No. 8 coal, which is a medium sulfur, high Btu fuel. The current fuel source for Polk is an Ohio No, 11 seam coal that's somewhat higher in sulfur level and a little bit lower in Btu.

Q In your testimony on Page 13, Lines 7 through 18, you discuss the efficiency and availability of the FGD units. There's a table N . 2-3 of the May 1998 report that's Page Bates stamp 119 of Mr. Hernandez's testimony exhibits that shows a capacity deration of approximately 14 megawatts on Big Bend 1 & 2.

What is the basis for the conclusion of that number of megawatts as a degradation?

A Could you give me those references again, and let me take a look at the document?

Q Yes. It's Page 119, Bates stamp 119 of the exhibits attached to Mr. Hernandez's testimony. It's Page 18 of 43 in the upper right.

A Let me check. (Pause) The decrease in unit capacity of 14 megawatts is associated with the additional power required to operate the scrubber and the wastewater treatment facility at Big Bend.

Q Thank you. In one of the production of document requests responses -- perhaps the best thing for me to do would be to just show it to you. (Handing document to witness.)

This is described as notes of a meeting January 14th, 1997, Clean Air Act SO2 Compliance

Strategies, and it appears to be a Tampa Electric memo. On the back page -- this is double-sided copy -- it talks about Big Bend integration, and there's a statement there about burning higher sulfur coal than traditional as part of a test burn of integrating Big Bend 2 into Big Bend 3 & 4.

It states that the result was a greater strain on the system to attain sulfur removal efficiency, and that efficiency was reduced by approximately 6%.

I'm wondering if TECO's plan to burn high sulfur coal at Big Bend 1 and 2 would have a similar result and, if not, why not?

A The activity that's referred to in this paragraph is an investigation that we performed to assess the viability of actually integrating Unit 2 into the Big Bend 4 scrubber just as we had integrated Unit 3.

We performed some tests and identified some technical issues associated with integrating Unit 2 into that existing system, and as such, decided that that was not technically something that we felt was feasible and wanted to maintain, partly because of the reasons cited in this memo.

Big Bend 1 & 2 scrubber is being designed from scratch to accommodate the full load, full efficiency situations that are required, and we've received guarantees from the vendor to assure both removal efficiency and availability.

Q In your direct testimony at Page 8, I believe you stated that Tampa Electric used the 1998 fuel price forecast from the 10-year Site Plan for its analysis; is that correct?

A Yes, ma'am.

Q I'm going to show you what is a portion of the Tampa Electric 10-year Site Plan information. (Handing document to witness.)

The information I've handed you are portions of the Tampa Electric Company supplemental data request, review of 10-Year Site Plan, Item 1, and it's several pages of 42 pages, which includes oil and natural gas price forecasts and coal price forecasts.

Are these forecasts consistent with Tampa Electric's historical experience regarding coal, oil, and natural gas pricing?

A These are consistent with the forecasting methodology that Tampa Electric has historically used.

Q Are the prices themselves consistent with your forecasts?

A I'm sorry. Could you repeat that?

Q Are the prices themselves consistent with your historical experience?

A The prices of the fuel is generally consistent. There are actual cases where -- particularly on coal prices, that we are either experiencing higher or lower prices than predicted by our forecast.

On our gas forecast, recent experience has indicated that the actual -- during periods of time last year some of the actual costs were higher than our forecasts. Gas prices are depressed right now, and they're below our forecast.

So in a general sense, I would say that our forecast is generally consistent with what we've experienced, but that doesn't mean that it predicts it absolutely.

MS. KAMARAS: Thank you. I now have a document that I'm going to ask to be identified just for purposes of identification. (Handing document to witness.)

CHAIRMAN JOHNSON: It will be identified as Exhibit 3, short titled, "Summary of FERC Form 1 fuel Costs."

(Exhibit 3 marked for identification.)

Q **(By Ms. Kamaras)** The first page is a summary of the attached information, which is information from the FERC Form 1 filings of Florida Power & Light, Florida Power Corp, Gulf Power Company, and Tampa Electric Company. And Mr. Howe has pointed out that under "Cost of Coal in Tons for FPL," the number "4", that first number, should be a dollar sign, not a four. I do my own typing.

MR. LONG: Madam Chairman, could I ask a couple clarifying questions? There appears to be a summary at the beginning of this information. I'd like to know the source of that, who prepared that summary, and I guess my second question has to do with the content. Is this Tampa Electric specific information?

CHAIRMAN JOHNSON: Ms. Kamaras?

MS. KAMARAS: The summary is information that is taken directly from the attached forms. The attached forms are formal filings by the Florida electric utilities with the Federal Energy Regulatory Commission for the year 1997. And I prepared the summary so that it would not be necessary to go through every page of each and every one of these forms.

MR. LONG: Well, Madam Chairman, without an opportunity to go through and check the ultimate conclusions that are on the summary, it seems to me that the evidentiary value of this is questionable.

The underlying documents filed with the FERC I think can speak for themselves. If there are questions concerning those documents, if the witness can answer, we have no objection to counsel posing those questions.

CHAIRMAN JOHNSON: Ms. Kamaras?

MS. KAMARAS: The FERC documents can speak for themselves. I can only verify that the numbers that appear in the summary are directly taken from the attached sheets, and I did it purely as a matter of convenience and for no other purpose.

COMMISSIONER DEASON: It seems to me the questions can be asked in terms of assuming these numbers are correct, and if in further verification they're incorrect, well, then that can be provided with a late-filed exhibit or something. But we need to get on with this proceeding. There's a hurricane coming. Okay?

Q **(By Ms. Kamaras)** If you wish to just assume for the sake of argument that the summary numbers do accurately reflect what's in the report, with the exception of another possible typographical error, I simply wanted to ask you whether or not you believe Tampa Electric's fuel price forecasts, both for coal and for gas, are consistent with the information that Tampa Electric reported to FERC.

A I'm sorry. Could you repeat that, please?

Q Is your fuel price forecast consistent with the data on coal pricing that Tampa Electric reported to the FERC?

A The year that the FERC Form 1 data represents is 1997.

Q 1997.

A The forecast information that you provided me starts in 1998, so I can't make any direct comparison between what our forecast might have been in 1997 for those actual costs in 1997.

The forecasted coal prices in the document that you provided me are somewhat lower than our actual fuel experience as reported on your summary would indicate.

Q Okay. Thank you.

COMMISSIONER CLARK: Mr. Black, are these delivered prices? Do you know?

WITNESS BLACK: I don't know. I'm not sure.

MS. KAMARAS: Are you talking about the FERC Form 1 prices? Yes, I believe they are.

COMMISSIONER CLARK: Okay.

MS. KAMARAS: Line 39 of the form says "Average cost of fuel per unit as delivered f.o.b. plant during the year."

COMMISSIONER CLARK: Thank you.

MS. KAMARAS: I have another document here that I'm going to ask to be numbered for purposes of identification, and this is some portions of 10-year Site Plans from Florida Power Corporation and Lakeland Electric Utility.

CHAIRMAN JOHNSON: Mr. Howe can pass those out, and I'll allow you to continue.

I'll identify it as Exhibit 4. What's the short title for that?

MS. KAMARAS: "Florida Power Corp and Lakeland documents."

CHAIRMAN JOHNSON: Florida Power Corp and Lakeland?

MS. KAMARAS: Yes.

CHAIRMAN JOHNSON: Okay.

(Exhibit 4 marked for identification.)

Q **(By Ms. Kamaras)** These are the fuel price forecasts for coal, oil, and gas for those two utilities, and I would ask you, Mr. Black, to review those and tell me whether you believe the Tampa Electric fuel price forecast is reasonably consistent with those of these other two utilities and, if not, why Tampa Electric's would be different.

A Just looking through these documents, it's difficult to come to a complete understanding, since I've never seen these documents before and don't exactly understand where the numbers came from.

But I think in looking at coal prices, it's important not only to categorize the sulfur content, but also the other parameters of the particular fuel. As I mentioned earlier, five of our boilers are of a unique design that requires fuel that's more specialized than some other utilities can utilize.

So without really knowing what the actual composition of the fuel that these prices represent, I'm not really able to draw any conclusions between their forecast of fuel and ours.

Q Thank you. You talked earlier about some of the obligations that Tampa Electric has to comply with the Clean Air Act besides its Phase II acid rain SO2 compliance.

Has Tampa Electric made any estimate of the potential compliance costs for EPA nitrogen oxide and/or ozone rule changes?

I'm not talking about the statutory compliance required under the acid rain provisions, but the ozone rule change that was made last year.

A The ozone -- are you speaking of the ambient air quality standard that was modified?

Q Yes.

A We are working with our local EPC. Part of our response to that was the memorandum of understanding that we entered into with Hillsborough County to reduce our nitrogen oxide emissions earlier than was required by the Clean Air Act amendment.

Again, nonattainment is on an area basis, and it's not a unit-specific kind of basis, and to the extent Hillsborough County becomes nonattainment for ozone, we will have to work with the local agencies to determine what the appropriate action is; but we've not had any indication as to what that might be.

Q Okay. What types of Clean Air Act compliance activities might Tampa Electric be required to take if the Tampa area is designated by EPA as nonattainment for ozone?

A Would typically include reductions in our nitrous oxide emission rates.

Q And what kind of activities would the company have to undertake to accomplish that in a nonattainment situation?

A Assuming that our compliance strategy for meeting the Clean Air Act requirements for NOx is successful, that we can do that through the combustion modifications that I talked about earlier.

As I pointed out, additional NOx requirements would be accomplished through the addition of selective catalytic reduction equipment on our large coal-fired boilers. The number of those installations and the extent of the installation would depend on the particular situation with Hillsborough County.

With respect to nonattainment, since it is a county issue, it's not solely a Tampa Electric obligation to correct the problem. Other industries in the county also would be affected as well as motor vehicles, and the county would take broad action to deal with a nonattainment area, not solely target it at Tampa Electric.

Q Thank you. Has Tampa Electric made any estimate of potential compliance costs for complying with modifications of the EPA particulate PM 10 rules. Not PM 2.5. I believe there was also some modifications to the PM 10 rule.

A Let me check. (Pause) Hillsborough County currently is in attainment for PM 10, and so we're not currently exploring any modifications required there.

Q Do you have a sense of what activities Tampa Electric would be required to undertake if the Tampa area became nonattainment for PM 10?

A Again, there would be a wide response by all-industry, other than just Tampa Electric. PM 10 typically is associated with precipitator performance and that sort of thing.

We believe that the scrubber addition for Big Bend 1 & 2 provides us the maximum flexibility of any of the other options we evaluated to deal with more stringent PM requirements.

Based on some testing that was done at Big Bend, we actually measured a significant decrease in particulate matter before it compared -- after the scrubber as compared to before the scrubber. So we believe that the scrubber is actually a positive benefit in that case, and beyond that, we would really need to see the magnitude of the actions that we would need to take.

Q Is the scrubber expected to result in a change in carbon dioxide emissions from Big Bend?

A Only to the extent that there's additional power requirements to operate the scrubber, the 14-megawatt deration that we talked about earlier. From that aspect, the total generation at Big Bend would be slightly greater. So the CO_2 levels would be slightly increased, but it's a function of the load on the station not directly associated with the technology being involved.

Q I believe you said earlier you had some familiarity with the Big Bend 3 & 4 scrubber project.

A Yes, ma'am.

Q Is that correct? Do you know what the projected and actual capital costs of that scrubber project were?

A Which project?

Q The scrubber on Big Bend 3 & 4?

A The scrubber was installed with Unit 4.

Q Right.

A The initial installation costs, I don't recall an exact number, but I believe it was on the order of 150 to $160,000,000.

The integration of Unit 3 into that existing scrubber, again I don't have the exact numbers, but it's on the order of 7 to $8 million.

Q Do you know what the O&M costs, operating and maintenance costs, of that scrubber are?

A The Big Bend --

Q On Big Bend 4, or 3 and 4.

A Let me check. (Pause) I'm sorry. I don't have that information with me. The O&M costs associated with the Unit 3 integration has been filed as part of our environmental cost recovery clause on a six-month basis and is available there. I don't have the Big Bend 4 numbers with me.

Q All right. Thank you. What is the average life of a coal plant boiler?

A I would expect that the boilers that we have built to our specifications and under our direction will last significantly beyond a 30-year period. An exact date is kind of hard to put your finger on.

Q Thank you.

CHAIRMAN JOHNSON: Ms. Kamaras, let me interrupt for just a second. We've gotten some indication that the State buildings may be closing down in the next couple hours; within the next two hours, in fact. I need to get a feel as to how much more you have for this witness.

MS. KAMARAS: About three minutes.

CHAIRMAN JOHNSON: And Staff?

MS. JAYE: Staff has about 30 questions for this witness.

CHAIRMAN JOHNSON: How much time do you thi~k that will take?

MS. JAYE: Most of them are yes and no answers. I would imagine we could probably get through it in maybe an hour.

CHAIRMAN JOHNSON: Okay. We're going to stipulate our -- well, we still have Mr. Hernandez. How much time is anticipated for Mr. Hernandez?

MR. McWHIRTER: I would contemplate 30 minutes.

CHAIRMAN JOHNSON: Okay.

MR. HOWE: 30 minutes to an hour.

MS. KAMARAS: Probably 20 to 30 minutes.

MS. JAYE: Commissioners --

CHAIRMAN JOHNSON: Is that direct and rebuttal?

MR. HOWE: I understand that we're going to stipulate rebuttal.

CHAIRMAN JOHNSON: His rebuttal also?

MR. HOWE: What I mean is, I think his rebuttal is to FIPUG's witness.

CHAIRMAN JOHNSON: Oh. I got you. Yes.

MS. JAYE: Staff would anticipate maybe 30 minutes for Mr. Hernandez. However, if the parties would agree to stipulate the depositions of Mr. Hernandez and Mr. Black into the record, that could save some time.

MR. LONG: Well, we would certainly be willing to agree to that, the deposition and the deposition exhibits.

MS. JAYE: That would be wonderful.

CHAIRMAN JOHNSON: Well, at the appropriate time we'll try to take care of that, but there is a need to speed this up quite a bit if we intend to finish today; and we may not be open tomorrow, so we need to try to speed it up.

MR. HOWE: Is it scheduled for tomorrow?

MS. JAYE: The afternoon of the 11th.

(Inaudible simultaneous comments from speakers not at microphones.)

CHAIRMAN JOHNSON: Whenever that day is. So we have to finish. Go ahead, Ms. Kamaras.

Q **(By Ms. Kamaras)** Looking at the May 1998 compliance report attached to Mr. Hernandez on Page 118 -- I'm sorry -- Page 120, do you know where the savings from or cost of allowances is accounted for?

A I'm sorry. Could you repeat that, please?

Q Do you know where either the savings from or the cost of allowances is accounted for?

A You're on Page 120?

Q Yes, sir.

A Bates stamp 120?

Q Yes.

A It's a table?

Q Table 2-4.

MR. LONG: If I could clarify for the moment. The page that counsel is referring to is one that had some typos, and we filed a corrected version, which Mr. Hernandez will address. So just to keep that in mind.

CHAIRMAN JOHNSON: Okay.

WITNESS BLACK: The specific line item that speaks to allowances, I'm having trouble finding that one.

Q **(By Ms. Kamaras)** Me too. That's why I asked the question.

A Okay. Could you ask it again?

Q Can you tell me where the savings from or cost of allowances is accounted for in preliminary screening cost assumptions analysis?

A Mr. Hernandez can definitely speak to that. But my recollection is that the allowance assumptions for each of these various technologies was basically the same, and that you assume that they would scrub similar type fuel to similar efficiency levels, and that the amount of allowances that would be used in any of these scrubber options would be basically the same. So I don't know that there is any differential cost or savings.

Q Thank you. That same report, if you would flip over to Pages 121 to 122, describes a purchase power option. Tampa Electric states that it used the 1997 FRCC reliability assessment. Would the result change if the option analysis was based on the 1998 FRCC study?

A I don't know.

Q Would Mr. Hernandez know?

A He would know more than I would.

Q Okay. Thank you.

MS. KAMARAS: That concludes my questions. Thank you very much, Mr. Black.

CHAIRMAN JOHNSON: Staff?

MS. JAYE: Staff has asked that the deposition of Mr. Black be stipulated on the record along with the late-filed deposition exhibits. That's the first order of business.

Staff is handing around right now a stack of seven different exhibits that we'd like to get marked for identification. These would be Exhibits 5 through 11.

The first two documents on the top and on the bottom -- I'm sorry -- on the top, and then the one immediately behind that are a copy of Mr. Black's deposition and his late-filed deposition exhibits; and if the parties are willing, we would like to have that stipulated into the record and entered as if read.

CHAIRMAN JOHNSON: Let me start off by identifying them separately, or perhaps these two together if you want these two to be a composite.

MS. JAYE: Yes. This would be Exhibit 5.

CHAIRMAN JOHNSON: And Exhibit 5 would consist of the --

MS. JAYE: The deposition and late-filed deposition exhibits of Mr. Black.

CHAIRMAN JOHNSON: "Mr. Black's depo and late-filed exhibits" will be the short title, and it will be marked as 5.

MR. BEASLEY: Madam Chairman, we had submitted one page of that late-filed exhibit under notice of intent to seek confidential classification. I'm assuming that would remain in the Division of Records and Reporting?

MS. JAYE: It is not included in the information.

CHAIRMAN JOHNSON: Okay. We'll have that one marked.

(Exhibit 5 marked for identification.)

CHAIRMAN JOHNSON: And the next one?

MS. JAYE: The next one would be Exhibit 6, and we have that titled "TECO's response to Staff's Second Set of Interrogatories, Nos. 26 and 27."

CHAIRMAN JOHNSON: TECO's response to Interrogatories 26 and 27 is marked as 6.

(Exhibit 6 marked for identification.)

MS. JAYE: No. 7 would be "September, 1997 gypsum sale assumptions."

CHAIRMAN JOHNSON: That will be marked as 7 and so identified.

(Exhibit 7 marked for identification.)

MS. JAYE: No. 8 Staff has titled "An internal review of the CAAA SO2 compliance strategies, dated January 14, 1997."

CHAIRMAN JOHNSON: It will be marked as 8 and identified as "Internal review of CAAA SO2."

(Exhibit 8 marked for identification.)

MS. JAYE: Exhibit 9 Staff has titled "Tampa Electric Company Phase II CAAA compliance review, January 8, 1998."

CHAIRMAN JOHNSON: It will be marked as 9, and identified as "TECO Phase II CAAA compliance review."

(Exhibit 9 marked for identification.)

MS. JAYE: And Exhibit 10 Staff has titled

"Portions of TECO's response to Staff's first Request for Production of Documents No. 13.

CHAIRMAN JOHNSON: Marked 10 and identified as "Portions of TECO's response to Staff's First Interrogatory for Production of Document 13.

(Exhibit 10 marked for identification.)

Q (By Ms. Jaye) Mr. Black, if you could look at that first document from the stack and tell me what that is.

A The transcript of my deposition.

Q Do you have any changes you want to make to that deposition, or if I ask you those questions today, with would your answers be the same?

A Yes, ma'am, they would.

Q Mr. Black, I have a few questions to ask you about your deposition, and then I'd like to go ahead and move it into the record as if read. If you would refer to the transcript of your deposition at Page 30, Line 21 through Page 31, Line 20.

A Page 30, line what?

Q 21. It's through Page 31, Line 20. Staff gave you a hypothetical situation in which a so-called Project A referred to an alternative which reduces SO2, NOx, and particulate emissions, and so-called Projects B, C and D are each alternatives which reduce

SO2, NOx, and particulates respectively.

Compliance with Clean Air regulations encompasses reductions in SO2, NOx, and particulate emissions, correct?

A Yes.

Q In TECO's proposed project, the flue gas desulfurization, or FGD, system for Big Bend 1 and 2 is a project that reduces an individual component, or SO2, of compliance with Clean Air regulations, correct?

A Yes.

Q If you would, please refer specifically to the section of the deposition transcript on Page 31, Lines 9 through 15. Could you explain what you meant by the phrase "issues associated with other components," on Lines 12 and 13?

A What I was attempting to convey was that it was appropriate to evaluate the individual project which reduced SO2, if the technologies associated with the reduction of the other components were totally independent of that SO2 reduction technology. That is, it would be appropriate to evaluate the SO2 reduction technology if the technology and the options for reducing the other parameters were totally independent of what you did for SO2.

Q In your opinion, if the FGD is the most cost-effective of the different options that have been explored by TECO, then TECO should proceed with or without the Commission's approval; is that correct?

A We believe that the FGD system is the most cost-effective solution to the SO2 requirements for our Phase II compliance, and we believe it's appropriate, given the size of the investment, that we should get some indication from the Commission as to the appropriateness of the recovery of that cost.

COMMISSIONER CLARK: I think what she was asking was sort of the same thing Mr. Howe was. Even if we didn't approve it, if it's your view it's the most cost-effective way to do it, isn't that what you should be doing.

WITNESS BLACK: Yes, ma'am.

Q **(By Ms. Jaye)** Now to clear up a few issues that remain from a lot of the questions that you have heard earlier in the day, SO2 emissions are capped on a total system basis, correct?

A Yes.

Q NOx emissions are capped on a system emission rate basis, correct?

A As currently proposed -- my understanding is, as currently proposed by the EPA, the NOx emission limits are on a per-unit basis, depending on the type of boilers that are involved. We are working with the EPA to establish a system rate criteria for our system.

Q Earlier today you stated that 83,882 allowances applied to Big Bend Units 1, 2, 3, 4, Gannon Units 1 through 6, Hookers Point Units 1 through 5, and Polk Unit 1.

What would happen to that number of allowances if future units were added to TECO's system?

A My understanding is that the total number of allowances does not change.

Q Could you tell me if the existing stack for Big Bend Units 1 and 2 is brick-lined?

A I believe it is, but I'm not sure.

Q Does flue gas exiting from a wet scrubber have any destructive effects on a brick-lined stack?

A Yes.

Q Could you describe those effects?

A It's a corrosive effect that attacks the mortar that holds the brick together, unless the stack is constructed with acid resistant brick, which is sometimes employed in units that have scrubbers. I don't believe that was the case with Big Bend 1 & 2.

Q If you would move to the third document in the stack. This has been marked as, I believe, Exhibit 6. Could you tell me if you sponsored this response?

A I believe this was in response to a document production request.

Q Yes.

A And I don't recall seeing this document before. (Pause)

Q It's been marked as Exhibit 6, the response to Staff's Second Set of Interrogatories Nos. 26 and 27.

A I'm sorry. I'm looking at the wrong thing. (Pause) Yes, ma'am. I did sponsor this.

Q Okay. If you would look at the next document in the stack. I believe this one has been marked as Exhibit 7, the gypsum sale assumptions exhibit.

A Yes, ma'am.

Q Are the comments in the notes at the bottom of the page substantially true today?

A Yes, ma'am, I believe they are.

Q Okay. If you could look at the next exhibit. This one would be marked No. 8, an internal review of the CAAA SO2 compliance strategies, dated

January 14, 1997.

A Okay.

Q One of the attendees at the meeting that this memorializes was a man named Mr. Hugh Smith; is this correct?

A He's listed as an attendee, yes, ma'am.

Q In your current capacity with TECO, would it be appropriate to assume you are a likely candidate to typically attend meetings of this type and with these persons?

A It depends on the nature of the meeting, my schedule. I may or may not attend a meeting like this.

Q If you could, turn to the Bates stamped pages 04782 and 04783. These pages list nine items which have to do with assumptions and the issues of the study; is this correct?

A 04782 and 83?

Q Yes, sir.

A Yes, ma'am. These seem to be the assumptions used in the screening analysis.

Q If you would, please, review Item No. 7. It's titled "The Gannon FGD was a bare bones option. Has this philosophy been carried into the BB 1-2 stand-alone?" That's the quote on the page.

A This is Item 7.

Q Yes. I was wondering what the answer to that question is that I just read that's contained in there.

A Let me read the item, please.

Q Okay.

A (Pause) The Gannon FGD alternative that was evaluated was a common scrubber for several of the units at Gannon that was being designed to operate at a lower availability and removal efficiency. So I would say that the term that that unit is a bare bones kind of unit does not necessarily carry over into the design of Big Bend 1 & 2.

We've specified for the Big Bend 1 & 2 scrubber appropriate technical specifications which we believe will allow that scrubber to achieve both its efficiency and its availability, and we've backed those assumptions by contractual arrangements with the vendor which will provide liquidated damages to Tampa Electric to the extent that he does not meet those criteria.

Further, with respect to the issues of the accuracy of the estimate and whether it's appropriate, as I reported earlier, the Stone, Webster estimate was the basis for part of the early work, but before proceeding, we felt it was necessary to retain another independent evaluation of the capital costs, and that was done by Sergeant & Lundy.

So I think for the Big Bend 1 & 2 system these comments would not apply.

Q Okay. Then if you could move on to the next document in the stack. This is the one that's marked Exhibit 9, Tampa Electric Phase II CAAA compliance review, January 8, 1998. Could you tell me if this document appears to be an updated verse of the one we just discussed?

A No, ma'am. The one that we just discussed was with respect to the screening analysis. Once we performed that analysis and narrowed our options down, we took a more detailed look at the cost-effectiveness and the validity of all of those options; and that's what's represented in the second document.

Q If you could in this Exhibit 9 document, please turn to the page that is Bates stamped 02579.

A Yes, ma'am.

Q Okay. There is one subsection listing Capital Expenses and another subsection listing O&M, or operation and maintenance expenses. Do you see those?

A Yes, ma'am.

Q In the prior review, which is the 1997 review, TECO was looking at both increases and decreases to the base cost assumptions. However, here the only sensitivities are increases. Could you explain that?

A At this point the FGD case had been identified as the most cost-effective alternative when compared to the other things that we were evaluating, primarily the fuel switch and allowance purchase option.

We wanted to ensure through these sensitivities that if the cost of the scrubber option either on the capital side or the O&M side increased beyond what our current estimate was, that it was still a cost-effective option relative to these other options we had to comply.

If we had lowered these costs, it would have only made it a more cost-effective option, and we didn't need to see that.

Q Thank you. If you could turn, then, to the next paper on the stack. I believe this one has been marked as Exhibit 10, portions of TECO's response to Staff's First Request for Production of Documents, No. 13.

Staff asked you some questions at deposition regarding this POD, and I'd like to clarify some of the items, if I could. And this begins on Page 01965.

If TECO were to incur any SCR retrofit costs, are the costs listed here reasonable estimates of the level of those potential expenditures?

A We believe that they are. As I discussed earlier, the application of SCR would be the next level of NOx reduction we would move to if our classifier combustion modifications were not successful, and the $20 million number that I quoted earlier relates fairly closely to the 21 million 054 number listed here.

Q In response to some questions earlier in the day, you said that one SCR might be required. Which boiler would use that SCR?

A We've not made that determination as of yet.

Q Okay. If you could turn to your prefiled direct testimony on Page 8. On Page 8, Lines 19 through 23, you state "A forecast of expected fuel prices is developed annually to support the company's planning process. The forecast used in this analysis is the same forecast utilized in the Tampa Electric 1998 10-Year Site Plan." Is this statement correct?

A Yes, ma'am, to the best of my knowledge.

Q During which time period did Tampa Electric analyze and evaluate its alternative strategies to comply with the CAAA Phase II requirements?

A The final evaluations were done in the late part of 1997 and the early portion of 1998.

Q During this time period, did the difference between Tampa Electric's forecast of coal and natural gas prices widen, narrow, or stay the same?

A I'm sorry. I didn't understand. The forecast that we produce for 1998 is updated when we do a 1999 forecast.

Q Certainly. I am speaking, though, of the time period in which Tampa Electric analyzed and evaluated its alternative strategies, and you had said late '97 to '98 was the time frame.

A Yes.

Q During that time frame did the difference between Tampa Electric's forecast of coal and natural gas prices widen, narrow, or state the same? That would be the late '97 to 1998 time frame.

A I don't know specifically. The fuel budget is put together for '98 in late '97. There was supplemental data filed for the 10-Year Site Plan information, and I don't recall what the relationships were.

Q Subject to check, would you agree that they narrow?

A I really don't know.

Q Although the difference between Tampa Electric's forecasted coal and natural gas prices is -- we don't know, the FGD system would still be the most cost-effective alternative that Tampa Electric has evaluated. Would that be correct?

A Could you repeat the first part of the question?

Q Certainly. Even though you don't know what the difference was between the forecasted coal and natural gas prices, would you still agree that the FGD system is the most cost-effective alternative Tampa Electric evaluated?

A The cost-effectiveness evaluations that Mr. Hernandez performed in his area indicated the FGD is the most cost-effective solution. Those cost-effectiveness analyses were using our most current fuel forecast information and project what we believe is the most current situation.

Mr. Hernandez also filed a late-filed exhibit to his deposition where he looked at the cost of gas in order to make the two options equal and determined that there was a very large -- in excess of one billion dollars -- difference in present value revenue requirements between the gas option.

Q Does the proposed scrubber project on Big Bend 1 and 2 bring TECO's entire system into compliance with SO2 requirements of the Clean Air Act, or is it just bringing Big Bend Units 1 & 2 into compliance?

A The addition of the FGD system at Big Bend 1 & 2 combined with modifications in the fuel that is being utilized at Gannon station will achieve the Phase II compliance.

Q System-wide?

A Yes, ma'am.

Q For purposes of system compliance, TECO could have elected to replace coal-fired generation with natural gas-fired generation, or even purchased power?

A Those are options, yes.

Q Does new natural gas-fired combined cycle generation technology generally have lower NOx emission rates than Big Bend 1 & 2 and Gannon Units 3, 4, 5, and 6?

A Yes.

Q Do new natural gas-fired combined cycle generation technology generally lower particulate emission rates than TECO's Big Bend Units 3 & 4?

A Yes, they do.

Q If TECO installed new natural gas-fired combined cycle generation, one could expect TECO's system total emissions for particulates and NOx to drop?

A If the units were installed as additional units to our system? Or replacement units?

Q Installed new as of, say, tomorrow, if that were possible.

A If they were installed new tomorrow, we would have all of our existing emissions, plus the incremental emissions added by that new natural gas-fired capacity.

Q Is the proposed scrubber addition to Big Bend Units 1 & 2 going to allow TECO to reduce the price of coal delivered to these units?

A Yes, ma'am.

Q Is a proposed scrubber addition going to reduce the annual average delivered coal price?

A For the system or for the units?

Q For the system.

A We believe that it will, yes.

Q Would it also do that for the units?

A Yes.

MS. JAYE: No more questions.

CHAIRMAN JOHNSON: Commissioners? Redirect?

MR. LONG: Madam Chairman, could I just take a moment to talk with the witness? We may be able to obviate redirect.

CHAIRMAN JOHNSON: I'm sorry?

MR. LONG: May I have a moment to speak with the witness? We may be able to obviate redirect.

CHAIRMAN JOHNSON: There's no objection. Do you want to just go off the record for a while?

MR. LONG: Yes.

CHAIRMAN JOHNSON: Off the record.

(Discussion off the record.)

MR. LONG: We're ready to proceed. I have one question.

CHAIRMAN JOHNSON: We're going to go back on the record.

REDIRECT EXAMINATION

BY MR. LONG:

Q Mr. Black, you were asked a question about the lining of the stack, the existing stack, for Units 1 & 2.

A Yes, sir.

Q And I believe you thought that it was brick-lined?

A That was how I responded. Upon further thought, that is -- the existing stack on Big Bend 1 & 2 is a steel-lined stack.

MR. LONG: I have no further questions, Madam Chairman.

CHAIRMAN JOHNSON: Exhibits?

MR. LONG: I would like to move Exhibit 2 into evidence.

MR. HOWE: I object, in particular, Chairman Johnson, to Document No. 4 of Exhibit 2.

CHAIRMAN JOHNSON: Is your mike on?

MR. HOWE: It's flashing green, if that means anything.

CHAIRMAN JOHNSON: Go ahead.

MR. HOWE: On Document No. 2 -- I'm sorry -- Document No. 4 of Exhibit No. 2, we asked Mr. Black some detailed questions, particularly about AFUDC. I believe it's clear that at this time Mr. Black did not know what AFUDC rate was used to calculate it, did not know whether AFUDC had been calculated consistent with the Commission rule, did not know whether AFUDC had been calculated after or with consideration of the amount of CWIP in rate base.

And I believe in answer to one of my last questions, he stated that he was not in a position to give an opinion that this was a reasonable estimate of the amount of -- of AFUDC would actually be accrued if the other numbers are accurate.

So, Chairman Johnson, I would move to strike -- or to not admit Document No. 4 or, in the alternative, to strike the last two entries, which would be AFUDC and total project estimated cost from that document.

CHAIRMAN JOHNSON: Thank you. Response?

MR. LONG: Madam Chairman, I believe Mr. Hernandez is prepared to address those specific items in his testimony. We can defer admitting into evidence the last two lines of the exhibit until after Mr. Hernandez testifies, but I think clearly those questions will be answered.

CHAIRMAN JOHNSON: Okay. I'll go ahead and admit the document with the exception of the page -- the Document No. 4, and I'll just rule on that after Mr. Hernandez comes forward.

(Exhibit 2 received in evidence.)

MR. LONG: That's fine, Madam Chairman.

MS. KAMARAS: Madam Chairman, I'd like to move LEAF 3 and 4 into the record.

MR. LONG: Madam Chairman, I object to the admission into evidence of Exhibit 4. As I understand it, this is a Florida Power fuel forecast. There's no

Florida Power witness here, and given that, I'm not sure of the purpose for which this document is being offered.

Counsel for LEAF questioned Mr. Black for some time with regard to Tampa Electric's fuel forecast as lodged in the 10-Year Site Plan proceeding for '98.

It seems to me that material is clearly relevant, but if the purpose that Exhibit 4 is being offered for is to demonstrate somehow that the forecast contained here is some how superior or should give the Commission some guidance in terms of how to view the reasonableness of Tampa Electric's fuel forecast, I would submit that there's no evidentiary basis for that.

CHAIRMAN JOHNSON: Ms. Kamaras?

MS. KAMARAS: If the Commission doesn't choose to admit it in that manner, I would ask that the Commission take official recognition of the documents as documents that are submitted to -- filed formally with the Commission by electric utilities as required by the statute and the regulations of the Commission.

CHAIRMAN JOHNSON: To his -- I'm sorry. You're asking us to admit -- you're asking us to take official recognition of it under the same theory that has been objected to by TECO and offered by FIPUG?

I'm trying to understand what you want me to do. You're saying admit this, but your grounds, the grounds that you articulated, I was interpreting as you're asking us to take official recognition of.

MS. KAMARAS: I'm saying in the alternative if you choose not to admit it under Mr. Long's objection, that I would offer it as a document that the Commission could take official recognition of as it is an official public document filed with the Commission.

MR. LONG: Well, Madam Chairman, our object here is not to deprive the Commission of information. I mean, if the Commission wants to make our fuel forecast and the 10-Year Site Plan an exhibit, we can include this Florida Power forecast. I'm not sure how much probative value it has under those circumstances, but, you know, we wouldn't object to that kind of equal treatment.

CHAIRMAN JOHNSON: Okay. Ms. Kamaras, I'd like for you to speak to his original objection, not the official recognition, because I'm not going to allow it to come in under that. So let's speak to his original ground for objection, and that went more to relevance and probative value.

MS. KAMARAS: The documents that were submitted in that marked exhibit are portions of 10-year site plans filed by Florida Power Corp and Lakeland Electric Utility, specifically fuel price forecasts, and they are offered for comparative purposes with the Tampa Electric forecast.

CHAIRMAN JOHNSON: So it's not relevant directly to his testimony, but you're offering it up so we can compare what Florida -- the Florida Power Corp information with -- could you explain that again? And I apologize, but I cannot hear you all that well, and I think it's the mike system.

MS. KAMARAS: We seem to be having microphone problems today. A good portion of Mr. Black's testimony and some of the exhibits that were filed go to fuel price forecasting, particularly for coal, and my purpose in asking some of the questions I did and providing those exhibits, the FERC and the 10-Year Site Plan, are to try to put that into some context and to give it, if you will, a reality check in terms of what other utilities are projecting, what Tampa Electric has said at different times about coal prices and other fuel prices.

MR. LONG: Madam Chairman, again, to save time, Mr. Hernandez is prepared to address the differences between the forecasts. If we move forward and simply mark Tampa Electric's 10-Year Site Plan forecast as an exhibit and then move Exhibit 4 into evidence, we don't have any problem with that.

CHAIRMAN JOHNSON: That's fine.

MS. KAMARAS: That's fine.

CHAIRMAN JOHNSON: So with that, do you withdraw your objection?

MR. LONG: Yes, as long as we're going to mark the Tampa Electric --

CHAIRMAN JOHNSON: And it is understood that we'll do that. Very well. Show 3 and 4 admitted.

(Exhibits 3 and 4 received in evidence.)

CHAIRMAN JOHNSON: 5 through 10?

MS. JAYE: Staff moves Exhibits 5 through 10.

CHAIRMAN JOHNSON: Shows those all admitted without objection.

(Exhibits 5-10 received in evidence.)

MR. BEASLEY: Madam Chairman, the 10-Year Site Plan forecast that we got from Ms. Kamaras that Mr. Long referred to would need to be identified, I believe.

CHAIRMAN JOHNSON: Which --

MR. BEASLEY: This is the document that Ms. Kamaras referred to in her discussions with Mr. Black and that she's indicated a willingness to have identified as an exhibit as well to go in with Exhibit 4.

CHAIRMAN JOHNSON: Okay. We'll identify that as 11.

MR. BEASLEY: Thank you.

CHAIRMAN JOHNSON: Give me a short title.

MS. KAMARAS: I have some extra copies of that if you need it.

CHAIRMAN JOHNSON: That would be helpful.

MR. BEASLEY: The title on the document is "Tampa Electric Company FPSC Supplemental Data Request, Review of 10-Year Site Plan, Item No. 1."

CHAIRMAN JOHNSON: That's good enough. And it will be identified as stated.

(Exhibit 11 marked for identification.)

CHAIRMAN JOHNSON: Thank you, sir.

(Witness Black excused.)

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CHAIRMAN JOHNSON: While the next witness is coming forward, let's go back to Exhibit 1. That's FIPUG's exhibit.

MR. ELIAS: Madam Chairman, I've reviewed the cases and the statutes --

CHAIRMAN JOHNSON: Where is that voice coming from -- Mr. Elias? (Laughter)

MR. ELIAS: The proffered material identified as Exhibit 1 does not appear to fall within the ambit of Section 90.202(12) Florida Statutes as facts that are not subject to dispute because they are capable of accurate and ready determination by resort to sources whose accuracy cannot be questioned.

And I take some guidance from the 1996 1st DCA case of Marrity v. Marrity. The court there stated that when a matter is judicially noticed, it is taken as true without necessity of offering evidence by party who should ordinarily have done so, and the historical doctrine of judicial notice has been applied to self-evident truths that no reasonable person could question and the truisms that approach platitudes and banalities.

And I am not sure that TECO's surveillance reports for the years 1993 through 1997 fit within that definition.

The case goes on to state that the practice of taking judicial notice of adjudicative facts should be exercised with great caution. And in looking at some of the hundreds of cases that have looked at this question, it appears that the greater weight goes to facts which, indeed, are not capable of any reasonable dispute, such as the distances between towns, the day of the week that a particular date fell on; some things like the fact that the Gulf of Mexico between Florida and Texas is in not a sheltered body of water, such as a harbor or coastal waterway.

Those are the kinds of things the courts have taken judicial notice of. There is a case that says a court cannot take judicial notice of a tariff approved by a regulated utility commission; a fairly recent decision that says a court should not take judicial notice of a recorded mortgage or the seals of private corporations. And trying to line up these documents into those two categories, I believe that they don't fall within the ambit of the statute.

CHAIRMAN JOHNSON: Okay. Thank you for that analysis. I will deny the request for official recognition of the composite exhibit that we identified as Exhibit 1 that was offered by FIPUG.

MR. BEASLEY: Madame Chairman, we move the admission of Exhibit 11, which has been identified.

CHAIRMAN JOHNSON: Show that admitted without objection.

(Exhibit 11 received in evidence.)

MR. HOWE: Excuse me, Chairman Johnson. I believe the previous explanation was that Exhibit 11 was going to be subject to a comparison presented by Mr. Hernandez with respect to the company's 10-Year Site Plan. Am I incorrect in that?

MR. LONG: Well, Madam Chairman, what we said was to the extent that anyone is interested in a comparison, Mr. Hernandez would be able to address those questions.

CHAIRMAN JOHNSON: That's how I understood it, too. They withdrew their objection after it was agreed upon that their information would also be added to the record, but if you want to ask questions as to the comparative nature, he'll be prepared to do that.

MR. HOWE: I withdraw the objection.

CHAIRMAN JOHNSON: Okay. Any other matters before we hear from Mr. Hernandez?

MS. JAYE: No, ma'am.

CHAIRMAN JOHNSON: And, Mr. Hernandez, you've been sworn?

WITNESS HERNANDEZ: Yes, I have.

THOMAS L. HERNANDEZ

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Hernandez, will you please state your name and business address and your position with Tampa Electric Company?

A My name is Thomas L. Hernandez. I'm the vice-president of regulatory affairs for TECO Energy; business address, 702 North Franklin Street, Tampa Florida 33602.

MR. BEASLEY: Madam Chairman, as was discussed earlier, under Section IV of the prehearing order Tampa Electric has withdrawn certain portions of Mr. Hernandez's testimony, and exhibits reflect the fact that certain issues have been deferred from this proceeding.

We have supplied the court reporter with a modified version of that testimony which strikes through the withdrawn testimony, and I just wanted to make that reference to the testimony that Mr. Hernandez will now sponsor.

CHAIRMAN JOHNSON: Okay. Thank you.

COMMISSIONER CLARK: I have a question. How do we know what was stricken?

MR. BEASLEY: I have a list of the stricken portions.

COMMISSIONER CLARK: That would help. I'm happy for Mr. Hernandez to give his summary while that's being looked for. If I just get it sometime while he's on the stand, I'll be happy.

MR. BEASLEY: We can do that. I'll go ahead with Mr. Hernandez, and we'll supply that list of redacted portions.

Q **(By Mr. Beasley)** Mr. Hernandez, do you have a copy of your testimony with the portions stricken?

A Yes, I do.

Q If I were to ask you the questions set forth in your remaining testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Mr. Hernandez's testimony be inserted into the record as though read.

CHAIRMAN JOHNSON: It will be so inserted.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

THOMAS L. HERNANDEZ

Q. Please state your name and your business address.

A. My name is Thomas L. Hernandez. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Vice President-Regulatory Affairs for TECO Energy, Tampa Electric Company's parent.

Q. What is your educational background and business experience?

A. I graduated from Louisiana State University in August 1982 with a Bachelor of Science degree in Chemical Engineering. My responsibilities at Tampa Electric have included engineering and management positions in Production, Generation Planning and Energy and Market Planning. I was named Director-Fuels and Environmental Services earlier in 1998, and I was named Vice President-Regulatory Affairs for TECO Energy in March of this year.

I have participated in the preparation of key studies supporting the company's proposal in this proceeding. Tampa Electric's planning document to comply with Phase I requirements of the Clean Air Act Amendments of 1990 ("CAAA") and associated cost-effectiveness studies were prepared under my direction and supervision while I was in the position of Manager, Generation Planning. The cost-effectiveness studies used to develop a Phase II CAAA compliance plan was prepared under my direction and supervision while I was in the position of Director, Energy and Market Planning.

Q. Mr. Hernandez, have you previously testified before this Commission?

A. Yes. I testified before this Commission in the last annual planning hearing Docket No. 910004-EU. I also provided a description of Tampa Electric's planning process at the FPSC Staff workshop on March 3, 1994. I also submitted testimony in Docket No. 930551-EI which was the numeric conservation goals proceeding for Tampa Electric. Most recently I testified in Docket No. 960409-EI regarding the prudence of Polk Unit One.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the reasonableness and prudence of Tampa Electric's selection of a flue gas desulfurization ("FGD") system for Big Bend Units 1 & 2 as the company's primary means of satisfying the Phase II requirements of the CAAA. As discussed below, the FGD system is the most viable and cost-effective compliance alternative for meeting the requirements of the CAAA. In addition, I will explain why the Company's proposed regulatory treatment for the FGD system should be approved and why the Commission should conclude that the reasonable and prudent project costs incurred in connection with the FGD Project qualify for cost recovery through the Environmental Cost Recovery Clause ("ECRC"), pursuant to Section 366.8255, Florida Statutes (1997), over a ten year period, beginning when the system is placed in service.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes I have. My Exhibit No. 12 (TLH-1) consisting of four documents (Nos. 1-4) was prepared under my direction and supervision. It consists of detailed information related to Tampa Electric Company's CAAA Phase I and Phase II compliance plans and 1998 Ten Year Site Plan. The documents describe the methods and key planning assumptions used to develop the company's compliance plans and ten-year expansion plan.

FGD System Need

Q. Prior to selecting a Phase II compliance option, what steps did Tampa Electric take to defer the need for additional SO_2 emission mitigation measures?

A. The company is dedicated to the efficient use of energy and has maintained an aggressive conservation program that has reduced the total energy requirements of the system. The company continuously monitors the energy market and purchases capacity and energy when reliable energy sources are available to economically displace system generation from our own resources. Both energy conservation and purchased power effectively reduce SO_2 emissions from the company's system.

Q. How did the company prepare itself to meet Phase II compliance requirements?

A. For Phase II compliance, Tampa Electric reviewed previous studies that supported the Phase I compliance plan. Several options studied in the Phase I evaluation were eliminated as Phase II options because the Phase I study concluded that they were not viable or cost-effective. The remaining options were screened through quantitative and qualitative comparisons for Phase II. The results of these comparisons clearly showed that Big Bend 1 and 2 FGD system provided the greatest savings to the ratepayer on a cumulative present worth revenue requirements (CPWRR) basis. The results of the screening analysis are described in detail in Document No. 2.

Q. Did you perform any tests to verify the viability of the Big Bend Units 1 and 2 FGD option?

A. Yes. After a preliminary determination that the proposed Big Bend Units 1 and 2 FGD system was the most technically viable compliance option, Tampa Electric assessed the economic viability of this option. The capital cost estimates and fuel blending assumptions were evaluated to reflect Tampa Electric's most current data, and the FGD option was again compared to a fuel blending and SO_2 allowance purchase base case scenario. This comparison showed that the FGD system will generate significant savings of $80 million on a CPWRR basis over a twenty year period. In addition, Tampa Electric performed sensitivities to verify the economic viability of the FGD option. These sensitivities included: capital cost, SO_2 allowance market viability, and a deferral analysis.

For the capital cost sensitivity, the CPWRR savings were compared against the base case with 5% and 10% increases in the capital estimate. In both cases, the FGD option showed significant CPWRR savings versus the base case. To examine the SO_2 allowance market viability, Tampa Electric evaluated the CPWRR of scenarios with varying allowance purchase quantities. The FGD option was determined to have the lowest ten-year CPWRR. Tampa Electric therefore concluded that SO_2 allowance purchases alone would not be the most cost effective alternative. A one year deferral analysis concluded that deferral would decrease the CPWRR savings to the ratepayer. In each of these sensitivity analyses, the proposed FGD option remained economically viable compared to the base case. These are described in detail in Document No. 2.

Q. How do the economics of the FGD option compare to those of the other compliance options evaluated by Tampa Electric?

A. Of the various compliance options evaluated by Tampa Electric, the FGD option provides significantly greater CPWRR savings when compared to our base case scenario and nearly twice the expected savings of the next most economical option. The FGD option for Big Bend Units 1 and 2 offers the greatest fuel savings and will provide the greatest benefits to retail customers compared to the other alternatives analyzed.

Q. Are there other benefits associated with the proposed FGD system for Big Bend Units 1 and 2?

A. Yes, as discussed in Mr. Black's testimony, the proposed FGD system for Big Bend Units 1 and 2 has the added benefit of providing more operating flexibility and fuel diversity potential to Tampa Electric's system. The FGD options also minimizes any negative impact to system reliability compared to the blending options since these options resulted in higher capacity derations and additional maintenance outage hours.

Key Planning Assumptions

Q. How did Tampa Electric develop and utilize the cogeneration and wholesale interchange forecasts which it relied upon in its selection of the CAAA Phase II compliance plan?

A. The cogeneration and wholesale interchange forecasts for the cost-effectiveness studies contained in the Phase II compliance document were developed utilizing the same data and methodology contained in Tampa Electric Company's 1998 Ten Year Site Plan (TYSP) filed with the Commission on

April 1 of this year and attached as Document No. 4. Self-service cogeneration capacity and firm and as-available cogeneration purchase power reduce the system generation requirements and results in lower SO_2 emissions. For example, in the year 2000, self-service cogeneration and cogeneration purchase power are projected to reduce system energy requirements by 2,547 GWH. This amount of energy is approximately equivalent to 290 MW of coal-fired capacity from Big Bend unit 1 or 2 operating for every hour of a single year. Although firm and as-available wholesale energy sales increase the system generation requirements, the combined net effect of these sales and the self-service cogeneration and cogeneration purchases results in a decrease in estimated SO_2 emissions.

Q. How did Tampa Electric develop and utilize the demand and energy forecast it relied upon in selecting a CAAA Phase II compliance plan?

A. The system demand and energy forecast utilized in the cost-effectiveness studies is the same forecast and methodology described in detail in section III of Tampa Electric Company's 1998 TYSP. The demand component of the forecast is used to project system supply side capacity requirements to ensure adequate and reliable electric power. This same firm demand is used in system reliability studies in calculating projected reserve margins and is a key element in determining the need for adding new generating capacity to our system. The energy component of the forecast is used to project system generation and purchase power requirements. This same energy forecast is used in calculating expected unserved energy (EUE) and loss-of-load probability (LOLP) for the purpose of projecting system reliability. While both components of the demand and energy forecast are important for planning and operations purposes, the energy forecast and the related economic utilization of all the energy resources on Tampa Electric's system is a particularly important element of the Phase II compliance plan.

Q. How did Tampa Electric develop and utilize the fuel price forecast it relied upon in selecting a CAAA Phase II compliance plan?

A. The specific fuel price forecast utilized in the cost-effectiveness studies are described in detail by Mr. Black. The methodology used in the development of the specific fuel price forecasts is the same as described in section V of Tampa Electric Company's 1998 TYSP. The fuel price forecast and availability and quality of the fuels is a key element of the cost-effectiveness studies because revenue requirement analyses primarily focus on fixed and operating costs to determine the most cost-effective compliance alternative. The projected fuel savings associated with specific compliance alternatives are offset by the capital and O&M costs. The combined net effect of fixed and variable costs results in the cumulative differential revenue requirements on a present worth basis. The FGD option is the most cost-effective compliance alternative due to the significant fuel savings which more than offset the capital costs of constructing and operating the FGD system for both Big Bend Units 1 and 2.

Q. How did Tampa Electric develop and utilize the demand side management (DSM) forecast it relied upon in selecting a CAAA Phase II compliance plan?

A. The DSM forecast utilized in the cost-effectiveness studies is the same forecast and methodology described in detail in section III of Tampa Electric Company's 1998 TYSP. The dispatchable DSM programs contained in the forecast effectively reduce system load requirements at times of system peak when economic supply side capacity is unavailable. These programs do not significantly reduce system energy requirements but do defer the need to construct new generating capacity. The non-dispatchable DSM programs contained in the forecast effectively reduce system load requirements for all hours which result in lower system energy requirements. For example, in the year 2000, non-dispatchable DSM programs are projected to reduce system energy requirements by 415 GWH along with the associated SO_2 emissions. This amount of energy is approximately equivalent to 50 MW of coal-fired capacity from Big Bend Unit 1 or 2 operating for every hour of a single year.

Regulatory Treatment

Q. What regulatory treatment is Tampa Electric proposing for FGD related costs?

A. As noted above, Tampa Electric proposes to recover prudently incurred project related costs through the ECRC over a ten year period, beginning when the FGD system is first placed in service. In the interim, project costs will be tracked and accumulated in AFUDC until the FGD goes into service. We are asking the Commission to concur with Tampa Electric's selection of the FGD option as the most cost-effective compliance alternative and to confirm that all reasonable and prudent costs associated with this project will be recoverable through the ECRC cost recovery mechanism with the capital costs of the project to be recovered over a 10 year period. However, we are not requesting approval of any related FGD system project costs for cost recovery at this time. We recognize that the company will be required to present detailed evidence to support the actual and projected costs associated with the FGD system at a petition in advance of the projection period when the system goes into service and before any project related cost is recovered through the ECRC.

Q. How does Tampa Electric intend to treat costs associated with this project while it is under construction?

A. Tampa Electric will track its costs associated with the construction of the FGD system and accumulate them in AFUDC until the FGD system goes into service. This is consistent with the Commission's Rule 25-6.0141 identifying projects eligible for AFUDC accrual. The proposed FGD system will involve gross additions to plant in excess of 0.5% of the sum of the total balance in Account 101-Electric Plant in Service, and Account 106-Completed Construction not Classified, at the time the project commences. In addition, the project is expected to be completed in excess of one year after the commencement of construction. We request that in approving the project the Commission confirm that this project qualifies for AFUDC accrual under the above-referenced Commission rule.

Q. Why are the costs associated with the proposed construction and operation of a FGD system to serve Big Bend Units 1 and 2 appropriately recovered through the Environmental Cost Recovery Clause?

A. Consistent with the guidelines which this Commission established in Order No. PSC-94-0044-FOF-EI, the FGD related costs; A) will be incurred after April 13, 1993; B) will be incurred on the basis of a legal requirement of the CAAA; and C) are not currently being recovered through base rates or any other cost recovery mechanism.

The FGD system related costs proposed for environmental cost recovery were not among the compliance activities included in the basis for setting base rates in Tampa Electric's last rate case, Docket No. 920324-EI, in 1992. At the time of that rate case, the planned compliance activities for Phase I of the CAAA consisted only of fuel blending with low sulfur coals and allowance purchases.

Q. ~~Why is the ten year cost recovery period proposed by Tampa Electric appropriate~~?

A. ~~The determination of an appropriate recovery period necessarily involves the exercise of judgment. We believe the use of a ten year recovery period for the proposed FGD system is reasonable under the circumstances. Extending the recovery period beyond ten years, however, would disregard the goal of mitigating potential stranded cost. The Commission has previously recognized that stranded cost mitigation efforts are in the interest of customers and has in the past supported such efforts through reasonable means. We submit that our proposal is consistent with this policy and the Commission's past practice. Lastly, it should be noted that over the ten year recovery period customers who bear these costs will realize a net benefit. The use of a ten year recovery period is also consistent with the composite life of the project equipment used for tax purposes.~~

Q. Please summarize your testimony.

A. My testimony supports Tampa Electric's selection of a stand alone FGD system serving Big Bend Units 1 and 2 as the company's most viable and cost-effective option for meeting the heightened SO_2 emission limitations of Phase II of the CAAA. I explain our company's need for approval by the Commission of this project as a reasonable compliance means, and a corresponding determination by the Commission that costs prudently incurred by Tampa Electric in implementing this project will and should be eligible for environmental cost recovery beginning in the cost recovery period when the project is placed in service. ~~Finally, my testimony supports the use of a ten year recovery period for the proposed FGD system for Big Bend Units 1 and 2.~~

Q. Does this conclude your testimony?

A. Yes it does.

Q (**By Mr. Beasley**) Mr. Hernandez, have you also prepared the exhibit attached to your testimony identified as Exhibit TLH-1?

A Yes, I did.

Q With the portion removed from that exhibit that corresponds with part of your testimony that was removed, would you sponsor that as your exhibit in this proceeding?

A Yes, I would. Just to clarify, there were some changes and corrections made to some of the exhibits; two tables and a figure in the testimony.

Q Please identify those changes.

A Okay. The two tables were tables 2-4 and 2-6, and 3-1, and that's Bates stamp Pages 120, 125 and 135 of my exhibit.

The revised tables are basically just typographical in nature and did not constitute a change in the conclusions and recommendations contained therein.

MR. BEASLEY: Commissioners, we have copies of those. They have been filed and distributed, but if you need copies of those tables we have them available.

Q (**By Mr. Beasley**) Mr. Hernandez, would you please summarize your testimony?

A Good afternoon, Commissioners. Tampa Electric's proposed FGD system is the company's most viable and cost-effective means of complying with the Phase II SO2 requirements of the Clean Air Act.

Based on the company's cost-effectiveness study contained in my exhibit, the FGD option yields a net system present worth revenue requirements savings of $18 million over the first 10 years, 80 million over the first 20 years, and 95 million over the first 25 years of operation.

In developing our cost-effectiveness study, we adopted conservative assumptions, utilized proven planning methods and analytical tools familiar to this Commission, and tested the sensitivity of key assumptions.

The economic and financial assumptions used in this study are both viable and reasonable and are consistent with other business planning activities, including the development of the company's 10-Year Site Plan.

Through all phases of our analysis, the proposed FGD system remains the clear choice from both a customer and company perspective. The FGD option results in significant fuel savings to our customers in every year the FGD system is in service.

In fact, the fuel savings in just the first five years of operation nearly offsets the entire capital costs of the project. In addition to its cost-effectiveness, the proposed FGD system offers Tampa Electric the greatest flexibility for meeting future environmental requirements.

We are seeking your concurrence that Tampa Electric's selection of a stand-alone FGD system serving Big Bend Units 1 & 2 is the company's most viable and cost-effective option for meeting the more restrictive Phase II SO2 emission limitations of the Act.

It is critical that the Commission confirm that the FGD system is a reasonable and prudent compliance option, that it is a project which qualifies for AFUDC, and that all prudent and reasonable costs associated with the project will be recovered through the environmental cost recovery clause mechanism.

The proposed FGD system meets all of the Commission's established guidelines for ECRC recovery as the project related costs will be incurred after April 13th, 1993, will be incurred on the basis of the legal requirements of the Act, as discussed by Mr. Black, and are not currently being recovered through base rates or any other cost recovery mechanism.

This proposed project is clearly eligible for full recovery under the Commission's standards and is precisely the type of compliance endeavor which the ECRC was designed to cover.

We are also requesting your approval of accruing AFUDC on this project until the FGD system actually goes into service.

Although we are not asking the Commission to approve any particular level of AFUDC recovery at this time, we are requesting permission to begin accruing the full amount of AFUDC on the front end.

Prior to seeking actual recovery of costs associated with this project, Tampa Electric will file additional supporting testimony and exhibits for consideration at a subsequent hearing to establish the appropriate ECRC factors. This outcome is consistent with the efforts of Staff and all the parties to defer cost recovery to a subsequent proceeding.

The Commission has encouraged parties to come in for early determinations involving capital expenditures for environmental cost recovery so that timely guidance can be provided by the Commission with respect to that investment.

Consequently, the Commission should find that the FGD project is the most cost-effective alternative, and that all prudent and reasonable incurred costs will be recovered to the ECRC at the earliest possible time so that all parties may plan accordingly.

Thank you.

MR. BEASLEY: Commissioners, if I could have an exhibit number assigned to Mr. Hernandez's exhibit.

CHAIRMAN JOHNSON: It will be identified as Exhibit 12.

(Exhibit 12 marked for identification.)

MR. BEASLEY: Thank you. And we tender Mr. Hernandez for questioning.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Hernandez, in the summary you just made you referred to the fuel savings in the first five years will offset the cost of -- the capital costs, as I understand it. Is that what you said?

A Yes, sir, I did.

Q And where is that to be found in your prefiled testimony?

A Figure 3-1, the differential cumulative present worth revenue requirements graph.

Q Figure 3-1?

A Yes.

Q What page is that on?

A Give me one second. Bates stamp Page 135.

Q So that is not in your testimony, but it is in your exhibit?

A That's correct.

Q And we are to -- point out to me how those lines on a Y axis and X axis support your proposition that the savings will occur in the first five years from fuel that will offset the capital costs.

A Sure. As I mentioned in my opening statement, the $18 million net system present worth revenue requirements consists of approximately $100 million in fuel savings. So you net that against the capital costs.

What this figure on Bates stamp Page 135 refers to, it's a differential cumulative present worth revenue requirements that incorporates both the fixed costs, the capital costs, the O&M costs, and the fuel savings associated with the FGD option relative to the next best -- or most cost-effective option in the final cost-effectiveness study, which is the fuel blending scenario that we discussed.

If you look at the construction period

beginning in year 1998 with an in-service date going along the Y axis of year 2000 midyear convention in this assessment, you look at the point at which the estimated capital costs -- that's what's designated as a square on this diagram -- the point at which that it crosses that reference line, the zero line, what that means is on a cumulative present worth revenue requirement basis, between the years 2004 and 2005, that effectively in every year beyond that, the cumulative present worth differential revenue requirements associated with the fuel blending scenario -- in fact the FGD option -- generates the savings associated with the fuel to offset the capital and the fixed operating costs.

I wasn't sure if everyone could get that out of this chart, so that's why I stated it.

Q I'm glad you did, because I sure didn't get it out of your testimony.

If I understand that chart, the line that has the squares in it, in every year for 2000 -- late 2004, the capital cost will exceed the fuel cost, I suppose, but then after the year 2005, your future cost savings will result and more than offset the capital costs?

A That's correct. As I stated before, you actually have fuel savings in every year, including the first year, when the FGD system is in operation.

Q So on a nominal basis, the customers between now and 2005 will pay more, but if you look at a net present value, the savings that are achieved by the customers after 2005 will redound to the reduced cumulative net worth and, therefore, it justifies the comment you made. Is that a correct analysis?

A Not exactly. There's an offset. And, again, I think this is more of the issue that's going to be heard in the cost recovery proceeding.

What you've got relative to what the ratepayers will see is a reduction in the fuel component of cost recovery. That's the fuel and purchase power cost recovery clause. So you have a decrease in that amount relative to what they would have paid if we were in a fuel blending scenario.

It gets back to what Mr. Black was talking about, that lower sulfur coal that would be utilized in the fuel blending scenario tends to cost more. So you've got a reduction in the fuel and purchase power cost recovery clause that offsets the increase that would be associated with the -- putting these costs in the environmental cost recovery clause. So you've got to net those two things against one another.

Q But the cost recovery clause will develop a factor that's a capital cost, and that will be charged under the recovery cost. The fuel savings will be reflected in another cost recovery proceeding. Am I accurate in that?

A I think that's what I just said, yes.

Q So you have to put the two of them together to achieve the savings.

A That's correct.

Q And will all the fuel savings redound to the retail customers, or will some of the incremental low fuel costs during your off period -- off-peak period redound to the wholesale customer?

A As you know, the cost-effectiveness study was based on a native load, not on a total load basis, so it included all of the retail customers and the firm wholesale customers. We did not include the as-available or broker type sales in the analyses. So --

Q So it's your testimony that the fuel savings that come to the retail customers and those firm customers under Schedule D that are wholesale customers, their fuel savings are the only fuel savings that are considered in your study?

A In the final cost-effectiveness study;

that's correct.

Q How does the final cost-effectiveness study differ from other studies?

A The screening analysis contained a total load sensitivity. There was a native load look and total load look that included economy sales. In the final cost-effectiveness study, we did not want to include nonfirm or noncommitted sales since you don't know if you're going to actually make those sales; and so we wanted to demonstrate that, in fact, this was the best and most cost-effective alternative for the firm retail and the total retail customer base, as well as the firm wholesale customers.

So with the addition of any other additional generation requirements associated with the as-available or broker type sales, the screening sensitivity showed that, in fact, the benefit to cost ratio is improved.

Q I'm not sure I followed all that. But those sales, those economy sales are thrown out of all your analyses and not contained in any analysis that was used in justifying the FGD.

A The additional benefits associated with economy sales and the 80% margin from those sales that flows back to the retail ratepayers was excluded.

That's on the up side, and that's why I indicated that if you included those additional sales, the benefit to cost ratio on this project only increases.

Q As I understand it, you're not an accountant; is that correct?

A That's a fair assessment.

Q You're a chemical engineer; is that correct?

A Yes, it is.

Q And you are assigned by Tampa Electric Company to be in charge of their regulatory presentations. Is that essentially it?

A Since late March of this year; that's correct.

Q Does that then mean that the documents that are filed with this Commission are filed under your supervision and aegis, and you're the responsible authority for Tampa Electric for the record keeping that's filed with the Commission?

A I hate to ask you this, but I'm not sure what your second word was. Aegis?

Q It's A-E-G-I-S. It means focus, I guess.

A Okay. And your question was did I sponsor all of the --

Q Well, are you the responsible party for ensuring that the proper regulatory documents are filed with the Commission?

A Oh. Yes, I am.

Q Are you familiar with the fact that each month your company files surveillance reports with the AFAD division of the Public Service Commission?

A Yes, sir, I do. That's the regulatory accounting area that is not under my direction and supervision; but, yes, I understand that they file those on a regular basis with the Commission.

Q When you file those documents, are they truthful statements of your financial circumstances as they are filed, as far as you know?

A I would say yes, but, again, that -- I cannot directly attest to the content of the information that's filed that doesn't fall under my area of responsibility.

Q But you do testify that those are documents that are filed by your company for whatever purpose they are filed; is that correct?

A Yes.

Q With this Commission?

A Yes.

Q Because of the hurricane-truncated nature of these proceedings, I'm going to limit my questions to Issues No. 6 and 7, and I'm going to quickly go through those because I know that OPC has some questions on 6.

I'll just ask a quickie in that area, and that's the one that deals with allowance for funds used during construction.

And, Mr. Hernandez, with respect to your request in Issue 6 that the Commission specifically rule on this project as an AFUDC project, why is it necessary for you to have the Commission do that when there's already a rule in place that deals with AFUDC?

A My understanding of the environmental cost recovery clause is that in general, that the Commission would like to hear what the projected costs -- total costs for a project that will be eligible for cost recovery, full cost recovery, under the environmental cost recovery clause. AFUDC is simply another component of that total project cost.

As we've discussed before and identified in my testimony or exhibit, that number is approximately 7.2, $7.4 million. That's the estimated cost. And so we wanted to make sure that that amount was, in fact, included so that you saw the total project costs, and, therefore, we're asking simply that we be allowed to accrue the AFUDC and to demonstrate that -- with the contribution towards the total project costs.

Q But doesn't the rule already take care of that so you don't have to worry about it at this juncture? You're giving that for informational purposes only, is that correct, and whatever the rule says, that's what will happen?

A Well, again, my understanding -- and I don't pretend to -- in five months on the job to know all the rules and the orders and the guidelines that are in place. I'm learning very quickly.

But, again, my interpretation in looking at the environmental cost recovery clause and what's required there is simply to show what our projected costs are and what the projected benefits of a project are, and that's why we're here.

Q And other than that, there is no reason why you are specifically asking the Commission to approve AFUDC in this docket? There's nothing in the rule that requires you to come forward and say, this is different than the normal AFUDC situation and, consequently, the rules should not be applied, but something special about this case requires us to get a specific ruling from you that AFUDC is necessary?

A Well, let me add that my understanding, again, of the environmental cost recovery clause is that we had the option to either seek recovery of the carrying costs associated with the project through the clause immediately as we incurred those expenses.

We decided to defer that incremental cost to our ratepayers until the point in time that, in fact, the unit was placed in service. And since we took that option, we wanted to clarify and get an acknowledgment that we were going to instead to defer cost recovery of the carrying costs associated with this project, accrue it as AFUDC, and then put that in a cost recovery in the same year that the unit is placed into service.

Q All right. Now, let me ask you this with respect to AFUDC: You presently have the unusual circumstance of holding a pot of money that has been designated by your company as deferred revenue and is thought by customers to be moneys held for potential refund, and you are accruing an interest rate at 5.4% on that money.

Why do you think it would be more appropriate to use a 7.79% AFUDC rate rather than the cost rate that's attributable to customers' fund that you're holding?

A Again, I'm not an accountant. These studies were developed when I was in the capacity of director of energy and market planning. The 7.79% AFUDC rate was the one provided to us and that we utilized in the cost-effectiveness evaluations.

Q Are you familiar with the press release that was issued by your company in mid-August to the effect that you were issuing $200 million worth of bonds that would bear interest at 5.49%, or 5.94 -- I forget -- and that money would be used for the construction of the FGD project plus other things?

A I have not read that article. I believe you might have mentioned that at the deposition, but I have not read that article.

Q You're not familiar with your company's press release?

A I read some of them.

Q Are you familiar with the fact that your company issued $200 million worth of bonds?

A I think you brought that to my attention at the deposition, yes.

Q Did you independently verify that --

MR. BEASLEY: Madam Chairman, if Mr. McWhirter has an article or a document that he wants Mr. Hernandez to respond to, I think it would be appropriate for him to present it to him.

MR. McWHIRTER: If you'll bear with me, I'll do that.

MR. BEASLEY: And while he's getting that, I would suggest that a lot of this appears to be bordering on those issues that can be addressed in the cost recovery aspect of this proceeding, which the parties have agreed is something that we're not asking for at this time.

MR. McWHIRTER: I would be pleased to defer issue No. 6 until you seek cost recovery, if that is counsel's desire. Is that -- do you wish to stipulate to that?

MR. BEASLEY: Madam Chairman, we just don't want to have the same hearing twice is what it amounts to.

MR. LONG: Can we have one moment? Maybe we can save some time off the record.

CHAIRMAN JOHNSON: Okay. Off the record.

(Discussion off the record.)

MR. LONG: Madam Chairman, it's our view that it's probably most efficient to address whatever AFUDC the parties have at this point. Mr. Hernandez is prepared to do that.

CHAIRMAN JOHNSON: Okay.

Q **(By Mr. McWhirter)** Mr. Hernandez, I hand you a press release that was issued by your company on July 31st. Would you read the portion of that press release that relates to the FGD process?

A Is this the highlighted area?

Q You have the press release. You'll have to use your own best judgment.

A Okay. Again, I have not seen this before today. But the sentence reads "We have significant activity in these businesses as illustrated by People's Gas System's major expansion in the high growth Naples and Fort Myers areas, and Tampa Electric's recent decision to add a $90 million scrubber to the Big Bend Units 1 & 2.

Q And what is the interest rates that press release says those bonds will hold?

A If I'm reading this right, 5.94%.

Q If you're able to sell bonds at 5.94% and accrue an AFUDC at a higher rate, who will get the benefit of the arbitrage that occurs?

A I don't know how to answer that question.

Q Is that because you're a chemical engineer and not an accountant?

A Probably.

Q That's all I'm going to ask you about AFUDC.

I'd like you to take FIPUG Exhibit 1, which has been marked for identification, and I'd like you to look at the pages after the first four pages. Do you recognize those documents?

A No, sir, I don't.

Q Do you know Mr. L.L. Lefler?

A Yes, sir, I knew Mr. Lefler. He's no longer with the company.

Q Do you have any reason to believe that documents filed by Mr. L.L. Lefler on behalf of Tampa Electric Company with the Florida Public Service Commission would not be wholly truthful?

A No, I do not.

Q Do you know Mr. P.L. Barringer, assistant controller of Tampa Electric?

MR. BEASLEY: Madam Chairman, if I may interject, it appears that Mr. McWhirter is attempting to relitigate the issue that was decided earlier regarding official recognition of this document, Exhibit 1.

MR. McWHIRTER: That's not correct, Madam Chairman. You ruled that you would not take official notice of this document, but Section 90.805, subsection 18, I believe it is, of the evidence code provides that the admissions of a party may be introduced in an adversarial proceeding in which that party is a participant.

And these are admissions of Tampa Electric officially filed with this Commission. Mr. Hernandez is the responsible regulatory person, although he's not an accountant, for supplying these documents, and I would suggest to you that they are admissions that are admissible under the exception to the hearsay rule.

MR. BEASLEY: Madam Chairman, the statute Mr. McWhirter refers to, 90.805, has to do with hearsay within hearsay, which is something that doesn't have anything to do with admissions. But admissions in the exceptions to the hearsay rule are admissions against interest, and these are apparently some documents that were filed prior to Mr. Hernandez having the responsibility he has now.

And it is hearsay, and I have not heard any exception to the hearsay rule which would allow these to be presented unless the individuals who prepared them are present.

MR. McWHIRTER: If the individuals who prepared them were present, it wouldn't be hearsay. I'm seeking to sponsor this exhibit under the focus of Mr. Hernandez, who is the official representative of his company to this Commission, and asking him to acknowledge that these documents are truthful documents filed by his company.

CHAIRMAN JOHNSON: Can you answer the question? Do you know?

WITNESS HERNANDEZ: I know the people. I can't -- I'm assuming that the documents provided to the Commission are, in fact, truthful as the way the question was framed, but I can't address the content in any way.

Q (By Mr. McWhirter) You know the people, and they are employees of your company, and these documents were filed in the normal course of business; is that correct?

A Yes.

MR. McWHIRTER: Madam Chairman, that gives another justification for the entry. They're business records filed in the normal course of business of Tampa Electric Company and, thereby, admissible under the evidence code.

MR. BEASLEY: We're not trying to prevent the Commission from having access to any information, but that, again, is not a legitimate exception to the hearsay rule.

If the custodian of the business records were here and could say, yes, I've had custody of these, I brought them with me to the hearing, you know, that's the way you lay a predicate for that exception; but that doesn't apply just because Mr. Hernandez is an employee of the company.

MR. McWHIRTER: Madam Chairman, would you issue a bench subpoena to Ann Causseaux so we could get her down here?

CHAIRMAN JOHNSON: No.

MR. McWHIRTER: At this time I'd like to proffer FIPUG Exhibit 1 into evidence. I would request you reconsider your ruling on official records.

I would request that you acknowledge that these documents are business records of Tampa Electric that have been filed with your agency, and I would ask you to take cognizance of the fact that Mr. Hernandez has said that these are truthful statements, as best he knows, of his company, and they would be classified as information filed by his company that would be admissible as an admission against interest, if I chose to use it in that fashion.

CHAIRMAN JOHNSON: Your request for me to reconsider the official recognition is denied, but I will ask Staff their opinion as to whether or not there are grounds upon which this can be introduced.

MS. JAYE: Without having the custodian of the records for the company here to authenticate these documents, I do not see a way they can be gotten in.

CHAIRMAN JOHNSON: Okay. Request for admission is denied.

MR. McWHIRTER: Well, Madam Chairman, would you, since I'm surprised by this ruling, and we raised the issue and put the company on notice that we were going to request this information, which is clearly public record information, to be introduced in the -- in this proceeding, I'd like to have the authority at our September 11th hearing, should that take place, to call the custodian of the corporation, the custodian of these records, as a witness.

CHAIRMAN JOHNSON: Staff, is there any another way --

COMMISSIONER CLARK: May I make a comment?

CHAIRMAN JOHNSON: Yes.

COMMISSIONER CLARK: Mr. McWhirter, if you're referring that they were put on notice at the prehearing conference --

MR. McWHIRTER: Yes, ma'am.

COMMISSIONER CLARK: -- it was indicated to me that there would be a request for official notice. I was relying on the fact that it was clearly something that could be officially noticed, and I think this is the type of thing you should have checked with Tampa Electric ahead of time and say, look, I want to put this in; can you look at it; do you have a problem with it.

Did you do that? Have you --

MR. McWHIRTER: Yes, ma'am. At the hearing -- and Ms. Kaufman read it out this morning, the things that we said we would ask you to take official notice of, and that was the annual reports from 1994 henceforth, and it was the surveillance reports filed with this Commission. That's pretty clear as to what they are.

COMMISSIONER CLARK: Did she do that at the prehearing?

MR. McWHIRTER: Yes, ma'am.

COMMISSIONER CLARK: Were you aware that they were going to ask for official notice of those documents at the prehearing?

MR. BEASLEY: We did, and we indicated that we would not at the time consent to those documents being officially noticed.

COMMISSIONER CLARK: Okay. My mistake, then.

CHAIRMAN JOHNSON: I recognize you asked a question about whether or not there would be another opportunity. Staff -- I don't think so in this particular proceeding. Oh, you're saying if we go on to --

MR. McWHIRTER: Yes, ma'am.

CHAIRMAN JOHNSON: If we don't finish up --

COMMISSIONER GARCIA: Madam Chairman, I just hesitate to warn you that if you agree to that, Mr. McWhirter's talent as a litigator will probably keep this Commission sitting all day until he's assured to returning. And that is a compliment to you Mr. McWhirter, not anything else. So I would hesitate before you agree to that, that it may just delay --

CHAIRMAN JOHNSON: Given the fact that the governor hasn't issued his order, we may be able to finish up this evening anyway. It looks like we probably will.

Staff had one more comment.

MS. JAYE: No; no comments.

MR. McWHIRTER: Madam Chairman, I'd like to proffer this exhibit, and as I understand it, I have proffered it, and you have rejected it.

CHAIRMAN JOHNSON: Yes, sir.

MR. McWHIRTER: Based on your ruling at this point in time.

CHAIRMAN JOHNSON: Yes, sir.

MR. McWHIRTER: So we have a proffered exhibit.

CHAIRMAN JOHNSON: Uh-huh.

Q **(By Mr. McWhirter)** Mr. Hernandez, I'm now moving to Issue No. 7, and Issue No. 7 deals with the justification for collecting the carrying costs on this plant through the cost recovery proceeding rather than base rates.

And I would like to address you first to Section 366.8255 Florida Statute, the statute on which this is based, and in subsection 2 of that section it says that an adjustment for the level of cost currently being recovered through base rates or other rate adjustments clauses must be included in the filing.

Did you make any adjustment to your -- the level of cost of being recovered in base rates as a result of this request that's appearing today?

Let me restate that question. It was sort of -- did you make any adjustment in the -- or will you make an adjustment in the level of costs that you seek to recover under this cost recovery clause as a result of base rate collections?

A No.

Q And would you give us your reasoning why you did not do that?

A Again, my understanding is that the Florida Legislature intended to separate base rate earnings and environmental cost recovery. They did not want the company decisions to incur cost related -- to incur costs related to environmental compliance to be based on any earnings impact.

They wanted to ensure that environmental expenditures were made on a timely basis and, again, to ensure compliance and would not require a lengthy regulatory process to ensure cost recovery.

Q I see. Now, Subsection 5 of 366.8255 specifically says any cost recovered in base rates may not also be recovered in the environmental cost recovery clause. Is that the provision in the statute that you're relying on?

A I'm sorry, Mr. McWhirter. Could you repeat that again?

Q It says any costs recovered in base rates may not also be recovered in the environmental cost recovery clause.

A I think that's a true statement. I guess what I'm referring to and relying on is that in the past, or prior proceedings, in any attempt to relate environmental cost recovery to base rate earnings has never, in fact, been considered by this Commission;

neither the fuel conservation nor capacity clauses are based, in fact, on base rate earnings. The company's base rate earnings should, therefore, have no impact on ECRC recovery.

Q If your company were earning 25% return on equity on its base rates, it's your opinion that the Commission could not consider that earning situation when it's considering cost recovery; is that correct?

A The hypothetical to me, Mr. McWhirter, is just so out of the realm, it -- I guess I don't know how to respond to it. 25% return on equity?

Q Yes.

A I think the Commission has the flexibility to make an appropriate determination, one that's based on fairness and reasonableness. The hypothetical you just posed doesn't seem very reasonable to me.

Q All right. Where would the Commission make that determination? In the cost recovery proceedings, or in -- by initiating a base rate case?

A Well, again, our approach is to recover the total cost, the full cost, through the environmental cost recovery clause, as I've described.

The cost recovery proceeding will, in fact, take place sometime around this time next year -- I guess in the fall of 1999 coincident with the change to the annual filings -- and at that point in time we will, in fact, seek total cost recovery as per the environmental cost recovery clause.

Q And it's your understanding as a regulatory representative of your company that it would be within the purview of the Commission to adjust cost recovery as the Legislature says, based on the amount of cost that might be recovered through base rates at that time?

A I guess what I'm suggesting is that the reason why we're here is to give a fair assessment about what we expect the total projected or estimated costs will, in fact, be and what the associated benefits will be to our retail ratepayers. And to the extent that we initiate a proceeding, a filing, and supporting testimony and witnesses to support the development of the appropriate environmental cost recovery cost factors, we plan to do that next time -- or next year in time to support the implementation of the cost recovery factors at that same year that the FGD system goes into service.

Q You apparently didn't hear my question, and it must have been confusing.

Is it your opinion that the Commission can adjust your cost recovery based on what it deems to be fair after considering base rates?

A I guess in my answer before I was trying to say that the Commission in this proceeding is going to review the reasonableness of our selection of an alternative and to make a determination that what we're asking for is full recovery through the environmental cost recovery clause, and that the full cost -- or full AFUDC amount would be the basis for our subsequent cost recovery proceeding next year.

Q I'm going to ask -- I don't want to badger you. I'm going to ask the question a little bit differently and ask you to give me a yes or no answer.

A I'll try.

Q If this time next year you come in requesting cost recovery, and at that point in time your base rates are earning your company 14% return on equity, which is more than the high the point in the authorized return on equity, and -- would it be your company's position that it must allow full cost recovery of your FGDT expenses irrespective of the fact that base rates may be earning 14%?

A I'm not aware of, again, the hypothetical 25%, 14%, as to what those projected return on equity numbers would be, in fact, at that time.

I guess to answer your question, I think the

Commission always has the flexibility to review specific circumstances, but in this case we are seeking full recovery of the costs and feel it is appropriate that the Commission also find that we should recover 100% of the costs associated with this project; again, based on the benefits associated to our ratepayers.

Q So your answer was yes, with explanation; is that correct?

A Yes.

COMMISSIONER CLARK: Mr. Hernandez, let me ask something. In your rebuttal testimony you refer to -- on this point you refer to an order the Commission issued. "For the basis that Mr. Selecky states the company's proposal is premature, because we do not know what the company's financial picture will be in year 2000, how do you respond?"

And you say "This line of argument is not germane to this proceeding and represents an effort to relitigate an issue which has already been squarely and unambiguously decided by the Commission." And then you cite to part of the order, and the part of the order you site to says, "Thus we find the Legislature clearly intended the recovery investment carrying costs and O&M through the environmental cost recovery clause. For this reason Public Counsel's argument must be rejected."

And then it says, "Accordingly, we find that if the utility is currently earning a fair rate of return, that it should be able to recover, upon petition, prudently incurred environmental costs."

Where is that in the order, and does that carry with it the implication if you're over your fair rate of return you could not get it through the cost recovery clause?

WITNESS HERNANDEZ: Can I get help with the first part of the your question?

COMMISSIONER CLARK: Say that again.

WITNESS HERNANDEZ: Can I get help with the first part of your question in terms of the reference to the order?

COMMISSIONER CLARK: That's what I need help with.

WITNESS HERNANDEZ: Okay. I need help, too.

COMMISSIONER CLARK: I have the order -- oh, I see. I'm sorry. Yes, you can get help.

MS. JAYE: Commissioner, I believe that quote comes from Page 4 of the order.

(Discussion off the record.)

WITNESS HERNANDEZ: (Pause) Commissioner, Ms. Jaye was right. It's on Page 4 at the order on the bottom, if you allow me to read it. "Thus we find that the Legislature clearly intended the recovery of investment, carrying costs, and O&M expenses through the environmental cost recovery clause. For this reason, Public Counsel's argument must be rejected. Accordingly, we find that if the utility is currently earning a fair rate of return, that it should be able to recover, upon petition, prudently incurred environmental compliance costs through the ECRC, if such costs were incurred after the effective date of the environmental compliance cost legislation and if such costs are not being recovered through any other cost recovery mechanisms."

That went on to Page 5 of the order.

COMMISSIONER CLARK: Let me ask a question. Is it your company's position that -- let's suppose there are overearnings in 2000. Is it your company's position we should address those overearnings as part of an overearnings investigation and that we should allow this recovery through the cost recovery clause, or could we deny cost recovery because you're overearning?

WITNESS HERNANDEZ: To tell you the truth I'm not sure which one comes first, absent of knowing what our position, in fact, is going to be. And my assumption is that that review would occur, in fact, after the year, in terms of how that year settled out; that the appropriate thing to do would be perhaps to go ahead and recover the full amount of the costs associated with the project, and then subsequent to the -- an audit review, perhaps, a review of the earnings for year 2000, that the Commission can take whatever action they deem appropriate.

Q **(By Mr. McWhirter)** Your quoted language used the phrase "fair return." As a regulatory representative of your company, what does that mean to you?

A We have a -- an amount, if you will, allowed in terms of the allowed rate of return, which I understand is at 12.75% return on equity, which is the top point of the range, and that we should be allowed to earn all the way up to that range. That would constitute in that sense, given that cap, a fair rate of return.

Q If you were earning 14%, would that be considered a fair return, in your opinion?

A I would say that's even a fairer, more fairer return.

Q (Laughter) All right. I'm about to wind up.

Mr. Hernandez, Mr. Black told us that this project is already under construction; the pilings are being driven and contracts have been committed. If the Commission declined to rule in your favor in this proceeding, would you stop construction?

A Well, again, you're giving me another hypothetical. Because I feel like this is the right thing to do. It's the appropriate thing to do for our ratepayers, and given that, I really can't see how the Commission can find any other way.

But given that, we have demonstrated that it's cost-effective to do so, to go ahead and to construct the scrubber. It's an effective means of complying, which we are obligated to do, and as long as we have the obligation to serve -- what doesn't change here is the system requirements. We've got retail customers in a growing service territory. We've got to be able to provide the energy.

So absent any other recourse, i.e., there are no other viable cost-effective means to provide that energy, we have to, in fact, move forward with this project. It makes sense to do so.

Q I'm not suggesting that the Commission would determine that it was an inappropriate project, but only determine that maybe the appropriate time to consider it would be at the time -- or consider cost recovery would be at the time that the plant is in service, as you have done in the past. You have not sought recovery until your plant was in service.

You wouldn't stop construction if the Commission just delayed its decision until later, would you?

A Given the fact that we still have projected system energy requirements, we've got about 2.2 to 2.5% retail energy growth on our system, and we've got to be in compliance by year 2000. To defer any action or stop construction of the facility would only increase the cost to our rate paper, i.e; we'd have to go back to the next most effective cost-effective alternative, which means blending of lower sulfur coal fuels, and that would result in a higher fuel adjustment, fuel and purchase power cost recovery factor than what otherwise we could develop moving forward with the project.

Q Now, you're not asking to collect money now; you're going to ask to collect money at a later time as we've all agreed upon; isn't that right?

A That's correct.

Q Well, if you wouldn't stop construction and you don't want money now, can you give me more than -- can you given me even one viable reason why it's necessary to have cost recovery approved today before construction is completed and before all the facts are known?

A I'm not clear on what cost recovery you're suggesting that we're --

Q Well, what is it you're asking for in Issue No. 7?

A We're simply asking -- and I'll read it as stated: "Should TECO's petition for cost recovery of an FGD system on Big Bend Units 1 & 2 through the environmental cost recovery clause, ECRC, be granted?" So we're just seeking recognition that, in fact, this is the appropriate cost recovery mechanism.

Q You're seeking comfort from the Commission, is that it? Is there something binding that's going to happen at this proceeding that will bind the Commission at a later time, in your opinion?

A Well, I think the Commission always has the opportunity to review prudence and appropriate costs, and in a cost recovery proceeding as we're suggesting will occur sometime next year, they have the ability to go back and look at what are, in fact, the costs that are being sought and how that relates back to this time. We're seeking, really, the three things; that this is the most cost-effective alternative for our ratepayers; that the environmental cost recovery clause is, in fact, the appropriate cost recovery mechanism; and then to get an acknowledgment that we would like to defer the accrual of AFUDC, and that would also be a cost item when we go for cost recovery about this time next year. We are not seeking cost recovery at this time.

Q You're seeking a ruling that cost recovery is appropriate.

A The mechanism for cost recovery is appropriate.

Q And if next year the Commission looked at your base rates and found that it would be unfair to allow you to collect whatever you're then earning on base rates plus full cost recovery, would you object if the Commission at that point in time rescinded the ruling that you're seeking today, that cost recovery is appropriate? Yes or no.

A I forgot how you framed the question so I'm not going to be able to say yes or no. I guess my point is --

Q Wait. Stop. It was very artfully phrased.

MR. McWHIRTER: Read back the question to me.

THE COURT REPORTER: "And if next year the Commission looked at your base rates and found that it would be unfair to allow you to collect whatever you're then earning on base rates plus full cost recovery, would you object if the Commission at that point in time rescinded the ruling that you're seeking today, that cost recovery is appropriate? Yes or no."

MR. BEASLEY: The witness has expressed some problem with that question, and I'm having a little difficulty with it, too. It may have already been answered.

MR. McWHIRTER: Do you still have problems with it, Mr. Hernandez?

WITNESS HERNANDEZ: Yes, I do, because of the two references I've made now to the Commission's own order related to the Gulf proceeding on this issue.

COMMISSIONER CLARK: Mr. Hernandez, let me ask the question, because I'm curious as to your position, too.

If we get to 2000, if we get to 2000 and we conclude in, I guess, this August of the year 2000 that it's a pretty good bet you're going to be overearning for that year, is it -- and by that I mean above what was previously authorized -- is it your position that if we make a decision today that it's eligible for cost recovery under the environmental cost recovery, that you are entitled to that despite the fact that you may be overearning?

WITNESS HERNANDEZ: Again, and I'm not -- not trying to be difficult. And I guess I see this as two different proceedings perhaps. There's the year 2000 audit review, and to see what actually happened versus what may happen versus what we think we're eligible to do as per the intent of the environmental cost recovery clause, and that I'm not sure which one comes first.

But does it make sense without knowing how, in fact, Tampa Electric would end up by the end of the year 2000 to not get full recovery of the costs associated with the clause and again with the intent do you do that first and then you take another look as to what actually happened in year 2000? I guess that's what I was suggesting before. I'm not saying --

COMMISSIONER CLARK: Let's assume you take another look. Would it then be appropriate to say we shouldn't have let you recover it through the environmental cost recovery?

WITNESS HERNANDEZ: I guess it's a timing issue, Commissioner, that I'm concerned with.

COMMISSIONER CLARK: I agree with you.

WITNESS HERNANDEZ: We would file for full cost recovery in a proceeding next year on a projected basis for the year 2000. It is a timing issue problem.

We would have to file testimony somewhere near around October 5th or the first week of October 1999 on a projected basis well before we know what our earnings are or return is, in fact, for the year 2000. That's the problem I've got.

COMMISSIONER CLARK: Let me ask a different question, then. If you do overearn in the year 2000, and let's say you have projections this time next year that you will overearn in the year 2000, is it your position that that should be taken care of in an overearnings investigation and you should get it under -- the scrubber should still be recovered under the environmental cost recovery?

WITNESS HERNANDEZ: I find myself not being able to answer yes or no again, and let me tell you why. And it's that 13 years of planning background. One thing I've learned, that is, a forecast is never going to be 100% accurate. There's variances one way or the other, and when it comes to making projections, you know, we could project a higher number, we can project a lower number.

I think what really matters to you is how we actually come up. How we end up. I'm sorry. And the analogy for that is, in fact, that we have a true-up mechanism associated with this fuel adjustment projection and any other projections.

There's ways to make adjustments based on what actually happens. So do you take action before something actually happens, or do you react? And that's the problem I've got. To me it's --

COMMISSIONER CLARK: I would agree with you on the adjustment clause, is it's a true-up, but it's not a true-up on base rates. And how do we capture the fact that you might be overearning? How do we factor that in?

Let me just ask this question. It seems to me your position would be that overearnings get taken care of in an investigation and that you should get the cost recovery through the environmental.

WITNESS HERNANDEZ: I'm not sure if that's the appropriate way to do that. I guess I'm stopping short and saying absent of knowing if we're going to be in an overearning situation, why -- the flip side of that is why take corrective action before you know how we may end up.

COMMISSIONER CLARK: Well, the reason is we have no jurisdiction over your overearnings if we don't. I mean, we have to take some action to capture the overearnings is what I would be concerned with. And I would agree with you in the true-up clauses it's a dollar-for-dollar recovery. You project, you true-up, so you don't recover more. But in order to capture overearnings, we would have to take some action to do that.

MR. BEASLEY: Commissioner, can I offer a legal response and partially legal, partially policy?

COMMISSIONER CLARK: It's okay with me.

MR. BEASLEY: Regulatory policy. We read the Gulf Power order as saying, don't try to credit a portion of the fact that they're earning within the return and say they can go all the way down to the bottom of their zone and you don't get any until you're below that.

You said this is a cost, an environmental compliance cost that's not built into your base rates. Consequently we're going to keep those pots separate. And we read the logical extension of that to say if you're overearning, we bring you in, and we've got --

the Commission has a continuing surveillance process which works well.

COMMISSIONER CLARK: Okay.

MR. BEASLEY: And the Commission has not mixed those pots before, and I think it would be an accounting morass to -- if you brought companies in that are overearning and didn't try to adjust that out of their fuel adjustment, for example.

COMMISSIONER CLARK: Well, I appreciate that, that that is going to be your legal position, but it isn't a strict reading of that order. It does require an interpretation, because it does say "Accordingly, we find that if the utility is currently earning a fair rate of return." It doesn't say what happens when it's earning more than a fair rate of return.

MR. BEASLEY: We certainly will not be overearning between now and 2000 on account of the stipulation, and we just would encourage -- not to speculate about --

COMMISSIONER CLARK: I understand your position to be the two should be kept separate, and if there are overearnings found, you deal with it that way, you don't deal with it by denying recovery for an environmental cost.

an answer on the question I asked.

A I think I answered. I'm not sure.

MR. BEASLEY: What was the question?

Q **(By Mr. Howe)** The question was did the final order issued in the Polk docket alter the amount of CWIP allowed in Tampa Electric Company's rate base? I think that deserves a yes or no answer.

A I'm not sure but I don't know.

Q Are you aware of any order that changed or modified the amount of CWIP authorized in the company's rate base, by that I mean CWIP eligible otherwise to accrue AFUDC, that altered or modified the order you have before you, 93-0664?

MR. BEASLEY: Commissioners, that's a legal question. I think the witness indicated what he relied on in responding to Mr. Howe's question.

MR. HOWE: This question is is he aware of any order that altered or modified 93-0664.

MR. BEASLEY: Mr. Howe, I believe his point was that there was language in the order that he was attempting to refer to that addressed the question that you're asking.

MR. HOWE: That addresses the issue of CWIP?

Q **(By Mr. Howe)** Please refer to any language, Mr. Hernandez, that refers to CWIP.

A If I may?

Q Certainly.

A Okay. There's two pieces that were extracted from the Order. I'll read the two. The first piece addresses the environmental cost recovery clause, as you anticipated. "As part of the stipulation, the parties agree that TECO will not use the various recovery clauses to recover capital items that normally would be covered through base rates. However, TECO would be allowed to recover its prudent expenditures associated with compliance with environmental laws and regulations through the environmental cost recovery clause."

The next reference to get to the CWIP and AFUDC issue, and referred relative to Rule 25-6.0141, Paragraph 1(g). "On a prospective basis, the Commission, upon its own motion, may determine that it is in the best interest of the ratepayers to exclude an amount of CWIP from a utility's rate base that does not qualify for AFUDC treatment per Section 1(a), and to allow the utility to accrue AFUDC on that excluded amount."

Q Excuse me. For that last part are you referring to the rule or an Order?

A This is relative to the rule that you

provided to me.

Q I see. You're reading from the rule; is that correct?

A It's relative to the rule. That's correct.

Q You're saying it's relative to the rule. Are you reading from the rule or from an Order that quotes the rule?

A I wasn't reading the rule you handed me. It's a reference to the rule, you're correct.

Q Then my earlier question, is there any Order issued by the Commission subsequent to 93-0664 in which the Commission has modified the amount of CWIP allowed in Tampa Electric's rate base?

A Not that I'm aware of.

Q Mr. Hernandez, I had asked you a question earlier, and I'll need to return to it. Have you to date read all of Rule 25-6.0141?

A No.

Q Does Tampa Electric currently calculate its AFUDC rate consistent with Rule 25-6.0141?

A As I stated before, I am not sure how that calculation is made. That number was used in the calculation of the AFUDC amount associated with the cost-effectiveness study. That's the 7.79%. How that calculation was made I cannot address.

Surveillance Report for 1997 and for 1998.

CHAIRMAN JOHNSON: Very well.

Q **(By Mr. Howe)** Mr. Hernandez, would you please refer and read from Section 8, Subsection 8 of the rule.

A It begins "Each utility shall."

Q Yes, sir.

A "Each utility shall include in its Forecasted Surveillance Report a schedule of individual projects that commence during that forecasted period and are estimated to equal or exceed a gross cost of $10 million. The schedule shall include the following minimum information." And it has four subparts. "Description of the project, estimated total cost of the project, estimated construction commencement date and estimated in-service date."

Q Now, Mr. Hernandez, you're welcome to review Tampa Electric's Forecasted Surveillance Reports for 1997 and 1998 that have been given to you there, and have been identified as Exhibit 13.

And I'm going to ask you would you agree that Tampa Electric, in its Forecasted Surveillance Reports, at least for the last two years, does not comply with Section 8 of Rule 25-6.0141. Just look

Surveillance Reports, which would then indicate that Tampa Electric has not yet implemented Section 25-6 or Rule 25-6.0141, and, indeed, they are not required to do so until January 1st of 1999.

A I'm sorry, was there a question in that?

Q Yes, sir. Would you agree that if these surveillance reports, these Forecasted Surveillance Reports, do not contain the schedules specified in Section 8 of Rule 25-6.0141, that would be indicative of the fact that Tampa Electric has not implemented Rule 25-6.0141 at this time, and is, indeed, not required to until January 1st of 1999?

A Just a minute. I'd like to see the date of the last report. (Pause)

Mr. Howe, it's difficult to make that determination. The date on this report is March 13th, 1998.

Q And it is the Forecasted Surveillance Report of Tampa Electric for 1998 as filed with this Commission, is it not?

A I'm trying to match up -- the original date of the petition was May 15th, and this projection has a date of March 13th, and you're asking me why this doesn't reflect the contents of our petition?

Q No, sir. Let's try to be as clear as we can.

A Okay. Please.

Q Subsection 9 of Rule 25-6.0141 which you read into the record, states, does it not, that the provisions of the rule are effective January 1st, 1996?

A Yes.

Q But that -- and that it shall be implemented by utilities no later than January 1st, 1999.

A Yes.

Q Okay. Now, the series of questions I was asking was given that this rule took effect January 1st of 1996, which is before all of the relevant dates in this proceeding, you would expect, would you not, that if Tampa Electric had implemented this rule, that its surveillance -- its Forecasted Surveillance Reports filed after January 1st, 1996, would be in compliance?

A To the extent we had projects that were in excess of $10 million, yes.

Q Yes, sir. And do you have any projects in excess of $10 million in 1998?

A The only project that I'm aware of at this point is the one at hand, and that's the FGD projected.

Q Is it estimated to equal or exceed a gross cost of $10 million?

A Yes.

Q Would you not, therefore, expect that if Tampa Electric had implemented Rule 25-6.0141 it would have included in its Forecasted Surveillance Reports --

A Not one dated March --

Q -- such a schedule?

A I'm sorry. Not one dated March 13, 1998.

Q If that March 13th was a forecast for all of 1998?

A Mr. Howe, we didn't file our Phase II cost-effectiveness study with the Commission until May coincident with the filing of the petition. And there was not yet a determination made by senior management prior to going through the cost-effectiveness study and making a determination that this is the appropriate way for compliance.

So I'm not -- I guess what I'm saying is it would be difficult to provide that information to the Commission in a surveillance report dated March 13th, 1998, before our board of directors and senior management approve the project.

Q Is it your position that Tampa Electric did not have any projects which were estimated to exceed -- equal or exceed $10 million in the years 1997 or 1998 as of the dates that those respective projected surveillance reports were provided?

A I'm not directly involved with that type of assessment as to projects that are in excess of $10 million. I'm not sure that there were. I'm not sure there weren't. It's difficult for me to answer your question.

Q Would it be fair to say overall, though, Mr. Hernandez that you do not know at this time whether Tampa Electric Company has implemented Rule 25-6.0141?

A That's correct.

Q Would you agree that by the terms of the rule you will have to implement the rule by January 1st of 1999?

A Yes, I do.

Q Would you agree that if the Commission were to grant your request in this docket to accrue AFUDC on the scrubber project, that that would only apply -- that decision would only apply through 1998 because January 1st of 1999 the rule would take over. (Pause)

Are you waiting for your attorneys to press the button?

A No. I'm actually trying to make a determination if I can answer that question.

Q Okay.

A I'd have to say before I can respond representing the company I'd have to go back and talk to folks in regulatory accounting and regulatory. I don't know. I can't answer your question.

Q I'm going to ask you a question directly out of my office's Statement of Basic Position. It appears on Page 9 of the Prehearing Order. And the question is there a question? And it is, "Is Tampa Electric intending to accrue AFUDC without regard to the CWIP-in-rate-base limitation and without saying so directly?"

A Not saying so directly. I guess my response is that what was used in the cost-effectiveness study and what I refer to in my opening remarks was that Tampa Electric intends to recover the full cost of the project through the environmental cost recovery clause. The full costs include an estimate at this time of approximately $7.2- to $7.3 million of AFUDC that would be accrued and deferred until the cost recovery proceeding the fall of 1999.

Q And I wrote down a couple more words in your summary, and I think you did use that word. You referred to the fact that you weren't asking for a particular level of AFUDC but you were requesting the full amount associated with the project. Is that what you're speaking of here?

A Yes.

Q And by the full amount do you mean charging AFUDC on the first dollar, the last dollar and every dollar in between?

A That's how the cost-effectiveness study was developed and the basis for the $7.2 million, that's correct.

Q Do you necessarily mean without regard to any limitation imposed by Order No. 93-0664, or Rule 25-6.0141 for the amount of CWIP currently allowed in Tampa Electric's rate base?

A Well, relative to the rule I believe -- and again, from the Order, it says until ordered to modify or cease by the Commission. So the Commission always has the opportunity and the flexibility to make that determination with our treatment.

Q I see. And you were not willing to state that directly, were you, to inform the Commission that you wanted to ignore the CWIP in rate base limitation?

MR. BEASLEY: Commissioners, that's an argumentative characterization. He can ask a question.

MR. HOWE: I asked if -- that he wasn't willing to say so directly. That's a pretty direct question.

WITNESS HERNANDEZ: I guess my answer was that we stated we were recovering -- our intent was to recover the full cost and the estimated amount of AFUDC that would, in fact, be accrued over the three year construction period would be approximately $7.2- to $7.3 million.

Q **(By Mr. Howe)** Let me try to phrase it directly then. Would Tampa Electric -- is Tampa Electric proposing to accrue AFUDC on the Big Bend 1 and 2 scrubber project -- 1 and 2 scrubber project without regard to any CWIP in rate base limitation imposed by either Order No. 93-0664 or Rule 25-6.0141.

MR. BEASLEY: Commissioner, Mr. Hernandez has not indicated any willingness or desire to disregard the rule. I think he has testified, Mr. Howe, that there's language in the stipulation order which can be construed to permit this.

MR. HOWE: I think the question I asked was clearly susceptible to a yes or no answer. And the question was simply is Tampa Electric asking for permission to accrue AFUDC without regard to any CWIP in rate base limitation contained in the cited order or rule. I think it's perfect for a yes or no answer.

MR. BEASLEY: Does your question assume that that's the only appropriate way that it can be justified?

MR. HOWE: No. It cites to that Order and that rule. You can take care of anything else on redirect.

WITNESS HERNANDEZ: I would say our intent is to get cost recovery for the full amount of AFUDC.

MR. HOWE: Chairman Johnson, could I have the witness directed to give a yes or no answer and then he is free to --

WITNESS HERNANDEZ: The answer is yes.

Q **(By Mr. Howe)** Excuse me?

A Yes, but -- I was reluctant to answer yes in the way the question was characterized.

Q Is the answer yes, Mr. Hernandez?

A Yes.

MR. HOWE: No further questions.

CROSS EXAMINATION

BY MS. KAMARAS:

Q Good afternoon, Mr. Hernandez.

A Good afternoon.

Q In response to Staff interrogatories there are some seemingly inconsistent answers on your part regarding the life of the Big Bend units. And I'm going to pass this out just for convenience of folks here. (Counsel passes out documents.)

In response to Staff Interrogatory 14, Tampa Electric replied it had no plans to retire any Big Ben or Gannon unit over the next 40 years, and that would make their retirement date sometime after the year 2028.

Then in response to Staff Interrogatory No. 19, Tampa Electric replied that retirement dates for Big Bend 1 and 2, for purposes of depreciation, were 2020 and 2023, respectively. And then in response to FIPUG Interrogatories 13 and 18 on the remaining life on Big Bend 1 and 2, Tampa Electric replied that the remaining life of Big Bend 1 and 2 were 20 and 21 years, respectively, meaning that in the years 2018 and 2019. Can you explain to me why there are so many different dates associated with the remaining life of these units?

A I'll try. For purposes of the depreciation study, in determining a schedule as to what needed to be set aside, the depreciation expense, there had to be a determination as to what -- pick a year, if you will, that -- in order to set that schedule. And so for purposes of the depreciation study and the update to that there was a date, in fact, picked in order to come up with the amount that should be set aside. And this is very different than the integrated resource planning process in determining the utilization of your existing resources as well as the need for additional or future resources, DSM or supply side; however you want to look at it. Relative to the planning studies, and the cost-effectiveness assessment, no plant, except for the Hookers Point uni-s, Hookers 1 through 5, was assumed to be retired throughout the study period. Because, in fact, there are no plans for retirement within that study period. And the study period began, and final cost-effectiveness study, somewhere 1997 through the year 2026, I believe it was.

So in order to try to address this potential conflict, there were two different responses. One was relative to the depreciation study and the other referred to the cost-effectiveness study.

Q Which one was your response to FIPUG in terms of remaining life that came up with the years 2018 and 2019 or 20 and 21 years. That's different from your depreciation study and different from the 30 years?

A The difference is your starting point. I think relative to the question it was relative to the Big Bend 1 and 2 in-service date -- I'm sorry, the Big Bend 1 and 2 FGD system in-service date, which you say be taken off the year 2000. So if you match that up to the last depreciation study -- I wasn't sure if we put the date in here -- the 2020 and the 2023, that's the response to Interrogatory No. 19?

Q Yes.

A Okay. Relative to the FIPUG Interrogatory No. 19 is approximately 20 years. If you start from the year 2000 and go to 2020, there's 20 years. And if you go to 2023 for Big Bend No. 2, the answer to response to Interrogatory No. 18 is approximately 21. And the difference is just months, so that's your difference.

Q So your answer to FIPUG is in relation to the depreciation life of the units?

A FIPUG is relative to the depreciation study and keying off the first year of the FGD system being in service.

Q Am I correct that Big Bend 1 was put in service in the year 1970 and Big Bend 2 in service in 1973?

A If you want me to verify it I can look it up in our Ten Year Site Plan.

Q Sure.

A Big Bend 1, November 1970. Big Bend 2, April 1973.

Q So those plants at this time are 28 and 25 years old respectively?

A Yes.

Q Okay. And in the year 2020, it's depreciation life for Big Bend 1, it will be 50 years old?

A Approximately, yes.

Q What experience does Tampa Electric have in operating a coal-fired power plant of that age?

A I don't believe any of our coal units are 50 years. Let me go back to the 50 years in terms of operating life. Let me just quickly go back to the first coal unit, which would be Gannon Unit 1 and see what the in-service date was for that unit.

And the first coal unit on Tampa Electric's system was Gannon Unit 1 and that was placed in service, September 1957. So that unit is about 41 years old.

Q Midlife crisis for humans.

A I'm sorry?

Q I'm sorry.

In the year 2323, which corresponds for your depreciation life for Big Bend 2, it will be 50 years old; is that correct?

A Yes. Approximately.

Q And in the year 2828, which is 30 years from now, those plants will be 58 years old and 55 years old respectively?

A Yes.

Q Okay. Is it fair to say that as a power plant, particularly the boiler ages, that it becomes less efficient?

A I would agree with the statements that Mr. Black made, that it's directly proportional to your maintenance program.

Q In that case would it be fair to say that as a power plant, and particularly the boiler ages, it may have increased operating maintenance costs associated with it?

A It may, it may not. It depends on equipment wears out over time and you have to replace some of that equipment. But in terms of performance and unit availability, it really gets back to how you utilize that resource as well.

Q Are you familiar with the Big Bend 3 and 4 scrubber project?

A A little.

Q I asked this question of Mr. Black and he was unable to answer it. Are you familiar with the projected or actual operating and maintenance costs associated with that project?

A Not offhand, no.

Q It was stated earlier, I believe, by Mr. Black that there is some probability of Tampa Electric needing to purchase allowances with the scrubber installed; is that correct?

A Yes.

Q Have you projected the price of those allowances?

A Yes. There is a projection that was used in the cost-effectiveness studies.

Q And what generally are the prices that you've projected?

A I think in the first year of Phase II, beginning around the year 2000, I believe the prices start on or close to about $130 per SO2 allowance time and then escalate through time.

Q In your cost-effectiveness analysis where is the savings from or cost of allowances accounted for?

A They are included in the total system revenue requirement analysis. And included in the differential.

Q Is there any specific breakout of those numbers?

A I don't believe so. I believe they would be contained in the fuel numbers. That's what you're offsetting. When you put in the allowances you're basically balancing the book at the end of the year on a projected basis as well as on an actual operating basis. So since -- again what I was talking about before on a projected basis, you may be off by a kilowatt-hour or two when you get to the end of the year. So you balance the books, if you will, with the purchase allowances. You also take advantage to the extent that if the allowances are available at an increment in price lower than what it would cost for you to fuel blend, that you should go ahead and buy the allowances based on that price mechanism. So the amount that actually gets booked depends on the utilizations of the resources again to meet the system requirement.

Q Page 6 of your testimony discusses the sensitivity of the conclusions relating to the cost of SO2 allowances. What was of the base cost of allowances assumed?

A The base cost. That was the $130. And then it escalates through time.

Q In regard to Tampa Electric's Late-filed Deposition Exhibit 1, the assessment of the natural gas option, I had some questions for you and I'm going to pass something out here just for reference.

COMMISSIONER DEASON: Ms. Kamaras, Mr. Howe probably would do that for you and you could sit down and ask your questions.

MR. HOWE: Thank you, Commissioner Deason.

Q **(By Ms. Kamaras)** This is a table taken from the Duke New Smyrna filing --

MS. KAMARAS: I'm not seeking to have it marked. I gave a copy to everybody as a courtesy.

Q **(By Ms. Kamaras)** This is a listing of power plants proposed for Peninsular Florida.

MR. BEASLEY: Could I briefly inquire, this is taken from the New Smyrna filing?

MS. KAMARAS: Yes, it is.

MR. BEASLEY: What proceeding?

MS. KAMARAS: It's 981042. It's the need determination filing.

MR. BEASLEY: For what purpose would this be offered?

MS. KAMARAS: This is just information. I'm not seeking to have this -- accepted as an exhibit. I just have some questions, and this is an easier way to ask it.

MR. BEASLEY: Recognizing that the witness hasn't necessarily seen this or verified the contents of it.

MS. KAMARAS: Correct.

Q **(By Ms. Kamaras)** In your late-filed deposition exhibit, Tampa Electric assumed a heat rate of 7,000 Btu per kWh for the gas unit. And I note that in this filing the heat rates are generally lower than that with two exceptions, and I just wanted to ask what was the basis for your assumption regarding a 7,000 heat rate?

A For planning purposes it certainly seemed reasonable. Are you asking me to make a comment on these numbers that you passed out or --?

Q If you can.

A Okay. The important thing that you need to remember when you talk about heat rate or any operating characteristic goes back again to how often that resource is utilized. A resource that's utilized for one day at 100% load factor is going to be -- all things considered equal, are going to be pretty close to an expected operating heat rate, if you will, just to focus on the heat rate issue. But to the extent if you back off that resource, instead of 100% load factor, you operate at, let's say, an 80% load factor or a 60% load factor, now you pull in all those other times where it's ramping up and down; it's not sitting in a stable state. And what you effectively get as you move off an ideal operating heat rate to one that's more actual. It's what you effectively realize when you account for normal operation. So you've got to be careful not looking at the context, they don't show what the capacity factor or the net operating factor is. It's simply a number with an availability factor. It does not address utilization. So I would say the 7,000 net heat rate number that was utilized in that hypothetical is certainly reasonable looking at these numbers.

Q In your late-filed deposition exhibit the analysis indicates that for a coal unit the basis for a heat rate of 10,000 Btu per kWh for TECO's proposed compliance options, I note pursuant to Tampa Electric's filing with FERC I proffered earlier, that the heat rate for Big Bend is approximately 11,275 and for Gannon is a little over 11,000. And I would like to know what the basis of a heat rate of 10,000 was?

A Big Bend Units 1 and 2 operate on an average approximately 10,000 Btus per kilowatt-hour. I cannot address the 11,000 reference. That seems way too high for the coal units. You get different heat rates based on operating temperatures, both ambient cooling water temperatures that affect that number. But on an actual basis it should be very close to the 10,000 Btu kilowatt-hour.

Q Your late-filed exhibit says average heat rate 10,000?

A Right. That would account for the seasonality that I was talking about. The heat rates tend to be higher than 10,000 over the summer months because of the operating conditions. Ambient temperatures are up; cooling water temperatures are up. In the winter you gain efficiency and it tends to be below 10,000. It also gets to the fuel issues and other operating characteristics, but generally the 10,000 is a good number.

Q Why the higher numbers reported to FERC?

A Can you show me the reference? I haven't seen that.

Q Yes. (Hands document to witness.)

A You can't tell it's the heat rate. There's no reference. (Pause) Okay. I understand the concern.

What Ms. Kamaras was referencing was not heat rate. It's heat content and it's Btu per pound of fuel. That's the value of heat that's in a unit of fuel. It's not the heat rate of the unit.

MS. KAMARAS: Thank you. I have no further questions. Thank you, Mr. Hernandez.

MS. JAYE: Staff is now going to distribute a package of documents as we did for Mr. Black. We'd like to get these documents marked for identification.

CHAIRMAN JOHNSON: Go ahead.

MS. JAYE: If we could make a composite exhibit of the first two documents, and this would be Exhibit No. 14, both the transcript and the late-filed deposition exhibits of Mr. Hernandez.

CHAIRMAN JOHNSON: They will be marked as composite 14.

(Exhibit 14 marked for identification.)

MS. JAYE: The third document in this stack to be marked as Exhibit 15, TECO's revised August 1998 Ten Year Site Plan for Electric Generating Facilities.

CHAIRMAN JOHNSON: That will be marked as 15.

(Exhibit 15 marked for identification.)

MS. JAYE: And the next document to be marked as 16, TECO's revisions to the April 1, 1998, filing of the Ten Year Site Plan.

CHAIRMAN JOHNSON: Marked 16.

(Exhibit 16 marked for identification.)

MS. JAYE: And the last one to be marked as 17, TECO's response to Staff Request for Production No. 23.

CHAIRMAN JOHNSON: Marked 17.

(Exhibit 17 marked for identification.)

CROSS EXAMINATION

BY MS. JAYE:

Q Mr. Hernandez, if you would take a look at that first document, No. 14. Could you tell me what that looks to be to you?

A No. 14?

Q Yes.

A Is that the late-filed deposition exhibit?

Q It would be the document before that. Those are both marked just 14, a composite exhibit.

A Okay. It's the transcript of the August 11th deposition.

Q Okay. Have you had an opportunity to read and sign that?

A Yes, I did.

Q If I ask you the same questions today, would your answers be substantially the same?

A Making the adjustments on the errata sheet, yes.

Q If you would turn to the second group of documents in that Exhibit 14, which would be the late-filed deposition exhibits. Please turn to your Late-filed Deposition Exhibit 1.

A Yes.

Q Indicated on that exhibit is an average capacity factor of 80%; is that correct?

A Yes, that's correct.

Q Subject to check, would you agree that the capacity factor for an 850 megawatt unit which generates 5,600,000 megawatt-hours per year is 75?

A 75 what?

Q Percent.

A Subject to check, yes. I can do the calculation but --.

Q That won't be necessary. Column 9 does not include catalytic reduction technology retrofit costs; is that correct?

A Column 9. I'm sorry, the question was it's NOX --

Q Column 9 does not include catalytic reduction technology retrofit costs?

A Yes, that's correct.

Q If we knew today that catalytic reduction technology retrofits would be required, would it be appropriate for those costs to be included in this column?

A If there was a determination that that was the appropriate way to comply, yes.

Q Have you listed only Big Bend 1 and 2 FGD costs in Column 11?

A Allow me just one second. (Pause) Yes, I believe that's right.

Q These are not all the nonfuel system costs, are they?

A All of the nonfuel system costs?

Q Yes.

A No. There would be other system-related costs, that's correct.

Q In arriving at these numbers it also appears that your assumption was that the FGD would be depreciated over ten years; is that correct?

A I don't recall if we used the ten year convention, but it appears that may be right. It doesn't indicate that on here, though.

Q Subject to check, would you agree that that appears to be the case?

A Yes.

Q Is the expected useful life of the proposed

FGD 30 years?

A The useful life, yes.

Q Yes. Looking now at Column 12, does it capture TECO's total nonfuel system compliance cost for NOX, particulates and SO2?

A I believe this is cost associated with Big Bend 1 and 2. And again relative to the context of hypothetical it's a displacement of Big Bend 1 and 2 units.

Q Is it not incremental to the base case or reference case?

A Yes, it is.

Q With that in mind, if you would, please turn to your Late-filed Deposition Exhibit No. 6, Page 4 of 4. Does this schedule also show TECO's Big Bend 1 and 2 FGD scrubber costs? These are the two on the far left, two columns on the far left.

A Yes, it does.

Q Should the sum of these two columns be the same as Column 11 in the Late-filed Deposition Exhibit No. 1?

A No.

Q Could you please explain?

A Yes. And I'm recalling now that the hypothetical that was set up in the Exhibit No. 1 was a displacement of the Big Bend capacity with combined cycle capacity. And so this is an estimate of the costs associated with the capital dollars associated with building the scrubber. Let me check that. Hold on one second. Let me check this. (Pause)

I'm sorry, these are the nonfuel operating costs associated with the scrubber. These are incremental. The Item No. 6 that you just referenced on the revenue breakdown is the non-levelized revenue requirements associated with the construction of the FGD system. They are two different things.

Q So if you were looking at your Late-filed Deposition Exhibit No. 6 is that total cost or incremental cost?

A These are differential revenue requirement costs associated with the different options from the screening analysis.

Q All right. Looking at Column 11 and the Late-filed Deposition Exhibit No. 1, is that total or incremental cost?

A Can I have one minute to check that calculation? (Pause)

Okay, I think I understand the difference now. The 10-year convention versus the 30-year convention, there's a difference in the assumptions related to the screening analysis associated with the response to No. 6. No. 6 was a question to provide the annual revenue requirements on the capital, O&M and fuel relative to the other options identified in the screening analysis. And the final cost-effectiveness study, we only have the two options, the FGD and the fuel blend. So in order to provide the response to Item No. 6, the information there is related back to the screening analysis. The information that was provided in response to No. 1 was based on the hypothetical displacement, was utilizing the information on the final cost-effectiveness study beside the 30- and 40-year convention. That's why the numbers don't match up. I apologize for the confusion.

Q Is the fuel cost listed in this late-filed exhibit -- again, we're looking the Exhibit 6, Page 4 of 4, an incremental cost or an incremental savings?

A Which column was that, I'm sorry?

Q This would just be the entire exhibit, the Late-filed Deposition Exhibit No. 6, Page 4 of 4. There's a fuel cost listed on this exhibit. And what I'm asking is is this an incremental cost or an incremental savings? I believe this would be the third column under each option.

A They are differential so it would be incremental.

Q Staying with that exhibit, Mr. Hernandez, if you look over the total revenue requirement column, I believe this would be the fourth one over?

A Page 4 of 4 still.

Q Yes. For at least the first two options, and for most of the second two options, those are negative numbers in the total revenue requirement column and I was wondering if you could explain how that can be. (Pause)

If you can just walk us through how you come from positive numbers in the first three columns to negative numbers under total revenue requirement in the fourth column that would be helpful.

A I believe if you take capital revenue requirement differential plus differential nonfuel O&M less the fuel differential you come up with the net. I can try to do the calculation for you.

Q I don't believe that will be necessary. Let me confer with Staff one moment. (Pause)

Mr. Hernandez, looking still at Page 4 of 4 on Late-filed No. 6, could you explain why you subtract fuel? That would be column No. 3.

A Sure. Let's just talk about the first

option, Big Bend 1 and 2 FGD. As we've discussed throughout this proceeding, the significant fuel savings associated with the scrubber option versus the fuel blending option, and all of these differentials are relative to the base case, it's a fuel blending option.

There's an incremental increase in capital revenue requirements. There's an increase for most years in nonfuel O&M, but you get a fuel savings. So to come up with the differential revenue requirements you would take the incremental capital revenue requirements plus the incremental nonfuel O&M and subtract out the fuel savings.

Another way to have done this would have been to show all the fuel differentials as a negative and then when you just add the numbers across and you net out.

Q Okay. Mr. Hernandez, consumables like limestone would be include in the nonfuel O&M cost columns or would they be in the fuel columns of your Late-filed Deposition Exhibit 6?

A Nonfuel O&M.

Q Going back now to your Late-filed Deposition Exhibit No. 1, Column 11 includes consumables like limestone, does it not?

A Yes. Yes.

Q Are the total TECO system-wide costs to comply with particulate requirements listed in Column 10?

A In Exhibit No. 1.

Q Yes.

A No. These are related to just Big Bend 1 and 2.

Q Now, look at Page 5 of 6 of Late-filed Deposition Exhibit No. 1, at Column 30, this appears to be an estimate of the break-even price of natural gas for a combined cycle unit to provide the same level of S02 compliance on TECO's system as the proposed FGD. Is that the case?

A Yes.

Q If natural gas could be delivered at the break-even price, TECO's revenue requirements with a new combined cycle option would be the same as the scrubber option, would they not?

A Based on this hypothetical, yes.

Q Now, if you would turn to Page 6 of 6 of the same document, which would be Exhibit 1, there's a fuel price comparison graph. How close to the projected natural gas price does the break-even natural gas price have to be for you, being TECO, to consider both the FGD and a new combined cycle option as being competitive? Would it be 5%, 15%, 20% or what?

A Well, again, looking at the graph on Page 6 of 6, they'd have to give us the gas free and pay us to take it in the first year, year 2000. For all of the years the break-even natural gas price is well below not only the natural gas price forecast but well below the coal price forecast. Relative to the coal price forecast in early years it's roughly 10% of what the coal price forecast would be. So natural gas as break-even would be practically -- you know, you can't get it. It's just not feasible.

Q All right. Assuming that the goods must be given away, as you say, in the first year, et cetera, if you could get the gas at the projected natural gas break-even price, how close does that have to be for you to consider natural gas in a combined cycle unit -- how close does that have to be for you to consider that option over FGD, or even consider it as being competitive with the FGD?

A How close does the natural gas price need to be to the break-even price?

Q Yes, and other fuel prices. Of course, if you go with the FGD you will not be using natural gas.

I realize that. Does it have to be within 10%, within 5%?

A In the initial years it's -- the initial year you can't get there. It's 100% plus reduction. They give it away and they give you some money. In all of the other years, beginning in the year 2001, we're looking at roughly -- I'm going to guess, but just looking at the graph it looks at about 5% or less of our natural gas price forecast. And then all the way going out to the year 2026 roughly 25% of our natural gas price forecast.

Q Asking it another way, how high does the break-even natural gas price have to be for it to be competitive?

A In order for the natural gas -- well, in order for the combined cycle displacement option burning natural gas to be competitive to the FGD option, natural gas prices would have to be very close to the break-even prices that we're talking about. Just as a reference point, for the year 2001 natural gas delivered would have to be 35 cents per million Btu, growing through time, up until the point, year 2026 it would get to be $2.64 per mmBtu. That's well below any coal price forecast.

Q Mr. Hernandez, if you would please turn to your Late-filed Deposition Exhibit No. 8. Is the question that these three tables addresses, is this question the annual compliance production cost scenarios for each option that has been reviewed?

A I'm sorry, you're looking at Page 2 of the response.

Q No. This is the Late-filed Deposition Exhibit No. 8. There should be three columns.

A I'm not sure we're looking at the same thing. My Late-filed Deposition Exhibit No. 8 is refiled production of documents No. 26. And it simply just provides the headings that were cut off for clarity, so it's just a refiling of those same documents with the additional headings added to the top of the columns. Are we looking at the same thing?

Q Yes, we are. We're looking at Pages 2, 3 of 4 and these are three tables. And what I'm asking is do these address the annual compliance production cost scenarios for each option that has been reviewed?

A No.

Q How many options are shown on these tables?

A The chart on Page 2 of 4 is the final cost-effectiveness study analysis. And this is for native load. And I can't tell if this is the fuel blending scenario or the scrub scenario. The document or table on Page 3 of 4 is a, again, final cost-effectiveness FGD case. So the other one must have been the base case. I'm sorry, I see that now. Again, on the native load basis and, again, the final cost-effectiveness study.

The chart on Page 4 of 4 is the screening analysis that was completed earlier in the process. So this was done in 1996, late 1996, and the earlier two charts were done in 1998. These screening analysis just addresses the fuel blending scenario on total load basis.

Q Given that, Mr. Hernandez, could you agree with me then basically TECO's final decision was not between five options, which would have been four FGD options and a fuel switching option?

A There were five options that were considered in the screening assessment done in late 1996, early 1997. And once the cost-effectiveness studies and the engineering feasibility studies determined that we effectively had two options, two viable options that were the most cost-effective. So both technically viable as well as cost-effective, we ended up in a fuel blending scenario as Mr. Black and I have discussed during the proceeding, as well as the FGD option, which is the recommended option.

So if you refer to the Phase II compliance study there's two phases. There's a screening phase where we have the five options and then there was the final phase where there were the two options. And that's what was relied on to make the determination that the FGD option is the most cost-effective and viable alternative.

Q If you would now turn to the document that has been marked as Exhibit 15. This would be the Revised August 1998 Ten Year Site Plan.

A Yes.

Q If you would turn to page Roman Numeral II-11, Schedule 3.3. Table Roman Numeral II-4 titled, "History and Forecast of Annual Net Energy for Load" gigawatt-hours, Column 8, titled "Net Energy for Load."

A Yes, I found it.

Q Does this net energy for load forecast include sufficient energy to operate the proposed FGD system?

A Does it include sufficient energy?

Q Uh-huh.

A Well, let me describe it. I think the answer is yes, but let me describe what the table is and how it relates back to the final cost-effectiveness study.

There's two pieces to look at on this page and it's Column 5 -- I'm sorry, Column 8 which is the net energy for load number, and that effectively includes both Column 5 and 6, the retail and wholesale firm energy sales. It excludes the as-available broker sales.

If we were to compare, if you will, Column 8 to the Ten Year Site Plan that was filed and attached as Document No. 4 in my exhibit, I think you'll see in all years except for perhaps the first year, 1998, that the combined net energy for load is, in fact, higher than the net energy for load that was the basis for the final cost effectiveness study.

So if I understand your question is there enough? Yes, there's sufficient energy projected in terms of system requirements, and, therefore, the FGD option is, in fact, just a little bit more cost affective.

Q Does the new load forecast make TECO's FGD compliance option more, less or equally cost affective?

A More.

Q Now, if you would refer to the April 1998 Ten Year Site Plan. These are the revisions that TECO filed to this April 1st, 1998 filing. This document contains revisions to six different schedules; history and forecast of summer peak demand; base high and low cases, and history and forecast of winter peak demand base high and low cases. Were these revisions filed at the request of Commission Staff?

A Yes, they were.

Q Why did the Commission Staff request these revisions?

A Why did Staff request them?

Q Yes.

A In reviewing the Ten Year Site Plan that was filed in April 1998 there was a determination upon the development of the amended 1998 plan that these schedules related to the summer and winter peak demand for both base case and high and low sensitivity were, in fact, in error. The D&E forecast was not in error. These schedules were prepared in error. What had happened was that there was a double counting of the nonfirm load, and effectively reduced the -- what was shown as the firm peak. And, in fact, if you were to compare the firm peaks in the schedules as filed, April 1998, they did not match up with a similar schedule later on in the Ten Year Site Plan filing related to the calculation of reserve margins.

The firm peaks in those calculations for reserve margins were correct, and the D&E forecast was correct. It was simply the preparation of these schedules had the error of double counting some nonfirm load.

Q Mr. Hernandez, which columns are double counted?

A I believe -- subject to check, I can go through and check this, either on the break -- but I believe it's the conservation numbers for both residential and commercial and industrial. And that error flows through as a calculation to back up to Column No. 2. You'll see that it affects not only the net firm, but also affects Column No. 2, the total. So I believe it's the conservation numbers, but I'd have to check that.

Q That's good. Thank you.

In Chapter 3 of TECO's Ten Year Site Plan filing that you filed with your prefiled direct testimony, at pages 184 through 213, you have a list of parameters in a load forecast model. And I was wondering if you could tell which of those are sensitive to changes in environmental regulations for SO2 and NOX?

A Bates stamp Page 184.

Q I don't know the Bates stamp page number. Yes, it is 184. (Pause)

A Okay. I found the page. What was the question again?

Q There's a list there of parameters and load forecast model. And what I'd like is for you to discuss which of those are sensitive to changes in environmental regulations for SO2 and NOX.

A To some extent all of them are. And it's related to the price elasticity issue. If you will, just a little diversion, to the extent that there's additional compliance costs and those costs are either passed on through the different cost recovery mechanisms as we've discussed, there will be a response to the price signal associated with that. So if prices go down, usage tends to go up, so that would affect the forecast when you get to the development of the forecast looking at the consumption by customer class. So there is an indirect relationship associated with potential changes in environmental compliance and the associated costs and how those costs are recovered.

Q Can the high/low load forecasts adequately address the expectation of changes in environmental regulations for SO2 and NOX?

A I will say that the -- it could be representative, but the bands were not developed with considerations specifically associated with compliance, additional compliance cost for NOX.

Q Will adoption of the FGD system increase or decrease TECO's participation in the trading of emission allowances?

A The expectation is that not to preclude that we could -- if it's more cost-effective to buy allowance versus to blend lower sulfur coal, that the expectation is, all other things considered equal, that we would, in fact, buy less allowances because of the benefits associated with the FGD system, and the fact that we would not have to blend as low in terms of lower amounts of low sulfur coal, which means the price on the fuel will not go up as much. So to the extent that's the most cost-effective thing to do we would do that in lieu of buying SO2.

Q If you could turn now to what has been marked as Exhibit 17, TECO's response to Staff Request for Production No. 23.

Does this exhibit show the assumptions or wholesale interchange TECO used in May 1998 C3A Phase II compliance report?

A Yes. It shows the firm wholesale

interchange that was used in the final cost-effectiveness notice.

Q Would you clarify why there are differences between sales listed under the Phase II screening analysis assumptions and sales listed under the Phase II cost-effectiveness study assumptions?

A Yes. It was simply a timing issue. The screening analysis contained in the Phase II document was completed in the fall of 1996 and so it was using planning assumptions associated with the business planning cycle that occurs in the fall of 1996.

The final cost-effectiveness study relied on the business planning assumptions developed in the fall of 1997. So when you go from year to year you could have some changes in all of the assumptions, but particularly in this chart, we're talking about changes in the firm wholesale interchange assumptions.

MS. JAYE: I have no further questions.

COMMISSIONER DEASON: I have one question. How do you account for the revenues from the sale of your -- the royalties from the FGD patent?

WITNESS HERNANDEZ: The revenues are in the order of 50,000 to -- let me check. 50,000 in 1998, year to date, and about 100,000 in 1997. They were charged to account 456-01 Other Revenues, and were treated above the line.

COMMISSIONER DEASON: Thank you.

CHAIRMAN JOHNSON: Redirect?

MR. BEASLEY: Could we have approximately three or four minutes.

CHAIRMAN JOHNSON: A break? I though you meant three or four minutes of redirect.

We'll go off the record. We'll go off the record for a couple of minutes.

(Discussion off the record.)

MR. BEASLEY: Very short.

CHAIRMAN JOHNSON: Let's wait one second. We're going to go back on the record.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Hernandez, I've handed you copy of Mr. Black's exhibit CRB-1? Do you have that in front of you?

A Yes, I do.

Q Would you look at Bates stamp Page 5 of that document, and the AFUDC number of $7,245,954 contained in that exhibit?

A Yes.

Q Is that a reasonable estimate for AFUDC for purposes of your cost-effectiveness calculations?

MR. HOWE: Objection. I've already asked Mr. Hernandez on direct if he was familiar with what AFUDC rate was used. He said that he was not. I asked if he used the AFUDC rate reflected in Rule 25-6.0141. He said he did not know. He's not in a position to express an opinion on the reasonableness of the dollar amount of AFUDC calculated by a mechanism he's unfamiliar with.

MR. BEASLEY: This is a different number than what was asked for earlier. And I think Mr. Hernandez can clarify that for Mr. Howe.

MR. HOWE: I'm sorry, the objection still stands.

CHAIRMAN JOHNSON: What was your question? You said this is a different --

MR. BEASLEY: Can he verify the reasonableness of this amount shown in Bates stamp Page 5 or purposes -- or as was used in his cost-effectiveness calculation.

CHAIRMAN JOHNSON: Mr. Howe.

MR. HOWE: My objection still stands. I asked Mr. Hernandez on cross examination if he was aware of how the AFUDC rate was calculated, and whether it was calculated consistent with the rule. He did not know. But it was the AFUDC rate period.

to be assuming that rate is reasonable, that calculation is reasonable and he said he didn't know about the rate.

MR. HOWE: He said he didn't know about the rate so he's in no position to state that the calculation based on the rate is reasonable for record purposes. This is evidence. He's expressing an opinion and he's not qualified to give it.

CHAIRMAN JOHNSON: Objection overruled and the answer will stand.

MR. BEASLEY: Thank you.

CHAIRMAN JOHNSON: Anything else?

MR. BEASLEY: That's all we have other, Commissioners, other than to move the admission of the balance of Mr. Black's Exhibit No. 2 and Mr. Hernandez's Exhibit 12.

MR. HOWE: I object to admission of Document No. 4 of Mr. Black's exhibits. It has not been established that the AFUDC --

MR. BEASLEY: Which one are you referring to?

MR. HOWE: He said the remainder of Mr. Black's exhibits, I assume you mean Document 4, which is the Bates stamp No. 5 page. He's still not -- I object. It has not been established as reasonable by anybody qualified to give such an opinion. The AFUDC amount and the total project amount should be stricken from the exhibit.

CHAIRMAN JOHNSON: And, Mr. Howe, give me your rationale, the reason. I understand that --

MR. HOWE: The issue is whether or not the -- I asked Mr. Black, for example, if he knew where the AFUDC rate came from. He did not. I asked Mr. Hernandez. He doesn't know. He doesn't know if it's consistent with the Commission's rule. As such, you have no evidence, no witness testifying, really, that this dollar amount, this $7,245,954 amount is reasonable. Since that's -- hasn't been established it's reasonable, the total has not been established either.

MR. BEASLEY: Madam Chairman, the witness has testified and it's been permitted for him to testify as to his opinion regarding the reasonableness of this number. And all the total is is simply this number, which he has provided a foundation for, added to the other numbers that produces the total. That's just an arithmetic function. So we submit there's a proper predicate for his opinion.

CHAIRMAN JOHNSON: I'm going to allow the document to come in. The information and the cross that you provided will definitely go to weight them. I'm going to allow the admissibility. And do you have other --

MR. BEASLEY: Exhibit 12.

CHAIRMAN JOHNSON: Show that admitted.

MR. HOWE: We would move the admission of Exhibit 13.

CHAIRMAN JOHNSON: 12 without objection. Show Exhibit 13 admitted without objection. And Staff?

MS. JAYE: Staff moves Exhibits 14 through 17.

CHAIRMAN JOHNSON: Show those admitted without objection.

(Exhibits 2 and 12 through 17 received in evidence.)

CHAIRMAN JOHNSON: Thank you, sir. You're excused.

WITNESS HERNANDEZ: Thank you.

MS. JAYE: Staff would also like to remind the parties of the dates left on the -- in this proceeding, if this is the proper time.

CHAIRMAN JOHNSON: Uh-huh.

MS. JAYE: Okay. The transcripts are due --

CHAIRMAN JOHNSON: We forgot, we have the testimony. The stipulated testimony. You need to go ahead and take care of that. Mr. McWhirter.

MR. McWHIRTER: I'd like to offer the prefiled direct testimony of Mr. Selecky as amended in the Prehearing Order.

CHAIRMAN JOHNSON: Show that inserted into the record as though read.

Docket No. 980693-EI

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY AND EXHIBIT

OF

JAMES T. SELECKY

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A James T. Selecky; 1215 Fern Ridge Parkway, Suite 208; St. Louis, MO 63141-2000.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A These are set forth in Appendix A to this testimony.

Q **ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?**

A I am appearing on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members are customers of Tampa Electric Company

(TECo or Company). They purchase substantial quantities of electric power and energy under various firm and interruptible tariffs.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I will address TECo's Petition which seeks the Florida Public Service Commission's (Commission) approval of cost recovery for the proposed Flue Gas Desulfurization (FGD) for Big Bend Units 1 and 2. In addition, I will address some of the issues raised by the Staff in its Second Amended List of Preliminary Issues in this Docket.

Q WHAT CONCLUSIONS HAVE YOU REACHED?

A The Company's request for cost recovery through the Environmental Cost Recovery Clause (ECRC) is premature and should be denied. However, if the Commission authorizes recovery of the FGD costs through the ECRC in this case, the recovery period should be set at a minimum of 20 years, the rate of return on common equity should be set at the low end of the Commission-approved range and a cap should be established for the amount of equity included in the capital structure that is used to develop the ECRC surcharges.

Response to TECo's Petition

Q WHAT IS TECO SEEKING IN ITS PETITION?

A The Company requests Commission approval for cost recovery of the Big Bend Units 1 and 2 FGD system through the ECRC, ~~over a ten-year recovery period.~~

Q SHOULD THE COMMISSION APPROVE RECOVERY OF THE COST OF THE FGD THROUGH THE ECRC?

A No. The Company's request for cost recovery through the ECRC is premature and should be denied.

Q WHY IS TECO'S PETITION FOR COST RECOVERY PREMATURE?

A First, the costs for which TECo is seeking recovery are related to Clean Air Act Amendment (CAAA) compliance. I am advised by counsel that before the Commission can consider cost recovery for CAAA compliance activities, it should first review a plan submitted by the utility pursuant to Section 366.825, Florida Statutes (1997), to determine whether a utility's compliance plan, the costs necessarily incurred to implement such a plan and any effect on rates resulting from such implementation are in the public interest. TECo has not provided the information needed to make such a determination in this case. Only when the Commission has approved such a plan can the utility seek recovery of the costs through the ECRC (Section

366.8255(2), Florida Statutes). However, TECo has not yet received approval for the proposed FGD system under Section 366.825. Consequently, its Petition for cost recovery is premature.

Q ARE THERE OTHER REASONS THAT THE COMPANY'S PETITION FOR COST RECOVERY IS PREMATURE?

A Yes. First, the proposed FGD system is not projected to commence operation until sometime in the year 2000. It is only possible to speculate what conditions might be like in the year 2000 that may warrant a different cost recovery treatment or no cost recovery at all.

For example, it is likely that, given its past history, TECo could continue to earn well in excess of a reasonable return on equity (ROE). This would be significant because a utility that earns a reasonable ROE is already fully recovering its cost of service. Consequently, a further adjustment to rates, such as imposing a surcharge or increasing a non-fuel related adjustment factor (i.e., ECRC), is unnecessary to give the utility a reasonable *opportunity* to earn a reasonable ROE on its prudent investment. Thus, cost recovery through the ECRC may not be needed to provide TECo the *opportunity* to recover the costs of the proposed FGD system.

To permit TECo to pass the costs of incremental investments through the ECRC, while it is earning a reasonable ROE or exceeding its authorized ROE including the incremental investment, is an invitation to create further over-earnings. This result would be detrimental to the utility's customers and is not reasonable or in the public interest.

Q **WHAT WOULD BE THE CONSEQUENCES OF DECIDING THE COST RECOVERY ISSUE AT THIS TIME?**

A By making assumptions now about events that will not be known and measurable until the year 2000, when the proposed FGD system is projected by TECo to commence operation, customers could be forced to pay rates that are higher than the actual cost of providing service. The Commission can prevent this outcome by waiting until commercial operation before deciding cost recovery issues. Deferring a decision until then would protect customers' interests. Further, there would be no harm to TECo since these costs cannot actually be recovered prior to commercial operation.

Q **HOWEVER, IF THE COMMISSION DECIDES THE COST RECOVERY ISSUES IN THIS DOCKET, UNDER WHAT CIRCUMSTANCES SHOULD**

TECo BE PERMITTED TO RECOVER THE COSTS OF THE FGD THROUGH THE ECRC?

A To the extent TECo is earning within its authorized ROE range, it <u>will</u> be recovering the costs of the FGD and no additional collection from consumers should be permitted.

Q **WOULD THE EARNING CAP MECHANISMS CURRENTLY IN PLACE PREVENT CUSTOMERS FROM PAYING EXCESSIVE RATES?**

A No. I have no evidence that the rate freeze is presently being applied to cost recovery mechanisms. Even if TECo is properly accounting for recoveries in excess of 11.75% in its reports to the Commission, the rate freezes and refund mechanisms for excess earnings expire at the end of 1999. Therefore, the customers have no guarantee that they will not be paying excessive rates in 2000.

Q **SHOULD THE COMMISSION APPROVE A TEN-YEAR RECOVERY PERIOD FOR THE FGD SYSTEM?**

A No. As discussed later in my testimony in response to Staff's Second Amended List of Preliminary Issues, I do not believe that a ten-year recovery period is appropriate. A more appropriate recovery period would ~~be 20 to 30 years, which approximates the useful life of the proposed FGD.~~

Q IF THE COMMISSION GRANTS TECO'S PETITION FOR COST RECOVERY, SHOULD ALL OF THE COSTS BE RECOVERED FROM THE COMPANY'S RETAIL JURISDICTION?

A No. Although I believe it is premature to address cost recovery issues in this docket, should the Commission authorize cost recovery through the ECRC, then it is my recommendation that retail customers should not bear 100% of the costs of the proposed FGD system. TECo has been, and continues to be, an active player in wholesale power markets. For example, during 1997, 17.3% of its energy sales were made to wholesale customers (TECo Annual Report, p. 22). Since TECo will use Big Bend Units 1 and 2, in part, for wholesale sales, it would be inequitable for retail customers to pay all of the FGD costs.

Also, it is my understanding that, absent CAAA compliance, TECo could not operate Big Bend Units 1 and 2. Consequently, the availability of energy for resale in the wholesale market would be critically impacted by the continued operation of Big Bend Units 1 and

2. For this reason, wholesale sales should be allocated a proportional share of the FGD system costs.

Q **HOW SHOULD THE COSTS BE ALLOCATED TO WHOLESALES SALES?**

A While FIPUG strongly disagrees with the use of an energy allocator, if the Commission employs an energy allocator to assign cost responsibility to the retail rate classes, it should use an energy allocator to assign costs to the wholesale class. In addition, to the extent that any of the wholesale contracts relate to purchases specifically from Big Bend Units 1 and 2, cost allocations should be made consistent with those contracts.

<u>Response to Staff Issues</u>

Q **IF THE COMMISSION DECIDES COST RECOVERY ISSUES IN THIS DOCKET, WHAT ARE YOUR RECOMMENDATIONS REGARDING THE PARAMETERS OF COST RECOVERY?**

A As discussed above, it is premature for the Commission to decide cost recovery issues at this time. Further, no recovery should be allowed if, as discussed earlier, TECo is earning within its authorized common equity ratio is getting too high. It did so by capping the equity ratio at 58.7%.

Further, TECo's authorized ROE range is excessive based on current conditions. It is my opinion that if the Commission were setting an ROE for TECo today, it would be in the range of 3% to 4% over its marginal debt cost of approximately 7%. This would produce an ROE of 10% to 11%. This level of ROE is more consistent with ROEs authorized by state regulators.

This recommendation, in part reflects TECo's lower regulatory risk. Unlike most utilities around the nation, TECo is permitted to recover a portion of its non-fuel and purchased power costs through adjustment clauses. These adjustment clauses reduce regulatory lag and provide virtually guaranteed dollar-for-dollar recovery of prudent costs. Thus, TECo has lower regulatory risk than most utilities.

For all of the above reasons, should the Commission approve an ROE for the proposed FGD System in this docket, it is my recommendation that the lower end of the authorized ROE range, or 10.75% should be used. Because of TECo's high common equity ratio, which is discussed below in my testimony, it is appropriate to

Therefore, to use a common equity ratio any higher would produce unreasonable customer rates.

Q **[ISSUE 13] SHOULD THE COMMISSION APPROVE TECO'S REQUEST FOR RECOVERY OF THE PROPOSED FGD SYSTEM ON BIG BEND UNITS 1 AND 2 OVER A TEN-YEAR PERIOD?**

A No. The Commission should authorize an amortization period equal to the useful life of the facility of the investment. Based on my review of the information, I would recommend an amortization period of *at least* 20 years.

Q **WHY IS TECO PROPOSING TO RECOVER THE INVESTMENT IN THE FGD SYSTEM OVER A TEN-YEAR PERIOD?**

A TECo states in the testimony of Thomas L. Hernandez that the determination of the ten-year period was based on the goal of "mitigating potential stranded cost" (page 14). TECo's proposed ten-year period is not based on any useful life, but rather on TECo's efforts to have current customers subsidize its preparation for competition.

Q **IS A TEN-YEAR RECOVERY PERIOD JUSTIFIED IN ORDER TO MINIMIZE POTENTIALLY STRANDED COSTS?**

Q (ISSUE 14) WHAT IS THE APPROPRIATE DEPRECIATION RATE FOR THE PROPOSED FGD SYSTEM ON BIG BEND UNITS 1 AND 2?

A The appropriate depreciation rate would depend on the projected life of Big Bend Units 1 and 2 and whether or not any portion of this investment would continue to be used and useful beyond the economic life of these units.

Q IF THE COMMISSION ESTABLISHES A DEPRECIATION RATE FOR THE PROPOSED FGD SYSTEM FOR BIG BEND UNITS 1 AND 2, WHAT SHOULD BE THE RATE?

A Although setting a depreciation rate in this docket would be premature, the period the Commission selects to amortize the investment for the FGD system should also be used to depreciate the units for book depreciation purposes.

Q WHAT ACTION DO YOU RECOMMEND THE COMMISSION TAKE ON TECO'S PETITION?

A The Company's request for cost recovery through the Environmental Cost Recovery Clause (ECRC) is premature and should be denied. However, if the Commission authorizes recovery of the FGD costs through the ECRC in this case, the recovery period should be set at a minimum of 20 years, the rate of return on common equity should be set at the low end of the Commission-approved range and a cap should be established for the amount of equity included in the capital structure that is used to develop the ECRC surcharges.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes.

Appendix A

QUALIFICATIONS OF JAMES T. SELECKY

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A James T. Selecky. My business mailing address is P. O. Box 412000, St. Louis, Missouri 63141-2000.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and am a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.**

A I graduated from Oakland University in 1969 with a Bachelor of Science degree with a major in Engineering. In 1978 I received the degree of Master of Business Administration with a major in finance from Wayne State University. I have also done graduate work in the field of economics at Wayne State University.

I was employed by The Detroit Edison Company (DECo) in April of 1969 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included evaluation of equipment for use on the distribution and transmission system; equipment performance testing under field and laboratory conditions; and trouble-shooting and equipment testing at various power plants throughout the DECo system. I also worked on system design and planning for system expansion.

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June, 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of Rate Research Division, supervisor of Cost-of-Service Division and director of the Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies, developed fixed charge rates and parameters and procedures used in economic studies, providing a financial analysis consulting service to all areas of DECo, developing and designing rate structure for electrical and steam service, analyzing profitability of various classes of service and recommending changes therein, determining fuel and purchased power adjustments and all aspects of determining revenue requirements for rate-making purposes.

In June of 1984, I joined the firm of Drazen-Brubaker & Associates, Inc. In April, 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and staff.

Q **HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?**

A Yes. I have testified on behalf of DECo in its steam heating cases. In these cases I have testified to changes in book depreciation rates, rate design and revenue deficiency. I also testified in a DECo main electric rate case on rate base, income statement adjustments and interim and final revenue deficiencies.

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Kansas, Maryland, Massachusetts, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Texas, Wisconsin and Wyoming, and the Provinces of Saskatchewan and Alberta. I also have testified before the Federal Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Iowa and New York. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M

expense levels, and rate base adjustments for items such as plant held for future use, working capital, and post test year adjustments.

Q ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A Yes, I am a registered professional engineer in the State of Michigan, based upon state examinations.

MR. BEASLEY: We would also offer Mr. Hernandez rebuttal testimony as amended, that it being inserted into the record.

CHAIRMAN JOHNSON: Show that inserted into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 980693-EI
SUBMITTED FOR FILING 08/17/98

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

THOMAS L. HERNANDEZ

Q. Please state your name, business address and position with Tampa Electric Company.

A. My name is Thomas L. Hernandez. My business address is 702 North Franklin Street, Tampa, Florida, 33602. I am the Vice President-Regulatory Affairs for TECO Energy, Tampa Electric Company's parent.

Q. What is the purpose of your rebuttal testimony?

A. Through a series of issue identification conferences, the parties have agreed that all issues relating to new costs associated with Tampa Electric's proposed FGD system will be recovered through the Environmental Cost Recovery Clause (ECRC) would be more appropriately considered when Tampa Electric requests authorization of an ECRC factor for recovery of the FGD system. However, Florida Industrial Power Users Group (FIPUG) witness Selecky has raised several issues which appear to be related to cost recovery through the ECRC. The purpose of my rebuttal testimony is to address the deficiencies in Mr. Selecky's direct testimony.

Q. On page 3 and page 4 of his testimony, Mr. Selecky claims that Tampa Electric's Petition for Cost Recovery is premature. How do you respond?

A. I disagree with his assessment. First of all, we are not seeking recovery of any of the actual costs associated with our proposed FGD system in this proceeding. Instead, Tampa Electric is seeking a determination by the Commission that the proposed project is reasonable, prudent and the most cost-effective means of complying with the SO_2 emissions limitations of Phase II of the Clean Air Act Amendments (CAAA). In addition, Tampa Electric is seeking confirmation that the project-related costs determined by the Commission to be reasonably and prudently incurred will be recovered through the ECRC.

Tampa Electric has evaluated numerous alternatives in an attempt to select the most appropriate and cost effective alternative available to the Company. All of our analyses clearly indicate that the proposed FGD system is the most cost-effective and otherwise appropriate means of achieving this end. Mr. Selecky has presented no evidence to the contrary.

Given the appropriateness of the FGD project, it is therefore not premature to determine that the ECRC is the appropriate mechanism for cost recovery of the FGD system. This Commission has encouraged utilities to seek an early determination for capital expended for environmental compliance so that guidance can be provided by the Commission with respect to such projects. Consequently, the Commission should find that the proposed FGD project is the most cost-effective alternative and is eligible for ECRC recovery at the earliest possible time so that all parties can plan accordingly.

Q. At page 3 of his testimony, Mr. Selecky reports a legal opinion given to him by counsel for FIPUG to the effect that Tampa Electric was required, as a matter of law, to file under Section 366.825, Florida Statutes (1997), for a prudence review before seeking cost recovery. Mr. Selecky further asserts that since Tampa Electric has not done so and, in his view, has failed to provide the information required under the above-mentioned Section, Tampa Electric's Petition in this proceeding is premature. Do you agree?

A. Mr. Selecky is simply wrong in this assertion. I am not testifying as a legal expert nor, to my knowledge, is Mr. Selecky. However, the flaws in Mr. Selecky's assertion were addressed directly in Tampa Electric's response to the motions to dismiss filed by [illegible] and [illegible] in this proceeding.

Q. On page 4 of his testimony, Mr. [illegible] states that the Company's proposal is premature because we do not know what the Company's financial picture will be in the year [illegible]. How do you respond?

A. This line of argument is not germane to this proceeding and represents an effort to re-litigate an issue which has already been squarely and unambiguously decided by this Commission. In Docket No. 930613-EI, the Commission rejected the Office of Public Counsel's attempt to relate ECRC recovery to a utility's earnings picture. The Commission stated in Order No. [illegible]-94-0044-FOF EI:

> Thus, we find that the [illegible] the recovery of investment carrying costs and O&M expenses through the environmental cost recovery clause. For this reason, [illegible] must be rejected.
>
> Accordingly, we find that if the utility is currently earning a fair rate of return, that it should be able to recover, upon petition, prudently incurred environmental compliance costs through the ECRC if such costs were incurred after the

> effective date of the environmental compliance cost legislation and if such costs are not being recovered through any other cost recovery mechanism.

In addition, this order is consistent with numerous decisions by this Commission allowing cost recovery under the fuel, capacity, conservation and environmental clauses for the Florida investor-owned utilities that was not dependent on earnings.

Since the Commission has already determined that earning within an allowed return on equity range should not impact the recovery of costs through the ECRC, it is not necessary to address or speculate about the Company's financial status in the year 2000 in order to consider the reasonableness and prudence of the Company's proposal.

Q. On page 5 of his testimony, Mr. Selecky further states that the FPSC should not decide whether to allow recovery through the ECRC at this time because we will be making assumptions about events that will not be known until 2000. Therefore, he concludes, customers could be forced to pay rates that are higher than the actual costs of providing service. Could you please address Mr. Selecky's concern?

A. Yes. I disagree with his concern. The Company will only flow costs through the ECRC that have been approved by the Commission. These costs will be identifiable and prudent as measured by the Commission, and will only be recovered after the Commission has reviewed such costs. Therefore, customers will never be "forced to pay rates that are higher than the actual cost of providing service."

Q. Witness Selecky states that a different cost recovery treatment or no cost recovery at all may be warranted because the Company may earn in excess of its allowed return on equity range. Could you please address this statement?

A. Yes. This Commission has an effective, continuing surveillance program that assures that the Company is earning within a return on equity range considered reasonable by the Commission. Therefore, there should not be a concern that the Company is overearning on its retail rate base at the same time that it is recovering costs through the ECRC.

In addition, cost recovery through the ECRC is unrelated to what the Company is earning on its rate base. The ECRC was established by the legislature and has been implemented by this Commission to provide for recovery of any environmental compliance costs not recovered in base rates and which are occurred after April [illegible]. There has never been an earnings test with respect to any of the [illegible] cost recovery clauses. Neither the [illegible] [illegible] environmental cost recovery [illegible].

Q. Do you disagree with Mr. [illegible] that the earnings cap mechanism [illegible] from paying excessive rates? [illegible] beginning of page [illegible], line [illegible].

A. I would say that his [illegible] [illegible] not [illegible]. Even if it were, the rate [illegible] environmental [illegible] appropriate cost recovery [illegible] with the [illegible] expires. [illegible]

Q. [illegible]

sales be allocated a share of the FGD System costs. How do you respond to his proposed cost allocation?

A. The question of what costs will be allocated to the wholesale jurisdiction should be raised, if at all, in an ECRC cost recovery proceeding when Tampa Electric proposes to commence cost recovery. We do not believe at this phase of the proceeding that issues regarding cost allocation are relevant to determining the reasonableness and prudence of the Company's selection of its proposed FGD system as the most cost-effective means of complying with Phase II of the CAAA and the appropriateness of the ECRC as the recovery mechanism of prudently incurred project-related costs.

In any event, it is clear that Mr. Selecky's concerns are based on a misunderstanding of Tampa Electric's current cost allocation practices. In the normal course of events, Tampa Electric would allocate costs such as those related to the FGD system to its retail and firm wholesale load, on an equal-cents-per-Kwh basis. Therefore, Mr. Selecky's concerns with regard to firm wholesale sales are unfounded. To the extent that Mr. Selecky is suggesting that fixed costs, such as the FGD- related costs, should be allocated to economy energy sales, he is advocating a course of action which would be illogical and unfair to retail and wholesale economy energy customers alike. First of all, the allocation of fixed costs to economy transactions is inconsistent with the economic objective of engaging in such transactions and would lead to a reduction in the number and volume of such transactions. As a result, the retail ratepayers would suffer the loss of the 80 percent revenue credit of the margin earned by Tampa Electric from these sales. In addition, the allocation of such fixed costs to economy energy transactions would result in double recovery of SO_2 compliance costs. To the extent that economy energy transactions cause Tampa Electric to incur incremental SO_2 compliance costs, those costs are automatically included in the quotes made under the current Florida Broker mechanism.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN JOHNSON: Mr. McWhirter, there were exhibits that we haven't marked yet.

MR. McWHIRTER: I think his resume would deal with his qualifications as an expert.

CHAIRMAN JOHNSON: There's a capital structure at 12-31-87. There are a couple of exhibits. I'll go ahead and mark them.

MR. McWHIRTER: Yes, if you would. I'd like to offer them without objection.

CHAIRMAN JOHNSON: Did they strike that?

COMMISSIONER CLARK: They should be in the Prehearing Order.

MR. McWHIRTER: Do we have capital structure, is that an exhibit?

CHAIRMAN JOHNSON: It looks like -- yeah, it looks like that was stricken or withdrawn. So the only other thing might have been the Appendix A, which is the qualifications.

MR. McWHIRTER: I'll offer that as part of his testimony.

CHAIRMAN JOHNSON: His qualifications, we'll just insert that into the record, too, as though read.

MR. BEASLEY: Madam Chairman, just a point of clarification. The rebuttal testimony of Mr. Hernandez was not amended. It was his direct testimony that was amended.

CHAIRMAN JOHNSON: Thank you for that clarification.

Now, any other preliminary matters or final matters before we go into the procedural matters? I think we're prepared to go to the procedural matters.

MS. JAYE: Thank you, Madam Chairman.

Transcripts will be due from this hearing on the 11th of this month. Staff notes an error in the CSAR which will be corrected when we refile to reflect the reply briefs, and that is a standard order is mentioned right under "transcripts due date." Standard order is not due on September 21st. That will be stricken off of the CSAR.

Briefs are due on October 2nd. Reply briefs will be due October 9th. A Staff recommendation on November 5th. Regular agenda, November 17th. A standard order on December 7th. And the docket will be closed or the CSAR revised on the 6th of January.

CHAIRMAN JOHNSON: Any questions? Is there something else?

MS. JAYE: There's nothing else.

CHAIRMAN JOHNSON: This hearing is adjourned.

(Thereupon, hearing adjourned at 5:25 p.m.)

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

We, JOY KELLY, CSR, RPR, Chief, Bureau of Reporting and H. RUTHE POTAMI, CSR, RPR, Official Commission Reporters,

DO HEREBY CERTIFY that the Hearing in Docket No. 980693-EI was heard by the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed by us; and that this transcript, consisting of 329 pages, Volumes 1 and 2, constitutes a true transcription of our notes of said proceedings and the insertion of the prescribed prefiled testimony of the witnesses.

DATED this 10th day of September, 1998.

JOY KELLY, CSR, RPR
Chief, Bureau of Reporting
(850) 413-6732

H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter