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July 1, 1996

HAND DELIVERY

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Prudency Review to Determine Regulatory Treatment of Tampa Electric Company's Polk Unit; FPSC Docket No. 960409-EI

Dear Ms. Bayo:

Enclosed for filing in the above docket on behalf of Tampa Electric Company are fifteen (15) copies of each of the following:

1. Rebuttal Testimony of John R. Rowe, Jr. 07017-96
2. Rebuttal Testimony and Exhibits of Hugh W. Smith. 07018-96
3. Rebuttal Testimony and Exhibits of Stephen L. Thumb. 07019-96
4. Rebuttal Testimony and Exhibits of Thomas L. Hernandez. 07021-96
5. Rebuttal Testimony and Exhibits of Charles R. Black. 07020-96

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: All Parties of Record (w/encls.)

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TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 960409-EI

REBUTTAL TESTIMONY
AND EXHIBITS OF

THOMAS L. HERNANDEZ

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 7/1/96

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

THOMAS L. HERNANDEZ

Q. Please state your name, address and occupation.

A. My name is Thomas L. Hernandez. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director of Resource Planning for Tampa Electric Company.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony in this docket on May 7, 1996.

Q. Do you have an exhibit in support of your rebuttal testimony?

A. Yes. Exhibit ___(TLH-2), titled "Rebuttal Exhibit of Thomas L. Hernandez," consisting of ten documents, has been prepared under my direction and supervision. The documents contain excerpts from several Commission proceedings and reports in which the Commission provided comments on Tampa Electric's planning assumptions and Ten-Year Site Plans in general; a summary of additional cost-effectiveness analyses; and additional interrogatory responses prepared under my direction and supervision.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain portions of the testimony filed by Mr. Thomas Ballinger and Mr. Jim Breman on behalf of the Florida Public Service Commission Staff ("Staff"); by Mr. Hugh Larkin on behalf of the Office of Public Counsel ("OPC"); and by Mr. Randall Falkenberg on behalf of the Florida Industrial Power Users Group ("FIPUG").

My rebuttal testimony supports the conclusion that the Integrated Gasification Combined Cycle ("IGCC") unit as approved by this Commission and as constructed by Tampa Electric was the most cost-effective alternative for Tampa Electric and it's customers. Tampa Electric continued to evaluate the cost-effectiveness of Polk Unit One subsequent to the Need Hearing, Docket No. 910883-EI, and all of the evaluations supported the continued construction of the IGCC unit. The planning assumptions used in the cost-effectiveness evaluations, including the fuel price and availability forecast, were found to be reasonable and suitable by both the Commission and its Staff in numerous proceedings since the Need Hearing. I will discuss the reasons why the cost-effectiveness analyses proposed by the other parties are flawed and, in addition, why a comparison of Tampa Electric's Polk Unit One to other existing and planned generating units is flawed and misleading.

Polk Unit One is Most Cost-Effective Alternative for Tampa Electric's customers

Q. It is the position of the FPSC Staff that Tampa Electric should have stopped construction of the Polk IGCC unit in the 1993-1994 time frame and should have, instead, constructed a natural gas-fired, combined cycle unit. Do you agree with this position?

A. No. Tampa Electric received approval from this Commission to construct the IGCC unit after careful consideration on the part of the Commission and its Staff of all other viable alternatives, including a natural gas-fired combined cycle unit. Tampa Electric has continued to monitor the overall cost-effectiveness of the project as compared to other viable alternatives. Each analysis concludes that the IGCC unit is the most cost-effective alternative for Tampa Electric's system.

Q. What, then, is your understanding of the basis for the Staff's position?

A. Staff witness Ballinger makes a general statement, on page 2 of his testimony, that "TECO relied upon unrealistic, inconsistent, and inflexible planning assumptions to justify the continued construction of the Polk IGCC unit." Both Staff witnesses Mr. Ballinger and Mr. Breman state specific concerns with Tampa Electric's use of certain assumptions related to the use of a petroleum coke/coal blend in the gasifier, natural gas forecasts and their relationship to coal forecasts, and Section 29 tax credit availability.

Q. Do you share the Staff's concerns?

A. No. The planning assumptions used in each cost-effectiveness analysis were the most appropriate assumptions given the information available at the time of the study.

Q. Please elaborate.

A. For instance, Staff witness Breman states that "the cost effectiveness of the Polk IGCC should not be based on the use of petroleum coke." Mr. Breman's conclusion fails to recognize important facts regarding the gasification process and the physical and chemical similarities of petroleum coke and coal. As Mr. Black testifies, petroleum coke is a technically viable feedstock for the Polk IGCC; and as Mr. Smith testifies, the cost, availability, and transportation of petroleum coke shows it to be best for our ratepayers. Tampa Electric selected its next generation alternative and its fuel feedstock alternatives based on meeting the needs of its customers in a reliable and cost-effective manner. The use of petroleum coke/coal blends in the gasifier represents a very attractive means of meeting the critical need for reliability and cost-effectiveness.

Q. On page 8 of his testimony, Mr. Breman challenges Mr. Smith's assertion that the use of firm gas in a combined cycle alternative is not a cost-effective option for Tampa Electric's system. Do you agree with Mr. Breman's position?

A. No. Document No. 1, page 4, of my rebuttal exhibit contains a summary of cost-effectiveness sensitivity analyses which compare the cost-effectiveness of as-available gas and firm gas for a combined cycle unit on our system. In all cases, the use of as-available transportation is more cost-effective than the use of firm transportation on the Tampa Electric system. This analysis supports Mr. Smith's assertion in this issue.

Q. Both Mr. Breman and Mr. Ballinger endorse the use of a worst-case scenario analysis utilizing the Staff's "acid test". Is it appropriate to evaluate the cost-effectiveness of a project and make decisions related to the continued construction of a project based on such a scenario?

A. No. The "acid test" is not a true fuel forecast and it is unclear what the "acid test" means since it has been modified several times in this proceeding.

On pages 6 and 7 of his testimony, Mr. Breman makes reference to excerpts from the "Review of 1994 and 1995 Ten - Year Site Plans" regarding a worst-case scenario also known as the "acid test" in which current fuel price differentials between coal and natural gas are held constant throughout the projection period. The Commission had previously recognized the lack of technical merits of the "acid test" and the inappropriateness of its use for cost-effectiveness evaluations in both Tampa Electric's

Need Hearing and later in the FPL-Cypress Energy Need Hearing. Document No. 2 of my rebuttal exhibit contains an excerpt from Commission Order No. PSC-92-1493-FOF-EQ, issued December 28, 1992 in Docket No. 920520-EQ regarding the joint petition to determine need by Florida Power and Light and Cypress Energy Partners, Limited Partnership. On page 4 of the order, the Commission found that:

> "Although we utilized a somewhat similar 'acid test' in determining the need for Tampa Electric Company's Polk County Unit (Docket No. 910833-EI), we emphasize that the test is merely an analytical device and not, in and of itself, a means to determine cost-effectiveness. <u>We do not view the test as a forecast and certainly do not believe that gas prices and coal prices will maintain the constant differential reflected in the test.</u> We may or may not choose to compare projects under such a fictional constant fuel differential in future need cases and therefore <u>we do not view the "acid test" as policy or precedent</u> to be followed in future need cases." (Emphasis Added.)

This order provided clear guidance that the use of an "acid test" to determine cost-effectiveness of a generating alternative was not appropriate.

Q. Has Tampa Electric been required to provide a worst-case or "acid test" analysis to Staff since the Determination of Need proceeding?

A. Yes. We did so in our responses to Staff's supplemental data requests for the 1994, 1995, and 1996 Ten-Year Site

Plan filings submitted by Tampa Electric. I am not aware of any concern or issue taken in these proceedings by Staff regarding the result of Tampa Electric's "acid test" sensitivities.

In this immediate proceeding, Staff requested numerous variations of the "acid test" analysis in Interrogatories Nos. 14 and 27 and in the deposition of Thomas L. Hernandez (Late Filed Exhibit No. 7). While this "acid test" analysis is not accepted by Tampa Electric as a viable method to determine cost-effectiveness, the results of each analysis still indicate that the IGCC technology is the most cost-effective alternative.

Q. Staff witnesses also question Tampa Electric's use of Section 29 tax credits in the 1994 and 1995 time frame. What assumptions did you make regarding tax credits in your 1994 and 1995 Polk IGCC cost-effectiveness studies?

A. The 1994 and 1995 cost-effectiveness studies included additional savings related to tax credits under Section 29 of the Internal Revenue Code of 1986, amended for producing synthetic gas which effectively lowered the overall cost to construct and operate the IGCC unit. These credits were assumed applicable for the first eleven and twelve years of

IGCC operation respectively with an approximate present worth of $98 million in the 1994 study and $87 million in the 1995 study.

Q. Should the Commission have any concerns about Tampa Electric's use of Section 29 tax credit savings assumptions in its 1994 and 1995 cost-effectiveness studies given that the prospect of being able to utilize them was not yet firm?

A. No. In the years in which tax credits were assumed, it appeared likely that they would be available to Tampa Electric as further explained in Mr. Rowe's rebuttal testimony. However, Tampa Electric had the option of using a petroleum coke/coal blend in each of those studies.

Q. Should the Commission have any concerns regarding the validity of the results of its 1994 and 1995 cost effectiveness studies using the Section 29 tax credit assumption?

A. No. As shown in Document No. 1, pages 2-3, of my rebuttal exhibit, the 1994 and 1995 studies using a petroleum coke/coal blend resulted in comparable savings when comparing the IGCC unit and using the Section 29 tax savings assumption to a combined cycle unit alternative.

Q. Are Mr. Ballinger's comments regarding Tampa Electric's planning assumptions consistent with the results of ongoing reviews by both the Commission and Staff?

A. No. The Commission and Staff have periodically reviewed Tampa Electric's planning assumptions both before and after the Need Hearing. On each occasion, the Commission and Staff have either consistently accepted Tampa Electric's planning methods and underlying assumptions to be reasonable, or expressed approval through lack of criticism. The Staff may now have, in hindsight, chosen to rely on different assumptions, but the test of whether Tampa Electric should have relied on the assumptions it did is whether a reasonable person would have done so at the time.

Q. Please describe the Commission's opportunities to review Tampa Electric's fuel forecast assumptions prior to the Need Hearing.

A. Document No. 3 of my exhibit contains excerpts from Commission Order No. 24989 issued August 29, 1991 in Docket 910004-EU regarding the planning hearings on load forecasts, generation expansion plans, and cogeneration prices for Florida's electric utilities, commonly referred to as the "mini-APH." On page 13 of the order, the Commission found that:

> "The resulting (TECO) fuel oil and natural gas prices are close to those submitted by FPL, and higher than those submitted by FPC. Although we believe that FPC forecasts are more realistic, there is no indication that the TECO fuel forecasts are unreasonable or inadequate for purposes of this proceeding". (Emphasis Added)

Q. Did the Commission review Tampa Electric's planning assumptions after the Polk Unit One Determination of Need proceedings in 1991?

A. Yes. There have been numerous Commission proceedings since the Determination of Need proceeding in 1991.

Document No. 5 of my rebuttal exhibit contains an excerpt from the Commission Order No. PSC-93-0165-FOF-EI issued February 2, 1993 in Docket No. 920324-EI regarding Tampa Electric's application for a rate increase. On page 12 of the Order, the Commission found that:

> "We believe that TECO's forecast models are capable of and have produced reliable projections and that the input assumptions are reasonable." (Emphasis Added)

Document No. 6 of my rebuttal exhibit contains an excerpt from the Commission Order No. PSC-94-1313-FOF-EG issued October 25, 1994 in Docket No. 930551-EG regarding the adoption of numeric conservation goals and consideration of National Energy Policy Act standards by Tampa Electric Company. On page 18 of the Order, the Commission found that:

> "We find that TECO's planning process and data utilized in evaluating the DSM measures was reasonable for the purposes of this docket." (emphasis added)

Q. Did the Staff review Tampa Electric's planning assumptions since the Polk Unit One Need Hearing in 1991?

A. Yes. The Commission Staff held three separate workshops to review Ten-Year Site Plans of Tampa Electric and other Florida utilities in the fall of 1992, 1994, and 1995. In these informal workshops there was no concern expressed by Staff at any of the workshops regarding Tampa Electric's planning assumptions or methodology. In fact, the Staff prepared a written review of the 1994 and 1995 Ten-Year Site Plans referring to Tampa Electric's planning assumptions. In the 1994 Ten-Year Site Plan Review (Document No. 7 of my rebuttal exhibit), there were several references indicating that Tampa Electric's load forecast was a reliable and reasonably accurate forecast of our future energy needs (page 12 of the Review). The Staff found that Tampa Electric's oil price forecast projecting the price of oil to rise at a relatively fixed rate through the year 2010 was reasonable for planning purposes (pages 3 and 29 of the Review). The Staff also stated that projected coal prices remained relatively constant with slight escalation that was consistent with historical price trends. On natural gas price forecasts, the Staff indicated that both Tampa Electric's and Florida Power & Light's (the largest electric utility user of natural gas in the state) forecasts indicated an ever widening gap between the price of coal and natural gas (page 30 of the Review). While Staff indicated that the gas forecasts were not indicative of historical trends, they did not state that the forecasts were unsuitable or unreasonable for future planning purposes.

In the 1995 Review of Ten-Year Site Plans (Document No. 8 of my rebuttal exhibit), the Staff again stated that Tampa Electric's load forecast was reasonable for planning purposes (page 65 of the Review). The Staff stated that Tampa Electric's natural gas price forecasts are consistent with other utilities in terms of the projections that natural gas prices will approach and cross residual oil prices in the distant future and did not state that Tampa

Electric's fuel forecasts were unreasonable. In fact, the Staff found that Tampa Electric's 1995 Ten-Year Site Plan was suitable (page 67 of the Review).

Q. What is the significance of the Commission and Staff findings just discussed?

A. There has been no statement on record by the Commission or Staff that supports Mr. Ballinger's assertion that Tampa Electric "relied upon unrealistic, inconsistent, and inflexible planning assumptions to justify the continued construction of the Polk IGCC unit," despite numerous opportunities to provide comments to Tampa Electric at the time the forecasts were made. This record clearly refutes Mr. Ballinger's assertion. In addition, in his deposition on June 21, 1996, Mr. Ballinger stated that the 1994 and 1995 Review of Ten-Year Site Plans were prepared under his supervision and direction (page 20 of Mr. Ballinger's Deposition transcript). The Staff opinions contemporaneously expressed in these reviews contradict Staff witness Ballinger's own testimony.

Based on the above, Staff has no basis for now concluding that, at any time, Tampa Electric's cost-effectiveness analyses should have indicated that the company should abandon its IGCC project and construct a natural gas-fired combined cycle unit.

Q. Does Staff make any other assertions related to the project's ongoing cost-effectiveness analyses?

A. Yes. On pages 12 and 13 of his testimony, Mr. Ballinger expressed concern over the range of savings in the cost-effectiveness studies presented to senior management at Tampa Electric and the values provided to Staff in response to interrogatories in this proceeding. However, his concern is not relevant if the project is cost-effective and if it has been prudently managed.

It is important to note that <u>all</u> of the savings in every cost-effectiveness study using Tampa Electric's base planning assumptions <u>exceed</u> the $62 million savings calculated in the analysis which was originally presented to senior management, which was the original basis for our Petition for Need, and which supported the decision to construct an IGCC unit in place of the less cost-effective combined cycle unit. Tampa Electric's senior management was advised regularly about the cost and progress of the Polk Unit One project throughout its construction. Tampa Electric continued the construction of the project because of our obligations to our customers to provide the most reliable and cost-effective service as pointed out in the direct testimony of Mr. Rowe and Mr. Anderson.

Rebuttal of Mr. Hugh Larkin, Jr.

Q. On page 11 of Mr. Larkin's testimony, he states that Tampa Electric Company's cost-benefit analysis is "flawed"? Do you agree?

A. No. I strongly disagree with Mr. Larkin's conclusions. Mr. Larkin simply misinterpreted the information provided in discovery by Tampa Electric.

Mr. Larkin incorrectly asserts that the combined cycle unit included in Tampa Electric's cost-effectiveness studies has higher construction costs than the IGCC unit. In each of the cost-effectiveness study summaries provided in Tampa Electric's response to Interrogatory No. 3, Staff's 1st Set, Docket No. 950379-EI, the IGCC construction costs are clearly greater than the combined cycle unit. Mr. Larkin erred in evaluating the construction costs of an IGCC unit provided during discovery by not including all of the categories of construction costs provided for each study.

Q. On page 17 of his testimony, Mr. Larkin questions the use of the Polk Unit One power block as the basis for developing the costs for the combined cycle unit alternative. Why didn't Tampa Electric use a different combined cycle unit that was <u>not</u> designed for integrated gasification in its cost-effectiveness studies?

A. The Polk Unit One power block is indeed a combined cycle unit that can operate on distillate oil at times when the gasification system is unavailable. Since Tampa Electric has always planned for the combined cycle to operate approximately 80% of the time in an integrated mode with the gasification system, the power block was appropriately designed <u>from the outset</u> to accommodate the syngas, gasifier process steam flows and a nitrogen gas stream from the air separation unit during normal operation of the combined cycle. Since the power block was custom designed specifically for gasification, the best option for Tampa Electric (if the gasification system in this scenario for discovery was not found to be a cost-effective option), would be to utilize the existing advanced combustion turbine and heat-recovery steam generator power block and to retrofit the fuel introduction and combustion system to accommodate natural gas, rather than scrap the power block we already had and purchase an additional power block.

Q. Mr. Larkin also states in his testimony that the unit Tampa Electric proposed in the Need Hearing was to be constructed in two phases, yet it was actually constructed in one phase. Please describe the basis for the change.

A. The complete Polk IGCC Unit will be placed in service on or about October 15, 1996. At the time of the Need Hearing for Polk Unit One, as Mr. Larkin points out, the best plan was to construct the unit as a phased construction IGCC plant with a commercial operation date of July 1, 1995 for the General Electric 7F advanced combustion turbine and commercial operation as an IGCC unit by July 1, 1996. As Mr. Black explains in his rebuttal testimony, the unexpected delay in the IGCC construction schedule, caused by permitting delays beyond our control, caused the company to re-examine its cost-effective options under the circumstances. Also, as a part of our ongoing economic and system reliability analyses, we determined during August 1993 that the advanced combustion turbine could be deferred from July 1995 to July 1996 while cost-effectively maintaining system reliability. Thus, we deferred the combustion turbine as was shown in our 1994 Ten-Year Site Plan. That deferral postponed revenue requirements that would have otherwise occurred beginning July 1995. It also allowed the company to consolidate some construction activities which provided cost savings as Mr. Black discusses in his rebuttal testimony.

Q. If deferral of the construction of the advanced combustion turbine portion of the IGCC resulted in savings, should the commercial operation date of Polk Unit One be deferred beyond October 1996?

A. No. There would have been significant costs associated with deferring the Polk Unit One in-service date beyond October 1996. Deferring the project beyond October 1996 would result in additional fuel and purchased power costs to our retail customers since Polk Unit One will be the first unit dispatched on our system on an incremental cost basis, and one of the lowest cost units to operate in Peninsular Florida. Another consideration is the level of construction expenses that have been devoted to the project. By year end 1994, we had spent approximately $200 million net of DOE reimbursements, or almost 40% of the total construction costs. By year-end 1995, our total expenditure was approximately $410 million net of DOE reimbursements, over 80% of the total construction costs. Therefore, from both a practical and an economic perspective, neither the avoidance of or the further deferral of Polk Unit One was a prudent, viable alternative.

Q. What is the impact on the cost-effectiveness of Polk Unit One in the event that the Hot Gas Clean-Up technology does not operate as originally expected?

A. In <u>all</u> of Tampa Electric's cost-effectiveness studies, the IGCC unit was assumed to operate using 100% Cold Gas Clean-Up technology after the DOE demonstration period. The change in the percentage of syngas that will be treated by the Hot Gas Clean-Up technology during the demonstration period is not an issue relative to the cost-effectiveness studies.

In the event that the use of the Hot Gas Clean-Up technology in Polk Unit One is economically viable, there would be a reduction in the unit heat rate. This additional benefit would further increase the cost-effectiveness of operating the Polk Unit One IGCC unit.

<u>Comparisons to Other Utilities Are Inappropriate</u>

Q. Both Staff and Intervenor witnesses have suggested comparisons between Tampa Electric's IGCC unit and various generating units of other utilities is appropriate. Do you agree?

A. No. It is very important for the Commission to realize that the comparison Mr. Ballinger wishes to make is completely irrelevant to the issues in this proceeding, namely, the prudence of Tampa Electric's investment in the Polk Power Station. A comparison of base-load resources on Florida Power & Light's system with the cost of a base-load resource on Tampa Electric's system provides no useful information with regard to cost-effectiveness of a base-load unit on Tampa Electric's system. If for some reason one wished to make this comparison for other purposes, the comparison should be done correctly on a life-cycle cost basis rather than a first year basis. A full-life levelized cost comparison captures the declining fixed costs associated with constructing a unit and the increasing operating costs over time, on a cents-per-kWh basis over the life of the unit, or on a dollar-per-kWh-per-year basis at varying capacity factors over the life of the unit. Mr. Ballinger's selection of the initial year of operation for his comparison ignores the long-term fuel savings associated with the IGCC unit and long-term higher fuel costs associated with the combined cycle units.

Q. Does Mr. Larkin's attempt to draw some analytical link between the decisions by some utilities to not construct IGCC units on their systems and Tampa Electric's decision to build such a unit on its system have any meaning?

A. No. Mr. Larkin fails to recognize significant differences in Tampa Electric's and Florida Power Corporation's existing generation system and customer demand and energy requirements which have a significant impact on the selection of new incremental energy resources. Mr. Larkin recognizes that the DOE funding available to Tampa Electric was a significant benefit that was not available to Florida Power Corporation. However, he failed to recognize other important differences between the two systems. The large amounts of firm contracted cogeneration capacity on Florida Power Corporation's system (which is purchased at a high capacity factor and high fixed capacity payments) are comparable to adding two 600 MW base-load coal units on a system that already consists of several base-load coal units and one nuclear unit. This type of system would not easily support the addition of IGCC technology on an economic basis without the benefit of the DOE funding.

Mr. Larkin also erred by suggesting that only Tampa Electric's fuel price forecasts showed an escalating price differential between coal and natural gas and oil. In fact, as shown in Document No. 9 of my rebuttal exhibit, Florida Power Corporation's and Florida Power & Light's forecasts provided to the Commission in the Ten-Year Site Plan supplemental data indicate a similar trend. We also prepared a sensitivity using Florida Power Corporation's and Florida Power & Light's natural gas price forecast for the 1993 and 1994 cost-effectiveness studies. The result was continued cost-effectiveness of the IGCC technology using FPC's natural gas forecast with approximately $112 million and $91 million in savings comparing the IGCC unit to a natural gas-fired combined cycle unit for the 1993 and 1994 studies, respectively (Document No. 1, pages 6 and 8, of my rebuttal exhibit). A similar analysis using the Florida Power & Light natural gas price forecast yielded $135 million and $123 million in savings for a comparable analysis (Document No. 1, pages 5 and 7, of my rebuttal exhibit).

Q. Please summarize your testimony.

A. Tampa Electric has continued to use appropriate and reasonable planning assumptions to support numerous Commission proceedings and Ten-Year Site Plan filings prior to and subsequent to the Polk Unit One Determination of Need proceeding. The evidence on record supports this position. While Staff has expressed concerns about Tampa Electric's natural gas forecasts, the Commission, when considering the forecasts at the time they were made, has stated it deems Tampa Electric fuel price forecasts, including forecasts for natural gas, are suitable for planning purposes and which have found Tampa Electric's Ten-Year Site Plans to be suitable. The results of the cost-effectiveness studies offered by Tampa Electric in this proceeding continue to support the cost-effectiveness of the IGCC unit compared to a natural gas-fired combined cycle unit. While various fuel price sensitivities and changes in methodology or key planning assumptions as proffered by Staff, OPC, and FIPUG witnesses may result in different cost savings, Tampa Electric stands by the technical merits of the methodology and base assumptions used in each of its cost-effectiveness studies.

Q. Does that conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
WITNESS: HERNANDEZ
EXHIBIT NO. _____ (TLH-2)

TAMPA ELECTRIC COMPANY

REBUTTAL EXHIBIT OF THOMAS L. HERNANDEZ

INDEX

DOCUMENT NO. 1

COST-EFFECTIVENESS SENSITIVITY ANALYSES

TAMPA ELECTRIC COMPANY
1994 POLK UNIT ANALYSIS

PET COKE BLEND (65/35%) SENSITIVITY
Resource Plans

YEAR	Polk IGCC	Polk CC
1994	-	-
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	CT	CT
2001	CT	CT
2002	CT	CT
2003	-	-
2004	CT	CT
2005	-	-
2006	CT	CT
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	CT	CT
2011	-	-
2012	-	CT
2013	CT	-

IGCC Plan Savings - 30 Year CPWRR (94$ x 1000)	
Capital	(177,587)
O&M	(82,097)
Fuel	341,352
Tax Credit	0
IGCC Plan Savings	81,668

TAMPA ELECTRIC COMPANY
1995 POLK UNIT ANALYSIS

PET COKE BLEND (65/35%) SENSITIVITY
Resource Plans

YEAR	Polk IGCC	Polk CC
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	-	-
2001	CT	CT
2002	CT	CT
2003	CT	CT
2004	CT	CT
2005	CT	CT
2006	-	-
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	-	-
2011	-	-
2012	CT	CT
2013	-	-
2014	CT	CT

IGCC Plan Savings - 30 Year CPWRR (95$ x 1000)	
Capital	(122,180)
O&M	(74,950)
Fuel	299,273
Tax Credit	0
IGCC Plan Savings	102,143

POLK IGCC COST EFFECTIVENESS STUDIES SUMMARY
FIRM VERSUS "AS-AVAILABLE" GAS SENSITIVITIES
DIFFERENTIAL SYSTEM CPWRR ($ x 10^6)

Impact of Firm Gas Versus "As-Available Gas

Year of Study	Capital	O&M	Fuel	Net System
1994	0	0	75	75
1995	0	0	62	62
1996	0	3	47	50

NOTE: The negative differential system CPWRR represents the savings of a CC on firm gas relative to a CC on "as-available" gas.

TAMPA ELECTRIC COMPANY
1993 POLK UNIT ANALYSIS

FPL GAS FORECAST
Resource Plans

Year	Polk IGCC	Polk CC
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	CT	CT
2000	CT	CT
2001	HRSG	CT/HRSG
2002	CT	CT
2003	CT	CT
2004	HRSG	-
2005	CT	HRSG
2006	CT	CT
2007	CT	CT
2008	-	CT
2009	HRSG	HRSG
2010	CT	-
2011	CT	CT

IGCC Plan Savings - 30 Year CPWRR (93$ x 1000)	
Capital	(249,996)
O&M	(48,993)
Fuel	433,956
Tax Credit	0
IGCC Plan Savings	134,967

TAMPA ELECTRIC COMPANY
1993 POLK UNIT ANALYSIS

FPC GAS FORECAST
Resource Plans

Year	Polk IGCC	Polk CC
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	CT	CT
2000	CT	CT
2001	HRSG	CT/HRSG
2002	CT	CT
2003	CT	CT
2004	HRSG	-
2005	CT	HRSG
2006	CT	CT
2007	CT	CT
2008	-	CT
2009	HRSG	HRSG
2010	CT	-
2011	CT	CT

IGCC Plan Savings - 30 Year CPWRR (93$ x 1000)	
Capital	(249,996)
O&M	(48,888)
Fuel	411,121
Tax Credit	0
IGCC Plan Savings	112,237

TAMPA ELECTRIC COMPANY
1994 POLK UNIT ANALYSIS

FPL GAS FORECAST
Resource Plans

YEAR	Polk IGCC	Polk CC
1994	-	-
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	CT	CT
2001	CT	CT
2002	CT	CT
2003	-	-
2004	CT	CT
2005	-	-
2006	CT	CT
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	CT	CT
2011	-	-
2012	-	CT
2013	CT	-

IGCC Plan Savings - 30 Year CPWRR (94$ x 1000)

Capital	**(176,047)**
O&M	**(81,461)**
Fuel	**282,630**
Tax Credit	**98,356**
IGCC Plan Savings	**123,477**

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TAMPA ELECTRIC COMPANY
1994 POLK UNIT ANALYSIS

FPC GAS FORECAST
Resource Plans

YEAR	Polk IGCC	Polk CC
1994	-	-
1995	-	-
1996	IGCC	CC
1997	-	-
1998	-	-
1999	-	-
2000	CT	CT
2001	CT	CT
2002	CT	CT
2003	-	-
2004	CT	CT
2005	-	-
2006	CT	CT
2007	CT	CT
2008	CT	CT
2009	CT	CT
2010	CT	CT
2011	-	-
2012	-	CT
2013	CT	-

IGCC Plan Savings - 30 Year CPWRR (94$ x 1000)	
Capital	(176,047)
O&M	(81,124)
Fuel	250,007
Tax Credit	98,356
IGCC Plan Savings	91,192

DOCUMENT NO. 2

FPSC ORDER NO. PSC-92-1493-FOF-EQ (p. 4)
DOCKET NO. 920520-EQ

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition to determine need for electric power plant to be located in Okeechobee County by Florida Power and Light Company and Cypress Energy Partners, Limited Partnership.	DOCKET NO. 920520-EQ ORDER NO. PSC-92-1493-FOF-EQ ISSUED: 12/28/92

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON
BETTY EASLEY

ORDER DENYING RECONSIDERATION

A hearing was held on August 19 through August 28, 1992, on the joint petition of Florida Power and Light ("FPL") and Cypress Energy Partners, Limited Partnership ("Cypress") for a determination of need for a coal-fired power plant. Nassau Power Corporation ("Nassau"), Ark Energy, Inc. and CSW Development-I, Inc. ("Ark") and the Legal Environmental Assistance Foundation, with Deborah B. Evans ("LEAF"), Okeechobee County, the Florida Department of Environmental Regulation, the Florida Municipal Power Agency, and J. Mokowski Associates participated as intervenors.

On August 28, 1992, at the conclusion of the hearing, parties were advised that Motions for Reconsideration must be filed within five days after the Special Agenda. A Special Agenda was held on October 22, 1992 at which time the joint petition for determination of need filed by FPL and Cypress was denied.

On October 27, 1992, both Cypress and FPL requested reconsideration and oral argument. Nassau responded to both requests for reconsideration and oral argument, filed a cross-motion for reconsideration, and requested oral argument on October 30, 1992. Cypress and FPL also resubmitted requests for reconsideration after the November 23, 1992 issuance of the Order Denying Determination of Need in this docket.

On November 3, 1992, Ark filed a response to FPL's and Cypress's reconsideration requests and LEAF moved to strike the requests for reconsideration. Thereafter, on November 6, 1992, Cypress filed a response to LEAF's motion to strike, and also filed a motion to strike Nassau's cross-motion, along with a provisional response to the cross-motion. On November 9, 1992, FPL responded to Nassau's cross-motion. On December 1, 1992, LEAF and Deborah Evans requested reconsideration and oral argument.

We granted oral argument on all motions for reconsideration filed in this docket. Oral argument was conducted on the motions on Wednesday, December 2, 1992.

DOCUMENT NUMBER-DATE
14935 DEC 28 1992

mathematically. Even with the error, the changes in later years (2020 and after) in net present value have less impact than changes in earlier years, and therefore the erroneous information did not make a difference in our decision in this docket. Put another way, correction of the error does not cause us to reach a different result.

In their oral arguments, both FPL and Cypress placed undue emphasis on staff's so called "acid test" (Ex. 31). The acid test was not a deciding factor in determining whether the Cypress project was the most cost-effective alternative. Rather, the acid test was simply an analytical tool utilized to compare projects under a fictional scenario wherein fuel prices maintain a constant differential.

Although we utilized a somewhat similar "acid test" in determining the need for Tampa Electric Company's Polk County unit (Docket No. 910833-EI), we emphasize that the test is merely an analytical device and not, in and of itself, a means to determine cost-effectiveness. We do not view the test as a forecast and certainly do not believe that gas prices and coal prices will maintain the constant differential reflected in the test. We may or may not choose to compare projects under such a fictional constant fuel differential in future need cases and therefore we do not view the "acid test" as policy or precedent to be followed in future need cases.

Cypress also argues that the Commission has construed Section 403.519, Florida Statutes," in a restrictive manner that is inconsistent with the plain meaning of the statute." (Motion For Reconsideration at p.1) Cypress contends that the Commission is not required to find that a proposed power plant is the most cost-effective alternative available, but is only required to take that factor into account along with others.

Section 403.519 requires that the Commission shall take into account whether the proposed plant is the most cost-effective alternative available. This is exactly what the Commission did in this docket. We have neither given the cost-effective criteria undue weight, nor have we minimized the importance of cost-effectiveness. Cypress may be disappointed because it was not determined to be the most cost-effective alternative available. This is not, however, an adequate ground for reconsideration.

DOCUMENT NO. 3

FPSC ORDER NO. 24989 (p. 13-15; p. 60-61)
DOCKET NO. 910004-EU

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Planning Hearings on Load)
Forecasts Generation Expansion)
Plans, and Cogeneration Prices)
for Florida's Electric Utilities.)

DOCKET NO. 910004-EU
ORDER NO. 24989
ISSUED: 8-29-91

The following Commissioners participated in the disposition of this matter:

THOMAS M. BEARD, Chairman
J. TERRY DEASON
BETTY EASLEY
MICHAEL McK. WILSON

FINAL ORDER

BY THE COMMISSION:

As a result of the revision of the cogeneration rules (Docket No. 891049-EU), we initiated a proceeding to approve new standard offer contracts. Pursuant to Order No. 23625, each utility was required to file by October 30, 1990, its most recent ten-year generation expansion plan, a standard interconnection agreement, and one or more standard offer contracts designed to avoid the construction of capacity identified in its plan.

A hearing was conducted in this docket on May 20, 22, and 23, 1991. Pursuant to Order No. 24142, the scope of this hearing was limited to those issues necessary to approve firm capacity and energy tariffs, standard offer contracts, as-available energy tariffs, and standard interconnection agreements.

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08670 AUG 29 1991

1. TECO'S RELIABILITY CRITERIA (STIPULATED)

All parties to this docket have stipulated to TECO's position or have agreed not to object to the stipulation on this issue. Based upon our Staff's analysis, we will accept the stipulation of the parties that the reliability criteria used by TECO are reasonably adequate for planning purposes.

2. TECO'S LOAD FORECAST (STIPULATED)

All parties to this docket have stipulated to TECO's position or have agreed not to object to the stipulation on this issue. Based upon our Staff's analysis, we will accept the stipulation of the parties that the forecasts of energy and seasonal peak demand as presented in TECO's load forecast are reasonably adequate for planning purposes.

3. TECO'S CONSERVATION FORECAST (STIPULATED)

All parties to this docket have stipulated to TECO's position or have agreed not to object to the stipulation on this issue. Based upon our Staff's analysis, we will accept the stipulation of the parties that forecasts of existing and projected conservation are reasonably and adequately considered in TECO's loan and energy forecasts.

4. TECO'S FUEL FORECAST

The fuel forecasts presented by the Company are based primarily on its existing coal requirements and reports from the independent consulting firm Groppe-Long-Littel. These reports address potential impacts of the Clean Air Act Amendments of 1990 and oil supplies/interruptions from OPEC nations. TECO added its transportation cost projections to the reports supplied by Groppe-Long-Littel. The resulting fuel oil and natural gas prices are close to those submitted by FPL, and higher than those submitted by FPC. Although we believe the FPC forecasts are more realistic, there is no indication that the TECO fuel forecasts are unreasonable or inadequate for the purpose of this proceeding. Lower oil and gas forecasts would not alter TECO's need for peaking and intermediate cycling units. We will continue to monitor and review all fuel costs incurred by TECO's customers.

5. TECO'S UNIT PERFORMANCE FORECAST (STIPULATED)

All parties to this docket have stipulated to TECO's position or have agreed not to object to the stipulation on this issue. Based upon our Staff's analysis, we will accept the stipulation of the parties that TECO's assumptions regarding the performance of existing units on its system are reasonably adequate for planning purposes.

6. TECO'S STRATEGIC CONCERNS (STIPULATED)

All parties to this docket have stipulated to TECO's position or have agreed not to object to the stipulation on this issue. Based upon our Staff's analysis, we will accept the stipulation of the parties that TECO's generation expansion plan adequately addresses risk and other strategic concerns including, but not limited to fuel flexibility, weather uncertainty, environmental restrictions, assistance from the Southern Company, constraints in transmission, and state and national energy policies.

7. TECO'S AVOIDED UNIT GENERATING TECHNOLOGIES

The use of the EPRI TAG document by TECO is reasonable for planning purposes. As previously discussed, the TAG document served as a point of reference for other in-house estimates and has also been used by the Commission and other utilities in past planning hearings. The Tag estimates for CT capacity are comparable to other utility's estimates.

We find that the pricing and operating parameters considered by TECO are reasonable.

8. TECO'S SUPPLY SIDE ALTERNATIVES (STIPULATED)

All parties to this docket have stipulated to TECO's position or have agreed not to object to the stipulation on this issue. Based upon our Staff's analysis, we will accept the stipulation of the parties that TECO adequately considered all reasonable forms of available supply-side technologies in order to meet its future load growth.

9. TECO'S APPROPRIATE GENERATION EXPANSION PLAN (STIPULATED)

All parties to this docket have stipulated to TECO's position or have agreed not to object to the stipulation on this issue. Based upon our Staff's analysis, we will accept the stipulation of the parties that the generation expansion plan proposed by TECO is appropriate.

FPC'S STANDARD OFFER CONTRACT

1. FPC'S AVOIDED UNIT DETERMINATION
2. FPC'S SUBSCRIPTION LIMIT
3. FPC'S AVOIDED UNIT PARAMETERS
4. FPC'S CAPACITY PAYMENTS
5. FPC'S AVOIDED COST CALCULATION
6. FPC'S LOCATION FACTORS
7. FPC'S CLEAN AIR IMPACT
8. FPC'S STANDARD OFFER TAX PROVISION
9. FPC'S CAPACITY BENEFITS FOR EARLY DELIVERY
10. FPC'S PERFORMANCE REQUIREMENTS
11. FPC'S SLIDING SCALE CAPACITY PAYMENTS
12. FPC'S COMPLETION SECURITY
13. FPC'S COMPLETION SECURITY ALTERNATIVES
14. FPC'S PROJECT MANAGEMENT REQUIREMENTS
15. FPC'S MILESTONE PROVISIONS
16. FPC'S CAPACITY ACCOUNT SECURITY
17. FPC'S PERFORMANCE SECURITY
18. FPC'S DEFAULT PROVISIONS
19. FPC'S REGULATORY OUT CLAUSE
20. FPC'S BILLING METHOD PROVISIONS
21. FPC'S INTERCONNECTION INSURANCE REQUIREMENT
22. NOTICE TO QF
23. FPC'S STANDARD OFFER CONTRACT AND INTERCONNECTION AGREEMENT APPROVAL
24. FPC'S SUBSCRIPTION

1. FPC'S AVOIDED UNIT DETERMINATION

FPC first proposed a 1991 coal unit, a 1991 combustion turbine, and a 1997 combustion turbine unit as its avoided unit. While the 1991 units could be avoided through negotiated contracts, the designation of 1991 units as avoided units in the standard offer contract violates Rule 25-17.0832 (3)(e)4, Florida Administrative Code, which states:

12. TECO'S COMPLETION SECURITY
13. TECO'S COMPLETION SECURITY ALTERNATIVES
14. TECO'S PERFORMANCE SECURITY
15. TECO'S PERFORMANCE SECURITY ALTERNATIVES
16. TECO'S DEFAULT PROVISIONS
17. TECO'S DEFAULT PROVISIONS
18. TECO'S LIQUIDATED DAMAGES PROVISIONS
19. TECO'S REASSIGNMENT PROVISION
20. TECO'S QF CERTIFICATION PROVISION
21. TECO'S REGULATORY OUT CLAUSE
22. TECO'S COMMITTED CAPACITY ADJUSTMENT
23. TECO'S ENERGY PROJECTION PROVISION
24. TECO'S OUTAGE SCHEDULE PROVISION
25. TECO'S METER PURCHASE PROVISION
26. TECO'S STANDARD OFFER APPROVAL
27. TECO'S SUBSCRIPTION

1. TECO'S AVOIDED UNIT DETERMINATION

TECO is proposing to build two 220 MW CC units that are phased into service over a three year period. In-service dates for the CC units are 1/1997 and 1/2000. As it's avoided unit, TECO has proposed to offer one of the CT's used to make up the CC unit. Even if one CT were fully subscribed, TECO would still build the second CT, and then complete the CC unit. For this reason, we believe that the proper avoided unit would be the 1997 CC unit. To offer a piece of a phased unit does not make sense if the total unit is going to be constructed anyway. By making the in-service date match the in-service date of the last phase, the QF has more time to decide whether to sign a standard offer or to negotiate a contract.

We therefore find that TECO's avoided unit should be a 1997 combined cycle unit.

2. TECO'S SUBSCRIPTION LIMIT

TECO has proposed to make its standard offer contract available to 75 MW of QFs. We approve TECO's proposed 75 MW subscription limit for the following reasons: 1) seventy-five megawatts represents a full year's requirements of capacity needs for TECO (TR 936); 2) TECO's proposed 75 MW subscription limit is large enough to allow a 75 MW QF to sign TECO's standard offer contract; and 3) a subscription limit larger than 75 MW is not required since TECO forecasts that only 50 MW of QF capacity will be added to its system through 2,000.

3. TECO'S AVOIDED UNIT PARAMETERS

We find that the following parameters associated with a 1997 Combined Cycle unit are appropriate.

TECO 1997 COMBINED CYCLE UNIT

a.	Type of fuel	Natural Gas/#2 Oil
b.	Average annual heat rate	8250 BTU/kWh
c.	Cost of fuel: Gas/Oil at Hardee Power or Polk site	
	Natural Gas ($1997)	$7.95/MBTU
	Distillate (#2 Oil) ($1997)	$10.64/MBTU
d.	Construction cost (1991 $/kW)	$649.09
e.	Construction escalation rate	5.1%
f.	In-service cost (1997 $/kW)	$906.32
g.	Incremental capital structure	
	1. Debt	45%
	2. Preferred Stock	7%
	3. Common Stock	48%
h.	Cost of capital	
	1. Debt	10.1%
	2. Preferred Stock	9.1%
	3. Common Stock	13.5%
i.	Book life	30 years
j.	AFUDC rate	8.53%
k.	Effective tax rate	37.63%
l.	Other taxes	2.5%
m.	Discount rate	9.95%
n.	Fixed O&M costs (1997 $/kW/yr)	$6.07
o.	Variable O&M (1997 $/MWh)	$5.56
p.	O&M escalation rate	4.8%
q.	Value of K	1.6940

The above parameters are required by Rule 25-17.0832, Florida Administrative Code, to calculate the value of QF capacity and energy payments pursuant to a standard offer contract. We have designated a 1997 Combined Cycle unit as TECO's avoided unit. At the hearing, Staff requested TECO to revise its COG-2 tariff to include the cost parameters and payments associated with the 1997 CC unit. The above parameters were taken directly from TECO's Revised COG-2 Tariff.

The above cost and operating parameters for TECO's combined cycle unit are comparable to those parameters of other units of the same technology type. We find that these parameters are appropriate for a combined cycle unit.

DOCUMENT NO. 4

FPSC ORDER NO. PSC-92-0002-FOF-EI (p. 6, 7)
DOCKET NO. 910883-EI

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for a Proposed Electrical Power Plant and Related Facilities in Polk County by Tampa Electric Company.	DOCKET NO. 910883-EI ORDER NO. PSC-92-0002-FOF-EI ISSUED: 03/02/92

GFA MJH SMM CRB
WNC GJK HWS MPM
JRR JBR TWM DEP
RHK DMM TLH G. Nelson
RC

The following Commissioners participated in the disposition of this matter:

SUSAN F. CLARK
BETTY EASLEY

<u>ORDER DETERMINING THE NEED</u>
<u>FOR A PROPOSED ELECTRICAL POWER PLANT</u>

BY THE COMMISSION:

Pursuant to Notice, a formal hearing was held in this docket on December 10-11, 1991 in Tallahassee, Florida. Having considered the record in this proceeding, the Commission now enters its Final Order.

<u>BACKGROUND</u>

Tampa Electric Company (TECO or Tampa Electric) filed a Petition for Determination of Need with the Commission on September 5, 1991. In that petition TECO requested that the Commission approve the construction of a 220 MW Integrated Coal Gasification Combined Cycle (IGCC) unit and related facilities at a site located in Polk County. The proposed IGCC project will consist of a 150 MW advanced combustion turbine (CT) unit to be placed in service in July, 1995, and a 70 MW heat recovery steam generator (HRSG) and coal gasifier to be placed in service in July, 1996. Transmission facilities associated with the construction of the plant include two circuits looping the Pebbledale-Hardee Power Station circuit and two circuits looping the Pebbledale-Mines circuit into a transmission switching station at Polk Unit One. Fuel transportation facilities associated with the construction of the plant include a natural gas lateral to the adjacent FGT pipeline for economy gas purchases, and an oil pipeline lateral to the GATX oil pipeline under construction next to the plant site.

The coal gasifier will employ a new technology that efficiently cleans coal gas at high temperatures. This technology will be a demonstration project for the U. S. Department of Energy (DOE). DOE has signed a cooperative agreement with TECO to provide project. As we will explain in detail below, the IGCC unit is the most cost-effective alternative to meet TECO's capacity needs. That fact drives our decision to grant TECO's petition.

The Need for Adequate Electricity at a Reasonable Cost

Fuel forecasts and Fuel Costs

With certain reservations we find that TECO's fuel price forecast is reasonably adequate for planning purposes. TECO Witness Mr. Smith stated that coal prices are expected to remain relatively stable through the year 2000, while natural gas and oil prices are projected to increase rapidly. TECO's forecasting methodology includes reliance on data from government sources and industry association forecasts, trends, and two independent outside consultants. Forecasted transportation prices are added to obtain total delivered prices.

It appears that different fuel price forecasts have little impact on the proposed IGCC project's cost effectiveness. We are concerned, though, that TECO's forecast favors the use of coal over oil or natural gas over the long term for projects with similar costs. An extremely low natural gas price forecast favors an expansion plan which contains just combustion turbine and combined cycles. A low natural gas price forecast does not favor an expansion plan that includes the DOE IGCC project.

The type of new generating unit chosen is not necessarily driven by fuel cost per se; rather, it is the difference in cost among competing fuels. TECO's fuel forecast projects a widening cost differential between coal and natural gas or oil, when in fact for many years the cost differential between the cost of coal and the cost of natural gas and oil has remained relatively constant. In the future, TECO should pay close attention to this differential, and must be ready to substantiate continued reliance upon fuel price forecasts that have not accurately predicted the relationship between the price of coal and the price of natural gas and oil.

TECO provided sufficient assurance in this case that primary and secondary fuel will be available for the proposed plant on a long and short term basis at a reasonable cost. Fuel purchases will be made at market prices. TECO proposes to use the following fuels at its IGCC facility:

- Natural Gas

  TECO is proposing to use natural gas on an interruptible basis to the extent available from Florida Gas Transmission. Dependence on interruptible gas means interruptions during peak demand or when the gas is most needed, and it is therefore practical to have on-site storage of No. 2 oil.

- No. 2 Oil

  TECO proposes to use No. 2 oil as the primary fuel in the first year and a backup or secondary fuel in all subsequent years. The Tampa Bay area is one of the key distribution areas for No. 2 oil. Delivery of No. 2 oil will be by truck from Port Manatee or by the GATX oil pipeline adjacent to the project site.

- Coal

  Coal will be the primary fuel for the IGCC unit. The coal to be used will be similar in sulfur content and price to that burned at TECO Big Bend Unit 4, and is the cheapest of all fuels. Delivery of coal to the plant will be by rail. Partial water borne delivery may be possible depending on the total delivered cost. Tests done using Eastern United States coals during the first two years will aid selecting the more cost-effective sources.

In conjunction with our semi-annual fuel cost recovery proceedings, we will of course evaluate all fuel related expenses to determine that the costs are reasonable and justified. We are satisfied here, though, that TECO has provided adequate assurances on the availability of primary and secondary fuel to the proposed facility on a long and short term basis at a reasonable cost.

<u>Costs of Clean Air Act Compliance</u>

The record in this case demonstrates that TECO adequately took into account the costs of environmental compliance associated with the Clean Air Act when it evaluated its future generation needs. TECO plans to comply with the Clean Air Act by one or more of the following: fuel switching; installing scrubbers; alternative technologies; and, purchasing allowances. Phase I compliance with the Clean Air Act will not be affected by the proposed IGCC plant, but the plant will be an asset to TECO in Phase II compliance. The Company estimates savings in the range of $50 to $100 million over the life of the proposed IGCC unit, compared to fuel switching or other Clean Air Act compliance strategies.

DOCUMENT NO. 5

FPSC ORDER NO. PSC-93-0165-FOF-EI (p. 12, 33)
DOCKET NO. 920324-EI
(TEC Rate Case)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application for a rate increase by Tampa Electric Company.) DOCKET NO. 920324-EI) ORDER NO. PSC-93-0165-FOF-EI) ISSUED: 02/02/93

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
BETTY EASLEY
LUIS J. LAUREDO

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on September 30, 1992, in Tallahassee, Florida; on October 7, 1992 in Tampa, Florida; and October 12 through 19, 1992 in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

APPEARANCES:

LEE L. WILLIS, Esquire, JAMES D. BEASLEY, Esquire, and KENNETH R. HART, Esquire, Ausley, McMullen, McGehee, Carothers and Proctor, 227 South Calhoun Street, Post Office Box 391, Tallahassee, Florida 32302.
On behalf of Tampa Electric Company.

JOHN ROGER HOWE, Esquire, Deputy Public Counsel, and H. Floyd Mann II, Esquire, Associate Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400.
On behalf of the Citizens of the State of Florida.

JOHN W. McWHIRTER, JR., Esquire and LEWIS J. CONWELL, Esquire, McWhirter, Grandoff and Reeves, 201 East Kennedy Boulevard, Suite 800, Post Office Box 3350, Tampa, Florida 33601-3350; and VICKI GORDON KAUFMAN, Esquire and JOSEPH A. McGLOTHLIN, Esquire, McWhirter, Grandoff and Reeves, 315 South Calhoun Street, Suite 716, Tallahassee, Florida 32301.
On behalf of Florida Industrial Power Users Group.

DEBRA SWIM, Esquire and ROSS BURNAMAN, Esquire, 1115 North Gadsden Street, Tallahassee, Florida 32303-6237; and TERRY BLACK, Esquire, Pace University Energy Project, Center for Environmental Legal Studies, 78 North Broadway, White Plains, New York 10603.
On behalf of Legal Environmental Assistance Foundation/John Ryan.

During the hearing, Mr. Moore was asked to provide the Load Forecast Variance Report for August, 1992. This report shows the year-to-date accuracy of the KW, KWH, and Customer forecasts. The report shows that Total Retail Sales are within -0.6% of forecast, and that Total Customers are within -0.2% of forecast, and that Weather Normalized System KW is within 0.3% of forecast. Mr. Moore stated that he believes that the KW, KWH, and Customer forecasts are sufficiently accurate that no modifications to the projections are required. No other party took a position on this issue.

We reviewed TECO's forecast models and assumptions, as well as compared the difference between the forecasted and actual values through August, 1992. **We believe that TECO's forecast models are capable of and have produced reliable projections and that the input assumptions are reasonable.** We note that the August 1992 year-to-date actual values for KW, KWH, and Customers are very close to their forecasted values. Accordingly, we approve the company's KW, KWH, and Customer forecasts.

C. Forecasted Inflation Rates

The inflation forecast is used for rate making purposes to determine the appropriate amount of projected test year expenses. As a basis for the Consumer Price Index (CPI) factors used in its MFR Schedules, Tampa Electric used forecasted data from the DRI/McGraw-Hill Forecast for the U. S. Economy published in late 1991. Late-filed Exhibit 30 provides an updated September, 1992 CPI forecast from DRI to use as a comparison. The updated CPI forecast predicts a slower growth in the consumer price index. We shall adopt the original CPI forecast to determine the level of O&M expenses in 1993 and 1994. The ultimate effect of using a lower CPI for O&M expenses in 1993 and 1994 is that the benchmark level for each functional area will be decreased. MFR Schedules C-53 and C-56 incorporate a true-up of actual CPI and customer growth multipliers to those forecasted in the company's prior rate case. Tampa Electric shall be required to true-up the forecasted CPI and customer growth numbers presented in this rate case to actual data during the company's next full requirements rate case.

D. Jurisdictional Separation

The jurisdictional separation study allocates rate base and operating expense items comprising the company's total system cost of service between those customers served under the jurisdiction of the Florida Public Service Commission (retail or jurisdictional)

Staff's witness, Jack Hoyt, proposed in the Staff Audit Report and through testimony that $35,515 ($36,429 system) be transferred from Account 105 (Electric Plant Held for Future Use) to Account 121 (Non-Utility Plant). The Commission ordered Tampa Electric to put the dollar amount in question into Plant Held For Future Use in Order No. 17281, Docket No. 860001-EI. Mr. Ramil testified that parcel B "may indeed be useful for the plant site" once the lease on the tank expires. Therefore, we find that the level of Plant Held for Future Use for the Gannon Coal Yard is appropriate.

4. Plant Held for Future Use - Port Manatee Plant Site

Power plant sites in Florida are becoming increasingly more difficult to find, purchase, and permit. Tampa Electric has a potential power plant site at Port Manatee. Utilities purchase power plant sites in advance, because the value of the land will generally appreciate at a rate greater than the utility's overall rate of return. If the Commission found that the Port Manatee site was an imprudent investment and did not allow Tampa Electric to earn a rate of return on the property, Tampa Electric would be encouraged to sell the site now. Tampa Electric would then have to search for, and purchase, another site for a future power plant, at much greater cost.

Public Counsel argues that Tampa Electric has no current plans for the Port Manatee plant site. Staff agrees that, at the current time, the company has not identified a particular generating unit to be built at the site. However, as discussed before, it will be more difficult to find an alternate plant site in the future. By allowing the Port Manatee site to remain in rate base, Tampa Electric will already have a viable generating site for future power plants. The Power Plant Siting Task Force recognized that the Port Manatee location was a viable generating site, although the task force ultimately recommended the Polk County location for Tampa Electric's next plant. Accordingly, we find that the requested level of Plant Held for Future Use in the amount of $4,640,000 ($5,094,000 system) for 1993 and $4,692,000 ($5,172,000 system) for 1994 associated with the Port Manatee plant site is appropriate.

5. Reclassification of Substation Sites as Non-utility

The Staff Audit Report, Audit Disclosure No. 7, stated that three substation sites listed in the MFRs for the Projected Test Year ended December 31, 1993 had been transferred out of Account 105, Property Held for Future Use, to Account 121, Non-Utility

DOCUMENT NO. 6

FPSC ORDER NO. PSC-94-1313-FOF-EG (p.18)
DOCKET NO. 930551-EG

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by FLORIDA POWER AND LIGHT COMPANY.	DOCKET NO. 930548-EG
In Re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by FLORIDA POWER CORPORATION.	DOCKET NO. 930549-EG
In Re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by GULF POWER COMPANY.	DOCKET NO. 930550-EG
In Re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by TAMPA ELECTRIC COMPANY.	DOCKET NO. 930551-EG ORDER NO. PSC-94-1313-FOF-EG ISSUED: OCTOBER 25, 1994

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
SUSAN F. CLARK
JULIA L. JOHNSON
DIANE K. KIESLING

__APPEARANCES:__

Charles A. Guyton, Esquire, and Bonnie E. Davis, Esquire, C. Allen Lawson, Esquire, Steel, Hector & Davis, First Florida Bank Building, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1804.
Appearing on behalf of __Florida Power and Light Company.__

TECO included five years (1993-1997) of transmission and distribution (T&D) projects in calculating its avoided cost. (Tr. 1335, Ex. 58) DCA points out that no T&D project costs were considered beyond 1997 and contends that by including such costs, more cost effective DSM would be implemented. We question the extent to which DSM avoids T&D. In theory, some transmission projects could be downsized due to reduced peak demand growth caused by DSM programs.

Given that TECO did analyze T&D projects in its planning process, we find that use of a five year planning horizon is reasonable. Because T&D, especially distribution, is driven primarily by the magnitude and location of growth, shorter term planning is reasonable. In addition, no evidence was presented showing additional potential T&D projects that TECO should have analyzed, or the impact on the cost-effectiveness of DSM measures.

DCA argues that TECO did not consider other societal benefits from DSM programs. Pursuant to Rule 25-17.008, Florida Administrative Code, utilities and other parties may include other benefits and other costs in the calculation of the TRC test, resulting in a societal test. No party in these dockets has quantified the suggested environmental and economic benefits of DSM programs. The Department of Environmental Protection has no plans to assign costs to environmental factors in the immediate future. (Tr. 3050) Therefore we have little basis upon which to consider the impacts of these effects on the cost-effectiveness of the DSM measures evaluated.

We find that TECO's planning process and data utilized in evaluating the DSM measures was reasonable for the purposes of this docket.

IV. DATA USED IN ESTABLISHING CONSERVATION GOALS

Except for the data and analyses for gas substitution, we rely heavily on the data contained in each utility's Cost-Effectiveness Goals Results Report (CEGRR) to establish conservation goals.

It is our desire to set achievable goals that incorporate the utility's planning process analysis as Rule 25-17.0021(3), Florida Administrative Code, provides. We do not place a great deal of reliance on SRC's Best Practices Scenario. The Best Practices Scenario contains some extremely optimistic assumptions, such as the removal of all investment cost barriers to conservation. It

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
WITNESS: HERNANDEZ
EXHIBIT NO. _____ (TLH-2)
DOCUMENT NO. 7

DOCUMENT NO. 7

FPSC REVIEW OF 1994 TEN YEAR SITE PLANS
(pages 3, 12, 24, 28-30, 33, 34)

FLORIDA PUBLIC SERVICE COMMISSION

Review of 1994 TEN-YEAR SITE PLANS

PREPARED BY THE:

Division of Electric and Gas
Bureau of Conservation, System Planning, and Electric Safety
Bureau of Electric Regulation
Bureau of Natural Gas Regulation

Division of Auditing and Financial Analysis
Bureau of Revenue Requirements
Forecasting Section

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LIST OF MAJOR ILLUSTRATIONS

The Statewide Plan

While the Commission finds that the 1994 Ten-Year Site Plans as filed are suitable for planning purposes, there are elements of risk which may affect the plans in the future. A brief discussion of these risks follows:

- *Plans filed by the reporting utilities show substantial reliance on natural gas as a generating fuel. Seventy-one percent of the generating capacity proposed by the electric utilities over the next ten years will use natural gas as a primary or secondary fuel source (4909 of 6903 MWs). While natural gas transmission capacity is expected to more than double during the next ten years, it appears that demand will continue to outpace supply. Utilities' incremental need for pipeline capacity is 945 million cubic feet per day. That is virtually all planned pipeline capacity. It does not take into account growth in gas use by gas utilities or by non-utility generators.*

- *For the most part, the load forecasts filed by the four investor owned electric utilities appear reasonable. However, the forecasts of usage per customer by Florida Power and Light Company and Gulf Power Company appear suspect. The models used by FPL and Gulf may have under-forecasted usage over the forecast period.*

- *The 1994 Ten Year Site Plans reflect forecasts of conservation achievements based on currently planned DSM programs. On October 3, 1994, the Commission adopted new conservation goals for Florida Power Corporation, Florida Power & Light Company, Gulf Power Company, and Tampa Electric Company. These utilities must now develop new conservation programs to meet these goals. In addition, public hearings to establish goals for Florida's municipal electric and rural electric cooperative utilities are scheduled for April, 1995. The effects of the new conservation goals on utility plans should be reflected in future Ten Year Site Plan filings.*

- *Fuel price forecasts should incorporate both current and expected market conditions. TECO's and FPC's oil price forecasts projecting the price of oil to rise at a relatively fixed rate through the year 2010 seem to be reasonable. FPL has projected oil prices to rise at rates that are substantially higher than any of the other utilities and that are inconsistent with published oil market indicators. In contrast to the other utilities, Gulf has projected oil prices to remain fixed over the projection period. Use of FPL's or Gulf's forecast alone to determine the most cost-effective capacity additions could result in inappropriate project selection.*

STEP FIVE

The Presentation of the Forecast Results

The final step in the load forecasting process is the presentation of the forecasts themselves. A proper presentation of a load forecast must not just list the forecasts themselves, but must also convey some feel for the validity of the input assumptions upon which the forecast is based, and provide some measure of the extent to which the forecast is sensitive to changes in those assumptions.

The Commission notes and agrees with the opinion of Mr. Mory that each of the four investor owned utilities should expand the load forecast section of their Ten Year Site Plan to include "Low Growth", "Expected Growth", and "High Growth" forecast assumption scenarios, and the load forecasts that would result from each scenario. Such a presentation would help illustrate how sensitive the load forecast is to changing economic conditions. The Commission believes that this information will assist the users of the Ten Year Site Plan by helping them determine the appropriate degree of reliance to be placed on the forecast results.

Conclusions About Forecasting Procedures

In general, the Commission believes that the load forecasting procedures used by the four investor owned utilities provide reliable and reasonably accurate forecasts of Florida's future energy needs. There are, however, five specific recommendations that the Commission believes would enhance both the precision and usefulness of these forecasts:

1) encourage all utilities to continue collecting household specific data through the use of on-site surveyors,
2) encourage Florida Power Corporation to diversify its modelling efforts and begin development of an end-use model,
3) encourage a more diverse mix of forecast assumptions, and require the development and use of Low, Expected, and High growth forecast assumption scenarios,
4) continue to monitor growth in residential use per customer for Florida Power and Light and Gulf Power for possible under-forecasts,
5) expand the load forecast presentation in the Ten Year Site Plan to include the Low Growth, Expected Growth, and High Growth forecast assumption scenarios and the resulting load forecasts based on those assumptions.

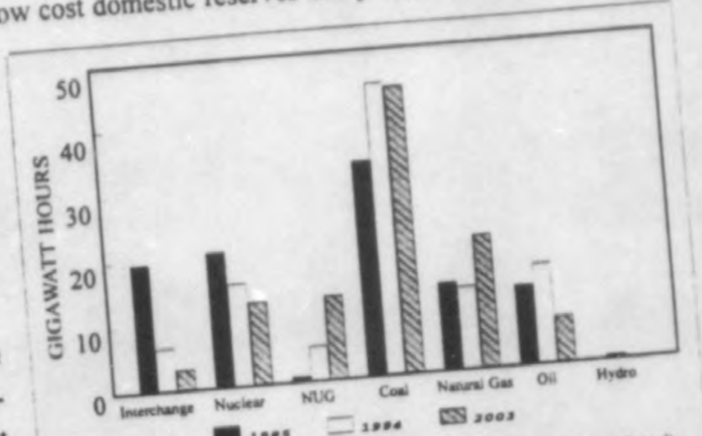
Once these reliability criteria are established, the utilities apply the load forecast to their existing system. If the utility's reserve margin falls below an established value, say 15%, or the probability of not being able to serve the load goes above 0.1 days per year, this raises reliability concerns. The utility must then build or purchase additional generating capacity or increase its DSM efforts to reduce the load. Multiple combinations of these options are developed in order to satisfy the reliability criteria. In other words, reliability criteria determine the timing of resource additions.

From a reliability perspective, it appears the reporting utilities have adequately planned to serve their customers needs. The least cost method of serving that need is discussed in the sections that follow.

◆ Forecast Analysis ◆

Coal

Across the nation, the use of coal continues to dominate electricity production due largely to the abundance of low cost domestic reserves and productivity advancements. In Florida, coal is currently used to generate over 44% of the total energy produced. Coal prices are projected to remain stable and production is expected to increase.



Energy production in Florida by fuel, 1985, 1994 and 2003 (percent of total)

Florida utilities have traditionally relied on Eastern supplies of coal to meet their generation needs. However, with potential restrictions on toxic emission levels by the Clean Air Act Amendments, utilities are turning to the use of both foreign and western sources of lower sulfur coal for generation of electricity. Three of the four Florida IOU's currently use or are planning to use coal from Venezuela, Columbia, South Africa and the Powder River basin in Colorado. These alternate sources of coal contain favorable chemical properties that will allow the utilities to meet load requirements and comply with emission constraints while avoiding the cost of capital intensive scrubbers in the near future.

Each utility has projected coal prices to remain relatively constant with slight escalation occurring throughout the forecast period. Utility forecasted prices are expected to rise from $40.62/ton in 1994 to $63.94/ton in the year 2010. The escalation rates used by the utilities are slightly higher than escalation rates projected by other forecast consulting groups. However, the projected price trends are consistent with historical price trends over the last 10 years.

Oil

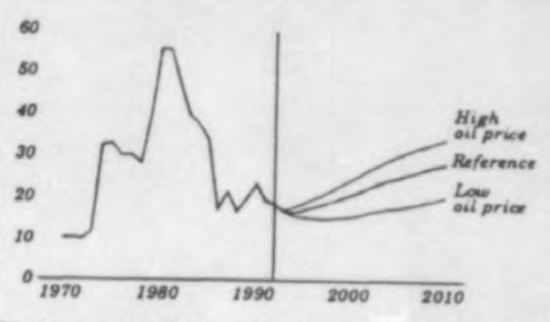
Historically, oil prices have fluctuated in response to many factors. Oil prices have been affected by such factors as expectations of world oil reserves, technological advances, productivity expansion and the market influence of OPEC. Increasing concern about environmental impacts caused by oil fired generation will further influence the price of oil.

Because of the uncertainty of these factors, Florida initiated a move away from reliance on oil-fired generation during the late 1970's and early 80's. As required by the Florida Energy Efficiency Conservation Act, the Commission established numeric goals for electric utilities. The goals were designed to reduce the growth rates of peak demand, reduce and control growth rates of electric consumption and increase the conservation of expensive petroleum resources. Trying to insulate Florida ratepayers from oil's political uncertainty and price volatility, the Commission established an Oil-Backout cost recovery mechanism. This mechanism allows utilities to recover the costs associated with cost-effective construction or conversion projects that economically displaces oil generated electricity. Since then, the Commission has approved two oil-backout projects: FPL's 500 KV transmission line and the conversion of TECO's Gannon plant from oil to coal. In addition, the Commission recently approved FPL's request to recover costs associated with its Manatee plant conversion to burn Orimulsion, a coal derivative product that has characteristics similar to oil. Over the next 20 years, this project is designed to replace approximately 144 million barrels of higher priced oil with fuel priced comparable to coal.

One common flaw in modeling future oil prices is that each utility typically includes the possibility of some catastrophic event occurring, such as the Oil Embargo and price shocks that followed the 1973 Arab-Israeli war. The problem is that, although the possibility does exist, no one is quite sure when or if it might happen. As a result, utilities' forecasts may include overinflated oil prices depicting overly pessimistic projections of prices that neither materialize nor communicate appropriate pricing signals.

Residual Oil

FPC and TECO have projected the price of residual oil to begin around $17.80/bbl and rise at a relatively fixed rate to $38.69/bbl in 2010. FPL is projecting a substantial price increase from $20.04/bbl to $23.03/bbl during the next two years and then a continued escalation at a fairly high rate to $61.26/bbl by 2010. FPL's projected escalation rates are substantially higher than any of the other utilities' and inconsistent with published oil market indicators. In contrast to the other utilities, Gulf is projecting residual oil prices to remain constant at $13.60/bbl throughout the projection period.



World oil prices, 1970 - 2010 (1992 dollars per barrel)

Historically, oil prices over the last 10 years indicate a downward trend. However, the year to year price changes have been both up and down. Compared to FPL's and Gulf's residual oil price forecasts, FPC's and TECO's forecasts appear to provide a more reasonable estimate of future price trends for planning purposes. Although FPC and TECO are projecting continual increases in residual oil prices, the escalation rates have been held to a relatively fixed rate and reflect projections of independent forecasting groups.

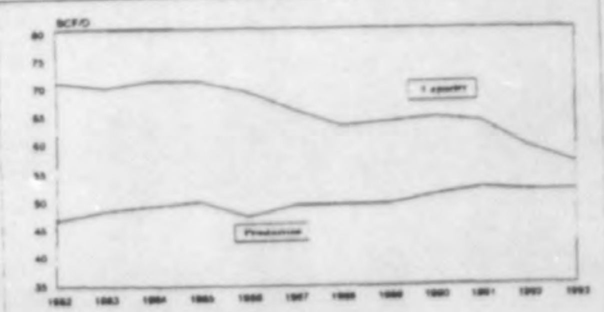
Distillate Oil

Distillate oil is typically the most expensive of all fuel types used for generation of electricity in Florida. The utilities have projected the average cost to be $26.25/bbl in 1994 rising to approximately $59.06/bbl in the year 2010.

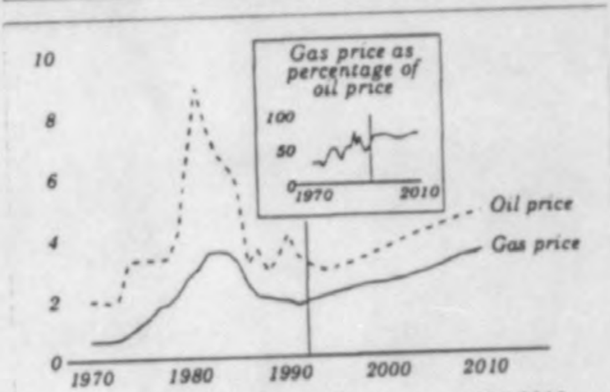
Distillate oil prices are expected to increase at a rate similar to residual oil and natural gas. This is a common assumption made by all the utilities and is consistent with leading economic indicators, but does not reflect historical trends.

Natural Gas

As the deadline for compliance with Phase I and II of the 1989 Clean Air Act Amendments approaches, natural gas is fast becoming the fuel of choice among many utilities. This low sulfur fuel can be burned with great efficiency while requiring low capital investment. Economically recoverable gas reserves have increased as a result of innovative gas recovery technologies. However, developed gas reserves are not keeping up with production. New gas reserves needed to meet increased production demand are expected to result in rising gas prices.



Decline in excess domestic deliverability ("The Gas Bubble")



Lower 48 oil and gas wellhead prices, 1970-2010 (1992 dollars per million Btu)

FPL, FPC and TECO project the price of natural gas to abruptly rise 9% due to enactment of Phase I of the Clean Air Act. FPL and TECO further predict that natural gas prices will continue to escalate throughout the projection period rising well above the price of coal. Additionally, FPC and TECO are predicting that the delivered price of natural gas will exceed the price of residual oil, a rare event that has only occurred during six months over the past 12 years.

Current economic indicators predict that the wellhead price for natural gas will turn upward and rise steadily toward the price of oil, a direct reverse from previous declines. In addition, the past trend of tracking oil prices while remaining at a stable margin above the price of coal should continue. FPL's and TECO's forecasts indicate an ever widening gap between the price of coal and natural gas. These forecasts are not indicative of historical trends that reflect market stability and continued growth in production.

Coal generation increased substantially during the 1980's in reaction to the increase in oil prices during the 1970's. Traditionally, coal plants have been justified based on forecasted low coal prices relative to oil or natural gas. However, coal fired plants are capital-intensive relative to oil- and gas-fired plants. Also, there are ever-increasing environmental concerns surrounding the emissions of pulverized coal plants, which may lead to stricter regulations that further increase capital investments at coal plants.

Coal gasification technology appears to provide the flexibility needed to meet potential environmental restrictions and address low initial capital investment if the combined cycle portion of the facility is constructed first. If the price differential of oil and natural gas compared to coal widens, the savings from coal gasification might justify additional capital investment at that time. As a result, for power plant siting purposes, it is important to consider whether a site is capable of supporting a coal gasification plant and all the implications to the local transportation infrastructure. One of Florida's investor-owned utilities, Tampa Electric Company, recently started construction on an integrated coal gasification combined cycle (IGCC) unit which will serve as a demonstration project for the U.S. Department of Energy.

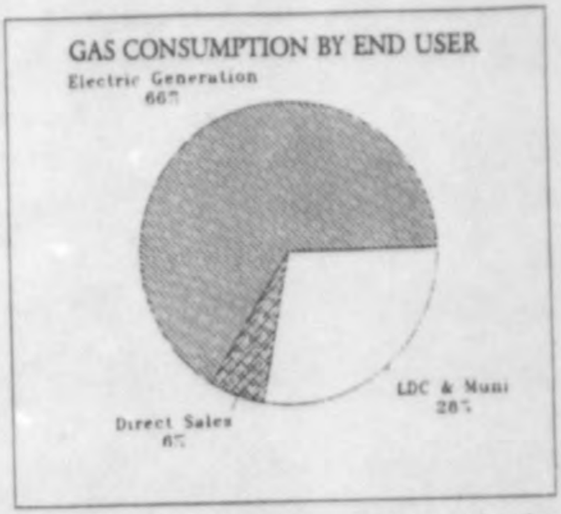
Hydroelectric generation continues to make a minute contribution to Florida's generation mix, but there are no plans to construct new units due to the absence of a new location feasible for such a unit.

The Commission continues to believe that utility Ten-Year Site Plans should be as flexible as possible with respect to fuel type. All new power plants should be capable of burning multiple fuels, and sites should be designed and infrastructure set to facilitate cost-effective fuel conversion of these units in the future.

The balancing of a generation mix does not stop once a resource is added to the system. Florida Power Corporation has made a substantial commitment to include firm purchases from QFs in its resource mix. FPC plans to continue this trend by increasing firm QF purchases from 412 MW in 1994 to 1086 MW in 2003. By purchasing a large percentage of its capacity from QFs, FPC's system may experience some unique problems.

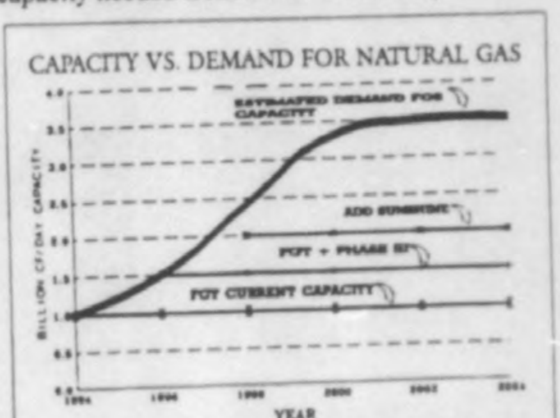
Because a utility's load changes from hour to hour, there may be periods of time when all the energy being purchased from QFs is not needed, such as in the middle of the night resulting in increased costs of power to the ratepayers. The Commission recognized the potential for this, as well as other situations that would increase costs as a result of purchasing power from QFs, when it adopted Rule 25-17.086, F.A.C. This rule gives the utility the authority to curtail purchases from a QF if such purchases result in increased cost or degrade reliability to the utility's system. FPC has attempted to implement this rule by negotiating with some of its QFs to back down their generation during low load conditions.

◆ Availability of Natural Gas ◆



In the next ten years, electric utilities plan to add more new gas fired power plants than can be supplied through existing natural gas pipelines or lines now under construction. If additional pipeline capacity is not built, these plans for new power plants cannot be met and are, therefore, not valid for planning purposes.

Natural gas pipeline capacity is expressed as maximum daily throughput capability in billion cubic feet per day (bcf/day). Florida Gas Transmission (FGT), the only pipeline serving peninsular Florida, has just under one bcf/day of capacity. The figure above shows how that capacity is used today. Note that electric generation uses 66% of Florida's gas. To fuel just new utility-owned gas fired generation shown in these ten year plans, an *additional* one bcf/day of pipeline capacity will be needed by 2003. It is important to note that the additional one bcf/day will serve only electric utility needs. It will not provide enough capacity to serve non-utility generators or to expand natural gas distribution utilities. That additional demand may increase the total pipeline capacity needed from 2.0 to 3.4 bcf/day.



Source: SunShine Pipeline need order no.PSC-93-0987-FOF-GP. Dcket no 920807-GP

The figure at the right is drawn from data in the SunShine need determination case. It shows projected shortfalls in pipeline capacity, even with FGT's Phase III expansion and the SunShine capacity discussed below. This chart includes gas for non-utility generation and growth in gas distribution utilities. The timing of the additional demand for capacity is subject to slippage, but the total capacity numbers are presumed accurate.

FGT's Phase III expansion will add almost half of the capacity needed for electric generation. Phase III, which is nearing completion, will increase FGT's capacity from 0.935 bcf/day to 1.45 bcf/day. That leaves a shortfall of just over 0.5 bcf/day by 2003 for electric generation needs. The SunShine Pipeline, if built, will add another 0.55 bcf/day. SunShine is now in the siting certification process. It is critical to these ten year plans that SunShine or pipeline capacity equivalent to SunShine be built.

DOCUMENT NO. 8

FPSC REVIEW OF 1995 TEN YEAR SITE PLANS
(pages 1, 2, 9-11, 32-38, 41, 64-67)

FLORIDA PUBLIC SERVICE COMMISSION

Review of
1995
TEN-YEAR
SITE
PLANS

PREPARED BY THE:

Division of Electric and Gas
Bureau of Conservation, System Planning, and Electric Safety
Bureau of Electric Regulation
Bureau of Natural Gas Regulation

Division of Auditing and Financial Analysis
Bureau of Revenue Requirements
Forecasting Section

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INTRODUCTION

Pursuant to Section 186.801, Florida Statutes, each generating electric utility is required to submit to the Florida Public Service Commission (Commission) a Ten-Year Site Plan. Each Ten-Year Site Plan contains projections of the utility's electric power needs for the next ten years and the general location of any proposed power plant sites and major transmission facilities. Comments in this document provide feedback to the utilities on any concerns that review agencies might have regarding proposed power plant sites. The Commission is responsible for making a preliminary study of the utility plans and must determine whether each plan is "suitable" or "unsuitable". As part of its review of the plans, the Commission solicits comments from federal, state, and local government agencies as well as from the public. All comments made by the Commission are forwarded to the Florida Department of Environmental Protection (DEP) for consideration at any subsequent electrical power plant or transmission line site certification proceeding.

Additionally, Section 377.703(3)e, Florida Statutes, requires the Commission to provide the Florida Department of Community Affairs (DCA) with electricity and natural gas forecasts. This report contains these forecasts which will be forwarded to DCA in order to satisfy the Commission's statutory responsibilities.

PURPOSE

What is the purpose of this document?

- *to review key assumptions underlying the long-range generation and transmission plans of Florida's electric utilities;*
- *to determine the validity of these assumptions; and*
- *to satisfy the requirements of Chapters 186.801 and 377.703(3)e, Florida Statutes.*

PUBLIC INVOLVEMENT

Pursuant to the State of Florida's policy of "government in the sunshine", all government meetings, workshops, and hearings at the Commission are open to the public. Members of the public may directly participate in any of the Commission's proceedings.

The Commission held a public workshop on August 16, 1995 to solicit comments on the Ten-Year Site Plans. The Commission received oral and written comments from the Legal Environmental Assistance Foundation (LEAF), the Project for an Energy-Efficient Florida (PEEF), and the Competitive Energy Producers Association (CEPA).

To submit comments on this document or request additional information pertaining to utility planning issues before the Commission, citizens may write to
Joseph D. Jenkins, Director, Division of Electric and Gas,
Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, FL 32399-0850

EXECUTIVE SUMMARY

During the 1995 Legislative session, Section 186.801, Florida Statutes was revised to make the Florida Public Service Commission the lead agency charged with determining the suitability of electric utility Ten-Year Site Plans. The following is a brief summary of how the Commission has complied with the newly enacted legislation.

REQUIREMENT	ACTION
Review the need for electrical power in the area to be served.	*Reviewed load forecasts, DSM assumptions, and reliability criteria. Discussed in Sections III(A) through III(C).*
Review the anticipated environmental impact of proposed power plant sites.	*Since the Commission does not have expertise in this area, we requested comments from Florida Department of Environmental Protection (DEP) regarding environmental impacts and compliance. Reply comments are contained in Sections IV(A) through IV (M).*
Review possible alternatives to the proposed plant.	*Reviewed DSM assumptions, fuel forecasts, and generation alternatives modelled to arrive at proposed plant. Discussed in Sections III(A) through III(F).*
Consider the views of appropriate local, state, and federal agencies with regard to water and growth management issues.	*Requested comments from affected agencies. Reply comments contained in Sections IV(A) through IV(M).*
Determine if the Ten-Year Site Plan is consistent with the State Comprehensive Plan	*Energy-related aspects of the Comprehensive Plan are discussed in Section III(B) of final report. Requested comments from the Department of Community Affairs (DCA) regarding growth management issues. Requested comments from regional and local planning agencies regarding local Comprehensive Plan issues. Reply comments are contained in Sections IV(A) through IV(M).*
Review the Ten-Year Site Plan for information on energy availability and consumption.	*Reviewed load forecast data and methodologies. Requested supplemental data from utilities which provides greater detail. All of this data is available to the public.*

energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its customers at the lowest system cost. The process shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other forms of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

EPAct defines "system cost" as:

all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance.

There is no requirement in EPAct to adopt the federal IRP standard -- states are only required to consider the standard. Full consideration of this standard was given during public hearings to set demand-side management (DSM) goals for the investor-owned utilities (re: Docket Nos. 930548-EG, 930549-EG, 930550-EG, and 930551-EG). The Commission has embraced the concept of integrated resource planning and believes that Florida's investor-owned utilities currently practice IRP. However, the Commission did not adopt the specific federal standard because of definitional uncertainties as to the role of the federal government in interpretation and enforcement of the standard.

The IRP Process in Florida

Although Florida Statutes and Commission Rules contain no specific reference to IRP, however that term may be defined, they do provide a solid framework for flexible, cost-effective utility resource planning.

The following statutes and rules constitute the basis for electric utility Integrated Resource Planning in Florida.

STATUTES:

(1) **Section 366.04 (2) (c), 366.04 (5), and 366.05 (8), Florida Statutes.** *Commonly referred to as the "grid bill," its purpose is to ensure the development and maintenance of a reliable and coordinated power grid throughout Florida.*

(2) **Section 366.80 - 366.85 and 403.519, Florida Statutes.** *Florida Energy Efficiency and Conservation Act (FEECA), originally enacted in 1980. FEECA requires the setting of goals for reduction in the growth rates of peak demand and energy use. Section 403.519 is the statute that makes the Commission the exclusive forum for the*

determination of need for an electrical power generating plant as defined by the power plant siting act (Section 403.501 - 403.517, Florida Statutes).

(3) **Section 403.517, Florida Statutes.** *Need determination statute for transmission lines as defined by the Transmission Line Siting Act (Section 403.52 - 403.536, Florida Statutes).*

(4) **Section 186.801, Florida Statutes.** *Statute that requires utilities to submit Ten-Year Site Plans to the Commission.*

RULES:

(1) **Rule 25-17.001 - 25-17.015, Florida Administrative Code.** *Addresses conservation goals and related matters. Rule 25-17.001 requires that utilities "aggressively integrate non-traditional sources of power generation into the various utility service areas to the extent cost-effective." Rule 25-17.0021 addresses the setting of numeric DSM goals and requirements for monitoring utility progress in meeting those goals.*

(2) **Rule 25-22.080 - 25-22.082, Florida Administrative Code.** *Governs power plant need determinations and requires detailed information on viable generating and non-generating alternatives to the construction of the proposed plant. Rule 25-22.082 is the Commission's bidding rule.*

(3) **Rule 25-22.075, Florida Administrative Code.** *Addresses transmission line need determinations and requires information on alternatives to the construction of the line.*

(4) **Rule 25-17.080 - 25-17.091, Florida Administrative Code.** *Referred to as the "co-generation" rules.*

While the specific approaches to IRP for each utility vary, they are all consistent with a generic process which consists of the following six broad steps:

Step 1: *All assumptions and system performance data are updated. This includes the assumptions that must change based on Commission decisions in various dockets as well as the other input assumptions regarding demographics, financial parameters, generating unit operating characteristics, etc. The load forecast at this step of the process excludes future DSM installations.*

Step 2: *A reliability analysis is conducted to determine when resources may be needed to meet expected load. Utilities generally use two reliability criteria: reserve margin and loss of load probability (LOLP).*

Step 3: *Based on the reliability analysis conducted in step 2, the magnitude and timing of new capacity needed is determined. At this step, it is undetermined whether the need will be met by a supply-side resource or a demand-side resource. Only the timing and amount of megawatts needed are known at this stage of the process.*

Step 4: *An initial screening of DSM programs and supply-side resources is made to determine candidates to meet the need determined in step 3.*

Step 5: *The demand-side and supply-side resources identified in step 4 compete against each other to determine which combination meets the need most cost-effectively.*

Step 6: *The results of the previous steps are reviewed by utility management and the final IRP plan is adopted. The IRP plan adopted by the utility may require Commission approval, such as in a power plant need determination proceeding. In addition, after reviewing the plan the Commission may, on its own motion, open proceedings to address any part of the plan.*

Utilities must retain the flexibility to respond quickly and effectively to the numerous changes facing them in the regulatory and competitive arenas. Actions taken by the utility must be prudent and in the best interest of ratepayers.

The final plan that is adopted by utility management is reviewed by the Commission, and appropriate action is taken to address any concerns. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving the day-to-day operations to utility management.

FUEL FORECAST

While strategic factors such as fuel mix, fuel availability, and environmental compliance must be considered by a utility prior to selecting a generating resource, the fuel forecast is the primary (and most potentially volatile) factor affecting the type of generating resource added. The sole use of any one fuel forecast may result in utility selection of a significantly different capacity addition as being the least-cost alternative. Consequently, a utility must use the best available information before proceeding with the planning process. Fuel price forecast information is not currently included in utility Ten-Year Site Plan filings; however, the Commission obtained fuel price forecasts separately through supplemental data requests.

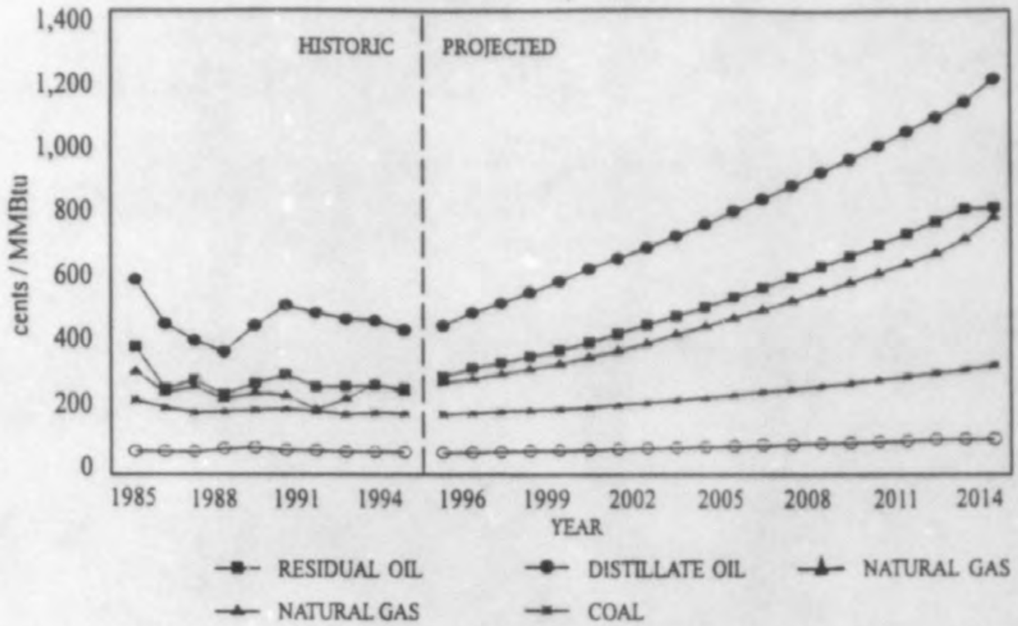
A utility's fuel price forecast should include an evaluation of applicable modeling assumptions such as inflation rates, available resources, levels of productivity and technological advances. Applying generally accepted escalation rates (such as those prepared by DRI/McGraw Hill or Annual Energy Outlook) to fuel prices currently being paid provides a starting point to project future pricing trends. Utilities should produce several fuel forecasts to evaluate the cost-effectiveness of potential generating plant expansions. A base case fuel forecast should depict the utility's best estimate of future price trends. Low and high case forecasts also should be produced to determine the sensitivity of a particular project's cost-effectiveness to changing fuel price trends.

To further determine this sensitivity, a worst-case scenario should also be evaluated as a sanity check. This is done by holding the current fuel price differentials constant throughout the projection period. This test will reveal whether a project will retain overall cost-effectiveness under severe and continuing price decreases.

The significance of historical price trends as predictors of future price trends should be carefully considered, as was evidenced when the Commission considered a joint petition by FPL and Cypress Energy Partners (Cypress) for a determination of need for two 400 MW pulverized coal power plants (Docket No. 920520-EI). FPL chose the Cypress project based, in part, on fuel forecasts that projected increasingly divergent prices between coal and natural gas or oil. However, the sustained divergence between gas and coal prices predicted in FPL's fuel forecast was not supported by historical figures. While the Commission granted FPL's need for additional electric generating capacity, the need for the specific units proposed by FPL was denied because the units were not found to be the most cost-effective alternatives available. No party offered a convincing explanation as to why a major divergence between coal and natural gas prices was projected when such action had not occurred in the past. Regardless of whether or not the fuel forecast would have proved accurate, FPL's selection of the Cypress pulverized coal project did not follow a course which would allow for the fuel forecast's inherent uncertainty. If the forecast had proven wrong, FPL's ratepayers would have been forced to pay the high capital cost of a pulverized coal plant. FPL subsequently found alternatives to the Cypress project.

The graph below illustrates historic and projected fuel prices for the reporting utilities:

REPORTING UTILITIES
BASE CASE FUEL PRICE COMPARISON
Historic vs. Projected



Forecast Analysis

Coal

Across the nation, the use of coal continues to dominate electricity production due largely to the abundance of low-cost domestic reserves and productivity advancements. In Florida, coal is currently used to generate over 40% of the total energy produced. Coal prices are projected to remain stable, and coal-fired electric production is expected to increase slightly over the next ten years.

Florida's utilities have traditionally relied on Eastern supplies of coal to meet their generation needs. However, with current and future restrictions on toxic emission levels by the Clean Air Act Amendments, utilities are turning to both foreign and Western sources of lower sulfur coal for electric generation. Three of Florida's investor-owned utilities currently use, or are planning to use, coal from Venezuela, Columbia, South Africa and the Powder River basin in Colorado. These alternate sources of coal contain favorable chemical properties that will allow utilities to meet load requirements and comply with emission constraints, while avoiding the cost of capital-intensive scrubbers in the near future.

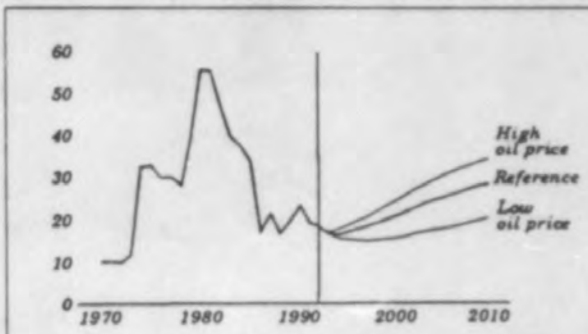
In general, the reporting utilities have projected that coal prices will escalate slightly throughout the forecast period. Average utility-forecasted coal prices are expected to rise from $41.55/ton in 1995 to $65.81/ton in the year 2010, based on 12,000 Btu/lb. The escalation rates used by the utilities are slightly higher than escalation rates projected by other forecast consultants. However, the price trends being projected by the reporting utilities are consistent with historical price trends over the last 10 years.

Oil

Oil prices have historically fluctuated in response to many factors, such as uncertain expectations of world oil reserves, technological advances, productivity expansion, and the market influence of OPEC. Increasing concern about environmental impacts caused by oil-fired generation will further influence the price of oil in the future.

Because of the uncertainty of these factors, Florida initiated a move away from reliance on oil-fired generation during the late 1970's and early 1980's. To insulate utility ratepayers from the political uncertainty and price volatility associated with oil, the Commission established an oil backout cost recovery mechanism that allowed utilities to recover costs associated with cost-effective construction or conversion projects that economically displaced oil-fired generation. Since adopting the recovery mechanism, the Commission has approved two oil-backout projects: (1) FPL's two 500 kV transmission lines from Georgia; and (2) TECO's Gannon plant re-conversion from oil to coal.

In addition, the Commission recently approved FPL's request to recover costs associated with its Manatee plant conversion to burn Orimulsion, a coal derivative product with physical characteristics similar to oil. Over the next 20 years, the Manatee orimulsion conversion project is expected to displace nearly 144 million barrels of higher priced oil with fuel priced comparable to coal.



World oil prices, 1970 - 2010 (1992 dollars per barrel)

The move away from oil-fired generation by Florida's electric utilities has resulted in past declines in the amount of energy produced by oil. This trend is expected to continue over the next five years, as the percentage of statewide energy generation from oil is expected to decline from 19.7% (33,294 GWh) in 1994 to 6.4% (12,533 GWh) in 1999. Starting in 2000, the amount of oil-fired generation is expected to begin escalating. FPL, Lakeland, Tallahassee and JEA are the driving forces behind the increased usage, as their plans include proposed unit upgrades and additions which will use oil as either a primary or alternate fuel source.

One concern in modeling future oil prices is that each utility typically includes a possible catastrophic occurrence, such as the oil embargo and price shocks of 1973. Although such a possibility does exist, the modeling of a catastrophe must be done with care since no one can accurately predict when or whether the catastrophe might occur. As a result, utility fuel forecasts may include overly pessimistic projections of prices. While low oil prices may imply that Florida's utilities should rely more on oil, such reliance on oil by the electric utility industry in the early 1970's resulted in the above-mentioned catastrophic price shocks. Oil markets have changed since the 1970's. Oil futures are now traded on commodities exchanges. A rapid oil price increase cannot be sustained unless there is an underlying systematic reason, as oil prices during the Gulf War demonstrated.

Residual Oil

The reporting utilities forecast residual oil prices to rise from an average of $18.06/bbl in 1995 to $42.92/bbl in 2010. Overall, GRU and SEC project the highest price increases, from approximately $21.23/bbl in 1995 to $62.69/bbl in 2010. In contrast, JEA forecasts residual oil prices ranging from $13.93/bbl in 1995 to $27.70/bbl by 2010. SEC's and GRU's projected residual oil escalation rates are substantially higher than those of the other reporting utilities and are inconsistent with published oil market indicators. As would be expected, neither GRU nor SEC expect to use any residual oil through 2004. Interestingly enough, neither does JEA.

While year-to-year prices of residual oil have fluctuated up and down over the last ten years, residual oil prices have historically shown an overall downward trend. SEC's and GRU's residual oil forecasts are the exception. Higher than average 1995 residual oil prices, coupled with excessive escalation rates, result in these two utilities having a fuel price forecast that is biased against residual oil. Fortunately, SEC and GRU plan to build fuel-flexible combined cycle and combustion turbine units, both of which can burn either distillate oil or natural gas.

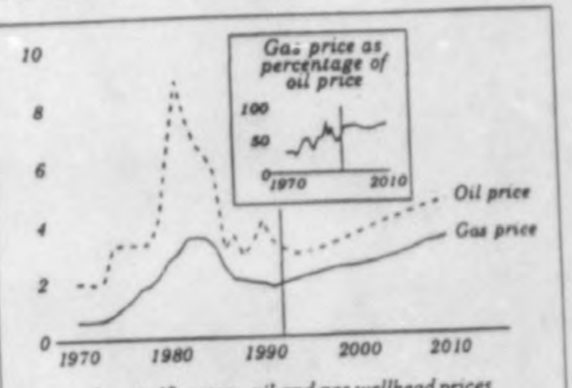
Distillate Oil

Distillate oil is typically the most expensive of all fuel types used for electric generation in Florida. The reporting utilities forecast distillate oil prices to rise from an average of $25.59/bbl in 1995 to $57.20/bbl in the year 2010. Distillate oil prices are expected to increase at a rate similar to residual oil and natural gas. This is a common assumption made by all the utilities and is consistent with leading economic indicators. However, these average price projections contradict the long term $40/bbl range forecasted by independent groups.

Natural Gas

Natural gas has fast become the fuel of choice among many utilities for compliance with emission restrictions placed on electric generation sources. This low-sulfur fuel can be burned cleanly, with great efficiency, and with minimal capital investment. Economically recoverable gas reserves have increased as a result of innovative gas recovery technologies. Natural gas reserves are a form of inventory. With new gas exploration technologies, it makes sense for natural gas suppliers to reduce reserves to minimize inventory cost. Natural gas continues to be an abundant domestic fuel. The quantity of gas reserves is dependent almost solely on price.

The reporting utilities forecast natural gas prices to rise at an average rate of 5.8% per year over the next fifteen years, from $2.68/MMbtu in 1995 to $5.94/MMBtu in 2010. As was the case last year, several utilities project the delivered price of natural gas to exceed the price of residual oil. This is a rare event that has only occurred a few times over the last thirteen years.



Lower 48 states: oil and gas wellhead prices, 1970-2010 (1992 dollars per million Btu)

Current economic indicators predict that natural gas prices will turn upward and rise steadily toward the price of oil, a direct reverse from previous declines. In addition, the past trend of natural gas prices tracking oil prices while remaining at a stable margin above coal prices should continue. Several utilities continue to forecast an ever-widening gap between the price of coal and natural gas, which is not indicative of historical trends that reflect market stability and continued growth in production. Despite the bias against natural gas that is inherent in these fuel price forecasts, natural gas still appears to be the fuel of choice for most of the planned generating units.

Orimulsion

Orimulsion is a coal derivative product with physical characteristics similar to oil. In Docket No. 940391-EI, FPL received Commission approval of a cost-recovery mechanism for the conversion of Manatee Units 1 and 2 from heavy oil to Orimulsion. Expected to be completed in 1998, the conversion project involves the installation of equipment (including scrubbers) to enable the two 783 MW Manatee generating units to burn Orimulsion. FPL has projected that fuel savings achieved as a result of conversion will save ratepayers approximately $2.6 billion. Based on projected fuel savings, FPL expects that the capital costs incurred to convert the generating plants will be recovered in approximately one year.

Petroleum Coke

Petroleum coke (petcoke) is a residual product of the oil refining process. Approximately 70% of the 25 million tons of petcoke produced annually in the U.S. is considered to be fuel-grade. Fuel-grade petcoke is essentially a pure carbon by-product which contains high levels of sulfur and vanadium. Petcoke is being marketed on long term "controlled" price agreements to electric utilities at prices around $0.70/MMBtu or less.

The City of Lakeland, FPC, TECO, and JEA and FPL (at St. Johns River Power

Park) are among several utilities nationwide that have undertaken test burns of petcoke or are proceeding with plans to incorporate petcoke in their fuel mix on a long-term basis. With the proper emission control technology in place, petcoke promises to aid in the goal of lowering future electricity prices from what they otherwise might be.

GENERATION SELECTION

A balanced utility system typically includes capacity from different generation types. As a whole, Florida's utilities supply electricity from numerous generating unit types. Each generating unit type has both advantages and disadvantages, as outlined below:

- **Pulverized coal (PC)** *units offer a low-cost, abundant, domestic fuel source but are capital-intensive. Overall cost savings may not materialize until several years of service. PC units primarily serve baseload capacity needs.*

- **Combined cycle (CC)** *units are extremely efficient units which use exhaust gases of one or more combustion turbine (CT) units to create steam and, in turn, generate additional electricity. These units are moderately capital-intensive, but burn either natural gas or oil for fuel. CC units may be built in stages to more closely track a utility's load growth. CC units typically serve intermediate capacity needs.*

- **Integrated coal gasification combined cycle (IGCC)** *units are a variation of the combined cycle technology. IGCC units utilize a coal gasifier which extracts gas trapped in coal. The gas is cleaned (to improve emissions) and used as a fuel for the combined cycle unit. IGCC units are capital-intensive but allow fuel flexibility. IGCC units typically serve baseload capacity needs.*

- **Combustion turbine (CT)** *units are the least capital-intensive unit type to construct and do not require permitting under Florida's Power Plant Siting Act. CT units are the least fuel-efficient unit type, and they burn either natural gas or oil. CT units are typically used to meet peak load needs.*

A utility's generation selection process typically begins with a financial analysis of the present worth revenue requirements (PWRR) of each option under consideration. Combinations of the unit types mentioned above are added to the system in years when the utility has projected a need for capacity. This process calculates incremental capacity costs and total system fuel costs. The unit(s) which result in the lowest system PWRR is chosen by the utility for construction. When analysis of alternatives yields options whose PWRR may be nearly the same, the final unit selection may be made utilizing strategic concerns. Strategic concerns include consideration of existing generation mix, environmental concerns, regulatory policy, and the flexibility of the plan to meet changing conditions. The objective of these strategic concerns is to add factors other than solely cost-effectiveness to the unit selection process.

Alternative scenarios, which result from consideration of strategic concerns, were not included by the utilities in their Ten-Year Site Plans. Most reporting utilities submitted scenario analysis in response to the Commission staff's supplemental data requests.

Coal Gasification

Coal gasification technology appears to provide flexibility needed to meet potential environmental restrictions and address low initial capital investment if the combined cycle portion of the facility is constructed first. If the price differential of oil and natural gas compared to coal widens, the savings from coal gasification might justify additional capital investment at that time. As a result, for power plant siting purposes, it is important to consider whether a site is capable of supporting a coal gasification plant and all the implications to the local transportation infrastructure. Tampa Electric Company is currently constructing a 265 MW IGCC unit which will serve as a demonstration project for the U.S. Department of Energy.

Hydroelectric

While hydroelectric generation continues to make a minute contribution to Florida's generation mix, there are no future plans to construct new units due to the absence of a new location feasible for such a unit.

Interchange Purchases

Florida's utilities often purchase capacity from other utilities. Interchange purchases are typically short-term purchases of excess capacity and energy between utilities. The maximum amount of power that Florida can import over the Southern Company-Florida interconnection is approximately 3600 MW. Over the next ten years, there appears to be a trend towards replacing interchange power with utility-owned capacity and purchases from qualifying facilities because of load growth in Southern Company's territory. While the amount of interchange power is projected to decrease, some capacity from the Southern/Florida interconnection will still remain for economy and emergency transactions.

Capacity Purchases from Qualifying Facilities

Qualifying facilities (QFs) sell electricity to Florida's utilities under long-term firm capacity purchases. QFs do not share the utilities' obligation to serve and, therefore, only build and operate generating units to satisfy a contractual requirement and make a profit. Florida's electric utilities plan to increase the amount of QF capacity purchases over the next ten years.

The Commission continues to believe that utility Ten-Year Site Plans should be as flexible as possible with respect to fuel type. All new power plants should be initially built with the capability to burn multiple fuels. Sites should be designed and infrastructure set to facilitate cost-effective fuel conversion of these units in the future.

TAMPA ELECTRIC COMPANY

TECO's Polk Unit 1, an integrated coal gasification combined cycle (IGCC) unit, is scheduled to be placed into service in October, 1996. TECO also plans to add one natural-gas fired combustion turbine at the Polk County site in each year from 2001 through 2004. TECO's Ten-Year Site Plan does not discuss any plan for delivering natural gas to the Polk County site. In addition, no contingency plans are provided in the event that natural gas pipeline capacity is not available in the future.

Treatment of Hardee Power Station

Hardee Power Partners, Limited (HPP -- a TECO Power Services Corporation) owns and operates the natural gas-fired Hardee Power Station Units 1 and 2 located in northwest Hardee County. Unit 1 is a 220 MW combined cycle unit consisting of two 75 MW combustion turbines and a 70 MW heat recovery steam generator. Unit 2 currently consists of a single 75 MW combustion turbine. Seminole Electric Cooperative (SEC) has first call on this capacity for backup purposes for its coal-fired Seminole Units 1 and 2 and its ownership share of Crystal River Unit 3. When one or more of these units are not available, SEC may utilize capacity from Hardee Power Station. TECO also has arrangements with HPP which allow TECO to purchase capacity from Hardee Power Station at times when Seminole is not exercising its capacity rights.

Because the Hardee Power Station is shared, there is particular interest in how this capacity is treated in SEC's and TECO's Ten-Year Site Plans. SEC has a dual reliability criteria of one percent expected unserved energy (EUE) and 15% reserve margin. TECO has a dual reliability criteria of 0.1 days per year loss of load probability (LOLP) and 20% reserve margin. EUE is a measure of the magnitude of the unserved energy, while LOLP is a measure of the frequency of occurrence of energy shortages.

Having first call on Hardee Power Station's capacity, SEC properly includes that capacity in calculating its reserve margin. However, TECO also includes Hardee Power Station's capacity in calculating its reserve margin and LOLP. There is disagreement between TECO and SEC on the appropriateness of TECO including Hardee Power Station capacity in calculating reserves.

Reserve margin is a simple reliability criteria which compares all supply side resources to system demand. This statistic assumes continuous availability of a supply side resource, such as a generating unit. Reserve margin does not take into consideration a resource which may be available in equal amounts to different utilities at different times during a year. This is the case with Hardee Power Station. SEC and TECO may use the maximum capacity available, but during different times of the year.

If the Hardee Power Station capacity is removed from TECO's reserve margin calculation, TECO's 20% reserve margin criteria is violated except for summer, 1995 and winter, 1997. Despite this fact, TECO does not plan to add generating capacity until the year 2003. If the Hardee Power Station capacity is included, TECO's percent reserve margin exceeds the criteria in each year of the ten year planning period.

In calculating LOLP, TECO removes the hours and capacity SEC would utilize from Hardee Power Station. The amount of hours and capacity has been estimated based on SEC's historical use of Hardee Power Station. Therefore, LOLP allows TECO to account for periods when Hardee Power Station capacity is unavailable. It appears that, for planning purposes, TECO is properly accounting for the Hardee Power Station capacity in its calculation of LOLP.

Load Forecast

TECO's base energy forecast is the result of three separate forecasting methods. The most comprehensive of the three is the detailed end-use model. The results of two additional models (Multiregression and Trend Analysis) are blended with the end-use model to form the basis of the forecast. TECO's Ten-Year Site Plan does not identify how these models are reconciled.

TECO separately forecasts the energy associated with Phosphate mining, and this forecasted energy is subsequently added to the base forecast. TECO also forecasts demand and energy savings associated with conservation programs, an amount which is deducted from the base forecast.

TECO's end-use forecast method takes into account a wide range of forecast assumptions identified in its 1995 Ten-Year Site Plan. However, TECO did not construct high and low band forecasts, thereby failing to identify the level of variability in the forecast associated with different assumptions. High and low band forecasts provide for the response of electricity usage to higher-than-normal and lower-than-normal economic, demographic, and weather variables which affect electricity usage.

From 1990 through 1994, the percent error of TECO's retail sales forecast was less than the average for the state's eleven largest utilities. The error rate of TECO's forecasted sales to actual sales for the five year period was 2.07 percent, whereas the average for the eleven utilities was 2.88 percent. In addition, forecast errors reveal no evidence of either systematic over-forecasting or under-forecasting by TECO.

TECO's base forecast for NEL, including the years 1995 through 2004, falls easily within the 95 percent confidence interval constructed around the Commission staff's forecasted NEL for TECO. In 2004, the 95% confidence interval ranges from 17,335 GWh to 19,992 GWh, and TECO's forecast is 18,953 GWh.

The Commission believes that TECO's load forecast as presented in its 1995 Ten-Year Site Plan is reasonable for planning purposes.

Conservation

The majority of TECO's winter demand savings over the next ten years are expected to come from TECO's load management program (320 MW in winter, 2004). TECO forecasts the load management program, other DSM programs, and other non-firm service tariffs to reduce winter peak demand by nearly 1020 MW in 2004, approximately

23% of TECO's total winter peak load. DSM programs are projected to reduce TECO's system annual energy usage by 329 GWh (1.7%) in 2004. Over the next ten years, TECO's DSM programs and non-firm service tariffs are projected to contribute over 15.5% of the winter demand savings and 4.5% of the annual energy savings forecasted by all reporting utilities.

Fuel Forecast

TECO's generation mix is dominated by coal-fired generation. Coal-fired generation provides more than 100% of TECO's load requirements, thus affording an opportunity to engage in power transactions with other utilities. Though TECO maintains the ability to rely on oil and natural gas generation, these fuel types remain undetectable in relation to coal generation. TECO is currently diversifying its fuel mix with the addition in 1996 of the Polk IGCC unit that will be fueled by gas extracted from coal. In the future, TECO plans to attempt to burn petcoke in its coal units as the economics of the fuel indicate continued cost-effectiveness.

TECO's base case coal price forecast is substantially below the average of the other reporting utilities. This outlook contradicts TECO's past performance of maintaining the highest cost of coal generation of the four IOU's since 1991. The Commission recognizes that TECO recently replaced its high-priced Peabody Coal contract with two lower-priced contracts that more closely resemble the market's current depressed condition. However, until TECO is able to replace its remaining high-priced coal contracts with other contracts representative of the current market, TECO should base its IRP process on a realistically higher coal price forecast.

Although TECO predicts natural gas prices to track those of residual oil, natural gas prices are expected to be substantially higher, and may approach distillate oil prices in the far future. Other reporting utilities also make the same prediction, but none estimate a difference as large as TECO.

Environmental Compliance

TECO is subject to both Phase I and Phase II compliance restrictions of the Clean Air Act Amendments of 1990. While it has not formally filed a Clean Air Act Compliance plan for approval by the Commission, TECO's strategy appears to be similar to that proposed by Gulf -- fuel switching and allowance purchases. For Phase I compliance, TECO has purchased a stream of allowances for the period 1995 through 1999 at an equivalent cost below the cost of a scrubber retrofit at the Big Bend Station. In addition, changes in TECO's fuel contracts point towards a shift to usage of lower sulfur content coal to control emissions. Finally, TECO is currently in the process of connecting the existing scrubber at Big Bend Unit 4 to serve Big Bend Unit 3 in a shared arrangement between the two units.

TECO has made effective use of market prices and maintained a high degree of flexibility in designing compliance strategies for compliance with the Act. TECO's plan mentions that public acceptance and environmental acceptability are criteria used to screen generating technologies. Environmental compliance and coordination with respective regulatory agencies are discussed to the extent that site certification is granted based on various conditions and requirements by the EPA and state certification hearing conclusions. Concerns and policies of county, regional planning, and management councils are also conditions of certification.

TECO used various reputable sources to determine emission levels. Estimates of emission levels for low demand and low fuel price sensitivities are higher than the base case. The proposed Polk IGCC unit does not appear to impact the trend of system emission levels other than a one-year drop in 1998. The low demand case has a higher emission rate than any other sensitivity. Because of their dependence on coal-fired generation, TECO's and Gulf's emission rates are higher than those of FPL and FPC.

TECO states that recent restructuring in federal and state politics makes it difficult to predict future environmental legislation. TECO is not aware of any proposals which would significantly affect its integrated resource plan.

State, Regional, and Local Agency Comments

The following agencies provided the Commission with comments on TECO's Ten-Year Site Plan:

- **Florida Department of Environmental Protection**: No comments filed.
- **Florida Department of Community Affairs**: No comments filed.
- **Tampa Bay Regional Planning Council**: Approves TECO's Ten-Year Site Plan as being consistent with regional policies.
- **Southwest Florida Water Management District**: Because new withdrawals from the Florida aquifer will be greatly restricted in the future, new power plants and plant expansions in this area will require careful planning and close coordination with the District. Early coordination with District regulatory staff is advised.
- **Hillsborough County**: States that TECO's Ten-Year Site Plan raised no issues of concern.

Based upon the foregoing review of TECO's Ten-Year Site Plan and the related government and public comments, we classify TECO's plan as **suitable**.

TAMPA ELECTRIC COMPANY
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WITNESS: HERNANDEZ
EXHIBIT NO. ____ (TLH-2)
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DOCUMENT NO. 9

FPC AND FPL COAL AND NATURAL GAS FUEL PRICE FORECASTS

Differential Fuel Price

Coal VS Natural Gas
FPL and FPC Forecasts (1)

Nominal $/MBTU

	FPL			FPC		
Year	(2) Coal	(3) Natural Gas	Differential	(2) Coal	(3) Natural Gas	Differential
1996	1.56	2.42	0.86	1.68	2.51	0.83
1997	1.61	2.55	0.94	1.77	2.61	0.84
1998	1.63	2.72	1.09	1.79	2.71	0.92
1999	1.66	2.85	1.19	1.83	2.82	0.99
2000	1.71	3.06	1.35	1.89	2.98	1.09
2001	1.77	3.29	1.52	1.93	3.14	1.21
2002	1.75	3.50	1.75	1.97	3.30	1.33
2003	1.75	3.72	1.97	2.01	3.46	1.45
2004	1.80	3.94	2.14	2.05	3.62	1.57
2005	1.86	4.16	2.30	2.09	3.73	1.64
2006	1.91	4.37	2.46	2.13	3.89	1.76
2007	1.98	4.61	2.63	2.17	4.07	1.89
2008	2.11	4.87	2.76	2.22	4.24	2.03
2009	2.18	5.14	2.96	2.26	4.43	2.17
2010	2.25	5.42	3.17	2.31	4.63	2.32
2011	2.32	5.69	3.37	2.36	4.83	2.47
2012	2.40	5.96	3.56	2.40	5.04	2.64
2013	2.53	6.25	3.72	2.45	5.26	2.81
2014	2.61	6.56	3.95	2.50	5.49	2.99
2015	2.70	6.88	4.18	2.55	5.74	3.19

Notes:

(1) Forecasts are from FPL and FPC 1996 TYSP Supplemental Data Request.
Note: Fuel prices beyond 2005 were not available in the FPC Supplemental.
The FPC fuel prices in 2005 were escalated using the five year AGGR
(2001 - 2005) for each fuel.

(2) Medium sulfur coal (1.0-2.0%) - Base Case

(3) Delivered natural gas - Base Case

DOCUMENT NO. 10

INTERROGATORIES FILED IN DOCKET 960409-EI
BEGINNING WITH STAFF'S 4TH SET

40. Please provide an itemized estimate of the savings that result from changing the original plan of phasing the IGCC unit into service in 1995 and 1996 to the present configuration of bringing the entire unit into service in 1996.

A. The resulting savings from deferring the advanced combustion turbine from July 1995 to July 1996 are shown in Table 40-1. The deferral analysis completed in August of 1993 shows a net savings of approximately $12.8 million.

TABLE 40-1

DEFERRAL OF ADVANCED COMBUSTION TURBINE

PHASED IGCC					
		Nominal Revenue Requirements			
YEAR	PLANT IN-SERVICE DATE	CAPITAL $000	FUEL & PURCHASE POWER $000	O&M $000	TOTAL $000
1993		4,300	250,759	2,596	257,655
1994		4,104	287,215	2,827	294,146
1995	ACT - 7/1995	13,500	326,629	4,510	344,640
1996	IGCC - 7/1996	68,828	336,252	4,111	409,191
CPW ($000)		72,287	1,046,348	12,129	1,130,763

SINGLE IGCC					
		Nominal Revenue Requirements			
YEAR	PLANT IN-SERVICE DATE	CAPITAL $000	FUEL & PURCHASE POWER $000	O&M $000	TOTAL $000
1993		4,300	250,759	2,596	257,655
1994		4,104	287,215	2,827	294,146
1995		5,372	327,636	3,843	336,851
1996	IGCC - 7/1996	60,410	337,086	3,591	401,087
CPW ($000)		58,997	1,047,834	11,169	1,118,000

DEFERRAL BENEFITS					
		Nominal Revenue Requirements			
YEAR	PLANT IN-SERVICE DATE	CAPITAL $000	FUEL & PURCHASE POWER $000	O&M $000	TOTAL $000
1993		0	0	0	0
1994		0	0	0	0
1995		(8,128)	1,006	(667)	(7,789)
1996		(8,418)	834	(520)	(8,104)
CPW ($000)		(13,289)	1,486	(960)	(12,763)

48. Using the data available at the time in question, how much would it have cost to acquire firm natural gas transportation in 1994 for a base load or intermediate 220 MW unit located at the Polk IGCC site?

A. Since FGT's Phase III capacity was fully subscribed, establishing a firm natural gas supply at that time would have required Tampa Electric to acquire relinquished Phase III capacity. Arrangements for selling the contracted gas starting in 1995 and continuing up to the in-service date of the unit (i.e., 1/1/96) would be required. Tampa Electric does not know whether such arrangements could have been made or whether the purchaser would have had to absorb the costs.

The cumulative present worth revenue requirements associated with the fixed and operating costs required to procure and establish a firm natural gas supply at an 80% capacity factor is approximately $730 million in 1994 dollars as shown in Table 48-1.

TABLE 48-1

1994 Spring Forecast*
Firm Gas Supply Analysis
Nominal Cost Projection

Unit In-service Date: 1/1/96

Year	Capital (Pipeline) ($000)	Natural Gas ($000)	Firm Gas Transportation ($000)	Total ($000)
1996	80	28,276	11,044	39,400
1997	77	30,750	11,044	41,871
1998	74	33,074	11,044	44,192
1999	71	35,673	11,044	46,788
2000	69	38,514	11,044	49,628
2001	66	41,624	11,044	52,735
2002	64	45,030	11,044	56,138
2003	62	48,763	11,044	59,870
2004	59	52,810	11,044	63,913
2005	57	57,196	11,044	68,297
2006	55	62,007	11,044	73,106
2007	53	67,228	11,044	78,326
2008	50	72,892	11,044	83,987
2009	48	79,038	11,044	90,131
2010	46	85,706	11,044	96,796
2011	44	91,239	11,044	102,328
2012	43	97,041	11,044	108,129
2013	42	103,213	11,044	114,300
2014	41	109,885	11,044	120,970
2015	40	116,988	11,044	128,073
2016	39	124,555	11,044	135,638
2017	38	132,613	11,044	143,695
2018	38	141,854	11,044	152,936
2019	37	151,742	11,044	162,824
2020	36	162,324	11,044	173,404
2021	35	173,645	11,044	184,724
2022	34	184,028	11,044	195,106
2023	34	195,035	11,044	206,113
CPW '94$	**586**	**621,311**	**107,872**	**729,769**

Notes:

1. Gas price based on Table 5-3 of Interrogatory No. 5 in Docket 950379-EI minus reservation charge.

2. Fuel reimbursement charge is not included in firm gas transportation values. (Approx. 3% of fuel charge.)

Table 48-2

Engineering and Economic Assumptions
for Firm Gas Supply

1994 Assumptions	
Capacity (MW)	220
Capacity Factor (%) (Annual)	80
Heat Rate (BTU/KWH) (Heat Rate @ Maximum)	7,641
MBTU (x 1000) (Annual Contracted)	11,781
Reservation Charge ($/MBTU)	0.75
Usage Charge ($/MBTU)	0.05
Gas ($/MBTU) (As delivered to FGT + usage charge)	1994 Spring Forecast Table 5-3 of Intr. No. 5 (Docket 950379-EI) (less reservation $/MBTU)
Gas Pipeline Assumptions (1996$):	
6 Inch Diameter Pipe (1.3 miles)	280,675
Hot Tap	16,841
Meter Station	120,906
Total (1996$)	418,422
Capital Escalation (%)	
1994	3.8
1995	4.0
Pipeline Book Life (years)	30
Pipeline Tax Life (years)	15
1994 Discount Rate (%)	8.47

Note: Gas pipeline base costs based on 1994 estimate from FGT.
Assumes FGT builds line, but TEC owns. (No tax gross-up included)

49. Using the data available at the time in question, how much would it have cost to acquire firm natural gas transportation in 1995 for a base load or intermediate 220 MW unit located at the Polk IGCC site?

A. Since FGT's Phase III capacity was fully subscribed, establishing a firm natural gas supply at that time would have required Tampa Electric to acquire relinquished Phase III capacity. Arrangements for selling the contracted gas starting in 1995 and continuing up to the in-service date of the unit (i.e., 1/1/96) would be required. Tampa Electric does not know whether such arrangements could have been made or whether the purchaser would have to absorb the costs.

The cumulative present worth revenue requirements associated with the fixed and operating costs required to procure and establish a firm natural gas supply at an 80% capacity factor is approximately $709 million in 1995 dollars as shown in Table 49-1.

TABLE 49-1

1994 Fall Forecast*
Firm Gas Supply Analysis
Nominal Cost Projection

Unit In-service Date: 1/1/96

Year	Capital (Pipeline) ($000)	Natural Gas ($000)	Firm Gas Transportation ($000)	Total ($000)
1996	84	27,087	11,002	38,173
1997	81	29,840	11,002	40,923
1998	78	32,585	11,002	43,665
1999	74	35,465	11,002	46,541
2000	71	38,290	11,002	49,363
2001	69	41,381	11,002	52,453
2002	66	44,767	11,002	55,836
2003	64	48,478	11,002	59,545
2004	61	52,501	11,002	63,565
2005	59	56,862	11,002	67,923
2006	56	61,645	11,002	72,704
2007	54	66,835	11,002	77,892
2008	51	72,467	11,002	83,520
2009	49	78,576	11,002	89,628
2010	46	85,205	11,002	96,254
2011	44	90,706	11,002	101,752
2012	43	96,473	11,002	107,519
2013	42	102,610	11,002	113,654
2014	41	109,242	11,002	120,285
2015	40	116,304	11,002	127,346
2016	39	123,826	11,002	134,867
2017	39	131,836	11,002	142,878
2018	38	141,024	11,002	152,064
2019	37	150,854	11,002	161,894
2020	36	161,373	11,002	172,411
2021	35	172,628	11,002	183,665
2022	34	182,951	11,002	193,987
2023	34	193,892	11,002	204,929
2024	33	205,491	11,002	216,526
CPW '95$	**613**	**601,403**	**107,391**	**709,407**

Notes:

1. Gas price based on Table 5-3 of Interrogatory No. 5 in Docket 950379-EI minus reservation charge.

2. Fuel reimbursement charge is not included in firm gas transportation values. (Approx. 3% of fuel charge.)

Table 49-2

Engineering and Economic Assumptions
for Firm Gas Supply

1995 Assumptions	
Capacity (MW)	220
Capacity Factor (%) (Annual)	80
Heat Rate (BTU/KWH) (Heat Rate @ Maximum)	7,612
MBTU (x 1000) (Annual Contracted)	11,736
Reservation Charge ($/MBTU)	0.75
Usage Charge ($/MBTU)	0.05
Gas ($/MBTU) (As delivered to FGT + usage charge)	See 1994 Fall Forecast Table 5-3 of Intr. No. 5 (Docket 950379-EI) (less reservation $/MBTU)
Gas Pipeline Assumptions (1996$):	
6 Inch Diameter Pipe (1.3 miles)	276,906
Hot Tap	16,614
Meter Station	119,283
Total (1996$)	412,803
Capital Escalation (%)	
1994	3.1
1995	3.3
Pipeline Book Life (years)	30
Pipeline Tax Life (years)	15
1995 Discount Rate (%)	9.51

Note: Gas pipeline costs based on 1994 estimate from FGT escalated to 1996 dollars. Assumes FGT builds, but TEC owns. (No tax gross-up included.)

50. What is the current cost to acquire firm natural gas transportation for a base load or intermediate 220 MW unit located at the Polk IGCC site?

A. Since FGT's Phase III capacity was fully subscribed, establishing a firm natural gas supply at that time would have required Tampa Electric to acquire relinquished Phase III capacity. Arrangements for selling the contracted gas starting in 1995 and continuing up to the in-service date of the unit (i.e., 1/1/96) would be required. Tampa Electric does not know whether such arrangements could have been made or whether the purchaser would have to absorb the costs.

The cumulative present worth revenue requirements associated with the fixed and operating costs required to procure and establish a firm natural gas supply at an 80% capacity factor is approximately $611 million in 1996 dollars as shown in Table-50-1.

TABLE 50-1

1995 Fall Forecast*
Firm Gas Supply Analysis
Nominal Cost Projection

Unit In-service Date: 1/1/96

Year	Capital (Pipeline) ($000)	Natural Gas ($000)	Firm Gas Transportation ($000)	Total ($000)
1996	109	20,691	10,346	31,145
1997	106	22,944	10,346	33,396
1998	102	24,967	11,085	36,154
1999	98	26,904	11,085	38,087
2000	94	29,141	11,085	40,319
2001	91	31,282	11,085	42,458
2002	88	33,584	11,085	44,756
2003	84	36,058	11,085	47,227
2004	81	38,718	11,085	49,884
2005	78	41,578	11,085	52,740
2006	75	44,652	11,085	55,811
2007	72	47,956	11,085	59,113
2008	69	51,509	11,085	62,662
2009	65	55,327	11,085	66,477
2010	62	59,433	11,085	70,579
2011	60	63,846	11,085	74,991
2012	58	67,325	11,085	78,468
2013	57	70,995	11,085	82,137
2014	56	74,867	11,085	86,008
2015	55	78,953	11,085	90,092
2016	54	83,262	11,085	94,401
2017	52	87,809	11,085	98,946
2018	51	92,606	11,085	103,742
2019	50	97,667	11,085	108,802
2020	49	103,006	11,085	114,140
2021	48	108,639	11,085	119,772
2022	47	114,582	11,085	125,714
2023	46	119,711	11,085	130,842
2024	45	125,072	11,085	136,202
2025	44	130,673	11,085	141,802
CPW '96$	**906**	**489,451**	**120,197**	**610,554**

Notes:
1. Gas price based on Table 5-3 of Interrogatory No. 5 in Docket 950379-EI minus reservation charge.
2. Fuel reimbursement charge is not included in firm gas transportation values. (Approx. 3.4% of fuel charge.)

Table 50-2

Engineering and Economic Assumptions
for Firm Gas Supply

1996 Assumptions	
Capacity (MW)	220
Capacity Factor (%) (Annual)	80
Heat Rate (BTU/KWH) (HHV @ ISO)	7,669
MBTU (x 1000) (Annual Contracted)	11,824
Reservation Charge ($/MBTU)	
1996 - 1997	0.70
1998 - beyond	0.75
Usage Charge ($/MBTU)	0.05
Gas ($/MBTU) (As delivered to FGT + usage charge)	See 1995 Fall Forecast Table 5-3 of Intr. No. 5 (Docket 950379-EI) (less transportation $/MBTU)
Gas Pipeline (1996$) *	550,000
Pipeline Book Life (years)	30
Pipeline Tax Life (years)	15
1996 Discount Rate (%)	9.26

* Based on 1996 FGT estimate assumes FGT builds and TEC owns. (No tax gross-up included.)

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51. Interrogatory Number 26, of Staff's First Set of Interrogatories in Docket 950379-EI, identifies that $4 million is required to burn pet coke. What improvements or retrofit activities are required to use pet coke at the Polk IGCC site? Response should include a detailed itemization of all cost components.

A. As in our response to interrogatory No. 9, in Docket No. 960409-EI, the $4 million estimate was included in the 1996 study only for IGCC plant modifications in order to support a petroleum coke/coal blend beginning in 1999 and beyond. The potential plant modifications are in the areas of fuel handling and fluxing of the petroleum coke/coal blends, sulfur removal and recovery sections of the plant, and in the zero discharge wastewater treatment section of the plant. A detailed scope of work to modify the plant to burn petroleum coke has not been developed at this time. Experience on Texaco gasification plants, as well as an analysis of the design basis of systems and equipment has allowed us to estimate the types of modifications which may be required. The plant will be tested on petroleum coke and the test results analysed to determine what modifications, if any, are required. These potential modifications were identified in May, 1995 and therefore were not included in prior studies.

58. Please provide a detailed itemization of the "sunk costs" amounts used in each of the yearly reviews to determine the cost-effectiveness of the Polk County IGCC unit. Please provide a separate tabulation for each year and for each unit, the IGCC and the combined-cycle.

A. A detailed itemization of "sunk" costs used in each of the cost-effectiveness analyses is provided in Tables 58A - 58E.

Sunk costs for the IGCC unit were not represented as a line item in the assumptions tables for the cost-effectiveness analyses provided in Interrogatory No. 3 of Docket No. 950379-EI as these expenditures were included in the total estimate for the IGCC unit and were not considered additive. The attached tables itemize project-to-date expenditures for the IGCC project at the time of each cost-effectiveness study and are included in the balance of categories for each study's capital cost estimate.

The sunk costs identified for the combined cycle as a line item in the assumptions tables (Interrogatory No. 3 of Docket No. 950379-EI) represent actual project-to-date expenditures for "non-combined cycle" related costs (i.e., gasifier sunk costs) at the time of each study. These sunk costs, itemized on the attached tables, were not included elsewhere in the combined cycle estimate and are considered additive.

Table 58-A

Tampa Electric Company
Polk Power Station
"Sunk Cost" Itemization
1992 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1992 Study PTD 12/92	1992 Study PTD 12/92
COMMON & GENERAL	12,660	326
HGCU & SULFURIC ACID PLANTS	330	330
COLD GAS CLEANUP	237	237
OXYGEN PLANT	75	75
GASIFICATION PLANT	3,823	3,823
POWER GENERATION	970	
HEAT RECOVERY (HRSG)	508	
PLANT ELECTRICAL		
SITE DEVELOPMENT & BUILDINGS	107	
PLANT UTILITIES		
TOTAL PROJECT	18,710	4,791

Table 58-B

Tampa Electric Company
Polk Power Station
"Sunk Cost" Itemization
1993 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1993 Study PTD 8/93	1993 Study PTD 8/93
COMMON & GENERAL	18,262	4,905
HGCU & SULFURIC ACID PLANTS	843	843
COLD GAS CLEANUP	700	700
OXYGEN PLANT	1,243	1,243
GASIFICATION PLANT	9,543	9,543
POWER GENERATION	21,304	0
HEAT RECOVERY (HRSG)	4,689	0
PLANT ELECTRICAL	21	11
SITE DEVELOPMENT & BUILDINGS	3,616	0
PLANT UTILITIES	191	102
TOTAL PROJECT	60,414	17,348

Table 58-C

Tampa Electric Company
Polk Power Station
"Sunk Cost" Itemization
1994 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1994 Study PTD 4/94	1994 Study PTD 4/94
COMMON & GENERAL	29,203	9,844
HGCU & SULFURIC ACID PLANTS	2,036	2,036
COLD GAS CLEANUP	1,292	1,292
OXYGEN PLANT	5,415	5,415
GASIFICATION PLANT	15,574	15,574
POWER GENERATION	44,144	0
HEAT RECOVERY (HRSG)	10,100	0
PLANT ELECTRICAL	151	55
SITE DEVELOPMENT & BUILDINGS	22,155	0
PLANT UTILITIES	1,202	632
TOTAL PROJECT	131,271	34,847

Table 58-D

Tampa Electric Company
Polk Power Station
"Sunk Cost" Itemization
1995 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1995 Study PTD 7/95	1995 Study PTD 7/95
COMMON & GENERAL	58,805	24,464
HGCU & SULFURIC ACID PLANTS	19,162	19,162
COLD GAS CLEANUP	7,530	7,530
OXYGEN PLANT	28,074	28,074
GASIFICATION PLANT	70,775	70,775
POWER GENERATION	74,363	0
HEAT RECOVERY (HRSG)	32,539	5,325
PLANT ELECTRICAL	16,756	6,281
SITE DEVELOPMENT & BUILDINGS	52,483	0
PLANT UTILITIES	16,473	8,804
TOTAL PROJECT	376,961	170,416

Table 58-E

Tampa Electric Company
Polk Power Station
"Sunk Cost" Itemization
1996 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1996 Study PTD 12/95	1996 Study PTD 12/95
COMMON & GENERAL	71,660	31,052
HGCU & SULFURIC ACID PLANTS	36,915	36,915
COLD GAS CLEANUP	9,951	9,951
OXYGEN PLANT	36,541	36,541
GASIFICATION PLANT	100,299	100,299
POWER GENERATION	77,394	0
HEAT RECOVERY (HRSG)	42,129	7,709
PLANT ELECTRICAL	21,101	8,713
SITE DEVELOPMENT & BUILDINGS	59,465	0
PLANT UTILITIES	24,283	13,762
TOTAL PROJECT	**479,740**	**244,943**

60. For each cost-effectiveness analysis included with the testimony of Thomas L. Hernandez, please provide a break down of the amount shown as land and development costs. State separately the purchase price, amount attributable to required reclamation and amount attributable to development.

A. The land acquisition costs and site development costs are shown separately for each cost-effectiveness study in Tables 60-A through 60-E.

The land acquisition costs itemized within are an estimate at the time of each of Tampa Electric Company's evaluation of Project 105.57 Polk Unit #1 land costs. The development/reclamation estimates are based on site prep costs associated with Project L50 and cannot be segregated for development versus reclamation, as the site prep packages accomplished the project requirements for development/reclamation within a single contract with a unified scope of work.

Table 60-A

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1992 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1992 Study	1992 Study
LAND ACQUISITION COSTS	16,455	16,455
SITE DEVELOPMENT	36,201	36,201
TOTAL PROJECT	**52,656**	**52,656**

Table 60-B

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1993 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1993 Study	1993 Study
LAND ACQUISITION COSTS	16,672	16,672
SITE DEVELOPMENT	40,368	40,368
TOTAL PROJECT	57,040	57,040

Table 60-C

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1994 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1994 Study	1994 Study
LAND ACQUISITION COSTS	19,943	19,943
SITE DEVELOPMENT	41,280	41,280
TOTAL PROJECT	61,223	61,223

Table 60-D

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1995 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1995 Study	1995 Study
LAND ACQUISITION COSTS	19,837	19,837
SITE DEVELOPMENT	44,698	44,698
TOTAL PROJECT	64,535	64,535

Table 60-E

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1996 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1996 Study	1996 Study
LAND ACQUISITION COSTS	19,840	19,840
SITE DEVELOPMENT	45,995	45,995
TOTAL PROJECT	65,835	65,835

63. Please provide a detailed itemization of the "Plant Costs" amounts used in each of the yearly reviews used to determine the cost-effectiveness of the Polk County IGCC Unit. For both the IGCC and the combined-cycle units, please itemize these costs separately by year and by unit.

A. A detailed itemization of "Plant" costs used in each of the cost-effectiveness studies is provided in Tables 63A - 63E.

Table 63-A

Tampa Electric Company
Polk Power Station
"Plant Cost" Itemization
1992 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1992 Study	1992 Study
	0	0
COMMON & GENERAL	24,498	0
HGCU & SULFURIC ACID PLANTS	36,249	0
COLD GAS CLEANUP	43,517	0
OXYGEN PLANT	36,994	0
GASIFICATION PLANT	54,810	46,574
POWER GENERATION	32,190	23,069
HEAT RECOVERY (HRSG)	152,911	75,102
PLANT ELECTRICAL	0	0
SITE DEVELOPMENT & BUILDINGS	570	280
PLANT UTILITIES	0	0
DOE COST SHARING	381,739	145,025
TOTAL PROJECT		

Table 63-B

Tampa Electric Company
Polk Power Station
"Plant Cost" Itemization
1993 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1993 Study	1993 Study
COMMON & GENERAL	0	0
HGCU & SULFURIC ACID PLANTS	39,382	0
COLD GAS CLEANUP	13,440	0
OXYGEN PLANT	35,482	0
GASIFICATION PLANT	124,090	0
POWER GENERATION	88,067	88,067
HEAT RECOVERY (HRSG)	39,750	30,523
PLANT ELECTRICAL	15,765	7,590
SITE DEVELOPMENT & BUILDINGS	0	0
PLANT UTILITIES	36,299	16,251
DOE COST SHARING	0	0
TOTAL PROJECT	392,275	142,431

Table 63-C

Tampa Electric Company
Polk Power Station
"Plant Cost" Itemization
1994 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1994 Study	1994 Study
COMMON & GENERAL	0	0
HGCU & SULFURIC ACID PLANTS	39,382	0
COLD GAS CLEANUP	13,441	0
OXYGEN PLANT	35,482	0
GASIFICATION PLANT	124,090	0
POWER GENERATION	88,067	88,476
HEAT RECOVERY (HRSG)	39,750	30,653
PLANT ELECTRICAL	18,965	10,994
SITE DEVELOPMENT & BUILDINGS	0	0
PLANT UTILITIES	36,299	16,512
DOE COST SHARING	0	0
TOTAL PROJECT	395,476	146,635

Table 63-D

Tampa Electric Company
Polk Power Station
"Plant Cost" Itemization
1995 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1995 Study	1995 Study
COMMON & GENERAL	0	0
HGCU & SULFURIC ACID PLANTS	41,681	0
COLD GAS CLEANUP	12,690	0
OXYGEN PLANT	36,384	0
GASIFICATION PLANT	111,972	0
POWER GENERATION	78,070	78,479
HEAT RECOVERY (HRSG)	51,440	38,967
PLANT ELECTRICAL	22,685	12,450
SITE DEVELOPMENT & BUILDINGS	0	0
PLANT UTILITIES	32,726	14,682
DOE COST SHARING	0	0
TOTAL PROJECT	387,648	144,577

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Table 63-E

Tampa Electric Company
Polk Power Station
"Plant Cost" Itemization
1996 Po!k Unit Analysis
($000)

	IGCC	Combined-Cycle
	1996 Study	1996 Study
COMMON & GENERAL	0	0
HGCU & SULFURIC ACID PLANTS	43,171	0
COLD GAS CLEANUP	11,447	0
OXYGEN PLANT	38,258	0
GASIFICATION PLANT	115,074	0
POWER GENERATION	79,544	79,953
HEAT RECOVERY (HRSG)	46,190	37,387
PLANT ELECTRICAL	17,895	10,008
SITE DEVELOPMENT & BUILDINGS	0	0
PLANT UTILITIES	33,292	14,820
DOE COST SHARING	0	0
TOTAL PROJECT	384,871	142,167

64. Please provide a detailed itemization of the "Land and site-development" amounts used in each of the yearly reviews used to determine the cost-effectiveness of the Polk County IGCC Unit. For both the IGCC and the combined-cycle units, please itemize these costs separately by year and by unit.

A. A detailed itemization of "Land and Site Development" costs used in each of the cost-effectiveness studies is provided in Tables 64A - 64E.

Table 64-A

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1992 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1992 Study	1992 Study
LAND ACQUISITION COSTS	16,455	16,455
SITE DEVELOPMENT & RECLAMATION	36,201	36,201
TOTAL PROJECT	52,656	52,656

Table 64-B

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1993 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1993 Study	1993 Study
LAND ACQUISITION COSTS	16,672	16,672
SITE DEVELOPMENT & RECLAMATION	40,368	40,368
TOTAL PROJECT	57,040	57,040

Table 64-C

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1994 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1994 Study	1994 Study
LAND ACQUISITION COSTS	19,943	19,943
SITE DEVELOPMENT & RECLAMATION	41,280	41,280
TOTAL PROJECT	61,223	61,223

Table 64-D

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1995 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1995 Study	1995 Study
LAND ACQUISITION COSTS	19,837	19,837
SITE DEVELOPMENT & RECLAMATION	44,698	44,698
TOTAL PROJECT	64,535	64,535

Table 64-E

Tampa Electric Company
Polk Power Station
"Land & Site Development Cost" Itemization
1996 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1996 Study	1996 Study
LAND ACQUISITION COSTS	19,840	19,840
SITE DEVELOPMENT & RECLAMATION	45,995	45,995
TOTAL PROJECT	65,835	65,835

65. Please provide a detailed itemization of the "common cost" amounts used in each of the yearly reviews used to determine the cost-effectiveness of the Polk County IGCC Unit. For both the IGCC and the combined-cycle units, please itemize these costs separately by year and by unit.

A. A detailed itemization of "Common" costs used in each of the cost-effectiveness studies is provided in Tables 65A - 65E.

Table 65-A

Tampa Electric Company
Polk Power Station
"Common Cost" Itemization
1992 Polk Unit Analysis
($000)

	IGCC 1992 Study	Combined-Cycle 1992 Study
COMMON & GENERAL	88,505	78,274
HGCU & SULFURIC ACID PLANTS		
COLD GAS CLEANUP		
OXYGEN PLANT		
GASIFICATION PLANT		
POWER GENERATION		
HEAT RECOVERY (HRSG)		
PLANT ELECTRICAL		
SITE DEVELOPMENT & BUILDINGS	0	0
PLANT UTILITIES		
DOE COST SHARING		
TOTAL PROJECT	88,505	78,274

Table 65-B

Tampa Electric Company
Polk Power Station
"Common Cost" Itemization
1993 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1993 Study	1993 Study
COMMON & GENERAL	86,456	46,148
HGCU & SULFURIC ACID PLANTS		
COLD GAS CLEANUP		
OXYGEN PLANT		
GASIFICATION PLANT		
POWER GENERATION		
HEAT RECOVERY (HRSG)		
PLANT ELECTRICAL		
SITE DEVELOPMENT & BUILDINGS	8,596	8,596
PLANT UTILITIES		
DOE COST SHARING		
TOTAL PROJECT	95,052	54,743

Table 65-C

Tampa Electric Company
Polk Power Station
"Common Cost" Itemization
1994 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1994 Study	1994 Study
COMMON & GENERAL	86,457	46,715
HGCU & SULFURIC ACID PLANTS		
COLD GAS CLEANUP		
OXYGEN PLANT		
GASIFICATION PLANT		
POWER GENERATION		
HEAT RECOVERY (HRSG)		
PLANT ELECTRICAL		
SITE DEVELOPMENT & BUILDINGS	7,684	7,684
PLANT UTILITIES		
DOE COST SHARING		
TOTAL PROJECT	94,140	54,399

Table 65-D

Tampa Electric Company
Polk Power Station
"Common Cost" Itemization
1995 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1995 Study	1995 Study
COMMON & GENERAL	100,400	55,202
HGCU & SULFURIC ACID PLANTS		
COLD GAS CLEANUP		
OXYGEN PLANT		
GASIFICATION PLANT		
POWER GENERATION		
HEAT RECOVERY (HRSG)		
PLANT ELECTRICAL		
SITE DEVELOPMENT & BUILDINGS	7,474	7,474
PLANT UTILITIES		
DOE COST SHARING		
TOTAL PROJECT	107,875	62,676

Table 65-E

Tampa Electric Company
Polk Power Station
"Common Cost" Itemization
1996 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1996 Study	1996 Study
COMMON & GENERAL	112,008	60,561
HGCU & SULFURIC ACID PLANTS		
COLD GAS CLEANUP		
OXYGEN PLANT		
GASIFICATION PLANT		
POWER GENERATION		
HEAT RECOVERY (HRSG)		
PLANT ELECTRICAL		
SITE DEVELOPMENT & BUILDINGS	6,453	6,453
PLANT UTILITIES		
DOE COST SHARING		
TOTAL PROJECT	118,461	67,014

66. Please provide a detailed itemization of the "DOE credit" amounts used in each of the yearly reviews used to determine the cost-effectiveness of the Polk County IGCC Unit. For both the IGCC and the combined-cycle units, please itemize these costs separately by year and by unit.

A. A detailed itemization of "DOE credit" amounts used in each of the cost-effectiveness studies is provided in Tables 66A - 66E.

Table 66-A

Tampa Electric Company
Polk Power Station
"DOE Credit " Itemization
1992 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1992 Study	1992 Study
COMMON & GENERAL	(16,010)	(2,111)
HGCU & SULFURIC ACID PLANTS	(12,249)	0
COLD GAS CLEANUP	0	0
OXYGEN PLANT	(8,703)	0
GASIFICATION PLANT	(7,399)	(455)
POWER GENERATION	(10,962)	(276)
HEAT RECOVERY (HRSG)	(6,438)	0
PLANT ELECTRICAL	(30,582)	0
SITE DEVELOPMENT & BUILDINGS	(8,172)	(14)
PLANT UTILITIES	(114)	0
DOE COST SHARING		
TOTAL PROJECT	(100,629)	(2,856)

Table 66-B

Tampa Electric Company
Polk Power Station
"DOE Credit " Itemization
1993 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1993 Study	1993 Study
COMMON & GENERAL	(17,487)	(5,873)
HGCU & SULFURIC ACID PLANTS	(13,484)	(782)
COLD GAS CLEANUP	0	0
OXYGEN PLANT	(7,096)	(696)
GASIFICATION PLANT	(24,818)	(2,592)
POWER GENERATION	(17,613)	(6,603)
HEAT RECOVERY (HRSG)	(7,950)	(1,307)
PLANT ELECTRICAL	(3,793)	(4)
SITE DEVELOPMENT & BUILDINGS	(12,109)	(986)
PLANT UTILITIES	(7,260)	(7)
DOE COST SHARING	463	
TOTAL PROJECT	(111,146)	(18,849)

Table 66-C

Tampa Electric Company
Polk Power Station
"DOE Credit " Itemization
1994 Polk Unit Analysis
($000)

	IGCC	Combined-Cycle
	1994 Study	1994 Study
COMMON & GENERAL	(17,496)	(5,681)
HGCU & SULFURIC ACID PLANTS	(13,484)	(994)
COLD GAS CLEANUP	0	0
OXYGEN PLANT	(7,096)	(952)
GASIFICATION PLANT	(24,818)	(3,107)
POWER GENERATION	(17,613)	(8,828)
HEAT RECOVERY (HRSG)	(7,950)	(2,019)
PLANT ELECTRICAL	(3,793)	(21)
SITE DEVELOPMENT & BUILDINGS	(10,743)	(1,028)
PLANT UTILITIES	(7,260)	(234)
DOE COST SHARING		
TOTAL PROJECT	(110,253)	(22,863)

Table 66-D

Tampa Electric Company
Polk Power Station
"DOE Credit " Itemization
1995 Polk Unit Analysis
($000)

	IGCC 1995 Study	Combined-Cycle 1995 Study
COMMON & GENERAL	(20,332)	(11,414)
HGCU & SULFURIC ACID PLANTS	(14,387)	(5,785)
COLD GAS CLEANUP	0	0
OXYGEN PLANT	(7,277)	(4,400)
GASIFICATION PLANT	(22,394)	(12,606)
POWER GENERATION	(15,614)	(14,734)
HEAT RECOVERY (HRSG)	(10,288)	(6,062)
PLANT ELECTRICAL	(4,537)	(2,843)
SITE DEVELOPMENT & BUILDINGS	(11,381)	(6,935)
PLANT UTILITIES	(6,545)	(2,674)
DOE COST SHARING	2,502	
TOTAL PROJECT	(110,253)	(67,452)

Table 66-E

Tampa Electric Company
Polk Power Station
"DOE Credit " Itemization
1996 Polk Unit Analysis
($000)

	IGCC 1996 Study	Combined-Cycle 1996 Study
COMMON & GENERAL	(22,659)	(14,027)
HGCU & SULFURIC ACID PLANTS	(15,405)	(13,105)
COLD GAS CLEANUP	0	0
OXYGEN PLANT	(7,652)	(7,308)
GASIFICATION PLANT	(23,015)	(20,051)
POWER GENERATION	(15,909)	(15,479)
HEAT RECOVERY (HRSG)	(9,238)	(8,426)
PLANT ELECTRICAL	(3,579)	(4,220)
SITE DEVELOPMENT & BUILDINGS	(11,436)	(8,865)
PLANT UTILITIES	(6,658)	(4,857)
DOE COST SHARING	156	
TOTAL PROJECT	(115,395)	(96,338)