BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : DOCKET NO. 950001-EI

Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.

VOLUME - 2

Pages 180 through 244

PROCEEDINGS: **HEARING**

BEFORE: COMMISSIONER J. TERRY DEASON
COMMISSIONER DIANE K. KIESLING
COMMISSIONER JOE GARCIA

DATE: Wednesday, August 9, 1995

TIME: Commenced at 9:30 a.m.
Concluded at 10:50 a.m.

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

REPORTED BY: ROWENA NASH HACKNEY
Official Commission Reporter

APPEARANCES:

(As heretofore noted.)

I N D E X

MISCELLANEOUS - VOLUME 2

WITNESSES - VOLUME 2

(Transcript continues in sequence from Volume 2.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARY JO PENNINO

Q. Please state your name, address, occupation and employer.

A. My name is Mary Jo Pennino. My business address is 702 North Fra~'klin Street, Tampa, Florida 33602. I am Manager - Energy Issues and Administration in the Regulatory Affairs Department of Tampa Electric Company.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Chemical Engineering from the University of South Florida, Tampa, Florida in 1985. Upon graduation, I began my career at Tampa Electric Company in the Production Department. My responsibilities included heat rate testing, support services for the Plant Chemical Engineers, and start-up assistance for Hookers Point Station. In 1991, I transferred to the Generation Planning Department where I was responsible for annual expansion planning analyses, alternative technology evaluation and several other business planning activities. In 1993, I was promoted to Administrator - Wholesale and Fuel in the Regulatory Affairs Department and in 1995 to Manager - Energy Issues and Administration, also in Regulatory Affairs. My present responsibilities include the areas of fuel adjustment filings, capacity cost recovery filings, and rate design.

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

A. The purpose of my testimony is to present the net true-up amounts for the October 1994 through March 1995 period for both the Fuel Cost Recovery and the Capacity Cost Recovery Clauses.

FUEL COST RECOVERY CLAUSE

Q. What is the net true-up amount for the fuel cost recovery clause for the period October 1994 through March 1995.

A. An over/(under) - recovery of ($5,963,794). The actual fuel cost over/(under) - recovery, including interest, is ($3,508,681) for the period October 1994 through March 1995 (Schedule A2, page 3 of 4, of March 1995 monthly filing, in Document No. 4, reflects an end of period total net true-up of $459,884. Subtracting the beginning of period deferred true-up of $3,968,565 yields the ($3,508,681). This ($3,508,681) amount, less the actual/estimated over/(under) - recovery approved in the March 1995 fuel hearings of $2,455,113 results in a final over/(under) - recovery for the period of ($5,963,794). This over/(under) - recovery amount of ($5,963,794) will be carried over and applied in the calculation of the fuel recovery factor for the period October 1995 through March 1996.

Q. How much effect will this ($5,963,794) over/(under) - recovery in the October 1994 through March 1995 period, have on the October 1995 through March 1996 period?

A. The ($5,963,794) over/(under) - recovery will cause a 1,000 KWH residential bill to be approximately $0.89 higher.

Q. Have you prepared an Exhibit in this proceeding?

A. Yes. Exhibit No. (MJP-1, Fuel Cost Recovery and Capacity Cost Recovery) which contains four documents. Document No. 3 is used to explain the capacity cost recovery clause which is discussed later in my testimony. Document No. 4 contains Commission Schedules A-1 through A-12 for the months of October 1994 through March 1995. Included with the March 1995 monthly filing is a six months summary for each of Commission Schedules A7, A7A, A8, A8a, A9, and A10, for the period October 1994 through March 1995.

Q. Please explain Document No. 1.

A. Document No. 1, entitled "Tampa Electric Company Final Fuel Over/(Under) - Recovery for the period October 1994 through March 1995" shows the calculation of the final fuel over/(under) - recovery for the period of ($5,963,794) which will be applied to jurisdictional sales during the period October 1995 through March 1996.

Line 1 shows the total company fuel costs of $158,519,222 for the period October 1994 through March 1995. The jurisdictional amount of total fuel costs is $158,317,099 as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over/(under) - recovered fuel costs for the period, shown on line 4. The resulting ($3,597,561) over/(under) - recovered fuel costs for the period, combined with $88,880 of interest shown on line 5, constitute the actual over/(under) - recovery of ($3,508,681) shown on line 6. The ($3,508,681) less the actual/estimated over/(under) - recovery of $2,455,113 shown on line 7, which was approved in the March 1995 fuel hearings, results in the final over/(under) - recovery of ($5,963,794) shown on line 8.

Q. What does Document No. 2 show?

A. Document No. 2, entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original Estimates for the period October 1994 through March 1995," shows the calculation of the actual over/(under) - recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period October 1994 through March 1995?

A. As shown on line D1 of my Document No. 2, the company collected $2,131,656 or 1.4% more jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period October 1994 through March 1995?

A. As shown on line A7 of Document No. 2, the fuel and net power transactions cost variance is $5,736,543 or 3.8%.

Q. What are the reasons for the total fuel and net power transactions cost being higher by $5,736,543 or 3.8%?

A. Although Net Energy for Load was up 112,959 MWH or 1.7%, the ¢/KWH cost for Total Fuel and Net Power Transaction was more than estimated by 2.0%. This 2.0% increase is primarily due to a 7.5% decrease in the ¢/KWH credited for power sales.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period October 1994 through March 1995?

A. An over/(under) - recovery of ($667,853). The actual capacity cost over/(under) - recovery, including interest, is $361,879 for the period October 1994 through March 1995 (Document No. 3, pages 2 and 3 of 5). This amount, less the actual/estimated over/(under) - recovery approved in the March 1995 fuel hearings of $1,029,732 results in a final over/(under) - recovery for the period of ($667,853) (Document No. 3, page 5 of 5). This over/(under) - recovery amount of ($667,853) will be carried over and applied in the calculation of the capacity cost recovery factor for the period October 1995 through March 1996.

Q. How much effect will this ($667,853) over/(under) - recovery in the October 1994 through March 1995 period, have on the October 1995 through March 1996 period?

A. The ($667,853) over/(under) - recovery will approximately cause a $0.10 increase in a 1,000 KWH residential bill.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARY JO PENNINO

Q. Please state your name, address, occupation and employer.

A. My name is Mary Jo Pennino. My business address is 702 North Franklin Street, Tampa, Florida 33602. My title is Manager - Energy Issues and Administration. I work in the Regulatory Affairs Department of Tampa Electric Company.

Q. Please provide a brief outline of your educational background and business experience.

A. I was educated in both public and private schools in Illinois and received a Bachelor of Science Degree in Chemical Engineering from the University of South Florida, Tampa, Florida in 1985. Upon graduation, I began my career with Tampa Electric in the Production Department. My responsibilities included heat rate testing, support service for the Plant Chemical Engineers, and start-up engineering for Hookers Point Station. In 1991, I transferred to the Generation Planning Department where I was responsible for annual expansion planning analyses, alternative technology evaluation and several other business planning activities. In 1993, I was promoted to Administrator - Wholesale and Fuel in the Regulatory Affairs Department and in 1995 to Manager - Energy Issues and Administration, also in Regulatory Affairs. My present responsibilities include the areas of fuel adjustment filings, capacity cost recovery filings, and rate design.

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

A. The purpose of my testimony is to present to the Commission the proposed Total Fuel and Purchased Power Cost Recovery factors for the period of October 1995 - March 1996, and the proposed Capacity Cost Recovery factors for the same period.

<u>Fuel and Purchased Power Cost Recovery Factors / Capacity Cost Recovery Clause</u>

Q. Did you review the projected data necessary to calculate the Total Fuel and Purchased Power Cost Recovery factors for the period October 1995 - March 1996?

A. Yes I have.

Q. Do you wish to sponsor an exhibit consisting of Schedules H-1 (October - March, 1993 through 1996) and Schedules E-1 through E-10 (October 1995 - March 1996)?

A. Yes. Also contained in this exhibit are Schedules E-2, E-3, E-5, E-6, E-7, E-8 and E-9 for the prior period April 1995 - September 1995. These schedules are furnished as back-up for the projected true-up for this period and consist of two actual months and four projected months.

(Have identified as Exhibit No. 28 (MJP-2), Fuel Projection.)

Q. Does Schedule E-1 of Exhibit No. 28 (MJP-2), Fuel Projection, show the proper value for the Total Fuel and Purchased Power Cost Recovery Clause as projected for the period October 1995 - March 1996?

A. Yes.

Q. What is the proper value for the new period?

A. The proper value for the new period is 2.365 cents per kwh before the application of the factors that adjust for variations in line losses.

Q. Please describe the information provided on Schedule E-1C.

A. The GPIF and True-up factors are provided on Schedule E-1C. We propose that a GPIF penalty of ($471,209) be included in the projection period. The True-up amount for the April 1995 - September 1995 period is an underrecovery of ($8,925,155). This underrecovery is comprised of a final True-up underrecovery amount of ($5,963,794) for the October 1994 - March 1995 period and an estimated underrecovery in the amount of ($2,961,361) for the April 1995 - September 1995 period.

Q. Please describe the information provided on Schedule E-1D.

A. Schedule E-1D presents the company's on-peak and off-peak fuel charge factors for the October 1995 - March 1996 period.

Q. What is the purpose of Schedule E-1E?

A. The purpose of Schedule E-1E is to present the standard, on-peak and off-peak fuel charge factors after adjusting for variations in line losses.

Q. Please recap the proposed Fuel and Purchased Power Cost

Recovery factors for the October 1995 - March 1996 period.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)
Average Factor	2.365
RS, GS and TS	2.380
RST and GST	2.597 (on-peak)
	2.297 (off-peak)
SL-2, OL-1 and OL-3	2.342
GSD, GSLD and SBF	2.368
GSDT, GSLDT and SBFT	2.583 (on-peak)
	2.285 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.299
IST-1, IST-3, SBIT-1, SBIT-3	2.508 (on-peak)
	2.218 (off-peak)

Q. How does Tampa Electric Company's proposed average fuel charge factor of 2.365 cents per kwh compare to the average fuel charge factor for the April 1995 - September 1995 period?

A. The proposed fuel charge factor is 0.021 cents per kwh (or 21 cents per 1000 kwh) lower than the average fuel charge factor of 2.386 cents per kwh for the April 1995 -

September 1995 period.

Q. Are you also requesting Commission approval of the projected Capacity Cost Recovery factors for the Company's various rate schedules?

A. Yes.

Q. Have ou prepared or caused to be prepared under your direction or supervision an exhibit which supports this request?

A. Yes. It consists of five pages indentified as Exhibit No. 29 MJP-3, Capacity Cost Recovery.

Q. What payments are included in Tampa Electric's capacity cost recovery factor?

A. Tampa Electric is requesting recovery, through the capacity cost recovery factor, of capacity payments made pursuant to cogeneration, small power production and purchased power agreements to which we are a party.

Q. What credits are included in Tampa Electric's capacity cost recovery factor?

A. One-half of the $1,106,760 option payment Tampa Electric received in 1993 from Polk Power Partners is included as a credit to the capacity cost recovery factor. The credit, plus interest, is included as part of the true-up calculation. This treatment is consistent with Order No. PSC-95-0450-FOF-EI of Docket No. 950001-EI issued on April 6, 1995.

Q. Please re-cap the proposed Capacity Cost Recovery Clause factors for the October 1995 - March 1996 period.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.229
GS and TS	0.211
GSD	0.159
GSLD and SBF	0.145
IS-1, IS-3, SBI-1, SBI-3	0.013
SL-2, OL-1 and OL-3	0.035

These factors can be seen in Exhibit No. 29 (MJP-3), page 3 of 5.

Q. What is the composite effect of the above changes on a 1,000 kwh residential Customer?

A. A residential bill for 1,000 kwh will decrease twice during the six month fuel projection period. It will decrese by $0.02 in October 1995. In January 1996, a residential bill for 1,000 kwh will decrease again by $0.59 when the oil backout recovery factor is eliminated. The prepared direct testimony and exhibits of Elizabeth A. Townes describes the derivation of the oil backout recovery factor for October 1995 through December 1995 and its elimination in January 1996.

Type of Charge	Apr. 95 thru Sep. 95	Oct. 95 thru Dec. 95	Jan. 96 thru Mar. 96
Customer	$ 8.50	$ 8.50	$ 8.50
Energy	43.42	43.42	43.42
Conservation	1.53	1.53	1.53
Oil Backout	0.81	0.58	0.00
Fuel	24.01	23.80	23.80
Capacity	1.87	2.29	2.29
FGR Tax	2.05	2.05	2.04
Total	$ 82.19	$ 82.17	$ 81.58

Q. When should the new charges go into effect?

A. They should go into effect commensurate with the first billing cycle in October 1995.

Q. Does this conclude your testimony?

A. Yes it does.

DOCKET NO. 950001-EI

TAMPA ELECTRIC COMPANY

SUBMITTED FOR FILING 5/19/95

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(TRUE UP)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

Q. Will you please state your name, business address, and employer?

A. My name is George A. Keselowsky and my business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company.

Q. Please furnish us with a brief outline of your educational background and business experience.

A. I graduated in 1972 from the University of South Florida with a Bachelor of Science Degree in Mechanical Engineering. I have been employed by Tampa Electric Company in various engineering positions since that time. My current position is that of Senior Consulting Engineer -Production Engineering.

Q. What are your current responsibilities?

A. I am responsible for testing and reporting unit performance, and the compilation and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony presents the actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period October 1994 through March 1995. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared an exhibit with the results for this six month period?

A. Yes. Under my direction and supervision an exhibit has been prepared entitled, "Tampa Electric Company, October 1994 - March 1995, Generating Performance Incentive Factor Results" consisting of 30 pages that was filed with this testimony (Have identified as Exhibit GAK-1).

Q. Have you calculated the results of Tampa Electric Company for its performance under the GPIF during this period?

A. Yes I have. This is shown on page 4 of my exhibit. Based upon -2.775 GPIF points, the result is a penalty amount of $471,209 for the period.

Q. Please proceed with your review of the actual results for the October 1994 - March 1995 period.

A. On page 3 of my exhibit, the actual average common equity for the period is shown on line 8 as $953,527,765. This produces the maximum penalty or reward figure of $1,938,772 as shown on line 15, page 3. Page 2 of my exhibit demonstrates that this calculated incentive amount has been modified to comply with the constraint set forth by the Commission that incentive dollars are not to exceed fifty percent of fuel savings.

Q. Would you please explain how you arrived at the actual equivalent availability results for the six units included within the GPIF?

A. Yes I will. Operating data on each of our operating units is filed monthly with the Florida Public Service Commission on the Actual Unit Performance data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the six months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on page 6, column 2, directly applicable to the GPIF table?

A. Not exactly. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on page 6 of my exhibit. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

<u>Gannon Unit No. 5</u>

On this unit, no planned outage hours were originally scheduled to fall within the Winter 1994 period. A major outage scheduled for the month immediately following the Winter 1994 period was postponed until later in the year. This necessitated a short fuel system planned outage during the period, which required 173.4 hours. Consequently, the actual equivalent availability of 90.4% is adjusted to 94.2% as shown on page 7 of my exhibit.

<u>Gannon Unit No. 6</u>

On this unit, 408 planned outage hours were originally scheduled to fall within the Winter 1994 period. A planned fuel system outage was rescheduled to take place after the period ended, and planned outage activities within the period required 243.1 hours. Consequently, the actual equivalent availability of 84.6% is adjusted to 81.2%, as shown on page 8 of my exhibit.

<u>Big Bend Unit No. 1</u>

On this unit, no planned outage hours were originally scheduled to fall within the Winter 1994 period. A planned outage was moved forward from the month following the period and took place within the Winter 1994 period. The outage required 335.2 planned outage hours. Consequently, the actual equivalent availability of 84.7% is adjusted to 91.8% as shown on page 9 of my exhibit.

Big Bend Unit No. 2

On this unit 1344 planned outage hours were originally scheduled to occur during the Winter 1994 period. The actual planned outage activities required 1297.8 hours. Consequently, the actual equivalent availability of 59.3% is adjusted to 58.4% as shown on page 10 of my exhibit.

Big Bend Unit No. 3

On this unit 840 planned outage hours were orignially scheduled to fall within the Winter 1994 period. Due to a revision of the outage schedule, the outage was shifted to begin after the end of the period, and no planned outage hours fell within the Winter 1994 period. Consequently, the actual equivalent availability of 87.4% is adjusted to 70.6% as shown on page 11 of my exhibit.

Big Bend Unit No. 4

This unit was not originally scheduled to have a planned outage during the Winter 1994 period. Due to a revision of the outage schedule, an outage scheduled to occur after the end of the period was rescheduled to take place during the Winter 1994 period and required 822.4 planned outage hours. Consequently, the actual equivalent availability of 71.1% is adjusted to 87.6% as shown on page 12 of my exhibit.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on page 6,column 4, of my exhibit. This number is entered into the respective Generating

Q. Does this conclude your testimony?

A. Yes, it does.

DOCKET NO. 950001-EI
TAMPA ELECTRIC COMPANY
SUBMITTED FOR FILING 6/23/95
(PROJECTION)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

Q. Will you please state your name, business address, and employer?

A. My name is George A. Keselowsky and my business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company.

Q. Please furnish us with a brief outline of your educational background and business experience.

A. I graduated in 1972 from the University of South Florida with a Bachelor of Science Degree in Mechanical Engineering. I have been employed by Tampa Electric Company in various engineering positions since that time. My current position is that of Senior Consulting Engineer - Production Engineering.

Q. What are your current responsibilities?

A. I am responsible for testing and reporting unit performance, and the compilation and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric Company's methodology for determining the various factors required to compute the Generating Performance Incentive Factor (GPIF) as ordered by this Commission.

Q. Have you prepared an exhibit showing the various elements of the derivation of Tampa Electric Company's GPIF formula?

A. Yes, I have prepared, under my direction and supervision, an exhibit entitled "Tampa Electric Company, Generating Performance Incentive Factor" October 1995 - March 1996, consisting of 35 pages filed with the Commission on June 23, 1995. (Have identified as Exhibit GAK-2). The data prepared within this exhibit is consistent with the GPIF Implementation Manual previously approved by this Commission.

Q. Which generating units on Tampa Electric Company's system are included in the determination of your GPIF?

A. Six of our coal-fired units are included. These are: Gannon Station Units 5 and 6; and Big Bend Station Units 1, 2, 3, and 4.

Q. Will you describe how Tampa Electric Company evolved the various factors associated with the GPIF as ordered by this Commission?

A. Yes. First, the two factors to be used, as set forth by the Commission Staff, are unit availability and station heat rate.

Q. Please continue.

A. A target was established for equivalent availability for each unit considered for this period. Heat rate targets were also established for each unit. A range of potential improvement and degradation was determined for each of these parameters.

Q. Would you describe how the target values for unit availability were determined?

A. Yes I will. The Planned Outage Factor (POF) and the Equivalent Unplanned Outage Factor (EUOF) were subtracted from 100% to determine the target equivalent availability. The factors for each of the 6 units included within the GPIF are shown on page 5 of my exhibit. For example, the projected EUOF for

Gannon Unit Six is 14.3%. The Planned Outage Factor for this same unit during this period is 3.8%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(14.3\% + 3.8\%)] = 81.9\%$$

This is shown on page 4, column 3 of my exhibit.

Q. How was the potential for unit availability improvement determined?

A. M-ximum equivalent availability is arrived at using the following formula.

Equivalent Availability Maximum

$$EAF_{MAX} = 100\% - [0.8\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine target equivalent availability. To attain the maximum incentive points, a 20% reduction in Forced Outage and Maintenance Outage Factors (EUOF), plus a 5% reduction in the Planned Outage Factor (POF) will be necessary. Continuing with our example on Gannon Unit Six:

$$EAF_{MAX} = 100\% - [0.8\ (14.3\%) + 0.95\ (3.8\%)] = 84.9\%$$

This is shown on page 4, column 4 of my exhibit.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than is the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before this Commission. Tampa Electric Company's approach to incorporating this skewed effect into the unit availability tables is to use a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is arrived at via the following formula:

Equivalent Availability Minimum

$$EAF_{MIN} = 100\% - [1.4\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with our example of Gannon Unit Six,

$$EAF_{MIN} = 100\% - [1.4\ (14.3\%) + 1.1\ (3.8\%)] = 75.8\%$$

Equivalent availability MAX and MIN for the other five units is computed in a similar manner.

Q. How do you arrive at the Planned Outage, Maintenance Outage and Forced Outage Factors?

A. Our planned outages for this period are shown on page 19 of my exhibit. A Critical Path Method (C.P.M.) for each major planned outage which affects GPIF is included in my exhibit. For example, Gannon Unit 5 is scheduled for a major unit inspection from October 4 to November 17, 1995. A short planned outage is also scheduled from February 3 to February 9, 1996. There are 1248 planned outage hours scheduled for the winter 1995 period, and a total of 4393 hours during this 6 month period. Consequently, the Planned Outage Factor for Unit 5 at Gannon is 1248/4393 x 100% or 28.4%. This factor is shown on pages 5 and 13 of my exhibit. Big Bend Units 1 and 3 have planned outage factors of zero. Gannon Unit 6 has a planned outage factor of 3.8%, Big Bend Unit 2 has a planned outage factor of 21.3, and Big Bend Unit 4 has a planned outage factor of 8.7%.

Q. How did you arrive at the Forced Outage and Maintenance Outage Factors on each unit?

A. Graphs of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, March 1995, 12 month ending value was used as a basis for the projection. This value was adjusted up or down by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planned outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in a EUOF of 8.0% for Gannon Unit Five. The Equivalent Unplanned Outage Factor (EUOF) for Gannon Unit Five is verified by the data shown on page 13, lines 3, 5, 10 and 11 of my exhibit and calculated using the formula:

$$EUOF = \frac{(FOH + EFOH + MOH + EMOH)}{\text{Period Hours}} \times 100$$

or

$$EUOF = \frac{(315 + 38)}{4393} \times 100 = 8.0\%$$

Relative to Gannon Unit Five, the EUOF of 8.0% forms the basis of our Equivalent Availability target development as shown on sheets 4 and 5 of my exhibit.

Q. Please continue with your review of the remaining units.

<u>Big Bend Unit One</u>

A. The projected EUOF for this unit is 14.6% during this period. This unit will not have a planned outage this period and the Planned Outage Factor is 0.0%. This results in a target equivalent availability of 85.4% for the period.

<u>Big Bend Unit Two</u>

The projected EUOF for this unit is 10.8%. This unit will have a planned outage during this period and the Planned Outage Factor is 21.3%. Therefore, the target equivalent availability for this unit is 67.9%.

<u>Big Bend Unit Three</u>

The projected EUOF for this unit is 12.6% during this period. This unit will not have a planned outage this period and the Planned Outage Factor is 0.0%. Therefore, the target equivalent availability for this unit is 87.4%.

Big Bend Unit Four

The projected EUOF for this unit is 8.4%. This unit will have a planned outage during this period and the Planned Outage Factor is 8.7%. This results in a target equivalent availability of 82.9% for the period.

Gannon Unit Five

The projected EUOF for this unit is 8.0%. This unit will have a planned outage during this period and the Planned Outage Factor is 28.4%. Therefore, the target equivalent availability for this unit is 63.6%.

Gannon Unit Six

The projected EUOF for this unit is 14.3%. This unit will have a planned outage during this period and the Planned Outage Factor is 3.8%. Therefore, the target equivalent availability for this unit is 81.9%.

Q. Would you summarize your testimony regarding Equivalent Availability Factor (EAF), Equivalent Unplanned Outage Factor (EUOF) and Equivalent Unplanned Outage Rate (EUOR)?

A. Yes I will. Please note on page 5 that the GPIF system weighted Equivalent Availability Factor (EAF) equals 80.9%. This target compares very favorably to previous GPIF periods in that it is better than four of the five previous periods, as well as the five period average EAF. These targets represent an outstanding level of performance for our system.

Q. As you graph and monitor Forced and Maintenance Outage Factors, why are they adjusted for planned outage hours?

A. This adjustment makes these factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since our units are usually base loaded, reserve shutdown is generally not a factor. To demonstrate the effects of a planned outage, note the EUOR and EUOF for Gannon Unit Six on page 14. During the months of October and November, and for January through March, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the month of December, EUOR exceeds EUOF. The reason for this difference is the scheduling of a planned outage. The adjusted factors apply to the period hours after planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes it does. Rates provide a proper and accurate method of arriving at the unit parameters. These are then converted to factors since they are directly additive. That is, the Forced Outage Factor + Maintenance Outage Factor + Planned Outage Factor + Equivalent Availability = 100%. Since factors are additive, they are easier to work with and to understand.

Q. You previously stated that you had developed a CPM for your unit outages. How do you use the CPM in conjunction with your planned outages?

A. The CPM's included in this exhibit are preliminary and include only the major work activities we expect to accomplish during the planned outage. Planned outages are very complex and are anticipated months in advance. The actual CPM's utilized in the execution of the planned outage are detailed for all major and minor work activities.

Since it is important to the company and beneficial to our Customers to control outage length, we have implemented a computerized outage management system. Essentially, this tool enables management to monitor outage progress, measure activity results against previously established milestones, and verify timely execution of all critical path events. This results in the shortest outage time possible and the maximum utilization of all resources. Any reduction in planned outage length directly improves unit equivalent availability.

Q. Has Tampa Electric Company prepared the necessary heat rate data required for the determination of the Generating Performance Incentive Factor?

A. Yes. Target heat rates as well as ranges of potential operation have been developed as required.

Q. On what basis were the heat rate targets determined?

A. Average net operating heat rates are determined and reported on a unit basis. Therefore, all heat rate data pertaining to the GPIF is calculated on this basis.

Q. How were these targets determined?

A. Net heat rate data for the three most recent winter periods, along with the PROMOD III program, formed the basis of our target development. Projections of unit performance were made with the aid of PROMOD III. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations, or equipment modifications having material effect on heat rate can be taken into consideration.

Q. Have you developed the heat rate targets in accordance with GPIF guidelines?

A. Yes.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate vs. net output factor curves have been developed for each station. This information is shown on pages 27 through 32 of my exhibit.

Q. Would you elaborate on the analysis used in the determination of the ranges?

A. The net heat rate vs. net output factor curves are the results of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each station. These curves are also used in post period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Can you summarize your heat rate projection for the winter 1995 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 9,931 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±184 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 9,837 Btu/Net kwh with a range of ±304 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,596 Btu/Net kwh, with a range of ±352 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 9,989 Btu/Net kwh with a range of ±322 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,178 Btu/Net kwh with a range of ±418 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,348 Btu/Net kwh with a range of ±347 Btu/Net kwh. A zone of tolerance of ± 75 Btu/Net kwh is included within the range for each target. This is shown on page 4, and pages 7 through 12 of my exhibit.

Q. Do you feel that the heat rate targets and ranges in your projection meet the criteria of the GPIF and the philosophy of this Commission?

A. Yes I do.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighing factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 12. Our PROMOD III cost simulation model was used to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $103,635,600 is shown on page 6 column 2.

The PROMOD III output was then used to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6 column 4. After all the individual savings are calculated, column 4 is totaled: $3,751,400 reflects the savings if all units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit One, the weighting factor for equivalent availability is 6.04% as shown in the right hand column on page 6. Pages 7 thru 12 show the point table, the Fuel Savings/(Loss), and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit One, page 9, if the unit operates at 88.3% equivalent availability, fuel savings would equal $226,700 and 10 equivalent availability points would be awarded.

The Generating Performance Incentive Factor Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. The left hand column of this document shows the Tampa Electric Company's incentive points. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $3,751,400. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to my exhibit on page 3, line 8, the estimated average common equity for the period October 1995 - March 1996 is shown to be $1,020,616,000. This produces the maximum allowed jurisdictional incentive dollars of $2,067,145 shown on line 15.

Q. Is there any other constraint set forth by this Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed fifty percent of fuel savings. Page 2 of my exhibit demonstrates that the incentive amount calculated on page 3 has been reduced to meet this constraint.

Q. Do you wish to summarize your testimony on the GPIF?

A. Yes. To the best of my knowledge and understanding, Tampa Electric Company has fully complied with the Commission's directions, philosophy, and methodology in our determination of Generating Performance Incentive Factor. The GPIF for Tampa Electric Company is expressed by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$\begin{aligned} GPIP = (\, & 0.0057\ EAP_{GN5} + 0.0347\ EAP_{GN6} \\ & + 0.0604\ EAP_{BB1} + 0.0488\ EAP_{BB2} \\ & + 0.0548\ EAP_{BB3} + 0.0316\ EAP_{BB4} \\ & + 0.0773\ HRP_{GN5} + 0.1286\ HRP_{GN6} \\ & + 0.0982\ HRP_{BB1} + 0.1294\ HRP_{BB2} \\ & + 0.1903\ HRP_{BB3} + 0.1402\ HRP_{BB4}) \end{aligned}$$

Where:

GPIP = Generating performance incentive points.

EAP = Equivalent availability points awarded/deducted for Units 5 and 6 at Gannon and Units 1, 2, 3 and 4 at Big Bend.

HRP = Average net heat rate points awarded/deducted for Units 5 and 6 at Gannon and Units 1, 2, 3 and 4 at Big Bend.

Q. Have you prepared a document summarizing the GPIF targets for the October 1995 - March 1996 period?

A. Yes. The availability and heat rate targets for each unit are listed on attachment "A" to this testimony entitled "Tampa Electric Company GPIF Targets, October 1, 1995 - March 31, 1996".

Q. Do you wish to sponsor an exhibit consisting of estimated unit performance data supporting the fuel adjustment?

A. Yes I do. (Have identified as Exhibit GAK-3).

Q. Briefly describe this exhibit.

A. This exhibit consists of 22 pages. This data is Tampa Electric Company's estimate of the Unit Performance Data and Unit Outage Data for the October 1995 - March 1996 period.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

W. N. CANTRELL

Q. Please state your name, address and occupation.

A. My name is William N. Cantrell. My mailing address is P. O. Box 111, Tampa, Florida 33601, and my business address is 6820 South Tamiami Trail, North Ruskin, Florida 33570. I am Vice President-Energy Supply of Tampa Electric Company.

Q. Please furnish a brief outline of your educational background and business experience.

A. I was educated in the public schools of Tampa, Florida and received a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology in 1974. I am a registered Professional Engineer licensed in the State of Florida. I also received a Master of Business Administration degree in 1979 from the University of Tampa. I have been employed at Tampa Electric Company since June 1975. Since that time I have served as Manager of

Generation Planning, Assistant Director, Budgets and Director of Fuels. In 1987, I was elected Vice Presidentof the company. In 1994, I was elected to my current position as Vice President-Energy Supply.

Q. Will you describe some of the responsibilities of your present position?

A. As Vice President - Energy Supply, I am responsible for the engineering, operation, maintenance, and construction of the power production facilities including safety of personnel and equipment, security, training, control of costs, and various personnel and administrative functions. I am also responsible for environmental matters and fuel procurement.

Q. Mr. Cantrell, what is the objective of your testimony?

A. The objective of my testimony is to present the cost associated with the conversion of four of Tampa Electric Company's generating units from oil to coal. In addition, I will sponsor the calculation of the operation and maintenance expense differential and the determination of fuel savings for the projection period and the projected payoff period.

Q. How does your testimony relate to the testimony of other witnesses in this proceeding?

A. Ms. Elizabeth Townes is sponsoring the overall calculation of the company's Oil Backout Cost Recovery Factor for the period October 1995 - December 1995, as well as the estimated payoff period for the total project. In these calculations, Ms. Townes develops the basic revenue requirements of the project using the actual cost of the conversion assets, and my projection of the operation and maintenance expense differential and the fuel savings resulting from the conversion. Kilowatt-hour sales and fuel costs are consistent with those used in the company's fuel adjustment filing.

Q. Have you prepared documents in support of your testimony?

A. Yes. I have prepared portions of documents which are included in a composite Exhibit No. (WNC/EAT-2) titled "Schedules Supporting Oil Backout Cost Recovery Factor" and Exhibit No. (WNC/EAT-3) titled "Comparison of Projected Payoff with Original Estimate, as of May 1995." These exhibits are being jointly sponsored by Ms. Townes and me.

Q. What is the status of the project?

A. The conversion of Gannon units 1 through 4 from oil to coal is complete. The units were placed into commercial service as follows:

Unit 1	October 6, 1985
Unit 2	May 23, 1985
Unit 3	July 12, 1984
Unit 4	November 7, 1983

Q. What is the cost of the Oil Backout assets which are included in the cost recovery computation in this proceeding?

A. The total cost of the conversion project to be recovered through the Clause is $140.5 million. No additional expenditures are anticipated.

Q. What are the projected fuel savings which will occur as a result of the operation of the converted Gannon units during the projection period?

A. As shown on Line 4 of Document 1, total fuel savings resulting from the project for the period October 1995 - December 1995 are expected to be $1,305,690. This amount is based upon the difference in fuel expenses from production costing runs which simulate dispatch of all generating units with and without the conversion of the Gannon units. The assumptions for sales, unit ratings, heat rates, coal and No. 6 oil prices and availability factors are consistent with those used by the company in its fuel adjustment filing in this docket.

Q. Have you calculated the projected operating and maintenance expense differential of the project for October 1995 - December 1995?

A. Yes, I have calculated the operation and maintenance expense differential for this period to be $824,880 as shown on line 9 of Document 1.

Q. Please explain how the operation and maintenance expense differential was calculated.

A. The operation and maintenance differential consists of the oil/non-oil operating expense differential and other projected costs resulting from the Oil Backout project. This differential was calculated by applying a percentage representing the increased operation and maintenance costs associated with coal-firing to total projected operation and maintenance expenses pertaining to the converted Gannon units. The percentage was derived by comparing historical operation and maintenance costs for Gannon units 1-4 as oil-fired to historical operation and maintenance costs for Gannon units 5 and 6 as coal-fired. Specifically identifiable costs to be incurred to comply with the Oil Backout Cost Recovery Rule were added to the operating expense differential to derive the total operation and maintenance differential.

The operation and maintenance differential as shown on Exhibit No. (WNC/EAT-3) "Comparison of Projected Payoff with Original Estimate, as of May 1995," is now higher than the original estimate since the original estimate did not include maintaining the assets required for dual firing capability. In addition, the current estimate is based on more detailed engineering estimates and actual experience associated with the converted units.

Q. Mr. Cantrell, please explain the decrease in fuel savings indicated on the projected payoff exhibit.

A. The reduction in fuel savings is due to a decrease in the projected differential between the price of oil and the price of coal, and a decrease in the projected system energy requirements. The current estimate of fuel savings is based on long-term fuel price and energy projections prepared in conjunction with this current fuel adjustment clause filing.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ELIZABETH A. TOWNES

Q. Would you please state your name and address?

A. My name is Elizabeth A. Townes. My business address is 702 North Franklin Street, Tampa, Florida 33602.

Q. Please describe your educational background and experience.

A. I received a Bachelor of Business Administration degree in Accounting from Florida International University in 1978 and a Master of Business Administration from the University of Tampa in 1982. I am a Certified Public Accountant in the state of Florida and a Member of the Florida Institute of Certified Public Accountants and American Institute of Certified Public Accountants.

Prior to joining Tampa Electric Company in January 1982, I was employed by General Telephone Company of Florida. I joined Tampa Electric as a regulatory accountant. In September 1983, I was promoted to Manager-Regulatory Control and subsequently in February 1991, I was promoted to my current position as Assistant Controller.

My current responsibilities include accounting for fuel activities, conservation, oil backout and other regulatory accounting areas. I am also responsible for the revenue and financial reporting functions and accounts payable.

Q. Ms. Townes, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present a summary computation of the estimated Oil Backout Cost Recovery Factor to be collected during the three-month projection period beginning October 1995 and ending December 1995, including the estimated true-up adjustment required as of September 1995.

Q. Have you prepared documents in support of your testimony?

A. Yes. I have jointly prepared with Mr. Cantrell a composite exhibit titled "Schedules Supporting Oil Backout Cost Recovery Factor" indicated as Exhibit No. (WNC/EAT-2). This exhibit is a summary of the detailed computations, prepared under my supervision and direction, to derive the estimated Oil Backout Cost Recovery Factor. This exhibit consists of six documents and I will make references in my testimony to each of the documents and explain the development, or source, of each line item. I have also jointly prepared with Mr. Cantrell Exhibit No. (WNC/EAT-3) titled "Comparison of Projected Payoff with Original Estimate, as of May 1995." This exhibit provides a comparison of the estimated payback of the Gannon conversion project with the original projection submitted during the 1982 qualification hearings.

Q. Ms. Townes, would you first please summarize the key assumptions used in your derivation of the estimated factor?

A. Yes. The key assumptions involved with the determination of the factor for the projection period are the estimated fuel savings, the estimated revenue requirements associated with the converted Gannon Units and common facilities, the estimated energy sales, and the estimated true-up as of September 1995.

Q. What is the estimated Oil Backout Cost Recovery Factor which you have determined for the three-month projection period ended December 1995?

A. The factor which I have determined to be appropriate for the projection period is .058 cents per kilowatt hour. This factor is shown on line 19, of Document 1.

Q. Please explain the computations shown on Document 1.

A. The computations begin with the estimated energy sales during the projection period shown on line 1. These amounts are consistent with the company's fuel adjustment filing in this docket. Lines 2 through 4 reflect the estimated fuel savings supplied by Mr. Cantrell. Lines 5 through 10 reflect a computation of the estimated revenue requirements associated with the Gannon Oil Backout Project. Lines 11 through 13 reflect a computation of the estimated net savings and the amount available for additional depreciation under the Clause, as determined on a six-month basis. Lines 14 through 19 reflect the computation of the Oil Backout Cost Recovery Factor including the estimated net true-up adjustment required as of September 1995.

Q. Ms. Townes, please explain your computation of revenue requirements shown on lines 5 through 10.

A. The computation begins on line 5 with the estimated straight-line depreciation expense associated with the various components of the Plant in Service investment. The monthly provisions for depreciation reflected on line 5 are based on the currently approved depreciation rates for the various components of the Plant in Service investment. Line 6 reflects the estimated interest carrying cost of the Plant in Service investment. The projected monthly interest expense is determined based on the projected debt cost applied to the average debt balance for each month. Income tax expense, shown on line 7, is computed on Document 3. The estimated monthly property tax expense is shown as Taxes Other Than Income Taxes on line 8. The amounts shown on line 9 represent the operation and maintenance expense differential which was furnished by Mr. Cantrell. Total revenue requirements reflected on line 10 represent the sum of all revenue requirement components shown on lines 5 through 9.

Q. Ms. Townes, would you please explain Document 2 reflecting your computation of the Plant in Service investment?

A. Yes. Line 1 of Document 2 reflects the actual unrecovered investment in Plant in Service at the beginning of each month shown. Since no additional expenditures are currently anticipated, line 2 indicates no additions to

Plant in Service. Line 5 reflects the provision for depreciation for the period. These are the same amounts shown on line 5 of Documents 1 and 5. Line 6 reflects the additional depreciation permitted under the Oil Backout Recovery Clause, equivalent to 2/3 of the estimated net savings which is shown on line 13 of Documents 1 and 5. Line 7 reflects the estimated net unrecovered investment in Plant in Service at the end of the month.

Q. Ms. Townes, would you please explain further the computation of income tax expense reflected on line 7 of Documents 1 and 5?

A. Yes. The computation of these amounts is shown on Document 3. Referring to Document 3, lines 1 through 5 agree with amounts shown as components of revenue requirements including those associated with additional depreciation, on lines 5, 6, 8, 9, 10 and 13 on Documents 1 and 5. Line 7 reflects the portion of depreciation on line 2 which represents depreciation of the equity portion of AFUDC capitalized during construction. As this amount is not tax deductible, it represents a "permanent" difference between book and tax basis of plant. Thus, this portion of depreciation expense for each month must be added back to book income to compute income before income taxes on line

8. Line 9 reflects the income tax expense before ratable amortization of investment tax credits using an effective income tax rate of 38.575%. Line 10 reflects the ratable amortization of investment tax credit consistent with the investment recovery via depreciation expense. Line 11 reflects the total income tax expense which agrees with amounts shown on line 7 of Documents 1 and 5.

Q. Ms. Townes, you indicated earlier that a key assumption in determining the factor for this projection period is the estimated true-up adjustment required for the six-month period ending September 1995. Please explain the calculation of the net true-up adjustment.

A. The projected cumulative net true-up adjustment as of September 1995 represents an overrecovery of $909,253 as shown on line 15 of Document 1. The true-up adjustment is calculated on Documents 4, 5 and 6.

The computation begins on Document 4 with the estimated tariff revenues to be billed under the Clause for each month in the period from April 1995 through September 1995, shown on Line 1. The Oil Backout Revenue applicable to this period is then reduced by the estimated/actual cost recovery under the Clause for each month in the period from

April 1995 through September 1995. The amounts on Line 4 are calculated on Document 5. To this true-up provision shown on Line 5 by month, is added the beginning of the month true-up and interest provision, shown on Line 6 for a cumulative end of the period net true-up before interest, shown on Line 8. The resulting estimated true-up provision at September 1995, of $909,253 is shown on Line 10 of Document 4.

Q. What was the projected true-up amount for the six months ended March 1995 which was included in the Oil Backout cost recovery for the period April 1995 - September 1995?

A. In the filing dated January 17, 1995, the company projected a cumulative overrecovery of $153,138 as of March 1995 which is currently being collected. The actual overrecovery at March 1995 was $375,548, as reflected on line 6 of Document 4. The actual overrecovery at March 31, 1995, is due to lower than anticipated operating expense.

Q. What is the status of the estimated payback of the Gannon conversion project?

A. As shown on Exhibit No. (WNC/EAT-3), titled "Comparison of Projected Payoff with Original Estimate, as of May 1995," cost recovery is now projected to end on January 1, 1996. On January 1, 1996, the oil-backout cost recovery clause will be eliminated pursuant to PSC Order No. PSC-95-0580-FOF-EI, Docket No. 950379-EI. Any remaining true-up dollars related to oil-backout costs for 1995 will be recovered as a line item adjustment to fuel cost through the fuel and purchased power cost recovery clause during the period April 1, 1996 through September 30, 1996.

Q. Please explain any significant variances noted in the payoff comparison.

A. Actual straight-line depreciation is less than the original projection in 1982. This is due to the 1982 estimation of early retirement of existing plant.

Significant variances noted in the cost of capital and income tax components are due to the current estimate being based on the approved 100% debt financing; whereas, the original estimate was based on conventional financing, which included a combination of debt and equity. Since conventional financing included an equity component, income taxes were provided on the return associated with the equity component.

An estimate for taxes other than income taxes was not included in the original estimate. An estimate is now included since property taxes can be more reasonably determined.

In the original estimate, revenue taxes were included as part of the base revenue requirement (the sum of straight-line depreciation, cost of capital, income taxes, taxes other than income taxes, operation and maintenance differential, and revenue taxes). Revenue taxes are now excluded from the base revenue requirement. The Regulatory Assessment fee is included in the total to be billed by grossing up the Oil Backout factor.

The net result of the changes between the original and current estimate is a decrease in base revenue requirement. However, the expected additional depreciation has declined due to reduced fuel savings. Additional depreciation is computed as two-thirds of the excess of fuel savings over the base revenue requirement determined on a six-month filing period as required under the Oil Backout Clause.

Q. Ms. Townes, does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM N. CANTRELL

Q. Please state your name, address and occupation.

A. My name is William N. Cantrell. My mailing address is P.O. Box 111, Tampa, Florida 33601, and my business address is 6820 South Tamiami Trail, North Ruskin, Florida 33570. I am Vice President-Energy Supply of Tampa Electric Company.

Q. Please furnish a brief outline of your educational background and business experience.

A. I was educated in the public schools of Tampa, Florida and received a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology in 1974. I am a registered Professional Engineer licensed in the State of Florida. I also received a Master of Business Administration degree in 1979 from the University of Tampa. I have been employed at Tampa Electric Company since June 1975. Since that time, I have served as Manager of Generation Planning, Assistant Director, Budgets and Director of Fuels. In 1987, I was elected Vice President of the company. In 1994, I was elected to my current position as Vice President-Energy Supply.

Q. Will you describe some of the responsibilities of your present position?

A. As Vice President - Energy Supply, I am responsible for the engineering, operation, maintenance, and construction of the power production facilities including safety of personnel and equipment, security, training, control of costs, and various personnel and administrative functions. I am also responsible for environmental matters and fuel procurement.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Commission the actual 1994 costs of Tampa Electric's affiliated coal and coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298 (coal transportation) and Order No. PSC-93-0443-FOF-EI ("Order No. 93-0443") (coal). I conclude that the 1994 prices paid by Tampa Electric to its affiliates TECO Transport and Trade Company and Gatliff Coal are reasonable and prudent.

Q. Have you prepared an exhibit which you sponsor in this proceeding?

A. Yes. Exhibit No. (WNC-1) titled "Exhibit of William N. Cantrell", consisting of 2 documents, was prepared under my direction and supervision.

AFFILIATED COAL TRANSPORTATION PRICES

Q. Were Tampa Electric's actual affiliated coal transportation prices for 1994 at or below the transportation benchmark?

A. Yes, they were. This is reflected in Document No. 1 of my exhibit.

Q. Were Tampa Electric's actual 1994 affiliated coal prices at or below the benchmark as established in Order No. 93-0443?

A. Yes, they were. This is reflected in Document No. 2 of my exhibit.

Q. Please summarize your testimony.

A. My testimony justifies the prices paid for coal and coal transportation by Tampa Electric Company in 1994 to its affiliated suppliers, Gatliff Coal and TECO Transport and Trade. I demonstrate that the average prices for the year 1994 for all coal and coal waterborne transportation services were at or below the appropriate benchmark calculations as directed by Order No. 20298 and Order No. 93-0443 of this Commission. Therefore, Tampa Electric should recover its payments for coal and coal transportation made during 1994.

Q. Does this conclude your testimony?

A. Yes, it does

COMMISSIONER DEASON: So at this point we have a full and complete record?

MS. JOHNSON: That's correct.

Staff would request that the Commission approve the stipulation as identified in the Prehearing Order.

COMMISSIONER DEASON: We have the stipulations presently before us. Before we vote on that, I've already shared some information with Commissioner Kiesling that was just presented to me by Staff. I'll also show that to Commissioner Garcia, especially the comparison of the fuel factors from the previous period and what the stipulated factors are today. And it shows the changes in those factors.

Commissioner Garcia, would you like to review that?

Okay, Commissioners, we have the full record before us. All issues have been stipulated. The stipulations are currently before us. We can approve those. If there are any problems with any of these stipulations, we can at this time take those up and discuss those.

COMMISSIONER KIESLING: Well, I have no problems within the stipulations having reviewed them, and I would move that we adopt the stipulations and move the issues as set forth.

COMMISSIONER DEASON: And we have a motion. Is there a second to that motion?

COMMISSIONER GARCIA: Yeah, I'll second the motion.

COMMISSIONER DEASON: The motion has been made and seconded. Show that the stipulations are approved unanimously. And I believe that would conclude the 0001 docket?

MS. JOHNSON: That's correct.

(Thereupon, the hearing concluded at 10:50 a.m.)

* * * * *

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, ROWENA NASH HACKNEY, Official Commission Reporter,

DO HEREBY CERTIFY that the Hearing in Docket No. 950001-EI was heard by the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of Volumes 1 and 2, 243 pages, constitutes a true transcription of my notes of said proceedings.

DATED this 10th day of August, 1995.

Rowena Nash Hackney

ROWENA NASH HACKNEY
Official Commission Reporter
(904) 413-6736